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# New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation's Annual Report Relative to its Gas Long-Term Plan

## Updates due on May 23, 2025

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# 1. Introduction

In 2022, the New York Public Service Commission ("PSC" or "Commission") issued its Order Adopting Gas System Planning Process ("Planning Order").[1] The order required New York gas utilities to file long-term plans over a 20-year planning horizon on a three-year cycle with annual updates due on May 31 of the intervening years. New York State Electric and Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RGE") (collectively "the Companies") filed their first long-term plan on April 26, 2024.[2] In January 2025, the PSC issued its Order Regarding Long-Term Natural Gas Plan and Direction Further Actions ("Further Actions Order") in response to the Companies' first Long-Term Plan filing.[3] This filing presents four reports, summarized below, due on May 23, 2025.

- Report on Contract Restructuring and De Contracting is presented in Section 2.
- Report on Capacity Reserve Margin is presented in Section 3.
- Report on the work of the Companies' third-party expert on program development and implementation around full-building electrification incentives to targeted leak prone pipe (LPP) areas is presented in Section 4
- Report on development of more extensive outreach and education on alternatives to fossil fuel heating options to spread information about electrification alternatives to existing gas customers with an emphasis on LPP is presented in Section 5.

# 2. Contract Restructuring and De Contracting

The Further Actions Order noted the Companies can expect to see demand for natural gas decrease as electrification moves forward. The Order directed the Companies to file a report on contract restructuring and de contracting that listed all pipeline and storage capacity contracts along with their termination dates and daily, monthly, and annual deliverability as applicable. It also directed the Companies to provide criteria they will use to identify pipeline or storage contracts that can be terminated without impacting reliability as demand decreases.

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[1] 20-G-0131, *Order Adopting Gas System Planning Process*, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures (May 12,2022) (Gas Planning Order).

[2] 23-G-0437, *New York State Electric & Gas and Rochester Gas and Electric: Final Long-Term Gas Plan*, In the Matter of a Review of the Long-Term Gas System Plan of New York (April 26, 2024) (Final Gas LTP).

[3] 23-G-0437, *Order Regarding Long-Term Natural Gas Plan and Directing Further Actions*, In the Matter of a Review of the Long-Term Gas System Plan of New York State Electric & Gas and Rochester Gas and Electric (January 23, 2025) (Further Actions Order).

## 2.1. Metrics for Contract Restructuring and Decontracting

The Companies utilize contract restructuring and decontracting to optimize their natural gas capacity portfolios and reduce exposure to excess supply. The methods also support emission reduction goals outlined in the Companies' Gas Final Long Term Plan as well as NY's Climate Leadership and Community Protection Act ("CLCPA"). However, this process must be approached cautiously, as it increases system risk if a new coldest day above design day occurs within the Companies' distribution system. Key metrics for contract restructuring and decontracting include the following:

1. Citygate or Peaking Supply Services Reduction
    a. Peaking Capacity Contracts: Typically acquired year-to-year rather than long-term extensions, focusing on specific times of the year (i.e., November through March). These can be reduced annually if design day analysis deems it necessary.
2. Impact on Multiple Services Areas
    a. Supply Support: Some pipeline contracts affect multiple service areas, requiring additional support from another pipeline contract. For example, NYSEG utilizes 30,000 dths from an Eastern Gas Transmission and Storage ("EGTS") contract, delivering it to their Columbia Gas Transmission ("TCO") service area via the Twin Tier Pipeline.
3. Pipeline Rates
    a. Cost Impact: Firm capacity is the highest priority, but contract rates impact customer costs. The Companies intervene in pipeline rate cases in an effort to limit service cost increases. If cheaper supply options arise, capacity volumes may be reduced. For instance, NYSEG recently decontracted some TCO capacity due to lower cost supply and capacity from EGTS via the Twin Tier Pipeline.
    b. City Gate Deliveries
    c. Alternative Supply Methods: For service areas needing small amounts of contracted capacity only a few times per year, other supply methods like Liquefied Natural Gas ("LNG") and Compressed Natural Gas ("CNG") may be considered if cost-benefit analysis favors them over contracted pipeline capacity.

## 2.2. Contract Review

The outlined metrics are crucial when reviewing contracts nearing termination dates. It's important to recognize that the Design Day needs outlined in the Gas LTP were developed without future growth. In reality, despite stopping natural gas marketing and offering alternatives, the Companies have seen sustained load growth year over year, and load reduction is not anticipated until all CLCPA directives are implemented. Chapter II - Section G of the Companies' Final Gas LTP outlines criteria for safely and reliably reducing contracted capacity in the future.

Section II – G – P. 26, the Commission will find excerpts from the Supply Portfolio description from Companies' Final Gas LTP:

> *"The Companies maintain portfolios of gas supply, transportation, storage and peaking assets necessary to reliably serve customers, even on the coldest days of the year. The majority of both NYSEG and RG&E's portfolios are comprised of long-term contracts for flowing supplies (i.e. supplies delivered via upstream transportation) and storage. RG&E relies on winter delivered citygate peaking contracts, whereas NYSEG relies on compressed natural gas ("CNG") at one site for peaking supplies. The Companies' territories are grouped into pooling area for the purpose of supply planning based on the pipelines that supply the area.*
>
> *NYSEG holds long-term upstream pipeline capacity contracts on Algonquin Gas Transmission ("AGT"), Eastern Gas Transmission and Storage ("EGTS"), Empire Pipeline ("Empire"), Iroquois Gas Transmission ("IGT"), North Country Gas Pipeline ("North Country" or "NCPL"), Columbia Gas Transmission ("TCO") Tennessee Gas Pipeline ("TGP"), and TransCanada PipeLines ("TCPL"), and long-term storage contracts on Arlington Storage Company ("ASC"), EGTS, TCO and TGP. As noted, NYSEG also relies on CNG for peaking supplies. RG&E holds long-term upstream pipeline capacity contracts on EGTS, Empire, and TCPL, and long-term storage contracts on EGTS and Empire. RG&E also relies on firm delivered citygate contracts for peaking supplies."*
>
> *"Maintaining a portfolio of sufficient firm supply, storage, and transportation assets is key to providing reliable firm service to customers. Expected changes in gas demand, both increases and decreases, could impact the Companies' portfolio. The Companies continuously evaluate the portfolio's ability to meet forecasted demand and consider factors that include the cost, quantity, reliability, diversity, flexibility, duration, contract begin and end dates, likelihood of re-contracting in the future, and operational issues associated with each resource individually as well as for the portfolio. This evaluation is especially important when contracts are approaching the end of term. Staff is made aware of how this evaluation affects contracting decisions through periodic meetings to discuss the Companies' portfolio.*
>
> *If decarbonization policies or other market changes cause sustained reductions to firm peak demand, NYSEG and RG&E will need to restructure their respective portfolios to better align with observed customer demand. Once capacity is turned back, it is unlikely to be reacquired if it is needed in the future because the pipelines in and around New York on which the Companies hold capacity are constrained. As a result, premature restructuring creates risks that the portfolio may be unable to meet customer demand, which will cause serious safety and reliability issues. Therefore, as the Companies consider their contract restructuring strategy, the ability to maintain a safe and reliable source of energy to serve customers today and in the future must remain top priority.*
>
> *NYSEG and RG&E will begin decreasing their firm capacity portfolio when meaningful reductions in demand have been observed within distinct locations for prolonged periods.*

*Contract restructuring decisions will also have to consider the timing in which relevant existing contracts are set to expire or enter re-negotiation. It is important to note that NYSEG's non-contiguous service areas create unique challenges associated with contract restructuring. Due to the dispersed nature of NYSEG's customer base and gas pooling areas, supplies from one pooling area or citygate often cannot be used to serve another area. Therefore, prolonged demand reductions must be experienced within distinct areas, rather than dispersed across the entire system. Contract restructuring may unfold differently at RG&E compared to NYSEG because RG&E's service area is one contiguous territory with more flexibility to transport gas across the territory. Contract restructuring for both utilities will depend not only on the location where demand is reduced, but also on the timing of contracts' renewal dates within that location. To the extent possible, the Companies will adopt the following strategy in restructuring firm contracts:*

*Quantify observed reductions in customer demand within one of NYSEG and RG&E's pooling areas or citygates.*

*Confirm such reductions in demand have occurred for a prolonged period such that demand is not expected to increase, to ensure that capacity is not turned back prematurely.*

*Once prolonged, material reductions occur within an area, review the contracts serving that area to identify options to restructure contracted capacity. This step will depend on contract renewal dates and negotiations with pipelines. If multiple contracts supplying an area are approaching their end of term, the Companies will evaluate each contract based on factors such as flexibility, target reduction volume, access to storage, and price.*

*In addition, the Companies will continue to execute available capacity release transactions to reduce costs for customers and evaluate all portfolio opportunities. Updates to the Companies' portfolios will be provided in future LTPs and Winter Supply Plans."*

The Commission directed the Companies to provide criteria identifying which pipeline or storage contracts can be terminated without compromising reliability as demand decreases. In Case 23-G-0437 Attachment 1, the Commission will find proposed examples for each OPCO on how it would reduce capacity using secured assets as Design Day Demand decreases.

A key point regarding contract restructuring and decontracting is that the current industry practice typically involves extending contracts for five years with major pipelines and/or as required by the Pipeline's FERC-approved tariff. Some pipelines specify in their tariffs that contracts must be extended at least five years, or Local Distribution Companies ("LDCs") risk losing their contracted capacity to another party in an open season, or they must match the successful bidders bid (term and price) to retain the capacity.

In Case 23-G-0437 Attachment 1, the Companies propose approaching decontracting as one-year contract extensions when their current contracts expire, assuming that major pipelines will align with CLCPA efforts similarly to how the state has requested the LDCs to approach reductions. However, since not all pipelines are regulated by NY state and some are federally regulated by the Federal Energy Regulatory Commission (FERC), LDCs may still be required to

extend contracts at least five years to hold their capacity at reasonable costs depending on the pipelines tariffs approved by FERC.

Below, the Commission will find written examples of steps the Companies have taken or may take to reduce contracted capacity for each OPCO as design day demand decreases.

- NYSEG: Recently, NYSEG observed excess capacity in its service area served by Columbia Pipeline ("TCO") during a recent contract extension decision with TCO. NYSEG has submitted a request to extend the contract for five years at a reduced level of 9,500 Dths per day from TCO pipeline/storage services. This reduction will be managed through service agreements with EGTS and National Fuel Gas Supply Corporation.
- RG&E: As noted in Case 23-G-0437 Attachment 1, RG&E currently holds approximately 4% (or 18,500 dths per day) of available capacity over Design Day Demand conditions. The Companies find this to be a reasonable margin due to the risk of a new Design Day occurring. For RG&E, a 1 HDD swing in either direction results in excess of 5,300 dth change in system load. This indicates that a 4 HDD increase over the current Design Day would quickly exceed the contracted supplies over Design Day conditions. In Case 23-G-0437 Attachment 2, the Commission will find an example of a regression analysis used by RG&E that outlines how a 1 HDD swing equates to in excess of 5,300 dths on the system. This analysis utilized winter load from the 2022-2023 winter. Although this analysis is done yearly, the 2022-2023 winter analysis is used due to RG&E not seeing a higher design day analysis since that period.

As discussed in the Companies' Final Gas LTP, Renewable Natural Gas ("RNG") is outlined as a supply opportunity for the Companies to utilize in their service areas to replace some pipeline capacity. Although NYSEG is currently procuring RNG from six facilities, RNG is still considered an interruptible supply due to issues with facilities where RNG may not be available for an extended period of time. This supply source is not considered firm service and was not identified in the LTP as available capacity. The Companies will continue to utilize RNG when applicable on the system, but RNG is still a developing industry that will take time to become firm service, if ever.

## 2.3. Active Pipeline and Storage Contracts

In Case 23-G-0437 Attachment 3, the Commission will find the Companies' current pipeline and storage contracts along with their termination dates and daily, monthly and annual deliverability where applicable.

## 2.4. Capacity Release

Capacity release is a portfolio optimization mechanism used to bring value back to customers when opportunities arise. The Companies release capacity in three ways: yearly, monthly, and daily.

Yearly capacity is typically released only through Asset Management Agreement ("AMA"). Currently, the only AMA the Companies have under contract is their Canadian capacity held on

TransCanada PipeLine. Through the AMA, the Companies have the right to call on any amount of their contracted gas on any day but release all excess capacity to the Asset Management counterparty. The counterparty pays the Companies a set monthly fee for the right to the capacity that was determined through an RFP process.

Monthly capacity is released approximately one week prior to the end of a current month for the next month after the Companies have determined their baseload needs. This process is executed through a pre-negotiated arrangement with a counterparty or through a bid process, which must adhere to FERC requirements, where the Companies offer the capacity to any counterparty who offers the best value. This capacity is fully recallable, within specified pipeline notice requirements, on any given gas day-ahead if the Companies need the capacity for their customers' needs.

Daily capacity is released based on bidding requests via the Intercontinental Exchange ("ICE") Platform after customer needs for the next gas day have been determined. These requests can be direct inquiries to the Companies' buyers or posted by a counterparty for the entire ICE network to see.

As discussed earlier, temperature swings in service areas across the Companies' portfolio can dictate higher demand, so the Companies must balance between expected need and risk involved in capacity releases. There are instances where the Companies may have excess capacity in areas that are not in a high market demand, typically during winter months between November and March. As such, there may be times that there is no market for excess capacity. Therefore, capacity release revenues change year over year and are never guaranteed. As NY state transitions to electrification, natural gas demand should decrease, increasing the amount of available capacity on the pipelines. This increase in capacity availability could reduce the value of the capacity and diminish the opportunity for any Local Distribution Company within the New York service areas to generate revenues from capacity release.

# 3. Capacity Reserve Margin

The *Further Actions Order* noted the Companies employment of a reserve margin on top of design day conditions may unnecessarily burden ratepayers. The Commission directed the Companies to provide a report including design day load forecast for each Company for each year of the planning period in the Final Gas LTP, the total amount of assets currently secured broken down by type (daily deliverability, storage, peaking, etc.) and their contribution to design day demand, calculation of the reserve margin for each year of the planning period, and cost per dekatherm of each asset on an average basis. The Commission determined that this report will provide Stakeholders the information they need to provide meaningful input on the necessity of maintaining a reserve margin.[4]

[4] *Further Action Order,* P. 38-39, 75.

## 3.1. Calculation of Reserve Margin

The Commission ordered the Companies to calculate the reserve margin for each company for each year presented in the Companies' Long Term Plan. In Case 23-G-0437 Attachment 4, the Commission will find the design day load forecasts for each Company along with the calculation of the reserve margin on design day for each year of the planning period. Each OPCO outlines the Total Capacity available, the Total Design Day Demand, and the Available Capacity % (Reserve Margin). The Available Capacity Percentage (%) is calculated using the following formula:

**Available Capacity (%) = ((Total Capacity - Total Design Day Demand) / Total Design Day Demand) X 100**

## 3.2. Current Assets and Design Day Demand

The Commission also ordered the Companies to outline the total amount of assets currently secured broken down by type (daily deliverability, storage, peaking, etc.) and their contribution to design day demand. In Table 1 and Table 2 below, the Commission will find the total amount of assets currently secured, broken down by type, with a percent (%) of their contribution to design day and an explanation of the asset's importance to design day supply for each OPCO. Table 1 and Table 2 reflect the contribution percentage to Total Design Day Demand for the 2025-2026 winter period that was forecasted in the Companies Long Term Plan planning period.

**Table 1 - NYSEG Assets Contribution to Design Day**

| Firm Peak Day Capacity | Secured Capacity | Contribution to Design Day Demand (%) | Importance to Design Day Demand |
|---|---|---|---|
| Daily Deliverability - Flowing Supplies | 223,519 | 49% | Physical gas contracted for extended periods of time with Rights of First Refusal (ROFR) that can be called on any day as needed. This would be considered primary gas to be called upon. |
| Daily Deliverability - Storage | 239,560 | 53% | Physical gas that has been stored under contract with a peipeline counterparty. These assets are contracted for extended periods of time with Rights of First Refusal (ROFR) that can be called on any day as needed during the months of November through March.This would be considered primary gas to be called upon during the winter months. |
| Winter Peaking | 2024: 1,000<br>2025-2042: As Needed | 0% | Winter peaking capacity is contracted on a year to year basis and is not guaranteed. This is capacity that a pipeline has available each winter that must be won during an open season. There is a risk to this asset where it may not be available for a certain winter, forcing the Company to find alternative supply, such as city gate purchasing. This supply is variable year to year as it is not a long term contracted supply. |
| Compressed Natural Gas (CNG) | 1,050 | 0% | CNG used for peaking services in NYSEG's Mechanicville distribution area |
| Mandatory Retail Access Capacity | 63,500 | 14% | Physical gas delivered to Energy Service Companies (ESCO's) within the Companies territory to serve their customers. This is capacity owned by ESCO's used to serve their customers within the Companies distribution system. |
| Grandfathered Retail Access Capacity | 6,406 | 1% | Physical gas delivered to Energy Service Companies (ESCO's) within the Companies territory to serve their customers. This is NYSEG's Daily Deliverable Capacity that must be given to ESCO's under New York law, and has been grandfathered to certain ESCO's. This capacity will only be released back to NYSEG if the ESCO no longer utilizes it or they are no longer in business. |
| **Total 2025 Design Day Demand** | **454,740** | **117%** | **For the 2025-2026 winter forecast, NYSEG currently has a reserve margin of 17% above design day conditions.** |

| Table 2 - RG&E Assets Contribution to Design Day | | | |
|---|---|---|---|
| **Firm Peak Day Capacity** | **Secured Capacity** | **Contribution to Design Day Demand (%)** | **Importance to Design Day Demand** |
| Daily Deliverability - Flowing Supplies | 226,100 | 45% | Physical gas contracted for extended periods of time with Rights of First Refusal (ROFR) that can be called on any day as needed. This would be considered primary gas to be called upon. |
| Daily Deliverability - Storage | 179,000 | 35% | Physical gas that has been stored under contract with a peipeline counterparty. These assets are contracted for extended periods of time with Rights of First Refusal (ROFR) that can be called on any day as needed during the months of November through March.This would be considered primary gas to be called upon during the winter months. |
| Winter Peaking | 2024: 40,000<br>2025-2042: As Needed | 8% | Winter peaking capacity is contracted on a year to year basis and is not guaranteed. This is capacity that a pipeline has available each winter that must be won during an open season. There is a risk to this asset where it may not be available for a certain winter, forcing the Company to find alternative supply, such as city gate purchasing. This supply is variable year to year as it is not a long term contracted supply. |
| Mandatory Retail Access Capacity | 73,618 | 15% | Physical gas delivered to Energy Service Companies (ESCO's) within the Companies territory to serve their customers. This is capacity owned by ESCO's used to serve their customers within the Companies distribution system. |
| Grandfathered Retail Access Capacity | 11,104 | 2% | Physical gas delivered to Energy Service Companies (ESCO's) within the Companies territory to serve their customers. This is RG&E's Daily Deliverable Capacity that must be given to ESCO's under New York law, and has been grandfathered to certain ESCO's. This capacity will only be released back to RG&E if the ESCO no longer utilizes it or they are no longer in business. |
| **Total 2025 Design Day Demand** | **505,103** | **105%** | **With winter peaking, RG&E has a reserve margin of 4-5% above design day conditions. Removing winter peaking, RG&E would be undersupplied by 3% to design day conditions for the 2025-2026 winter forecast.** |

## 3.3. Asset Cost per Dekatherm of Assets on an Average Basis

The Commission ordered the Companies to calculate the cost per dekatherm of each asset on average basis for each the Companies. Below in Table 3, the Companies identify the average cost per dekatherm for each operating company for the 2025-2026 Winter Season. As the Commission will find, only contracted firm capacity is included in the analysis. This removed citygate Winter Peaking services as they are not contracted long term nor are they guaranteed. Citygate Winter Peaking capacity must be secured every year, and there is always a possibility that this capacity may not be available for the Companies to secure. However, compressed natural gas ("CNG") remains as a long term contracted Winter Peaking service for NYSEG. The analysis included below includes all pipeline daily deliverable capacity and storage capacity the Companies have secured for extended periods of time with full ROFR rights, where the company has the ability to extend the contracts with the same capacity once the contract has ended without having to bid in an open season. Please note, some capacity charges are needed to transport flowing gas across different parts of the overall natural gas distribution system to get the Companies' flowing gas to their distribution systems. These charges are known as "demand charges" and the flowing gas dekatherms have already been accounted for within different contracts, but the charges will remain.

| Table 3 - NY Companie's Average Cost Per Dekatherm | | | |
|---|---|---|---|
| Company - Capacity Asset | Total Capacity Cost | Dekatherms | Average Cost Per Dekatherm |
| NYSEG - Flowing | $32,924,318 | 94,916,780 | $0.3469 |
| NYSEG - Storage | $35,462,923 | 41,565,181 | $0.8532 |
| NYSEG - Peaking | $135,000 | 94,500 | $1.4286 |
| NYSEG - Demand Charges | $1,998,313 | 1,277,500 | $1.5642 |
| NYSEG - Total | $70,520,554 | 137,853,961 | $0.5116 |
| | | | |
| RG&E - Flowing | $21,512,476 | 78,674,500 | $0.2734 |
| RG&E - Storage | $22,503,711 | 27,029,000 | $0.8326 |
| RG&E - Peaking | $0 | 0 | $0.0000 |
| RG&E - Demand Charges | $0 | 0 | $0.0000 |
| RG&E Total | $44,016,187 | 105,703,500 | $0.4164 |
| Companies - Total | $114,536,742 | 243,557,461 | $0.4703 |

# 4. Whole-Home Electrification Program – Leak Prone Pipes

## 4.1. Introduction

The Further Actions Order directed NYSEG and RG&E to report on the development and implementation of a comprehensive full-building electrification program in targeted areas identified with leak-prone gas infrastructure.

This filing provides a detailed account of the Whole Home Electrification Program ("The Program"), implemented as a Non-Pipes Alternative ("NPA") to conventional leak-prone pipe ("LPP") replacement. The Program aims to evaluate the feasibility of retiring gas infrastructure by fully converting all end-uses in participating buildings to electric technologies.

In support of The Program, the Companies partnered with a third-party expert with experience in customer engagement and electrification program delivery. The third-party provider conducts direct outreach to targeted customers, develops tailored educational materials, and supports project management activities for the electrification of LPP segments.

The information presented in this report outlines implementation progress, summarizes outreach and participations outcomes, identifies barriers encountered, and highlights lessons learned to date. The report also details the Companies' continuing efforts to evaluate new opportunities and fulfill the Commission's directives under this order.

## 4.2. Identification and Classification of Leak-Prone Infrastructure

For the purposes of The Program, leak-prone infrastructure is defined as those portions of the gas distribution system that, due to age, material, or condition, are prone to leaks and failures. In practice, this typically includes aging cast iron and unprotected steel gas mains that have a history of leakage or risk of corrosion. The Companies maintain an inventory of such LPPs and have segmented them into risk-based categories to prioritize action. These categories are as follows:

- **Category A**: Highest-risk LPPs (e.g. older cast iron or bare steel in high-density or sensitive areas) that are prioritized for immediate or near-term replacement or remediation.
- **Category B**: Moderate-risk leak-LPPs that exhibit aging and leak potential but with slightly lower risk factors (for example, mains in less densely populated areas or with somewhat newer materials); these are slated for replacement in the mid-term planning horizon.
- **Category C:** Lower-risk LPPs that are aging and scheduled for eventual replacement, but which currently show relatively lower leak rates or serve less critical locations, allowing for a longer-term replacement timeline.

These categories are assigned based on a comprehensive risk assessment model, ensuring that mains posing the greatest safety and reliability risk (Category A) are addressed first. The risk classification is underpinned by the Companies' Distribution Integrity Management. The Program's risk-ranking system quantitatively evaluates factors such as pipe material, age, leak history, operating pressure, and surrounding environment for each segment.

Identification of specific LPP segments targeted for The Program relies on multiple data sources and systems. Key data sources include:

- Geographic Information System (GIS) mapping – to locate and visualize leak-prone gas main segments and their proximity to customers and critical facilities.
- SAP enterprise asset database – to provide asset details such as installation year, material type, maintenance history, and leak repair records for each main segment.
- Operations & Maintenance (O&M) records – including leak survey results, leak repair logs, and safety inspection reports that indicate the condition and performance of mains over time.

## 4.3. NPA Strategy for Leak-Prone Pipes (Whole Home Electrification)

### The Program Objectives

The Whole Home Electrification Program is an NPA initiative developed to offer a viable alternative to conventional gas main replacement in targeted areas with LPP. The objective is to achieve 100% electrification of all buildings connected to a given LPP segment, thereby allowing the main to be fully retired. In other words, the Companies convert every building on the segment

to efficient electric heating and appliances, removing the dependency on the aging pipeline. This approach yields multiple benefits in line with New York's policy goals: it eliminates the safety risk of the LPP, avoids infrastructure replacement costs, and reduces greenhouse gas emissions.

Moreover, under the current Joint Proposal, the Companies receive a one-for-one credit towards the annual LPP retirement mileage targets when an NPA solution is implemented in lieu of a traditional gas main project. Accordingly, The Program directly contributes to system planning objectives by offsetting LPP replacement mileage, supporting rate plan compliance, and achieve the Companies' retirement goal.

## The Program Scope and Target Areas

Given the successful retirement of an LPP segment requires 100% customer participation, The Program scope focuses on LPP segments with a limited number of customers, primarily residential, where full electrification is operationally and economically viable. Candidate areas are primarily residential and are selected through a prioritization process based on factors that evaluate technical feasibility, customer participation likelihood, and alignment with broader energy objectives.

To identify these areas, the Companies developed a weighted prioritization framework for candidate LPP segments. This framework is intended to support the selection of project areas where full electrification is not only technically feasible, but also cost-effective and equitable. The prioritization methodology incorporates the following core criteria:

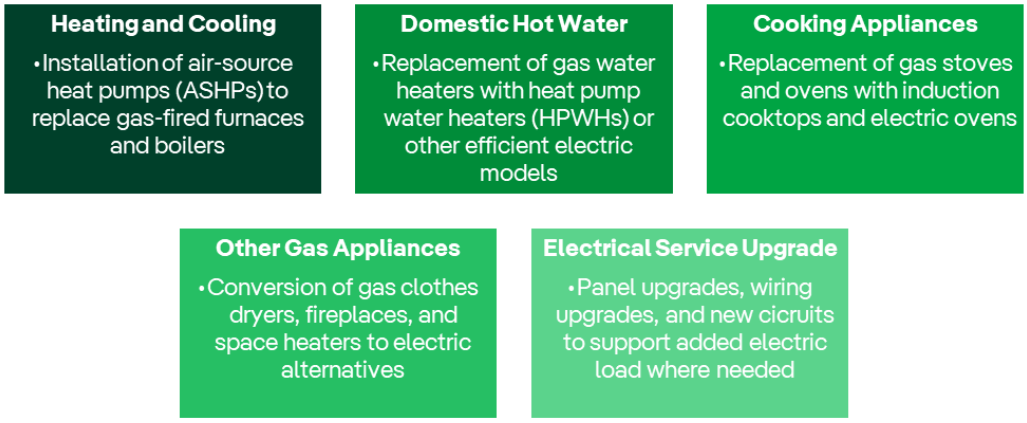
Figure 1: Prioritization Framework for Candidate LPP Segments


Each of these factors contributes to a composite prioritization score informed by its relationship with project feasibility, likelihood of full customer participation, and alignment with state equity objectives. The resulting composite score enables the Companies to prioritize electrification efforts in areas where the likelihood of successful implementation and cost-effective segment retirement is highest. This scoring methodology is reviewed and enhanced as additional data and observations are made through project deployment and stakeholder feedback.

## Incentive Offerings

To achieve full electrification, The Program provides an attractive suite of incentives and equipment upgrades to participating customers. The incentives are designed to cover most or all the costs of converting from gas to electric, ensuring that customers have no financial barrier to participation.

Figure 2: Eligible Electric Appliance and Infrastructure Upgrades




Additionally, The Program leverages other incentive programs such as the New York State Clean Heat Program rebates to supplement the Companies' contributions. By stacking incentives (state, federal, or manufacturer rebates) on top of the NPA funding, the Companies create a compelling "no-cost conversion" offer for the customer. The exact value of an upgrade package for each home depends on the home's size, age and the number of gas appliances to replace.

## Lists of Cases Identified by Year (2022-2025)

Table 4 LPP Cases Screened and Completed

| Year | OPCO | Cases Identified | Cases Advanced for Evaluation | Cases Removed from Consideration[5] | Active Customer Engagement | Completed Projects |
|---|---|---|---|---|---|---|
| 2022 | NYSEG | 116 | 2 | 2 | 0 | 0 |
| | RG&E | 115 | 1 | 1 | 0 | 0 |
| 2023 | NYSEG | 116 | 3 | 2 | 1 | 0 |
| | RG&E | 137 | 18 | 17 | 0 | 1 |
| 2024 | NYSEG | 87 | 5 | 5 | 0 | 0 |
| | RG&E | 74 | 13 | 13 | 0 | 0 |
| 2025 | NYSEG | 211 | 92 | 14 | 78 | 0 |
| | RG&E | 228 | 44 | 28 | 16 | 0 |

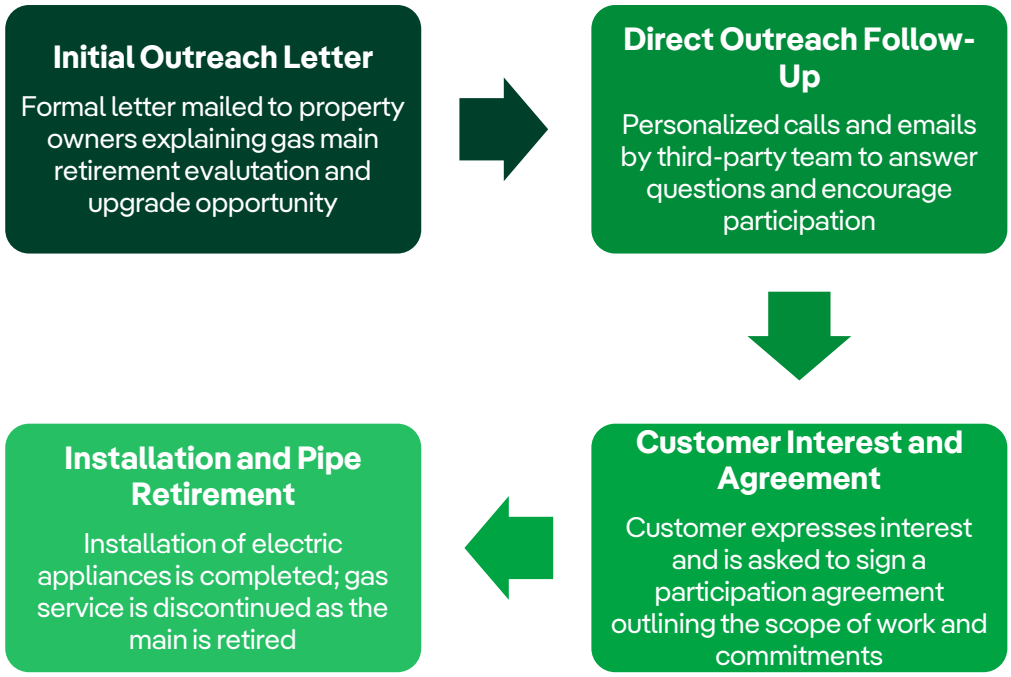
[5] *Cases removed from NPA consideration include areas where (i) 100% customer participation could not be achieved, (ii) cost-effectiveness thresholds were not met, or (iii) the project advanced to imminent traditional construction, precluding continued NPA pursuit.*

## 4.4. The Program Implementation

### Outreach and Engagement Strategy

Once candidate areas are selected, the Companies implement a structured customer outreach campaign designed to maximize awareness, legitimacy, and participation. Recognizing that early and transparent communication is critical to The Program's success, the following outreach channels are employed.

Figure 3: Customer Outreach Channels




### Marketing and Education

To support outreach, The Program developed targeted marketing and education materials, which serve to inform customers about the benefits of electrification and address common concerns. Key components include:

- **Dedicated Webpage:** RG&E and NYSEG created pages on their websites describing The Program. The webpage provides an overview of The Program's purpose and the upgrade offerings, framed as an exciting opportunity for customers. It reiterates information from the letter in a more detailed FAQ style, explaining why the utility is doing this (retiring gas infrastructure) and how the process works. It also lists example upgrades (heat pumps, induction cooking, etc.) and highlights the no-cost aspect. Having an online resource allows interested customers to verify the legitimacy of The Program and review details at their own pace.
- **Informational Brochures/Flyers:** Printed brochures were developed to accompany the outreach letter. These brochures introduce the concept of whole-home electrification,

showcase the modern electric technologies being offered, and outline the benefits (safety, comfort, environmental, financial savings). The brochure serves as a takeaway reference for the homeowner to discuss with family or other decision-makers in the home (See Attachments 5 and 6).

- **One-on-One Education (Pre-Installation):** Prior to installation, each participating household receives individualized support from a program representative or third-party outreach specialist. This includes an energy assessment and a discussion of the customer's specific needs and expected installation steps.
- **One-on-One Education (Post-Installation):** Following installation, the outreach team provides guidance on using and maintaining the new equipment (for example how to operate induction stovetop, replace heat pump filters, or adjust comfort settings).

## Required Customer Commitments

Customers who decide to participate are required to make certain commitments as part of The Program, reflecting the partnership nature of this undertaking. The primary commitment is that the customer agrees to fully discontinue gas service to their building upon completion of the electrification project. This means the customer will no longer use natural gas for any purpose in the home, and the gas service line to the property will be closed/abandoned after the project.

To formalize this, the customer signs a participation agreement (contract) with terms such as: allowing contractors to perform installations on their property and disposing of or decommissioning the old gas equipment. They also commit to maintaining the newly installed equipment (for instance, if a heat pump failed years later, the customer should repair/replace it with another electric system, not revert to gas).

Another commitment is scheduling and access. The customer must agree to schedule the energy audit and subsequent installation work within The Program's timeframe. Because these projects are coordinated to align with construction schedules (and sometimes to avoid the heating season rush), timely cooperation is needed. Customers commit to provide access to their home for the energy audit and for the installation crew on agreed dates, and to do any necessary preparation.

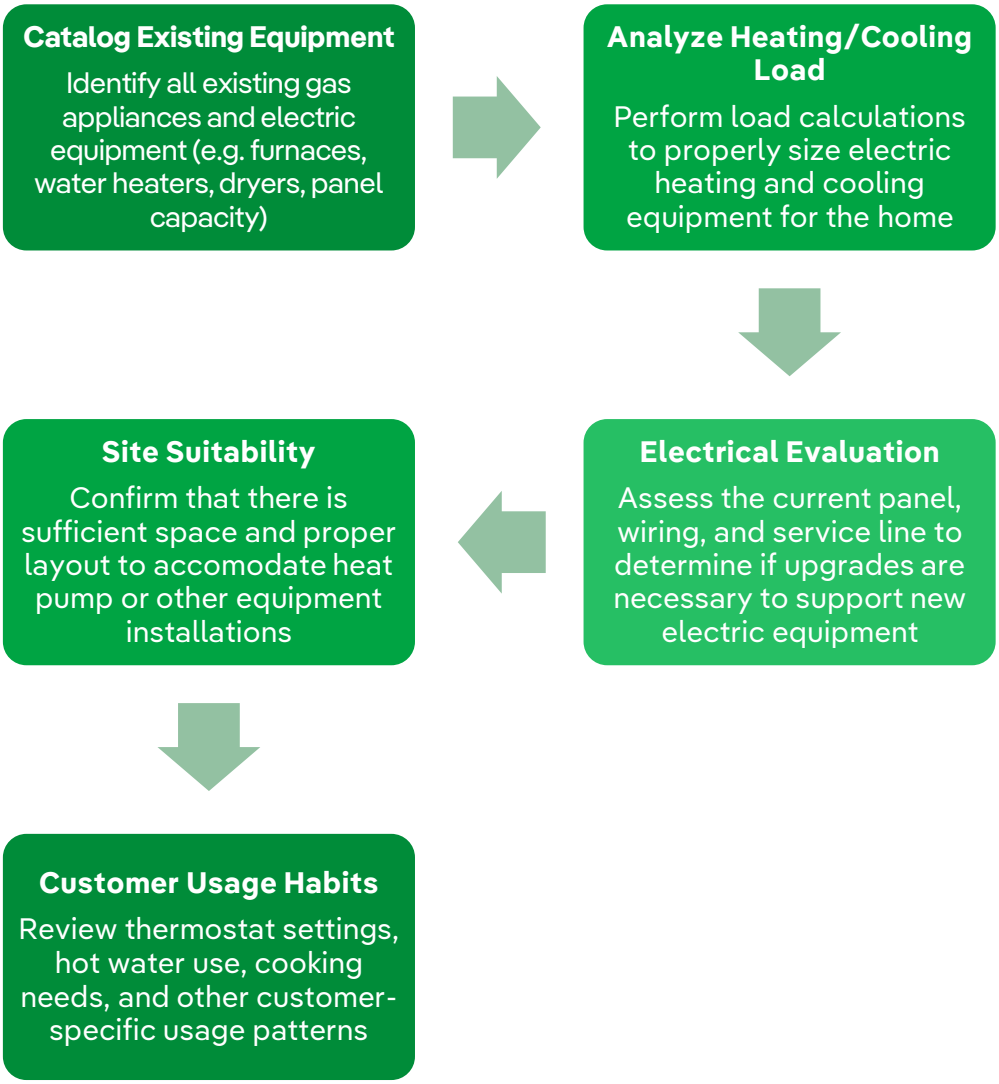
In some cases, customers might be asked to commit to minor home repairs or preparations. For instance, if a home's electrical panel is in very poor condition (e.g. unsafe wiring), The Program will cover upgrades, but the homeowner might need to address any code non-compliance on their side or clear any barriers. Typically, The Program tries to handle everything turn-key, but the agreement will spell out any homeowner responsibilities.

## Home Energy Assessments

Before any equipment is installed, each participating home undergoes a comprehensive Home Energy Assessment. This assessment is a critical step to tailor the electrification solution to the specific needs and conditions of the home. The third-party partner arranges for a certified

energy auditor or qualified contractor to perform the assessment, typically shortly after the customer signs the participation agreement.

Figure 4: Home Energy Assessment Process




## Measures and Incentives

Following the assessment and proposal stage, The Program moves into the installation of measures. The measures provided are those identified in Section 3.3: typically, a package of an air-source heat pump system, heat pump water heater, induction range, and any ancillary improvements (insulation, panel upgrade, etc.). Installations are scheduled in a sequence that minimizes disruption. For example, electrical upgrades might occur first, then old gas equipment is safely decommissioned and removed, and new electric equipment installed and tested. In many

cases, installations can be completed in a matter of days per home, though scheduling across multiple homes is orchestrated to make efficient use of crews.

Additionally, to encourage acceptance, The Program handles all logistics and costs for removing the old equipment. Old gas furnaces, boilers, water heaters, and stoves are removed and disposed of or recycled. Gas service is cut and sealed at the meter, and ultimately the service line is disconnected as part of main retirement.

## 4.5. Project Benefit-Cost Analysis (BCA)

The Companies apply a streamlined Benefit-Cost Analysis (BCA) framework to evaluate the cost-effectiveness of implementing The Program. This assessment informs project selection, regulatory reporting, and internal investment with ratepayer interests and Commission expectations.

### Cost Comparison: NPA vs. Traditional Gas Main Replacement

The BCA framework compares the total programmatic costs of electrification—including equipment procurement, installation labor, and administrative delivery—against the avoided costs associated with traditional gas infrastructure replacement. Avoided costs include capital expenditures for gas main construction as well as operations and maintenance expenses related to ongoing system upkeep, leak response, and regulatory compliance.

In all cases, the analysis accounts for full electrification of participating buildings, including space heating, water heating, cooking, and associated electrical upgrades. Cost-effectiveness is evaluated depending on the number of participants, total avoided gas infrastructure, and estimated load impacts.

### Societal Cost Test (SCT)

The Societal Cost Test is used to assess The Program's broader alignment with public policy objectives by monetizing environmental and social benefits. The SCT incorporates the following benefit categories:

1. **Avoided Gas Infrastructure** – Elimination of pipeline construction, excavation, and restoration costs.
2. **Avoided Commodity Costs** – Reduction in utility gas purchases due to electrification.
3. **Avoided Emissions** – Net reduction in $CO_2$, $SO_2$, and $NO_x$ emissions, monetized using values consistent with New York State guidance (e.g., NYSERDA's Social Cost of Carbon).
4. **Deferred or Eliminated O&M Costs** – Reduced future costs for pipeline inspections, leak response, and cathodic protection maintenance.

Emissions associated with new electric end-use equipment are subtracted from gross avoided emissions to yield a net environmental benefit. All emissions factors, price escalation assumptions, and discount rates are consistent with the Companies' internal NPA evaluation tools and DPS expectations.

## 4.6. Barriers and Lessons Learned

Informed by outreach experience and implementation to date, the Companies have identified several recurring barriers to participation in The Program, as well as key lessons that can inform future program delivery enhancements.

### Barriers to Participation

Figure 5: Barriers to Participation

**Customer Hesitation**

- Skepticism around the legitimacy of the offer; some customer perceived it as "too good to be true.'"
- Presence of gas backup system or generators reduced customer motivation to fully disconnect from gas
- Concerns about electric grid reliability and performance of electric systems in low temperatures.
- Prior investments in recent gas equipment (e.g., boilers, stoves) created reluctance to convert
- Resistance to electric cooking due to preferences for gas and concerns about appliance performance.
- Distrust of new technologies among older customers and those hesitant to make major home changes.
- Worry over post-conversion electricity bills and long-term equipment performance.
- Homeowners planning to sell soon showed lower willingness to invest in upgrades.

**Site Challenges**

- Physical constraints, such as lack of space for equipment or difficult installation paths for line sets.
- Aesthetic concerns, particularly in historic homes or homes with strict appearance guidelines.
- Local setback requirements limiting viable installation options.
- Poor insulation or air sealing, making some homes unsuitable without added efficiency measures.
- Some customers required emergency system replacement due to equipment failure.

### Lessons Learned

- **Focus on Segments More Likely to Convert:** As outlined in Section 3.2, project segments with high technical feasibility, limited customer count, and favorable building characteristics are more likely to achieve full participation. Prioritizing these segments improves the likelihood of success.
- **Establish Legitimacy Early:** Personalized outreach using trusted channels (e.g., FedEx-delivered letters) improves customer response rates.

- **Build Trust and Tailor the Pitch:** The Program's success improved when outreach staff actively listen, respond to concerns, and tailor solutions to customer priorities -whether savings, comfort, or peace of mind.
- **Demonstrate Product Knowledge:** Outreach staff who clearly articulate equipment benefits and address concerns in real time significantly increase conversion likelihood.
- **Account for Emotional and Financial Context:** Customers' willingness to engage often depends on prior investment timelines, aesthetics, or personal comfort with electrification.

# 5. Outreach and Education on Non-Pipes Alternatives and Leak Prone Pipe

## 5.1. Introduction

The Further Actions Order directed the Companies to develop and file outreach and education programs regarding NPAs, specifically targeted to customers residing in vulnerable locations or near remaining segments of LPP, withing 120 days of the date of the Order.

In accordance with this directive, the Companies hereby submit their Outreach and Education Program for NPAs and LPP-related activities. The purpose of this program is to provide clear, accessible, and targeted communication to customers in order support the implementation of NPAs and enable the successful transition away from aging gas infrastructure where feasible.

The report outlines the Companies' outreach goals, customer targeting strategies, messaging framework, delivery channels, stakeholders, and success metrics to ensure compliance with the Commission's directive.

## 5.2. Overview of NPAs and LPP Electrification Strategies

The Companies' long-term gas system planning incorporates both NPAs and targeted electrification of LPP segments as complementary strategies to reduce reliance on aging gas infrastructure. While both pathways aim to enhance system safety and cost-effectiveness, each involve distinct planning, customer engagement, and implementation approaches.

NPAs refer to non-infrastructure solutions – such as demand-side measures or electrification offerings – implemented in lieu of traditional gas infrastructure investments in vulnerable areas. These solutions are identified through system planning analyses and pursued when infrastructure deferral is technically feasible and economically justified. Where applicable, NPAs are implemented through a competitive Request for Proposals ("RFP") process and rely on third-

party developers to coordinate with eligible customers, deliver program offerings, and help achieve load reduction.

LPP-related electrification efforts focus on retiring targeted segment of LPPs and transitioning affected customers to electric alternatives through utility-led outreach and implementation. These projects are coordinated through a designated third-party implementer and structured as full-segment conversions under the Companies' Whole Home Electrification Program.

## 5.3. Program Goals

### Outreach Goals for NPA Project Areas

Outreach to customers in vulnerable areas will begin after a project is awarded through a competitive RFP process.

The outreach goals for these in these areas will include:

1. **Customer Awareness:** Clearly communicate that their area is part of an awarded NPA project, identify the selected developer, and explain their role in delivering electrification or demand-side solutions.
2. **Support Customer Understanding and Eligibility:** Provide clear and accessible information on the offering, eligibility criteria, participations steps, and how the program relates to local gas infrastructure conditions.
3. **Facilitate Enrollment and Measure Delivery:** Coordinate with the developer to ensure timely and supportive engagement that moves eligible customers through enrollment, site visits, and installation of measures.
4. **Reinforce Broader System Planning Context:** Position customer participation as critical to deferring gas investments and aligning with the Companies' long-term planning and the State's emissions and affordability goals.
5. **Engage Local Stakeholders and High-Impact Customers:** Coordinate with municipal leaders, community organizations, and commercial or industrial customers whose load profiles or visibility may influence projects success.

### Outreach Goals for LPP Electrification Areas

Outreach to customers on LPP segments will focus on facilitating the Companies' Whole Home Electrification Program in support of full LPP segment retirement.

The outreach goals for these areas will include:

1. **Customer Notification of Pipe Retirement:** Inform customers that their property is located on an LPP segment under evaluation for permanent retirement and that participation in an electrification program may eliminate the need for gas service reinvestment.
2. **Program Enrollment Support:** Provide customers with clear information about program scope (e.g. heating, hot water, cooking) and customer eligibility.

3. **Personalized Customer Engagement**: Conduct outreach through formal notification letters, follow-up calls, and door-to-door engagement to explain the offering and support customers through the enrollment and installation process.

Ultimately, the goal of the customer outreach for LPP segments is to enroll and electrify 100% of customers. If all customers do not enroll, the LPP segment will be replaced through traditional methods.

### Cross-Cutting Program Objectives

The Companies will apply the following principles across all outreach activities included in this program:

1. **Promote Equitable Participation**: Ensure outreach efforts are inclusive and accessible, particularly for low- and moderate-income ("LMI") customers and those in disadvantaged communities ("DACs"). Messaging will be catered to local needs and delivered through culturally appropriate and accessible formats.
2. **Align with Program Milestones:** Align customer engagement with internal project screening, RFP issuance, and construction timelines to ensure timely, relevant communication.
3. **Optimize Outreach Based on Observed Outcomes: Use** engagement results and stakeholder input to improve outreach methods, messaging, and delivery effectiveness.

## 5.4. Target Audiences

### Customers in Vulnerable Locations (NPA Planning Areas)

Customers located within areas under NPA evaluation are identified through system planning as potential contributors to infrastructure deferral. Outreach in these zones is intended to build early awareness, support full participation, and align with project timelines once a solution is selected through a competitive RFP (See Attachments 5 and 6 for program brochures, and Attachments 7-10 for customer letters and webpage content) .

Target audiences in these areas includes:

Figure 6: Key Target Audiences for NPA Project Areas


## Customers Served by LPPs

Customers served by LPP segments prioritized for potential retirement are targeted for direct engagement through the Whole Home Electrification Program. Segment selection is guided by a weighted scoring model that includes segment length, number of active services, housing stock age, and DAC status.

Figure 7: Key Target Audiences for LPP Electrification Areas

## 5.5. Marketing and Educational Content

### Messaging for NPA Projects Areas

Outreach messaging in areas under NPA evaluation is intended to build customer awareness of NPAs and to prepare eligible customers for potential participation in future programs, once a project is selected and developers are engaged.

Key messaging elements will include:

- **What's Happening in the Area:** Inform customers that their neighborhood is under evaluation for a potential NPA. Explain what NPAs are and how they relate to gas planning (e.g., deferring pipe investment, reducing load).
- **What Customers Need to Know:** Make clear that no immediate action is required and that more details will follow if the project moves forward.
- **Technology Overviews:** Provide introductory-level content on technologies commonly used in NPAs, such as heat pumps, building envelope upgrades, energy efficiency measures.
- **Why It Matters:** Frame messaging in terms of reliability, affordability, and alignment with New York's climate and clean energy transition goals.
- **Where to Find More Information:** Offer a point of contact, such a project webpage or call center, for customers seeking updates or future engagement opportunities.

### Messaging for LPP Project Areas

In areas served by LPP segments prioritized for potential retirement, messaging will be action-oriented and focused on immediate participation in the Whole Home Electrification Program.

Key messaging elements will include:

- **Your Home is Eligible:** Explain that the customer is located on a prioritized segment and qualified for the Whole Home Electrification Program.
- **What The Program Offers:** Outline the measures offered (e.g., heat pump installation, water heater replacement, induction cooking), and clarify that most upgrades are provided at no cost.
- **Why The Project is Happening:** Frame the project as part of a proactive safety and modernization(?) strategy to reduce risk associated with LPPs.
- **What To Expect Next:** Outline the steps for participations, including energy assessments and installation timelines.
- **Landlord/Tenant Coordination:** For rental properties, provide tailored messaging for both owners and tenants to help coordinate access and permissions.

### Shared Content Standards and Accessibility

All outreach materials will follow consistent guidelines for readability, tone, and accessibility:

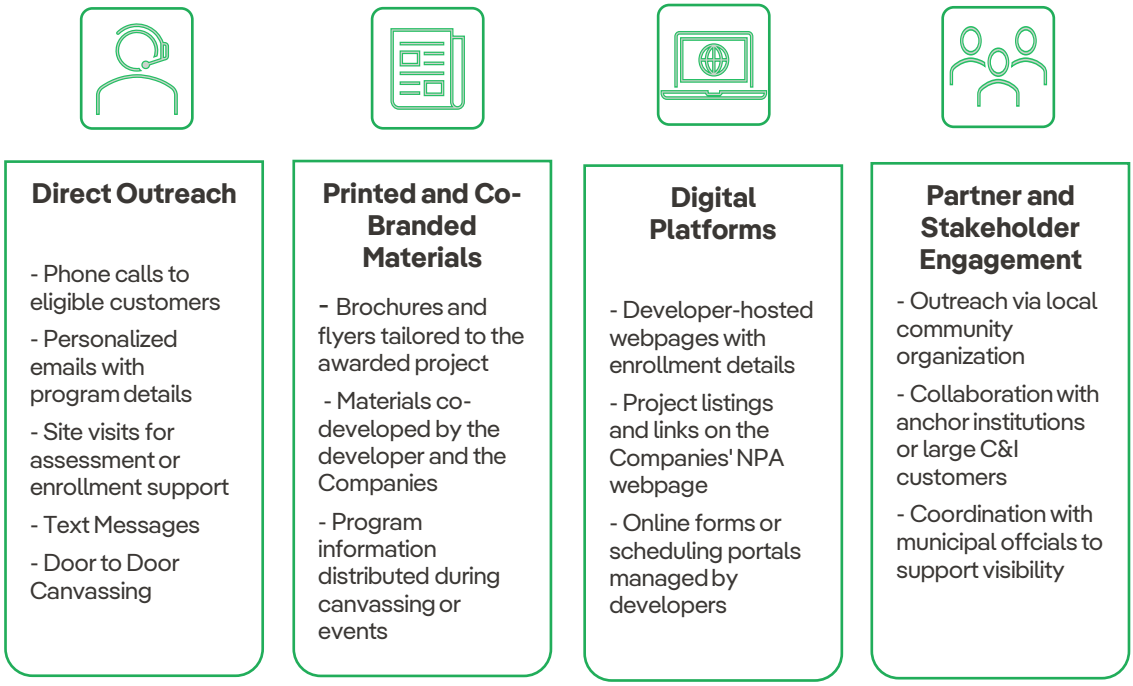
- **Plain Language:** Avoid technical terms or explain them clearly. Aim for simple, straightforward communication.

- **Multiple Formats:** Messaging will be delivered across multiple platforms to ensure broad accessibility.
- **Trust-Building Tone:** Emphasize transparency, customer choice, and reliability. Where relevant identify the Companies' implementation partner to clarify who is delivering the service.
- **Customization By Audience:** Adapt messaging to reflect customer different audiences – LMI, DACs, small businesses, or multi-family buildings.

## 5.6. Outreach and Digital Channels

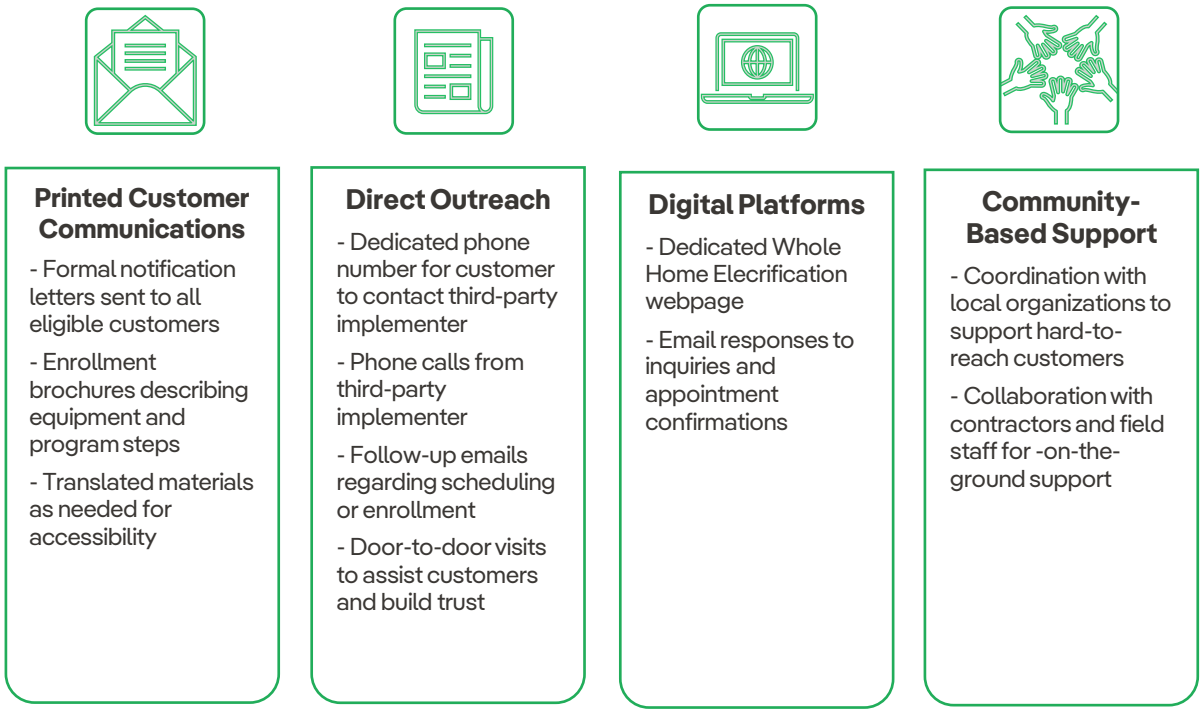
### Outreach Channels for NPA Project Areas

Figure 8: Outreach Channels for NPA Project Areas



### Outreach for LPP Electrification Areas

Figure 9: Outreach Channels for LPP Electrification Areas




See Attachments 5 and 6 for brochures sent to customers.

## 5.7. Partnership and Integration

The Companies will oversee all outreach and education activities conducted under this plan, including those by third-party vendors and implementation partners. For NPA projects, developers selected through RFP process will carry out customer engagement once projects are approved, under Company-defined outreach protocols. For LPP electrification efforts, the Companies' contracted implementer will be responsible for direct outreach, assessment scheduling, and coordination of installation logistics.

All outreach - whether delivered directly or through partners – will follow a consistent set of standards for branding, messaging clarity, customer responsiveness, and data tracking. The Companies will provide oversight, ensure materials are reviewed for accessibility and equity, and coordinate internally across Marketing, Conservation and Load Management, and Customer Service teams to respond to customer inquiries.

To extend reach, the Companies will also collaborate with municipal leaders and local organizations, especially in areas with DACs, to share information, increase credibility, and improve program access.

## 5.8. Implementation

The Companies will coordinate outreach activities with internal planning milestones and project timelines to ensure that customer engagement occurs at the appropriate stage of project development. Outreach timing and evaluation methods will differ slightly by track to reflect the structure and urgency of NPA and LPP efforts.

### Timeline and Phasing

Figure 10: Outreach Timeline for NPA Project Areas

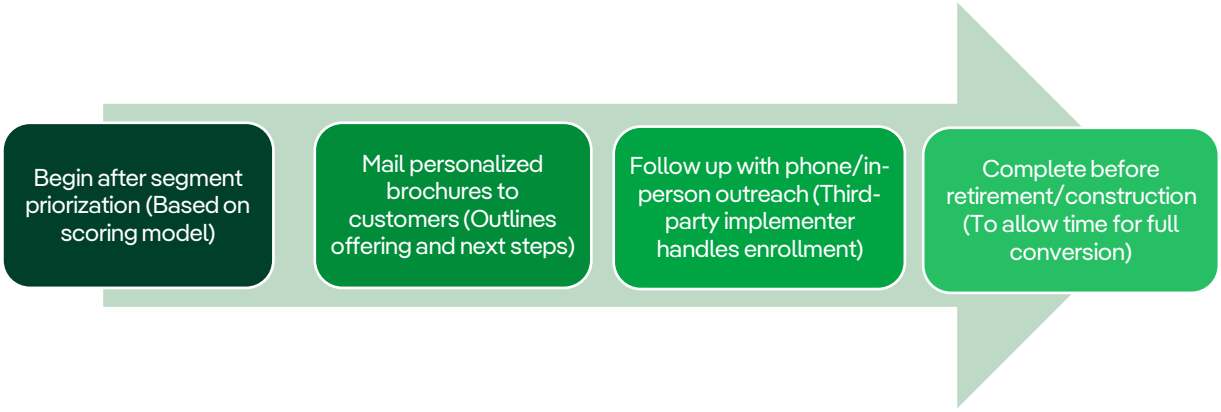
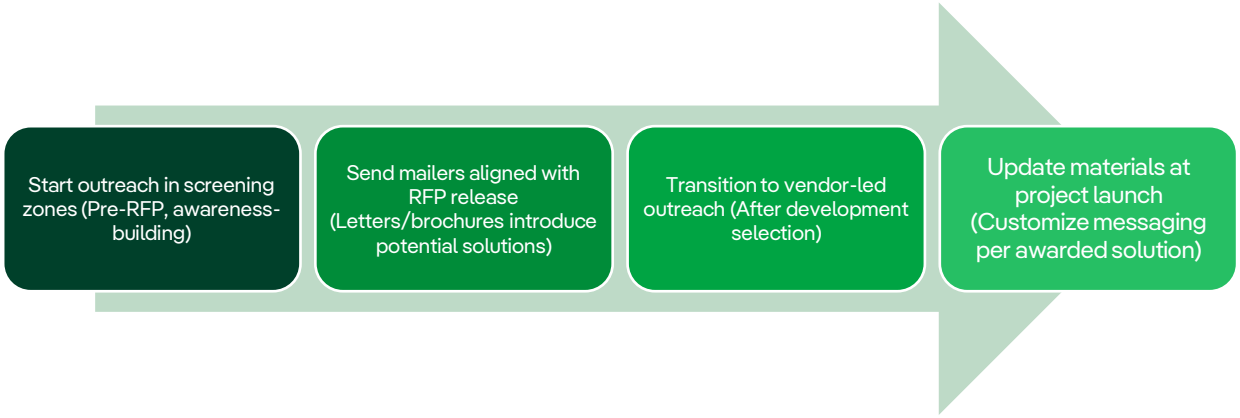


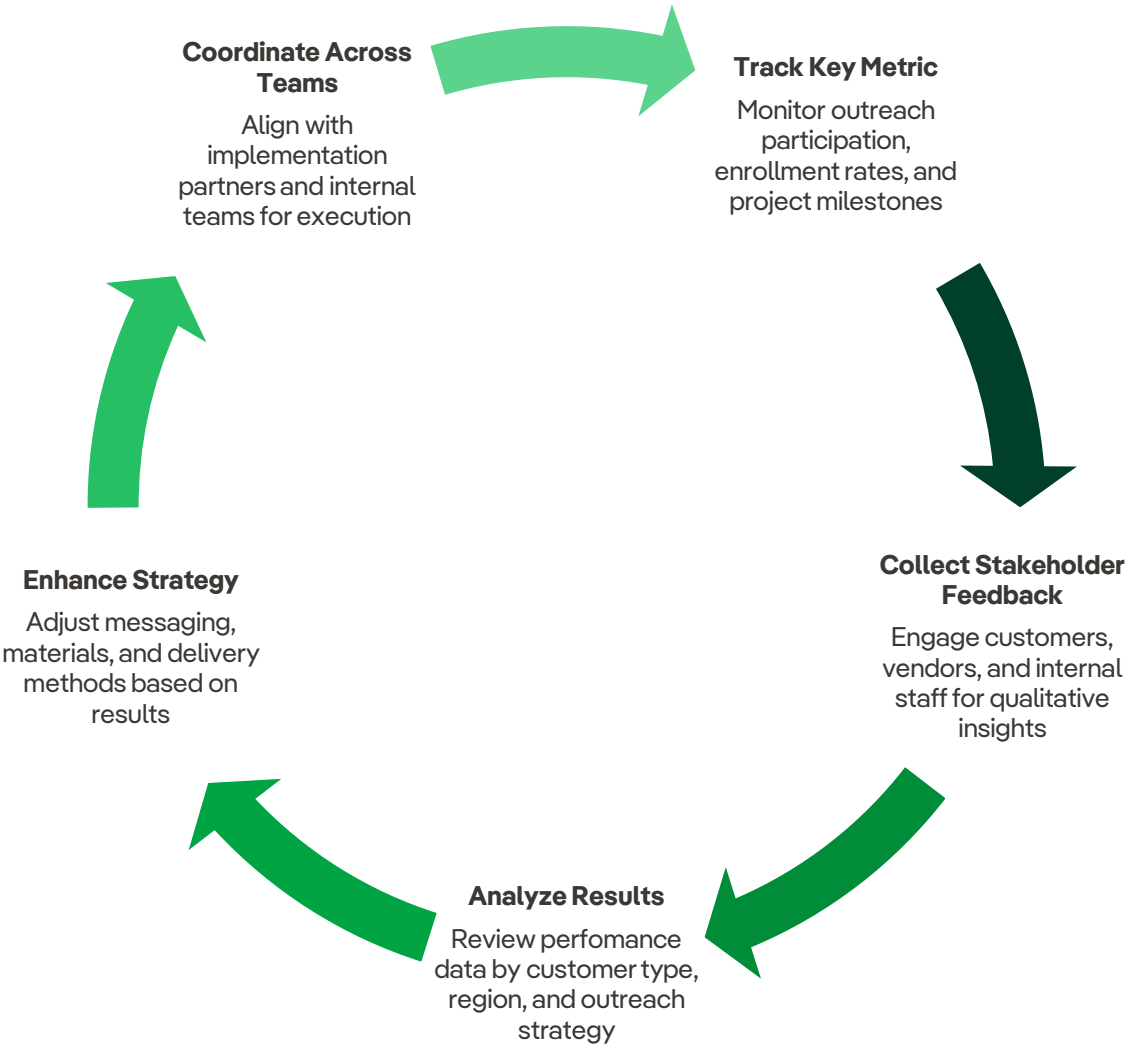

Figure 11: Outreach Timeline for LPP Project Areas




### Evaluation and Continuous Improvement

The Companies will implement a structured evaluation framework to assess the effectiveness of outreach and education efforts across both NPA and LPP programs. This framework will incorporate both quantitative and qualitative metrics to inform reiterative improvements and ensure alignment with Commission objectives.

Figure 12: Outreach Evaluation and Continuous Improvement Cycle




Evaluations will be reviewed internally on a quarterly basis and used to enhance future outreach strategies.