R.24-09-012 Workshop: Forecasting Analytics and Facilitating Non-Pipeline Alternatives

September 22, 2025

California Public
Utilities Commission

Workshop Logistics

- Today’s presentation will be sent to the service list
- There will be opportunity for Q&A after each panel and time for general comments at the end of the workshop.
- To ask a question of the presenters
  - In-Person:
    - Raise hand and speak into the mic
  - Webex:
    - Type question into the chat
- This workshop is being recorded

505 Van Ness

In case of Evacuation

1. Take internal stairs to ground floor
2. Exit to Van Ness Ave
3. Go right on Van Ness Ave
4. Meet at outside courtyard (across from City Hall)

Natural Gas Rates and Bills

CPUC Energy Division Staff Presentation

Jean Spencer

September 22, 2025

Agenda

- Basic Principles
- Rate Components
- Bill Structure

Basic Principles

- General Rates Cases vs. Cost Allocation Proceedings
- Core vs. Noncore Customers

General Rate Cases and Cost Allocation Proceedings

- General rate cases
  - Determine the revenue requirement the utility can collect to recover costs to:
    - Operate, maintain, and construct its pipeline and storage systems
    - Run the company, such as administrative costs and customer services costs
  - Allocate capital asset costs across time through depreciation
- Cost allocation proceedings
  - Allocate the revenue requirement to different utility functions and customer classes
    - Generally based on cost causation principles
  - Divide costs into fixed and variable rates with tiers

Core vs. Noncore Customers

- Core customers:
  - Residential and small commercial customers
  - The utility procures and transports their gas
    - Can choose a Core Transport Agent to procure gas
  - Pay a premium for more reliable service
  - Primary users of distribution lines

- Noncore Customers
  - Large commercial and industrial customers
    - Examples: Electric generators, refineries, factories, hospitals
  - Procure their own gas supply and inter- and intrastate transportation services or use a marketer
  - Exposed to more reliability risk

Rate Components

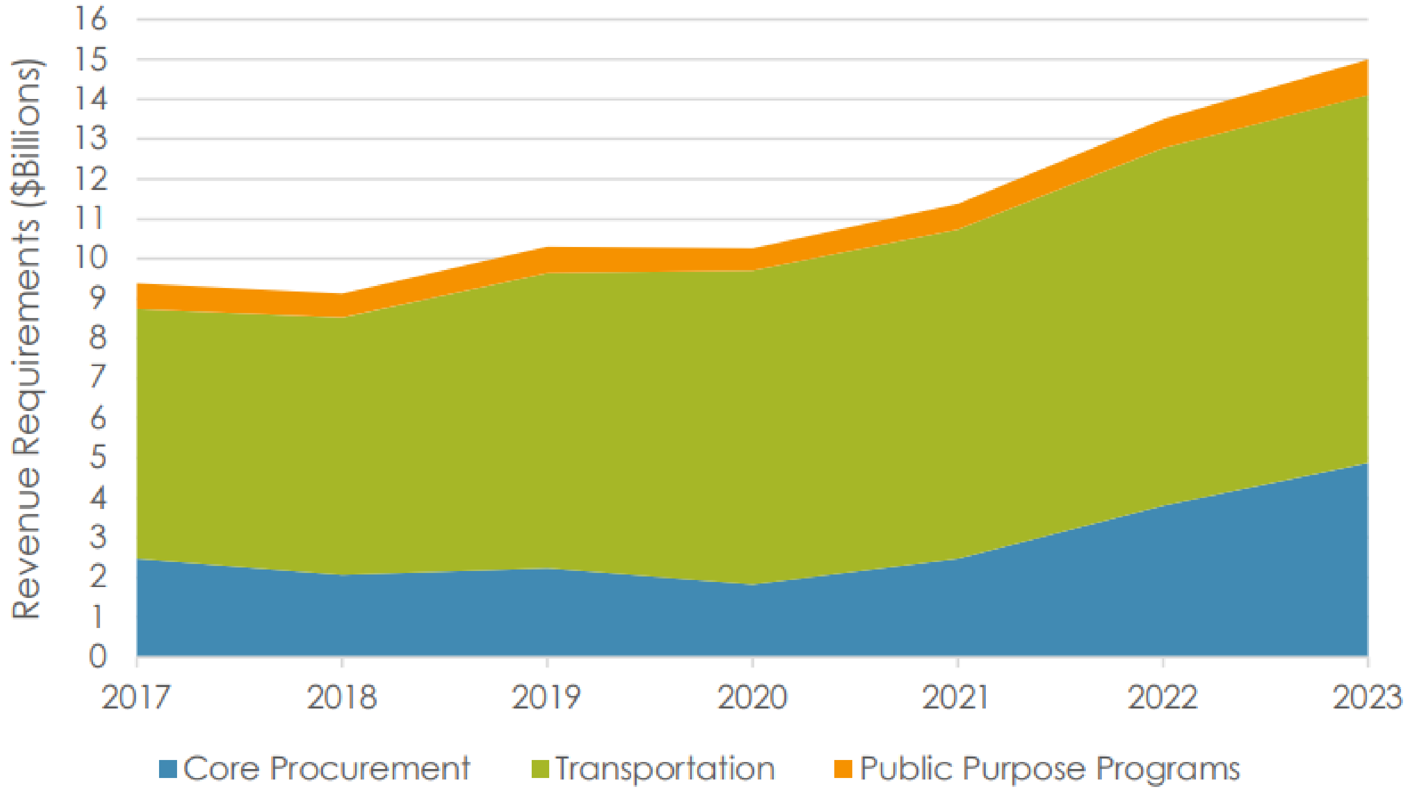
- Core Procurement Rate
- Transportation Rate
- Public Purpose Program Surcharge
- Climate Credit

Three Main Components of Gas Rates

- **Core Procurement Rate**
  - Applies only to bundled core customers
  - Recovers the cost of the gas commodity and the pipeline capacity to transport it to the local transmission system
    - Gas commodity cost is a pass-through cost; utilities don’t earn a profit on it
- **Transportation Rate**
  - Recovers revenue requirement, i.e., costs of utility’s transmission and distribution pipeline system, storage, and customer-related services plus a rate of return
- **Public Purpose Program (PPP) Surcharge**
  - Recovers costs of mandated public purpose programs

Rate Components Breakdown

Historical Trends in Gas Utility Revenue Requirement Components ($ billions)



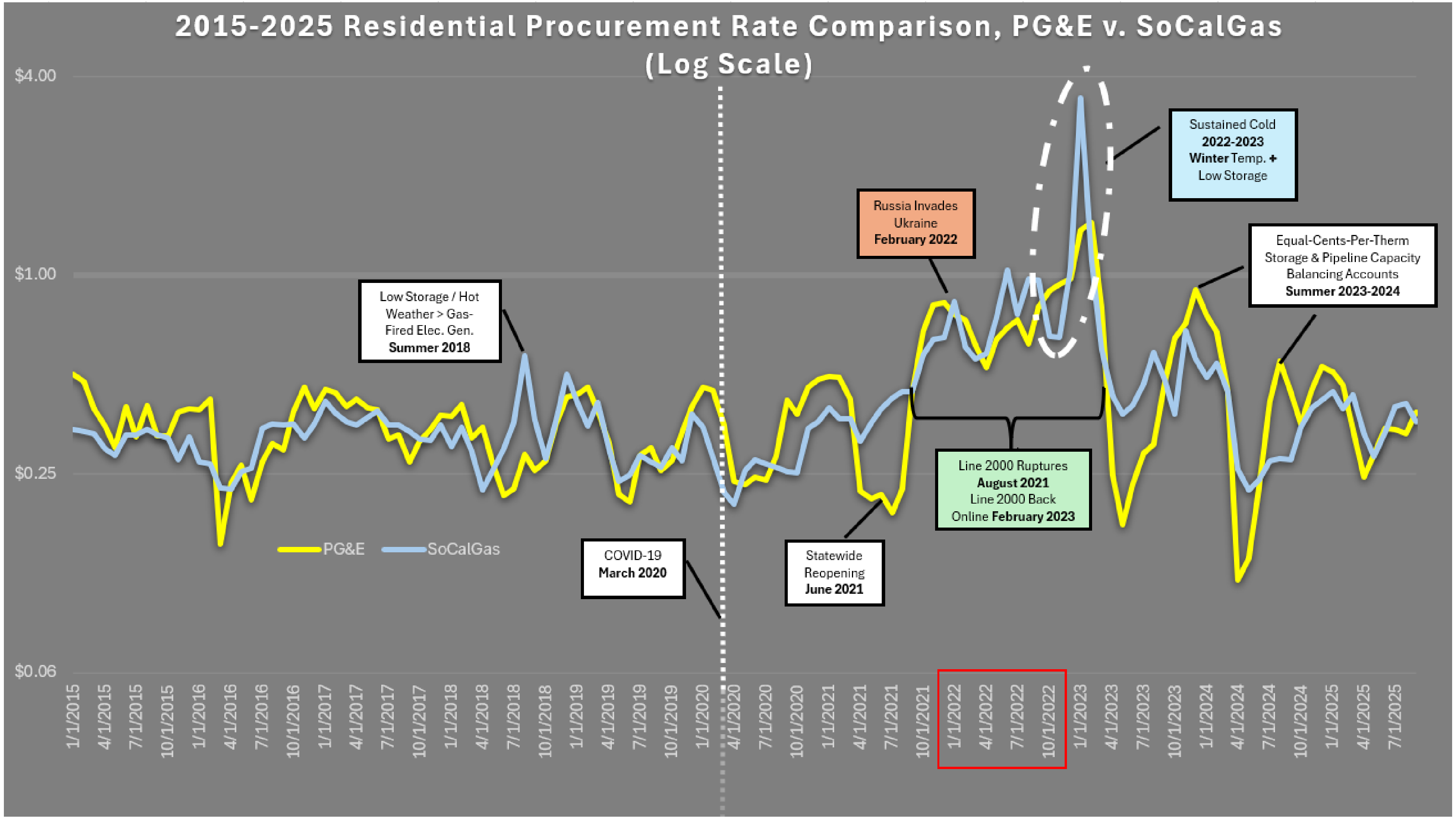
Source: CPUC 2024 AB 67 Report

- Transportation rates are the largest component of rates
- However, gas price spikes can increase core procurement costs

Core Procurement Rates

- Updated every month
- Changes are mostly due to fluctuations in gas commodity prices
- The CPUC reviews the reasonableness of gas purchases through gas cost incentive mechanisms

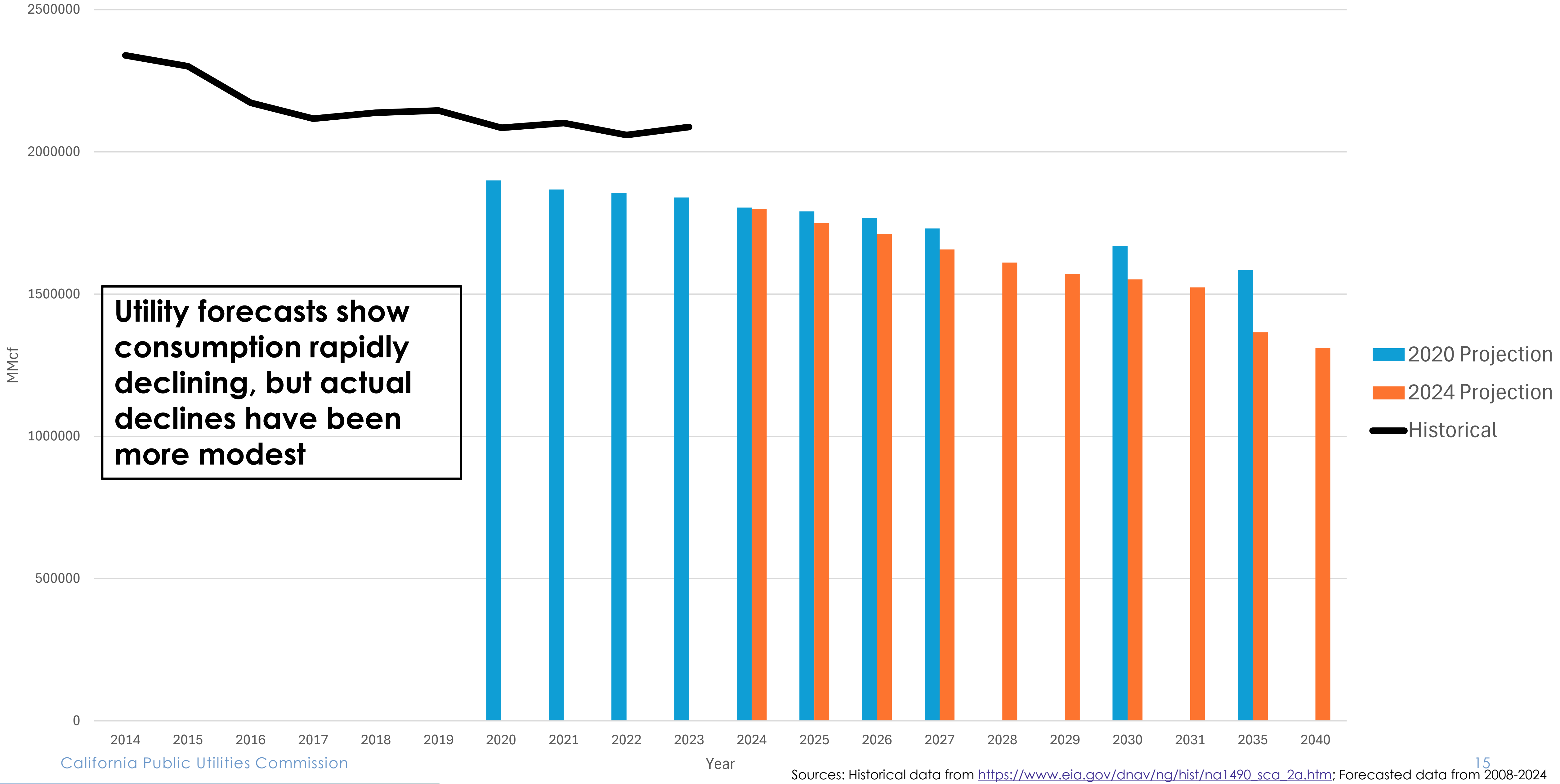
Core Procurement Rates: Impacts of Volatile Gas Market



Transportation Rates

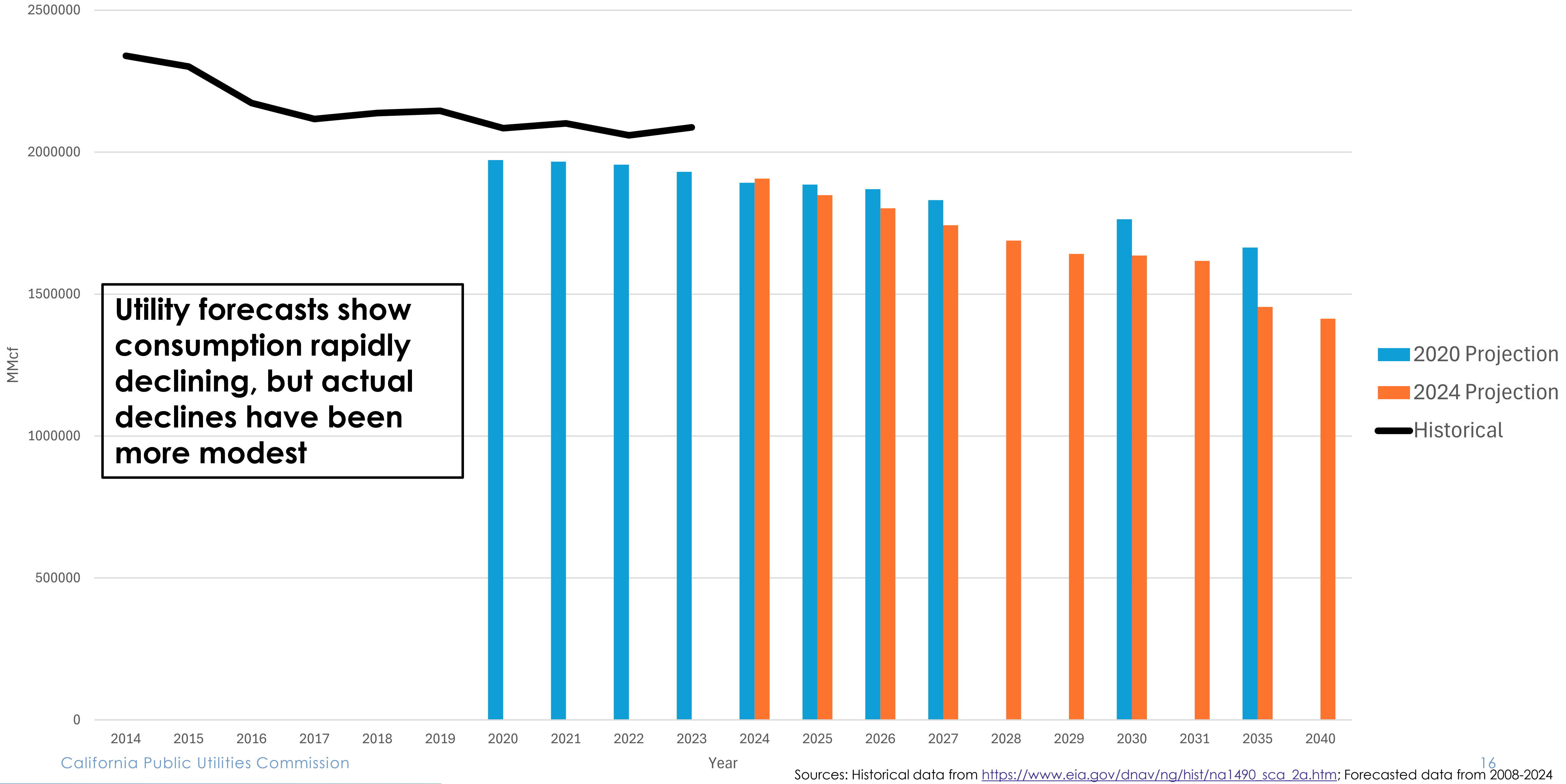
- Usually updated annually but can be updated more often
- Allow for the recovery of the revenue requirement based on a forecast of throughput
- A simplified way of thinking about this is:
  - Rates = Revenue Requirement/Demand
  - An increase in Revenue Requirement and a decrease in Demand = Higher Rates

California Historical Natural Gas Consumption vs Normal Demand Year Projected Consumption



Sources: Historical data from https://www.eia.gov/dnav/ng/hist/na1490_sca_2a.htm; Forecasted data from 2008-2024 California Gas Report | SoCalGas

California Historical Natural Gas Consumption vs High Demand Year Projected Consumption



Sources: Historical data from https://www.eia.gov/dnav/ng/hist/na1490_sca_2a.htm; Forecasted data from 2008-2024 California Gas Report | SoCalGas

Gas PPP Surcharge

- Typically updated annually on January 1
- PPP costs include:
  - Energy efficiency program,
  - A subsidy for CARE customers, and
  - Gas research and development program
- Required by legislation
- Electric generators don’t pay the gas PPP

California Climate Credit

- Natural gas utilities have been given some free allowances annually to be sold at auction
- Proceeds from sale of those free allowances have been mostly returned to residential gas customers on their April bill
- Residential gas customers receive a per-customer bill credit (not based on usage)
- Recently passed legislation (AB 1207, Irwin, 2025) may change this process

Bill Components

- Fixed Charges vs. Per-Therm Rates
- Rate Structure

Fixed Charges vs. Per-Therm Rates

- **Core Residential**
  - Procurement rate (unless CTA procurement is chosen) — per therm
  - Fixed charge or minimum bill — per day
  - Transportation rate: seasonal baseline and above baseline — per therm
  - Gas PPP surcharge rate — per therm
  - California Climate Credit — April bill credit

- **Noncore**
  - Customer or access charge — per day or month
  - Transportation rate (tiered decreasing rates for higher usage) — per therm
  - Gas PPP surcharge (but not for EG customers) — per therm

Note: Additional rates apply for noncore customers if they opt to purchase utility storage

Current Residential Rate Structure (Non-CARE as of September 2025)

	Fixed (Per Day)		Volumetric (Per Therm)				Fixed (Per Year)
	Fixed Charge	Minimum Bill	Transportation Rate		Procure-ment Rate	Public Purpose Charge	Climate Credit
			Baseline	Above Baseline			
PG&E	NA	$ 0.13	$ 2.11	$ 2.62	$ 0.39	$ 0.11	$ 67.03
SoCalGas	$ 0.16	NA	$ 1.19	$ 1.68	$ 0.36	$ 0.12	$ 86.60
SDG&E	$ 0.13	NA	$ 2.04	$ 2.39	$ 0.36	$ 0.12	$ 54.21
Southwest Gas	$ 0.19	NA	$ 1.55	$ 1.76	$ 0.25	$ 0.21	$ 73.68

- CARE rates are generally 20% less.
- Baseline usage is roughly half a therm per day in summer and 1-2 therms per day in winter and varies by climate zone.

Non-Residential Rates Are Structured Differently

- **Example: SoCalGas May 2024 Noncore Commercial/Industrial Customer**
- **Schedule GT-NC and G-PPPS**

- Customer charge $350 per month
- Transportation rate
  - Tier 1 0 to 20,833 therms 52.605 cents per therm
  - Tier 2 20,834 to 83,333 therms 41.227 cents per therm
  - Tier 3 83,334 to 166,667 therms 33.948 cents per therm
  - Tier 4 Over 166,667 therms 28.747 cents per therm
- Gas PPP surcharge 7.221 cents per therm

For more information:

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GAS DEMAND AND RATES: *FOUNDATIONAL FORECASTING ANALYTICS*

Interim Actions Workshop

Gas Planning OIR (R.24-09-021)

September 22, 2025

Table of Contents

Development of Demand Forecasts

Integrated Energy Policy Report (IEPR)

- California Energy Demand Forecast is developed every two (odd) years
- Collaborative, public process with data sharing and stakeholder input
- ***Includes:***
  - Annualized forecasts for residential, commercial, industrial, and NGV gas demand
  - Based on several factors, including economic and demographic trends, energy efficiency, and fuel substitution
- ***Does not include:***
  - NG-fired EG forecasts
  - Peak forecasts or load shape
  - Location/Customer-specific data
  - Wholesale customer demand
  - Customer count forecast

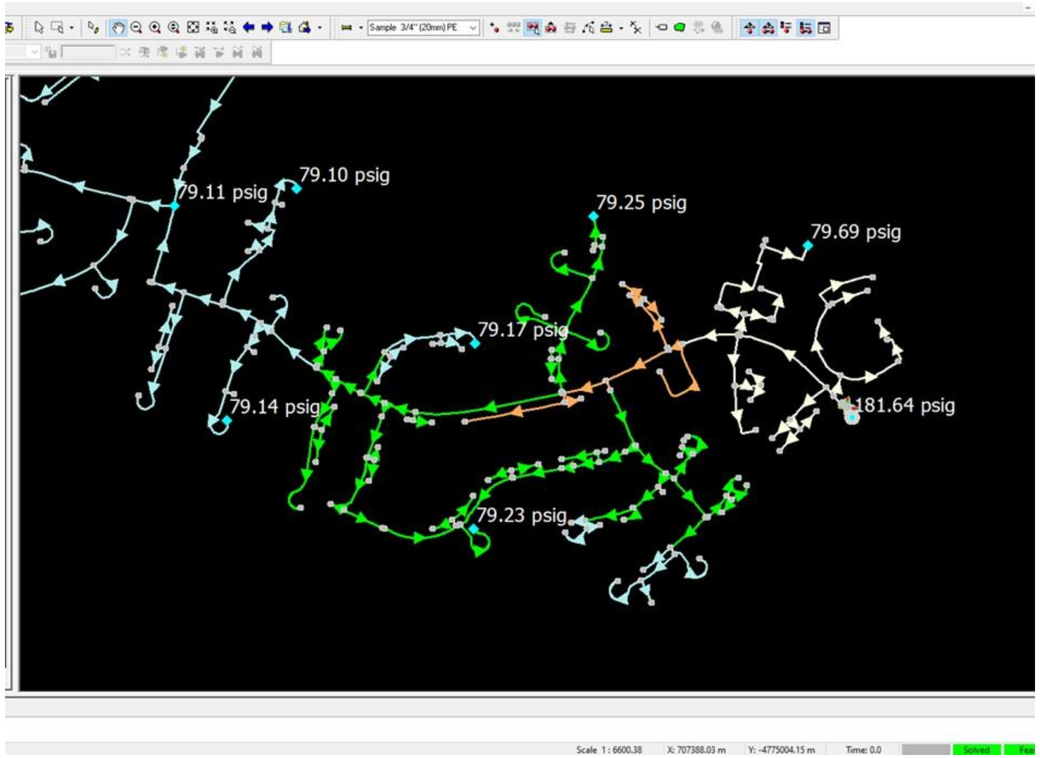
California Gas Report (CGR)

- Developed by statewide gas utilities every two (even) years.
  - Interim reports in odd years provide actuals, but no forecast updates
- Collaborative process that considers IEPR data
- ***Select additions beyond IEPR:***
  - NG-fired EG forecasts
  - Peak day forecasts
  - Selection of scenarios
  - Add wholesale customer demand forecast
  - Develop customer count forecast

How Demand Informs System Design

System Design Approach

- SoCalGas and SDG&E design their natural gas systems to meet demand under two design conditions:
  - 1-in-10-year cold day for all customers
  - 1-in-35-year extreme peak day for core customers only
- Gas system reliability is managed by our planning teams who employ fluid dynamics network software to model the expected performance of our system under design conditions
- The expected design day demand used in these models is derived from actual customer usage data, which is scaled as needed to replicate weather-dependent usage
- Engineers regularly update and run these models to verify that the system maintains safe and reliable service operating between minimum and maximum operating pressures
- These models are validated by comparing modeled results to pressure and other data from sensors on the system



Illustrative network model screenshot

SoCalGas SDGE

Glad to be of service.

How Demand Informs System Design

How Demand Forecasts are Used

- Demand forecasts are reviewed to make sure that changes in total demand and demand patterns are not expected to introduce reliability, resiliency or other risks for the gas system
- Customer requests for service are also considered, and appropriate investments are developed as and when needed to serve these new demands
- If gas demands decline in a certain area of our system, there may be opportunities to revisit system design when it could generate cost savings. Typically, this occurs when we are facing an investment decision, and alternatives are evaluated:
  - Consider re-sizing or re-routing infrastructure
  - Consider reducing MAOP (derating)
  - Consider infrastructure abandonment
- D.23-12-003 (Gas OIR 1 Phase 2) provides some guidance

How Forecasts Impact Rates

- Demand forecasts are utilized in SoCalGas and SDG&E's Cost Allocation Proceeding (CAP)
- If a California Gas Report forecast was completed in the year a CAP is filed, it is used for the CAP. If not, a current forecast is developed, using the same methodology
- The adopted forecasts in CAP are an artifact of litigation, and may not align exactly with initial proposals
- Revenue Requirements are not necessarily dependent on demand
- Demand forecasts impact rates in two major ways:
- **Cost Allocation**
  - Forecasts are used to update Marginal Demand Measures, which inform cost allocation of functional gas system cost areas to customer classes
- **Rate Design**
  - Forecasts are used to set rates that target recovery of approved revenues over the course of the year

PG&E Gas System-Level Demand Forecasting and Infrastructure Overview

September 22, 2025

Kurtis Kolnowski, Manager, Business Strategy, System Planning Analytics

Daven Phelan, Sr. Director Gas Engineering and Distribution Asset Manager Owner

System-Level Gas Demand Forecasting 101

System-level gas demand forecasts utilize multiple methodologies best tailored to each customer class. System-level forecasts are not granular enough for localized analysis (e.g., distribution).

Forecasting Tools

- **Econometric Regression**: Calculates relationship between historical forecast drivers (regression) and demand then applies the relationship to assumed future values of each driver to forecast future gas demand.
- **Production Cost**: Hourly electricity market simulation that optimizes resource dispatch to serve electric demand at least cost. Gas-fired electric generation (EG) is a key resource class in this optimization.
- **Technology-Driven**: Specialized models designed to capture forecast drivers that are not well represented by historical trends. Used for building electrification and other "load modifiers".

Tools Used by Class

- **Core** (e.g., Residential, Commercial) and **Noncore, Non-EG** (e.g., Industrial): Econometric regression + technology-driven
- **Electric Generation**: Production cost (electric load input uses regression and technology-driven)

Granularity of Forecasts Developed – PG&E Gas System

Annual/Monthly:

- Average Demand Year (1-in-2) aka "Expected" case
- Cold/Dry (1-in-10 Cold, 1-in-10 Dry Hydro)
- Cold (1-in-35 Cold)

Peak Day:

- 1-in-2 Cold Winter Day
- 1-in-10 Winter Peak Day
- Summer High Demand
- 1-in-90 Abnormal Peak Day *(Core Only)*

Types of System-Level Gas Demand Forecasts

Demand forecasts have many use cases. Selecting the right type of forecast for a specific purpose helps make that forecast useful.

Expected Case: Best estimate of what will actually happen.

- Useful for certain planning purposes where credible and well-vetted forecasts are needed.
- Assumptions reviewed for "reasonableness" – e.g., compare with history, benchmark multiple sources.
- Accounts for future policies "on-the-books" but incorporates expected uncertainty.

Policy-Driven: Assumes that a policy will be met and then develops assumptions to align.

- Useful for policymakers to understand gaps and identify actions to fully realize policy goals.
- Does not account for uncertainty in policy implementation.
- May not require policy to be enacted.

Sensitivities and Scenarios: Representation of uncertainty to help understand range of impacts and outcomes.

- Useful for identifying "least regrets" actions and difference between expected and policy cases.
- **Sensitivity**: Vary one assumption and quantify impact. (e.g., higher electrification or lower gas prices)
- **Scenario**: Vary multiple assumptions to reflect a coherent potential future (e.g., changes in federal policy could impact cost and trajectory for solar, batteries, transportation electrification, and building electrification.

System-Level Forecasts Utilized by PG&E

PG&E utilizes GT&S and CGR forecasts for internal use cases and accounts for known uncertainty. CEC's IEPR forecast used as a benchmark in system-level gas demand forecasting

Forecast ID: Use Case / Purpose	Forecaster	Forecast Type	Forecast Assumptions	Horizon
Gas Transmission & Storage (GT&S) Forecast: Gas rate setting every 4 years; allocate costs and gas rate design. (GT&S CARD, GCAP)	PG&E	Expected Case + Scenario (1-in-35 Cold)	PG&E-only **internal** assumptions. Accounts for known uncertainty in policy assumptions.	4 Yrs
California Gas Report (CGR): Compliance filing. Combines projections from gas utilities & non-utility stakeholders. Also used for Backbone Capacity Adequacy and informs range for Core Firm Interstate Pipeline Capacity supply and reliability standards.	PG&E	Expected Case + Scenarios and Sensitivities (many)	**External** forecast sub-committees (e.g., Joint IOUs, municipalities, CPUC, CEC) determine CGR forecast assumptions. Accounts for known uncertainty in policy assumptions.	Up to 20 Yrs
Integrated Energy Policy Report (IEPR): External forecast used in electric system planning and local reliability. PG&E's EG forecast utilizes SCE and SDG&E Planning Area inputs. Benchmark for PG&E forecasts.	CEC	Hybrid: Expected Case & Policy-Driven + Scenarios	**External** CEC-driven process that involves many stakeholders, including PG&E. Some assumptions reflect whether a policy is met or not but uncertainty in its implementation.	Up to 20 Yrs

Gas Demand Forecast Uncertainty

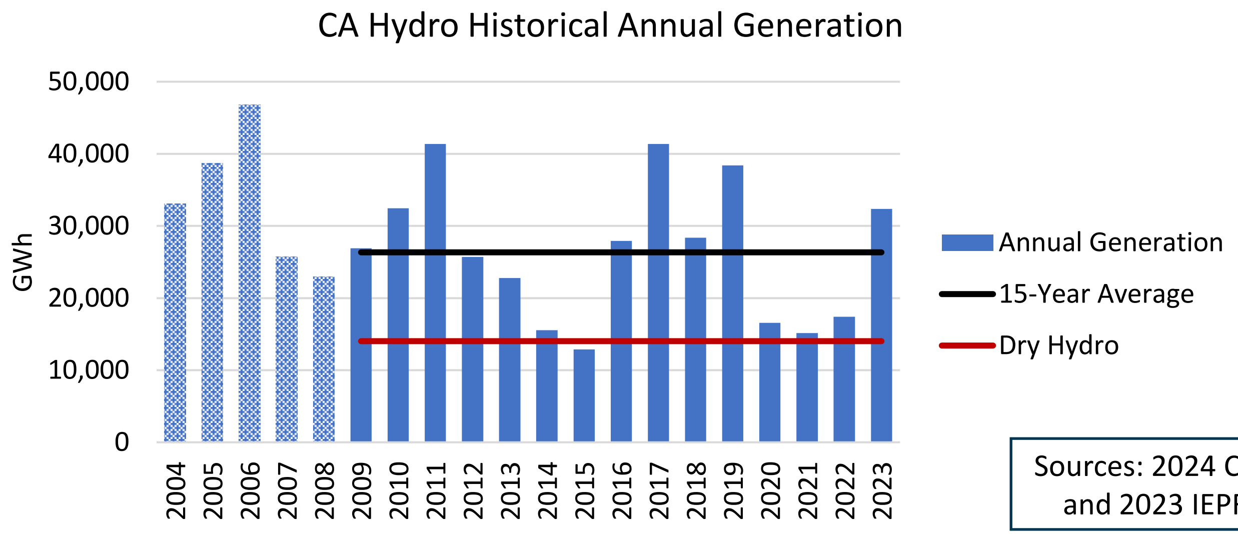
Point forecasts needed for rate-setting purposes. Point forecasts should use defensible assumptions but will not capture the impacts of all uncertainty.

Uncertainty That Does not Affect Expected Case

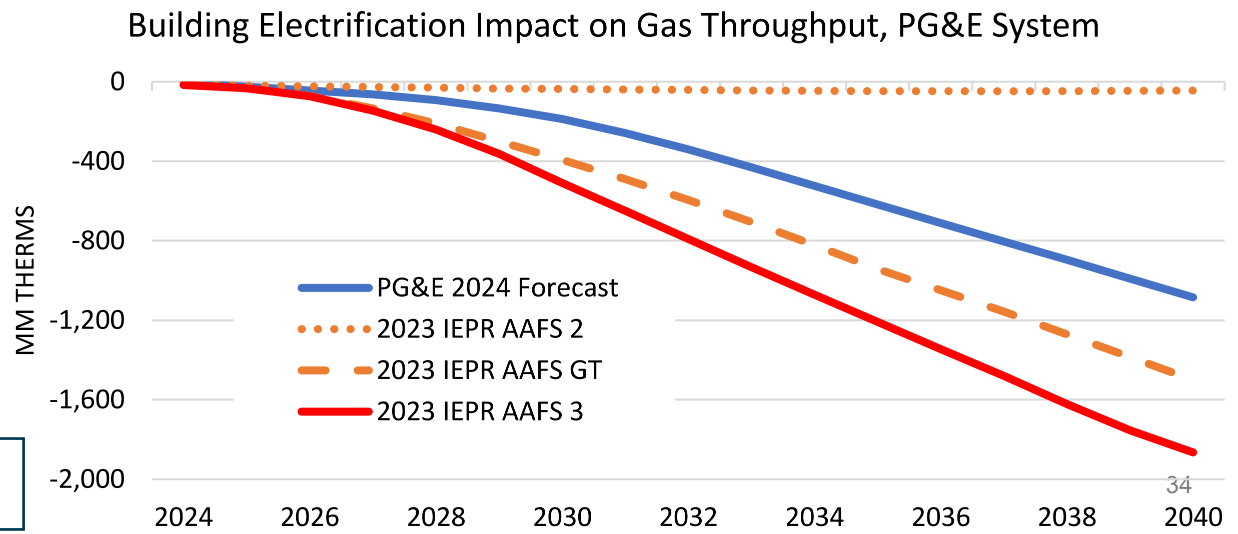
- Reflects periodic variation or events that do not represent an "average"
- This uncertainty does not affect a point forecast and is best captured by scenarios and sensitivities.
- Examples include temperature and rainfall.

Uncertainty That Changes Expected Case

- Reflects changes in assumptions that impact even an "average" year.
- This uncertainty shifts a point forecast up or down and could be the result of policy or market conditions.
- Examples include building electrification policy and rate of electric resource build.



Sources: 2024 CGR and 2023 IEPR



How Localized Demand Forecasts are Developed by PG&E

PG&E develops forecasts for local gas demand based on various sources

System-level forecasts are not granular enough for localized analysis (e.g., distribution), so external sources are used to develop localized demand forecasts.

For example, a new gas customer on Distribution System A may result in a localized constraint on 123 Main Street and is independent of declining gas demand in Distribution System B.

Description	Source(s)	Horizon
Customer Requests: Existing customers increasing gas demand or new customers connecting gas demand.	Customers	1 to 5 Yrs
Local Development: Master plans by cities and developers.	Cities and developers	5 to 10 Yrs

Forecasting Infrastructure Needs in GRCs

Demand Forecasts vs. Infrastructure Needs

- PG&E utilizes system wide demand forecasts to project large scale infrastructure needs (e.g. backbone transmission & storage) over time.
- Generally, Gas Distribution capital needs are not driven by system wide demand forecasts, and a very small portion is related to customer or demand growth.

Gas Distribution Capital and Expense Forecasts

- Gas Distribution CapEx is driven primarily by Operational and Maintenance requirements and Asset Management activities for the gas distribution system.
- PG&E's obligations under PUC 959 require us to fund "…those projects and activities necessary to maintain safe and reliable service and to meet federal and state safety requirements applicable to its gas plant, in a cost-effective manner."

Highest Priority Interim Actions

- Standardized, streamlined criteria to evaluate the cost-effectiveness of decarbonization projects and Non-Pipeline Alternatives (NPAs), and
- Creation of a "level playing field" for recovery of utility investments and long-term costs for decarbonization projects, including capitalization and a return on those investments comparable to the treatment of the gas system capital costs and assets they replace

Questions?

CEC IEPR Gas Demand Scenarios

Nicholas Janusch, Ph.D., Program and Project Supervisor
Energy Assessments Division
R. 24-09-012 Workshop: Forecasting Analytics and Facilitating Non-Pipeline Alternatives
September 22, 2025

Acronyms, Initialisms, and Abbreviations

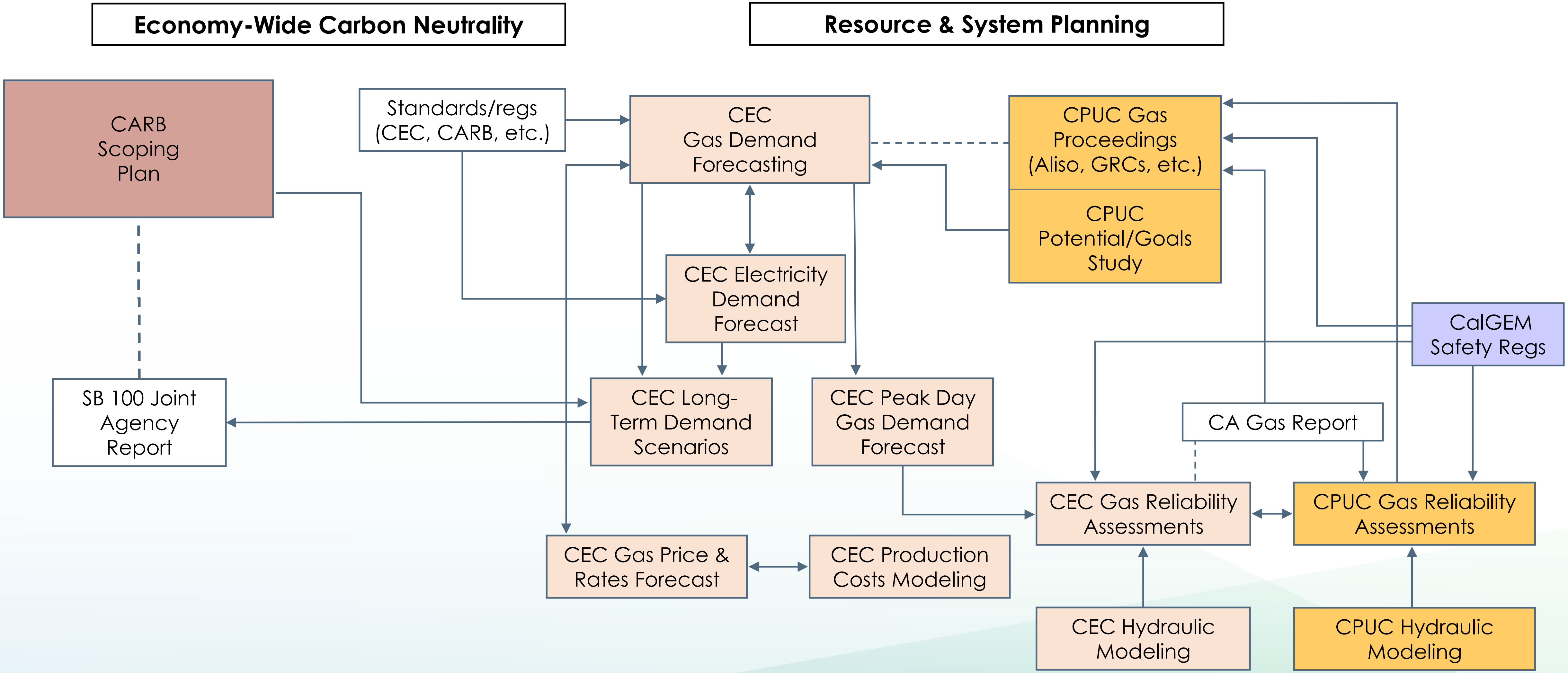
A&A – Additions and Alterations
AAEE – Additional Achievable Energy Efficiency
AAFS – Additional Achievable Fuel Substitution
Aliso – Aliso Canyon
AQMD – Air Quality Management District
BAU – Business as Usual
BUILD – Building Initiative for Low-Emissions Development
CalGem - Geologic Energy Management Division of the California Department of Conservation
CARB – California Air Resources Board
CCA – Community Choice Aggregators
CEC – California Energy Commission
CERIP – Clean Energy Reliability Investment Plan (CERIP)
CGR – California Gas Report
Com – Commercial Sector
EAD – Energy Assessments Division
EBD – Equitable Building Decarbonization
ECAA – Energy Conservation Assistance Act
FSSAT – Fuel Substitution Scenarios Analysis Tool
GRCs – General Rate Cases
GT AAFS – 2023 Gradual Transformation Additional Achievable Fuel Substitution Scenario
HOMES – Home Efficiency Rebates IRA Incentive Program
HPWH – Heat Pump Water Heater
IEPR – Integrated Energy Policy Report
IOU – Investor-Owned Utility
IRA – Inflation Reduction Act
NC – New Construction
QFER – Quarterly Fuel and Energy Report
PACE – Property Assessed Clean Energy (PACE) Financing
PiCS – Programs and incremental Codes and Standards

Acronyms, Initialisms, and Abbreviations (continued)

POU – Publicly Owned Utility
RENs – Regional Energy Networks
Res – Residential Sector
ROB – Replace on Burnout
Sc. - Scenario
SH – Space Heaters
TECH – Technology and Equipment for Clean Heating initiative
WH – Water Heaters
ZE - Zero-Emission

Overview of CEC's Gas Assessments

Natural Gas Planning Process



Gas System Planning – Layered Planning Horizons

Climate Goals Timeline (20-25 years ahead)

California Gas Report
(up to 15 years ahead)

Summer and Winter Reliability
Assessments (up to 1 year ahead)

CEC Gas Demand Assessments

	IEPR Gas Demand Forecast	Long-Term Demand Scenarios	Peak Day Gas Forecast
Uses	Some components used by gas utilities in the CGR	SB 100 planning	CEC Gas System Reliability Assessments
Forecast period	15+ years	2050	Next winter or summer
Update cycle	Every two years	Every two years	Twice per year
Products	Annual sales and consumption	Annual sales and consumption	Monthly peak day demand; Same 1-in-X metrics reported in CGR
Scenarios	Energy efficiency, fuel substitution, transportation electrification	Energy efficiency, fuel substitution, transportation electrification, hydrogen	None
Gas for Electricity Generation	Not included	Not included	Included

IEPR Gas Demand Forecast

AAEE/AAFS Load Modifiers Framework

CEC Load Modifiers: Additional Achievable Framework & Scenarios

- **Additional Achievable framework:** is applied to energy efficiency, fuel substitution, and transportation electrification for the IEPR demand forecast.
- The **additional achievable** scenarios capture a range of incremental market potential impacts, beyond what is included in the baseline demand forecast, but they are within the range of what is reasonably expected to occur.

Additional Achievable Scenarios

AAEE 1, AAEE 2, AAEE 3, AAEE 4, AAEE 5, AAEE 6

AAFS 1, AAFS 2, AAFS 3, AAFS 4, AAFS 5, AAFS 6

← Conservative Optimistic →

AAFS Modeling Framework

Baseline gas demand forecast generated using CEC's sector-based models using economic and demographic input data

Load Modifier Label	Modeling Component(s)	Description	Set of Scenarios Modeled
PiCS AAEE	Programs and incremental Codes & Standards (PiCS)	AAEE gas and electricity savings from PiCS	**PiCS AAEE** Scenarios 1-6
PiCS AAFS	PiCS	AAFS gas and electricity impacts from PiCS	**PiCS AAFS** Scenarios 1-6
FSSAT AAFS	PiCS and Zero-emission (ZE) appliance adoption modeling	Gas and electricity impacts from ZE appliance adoption above and beyond those realized in the PiCS scenarios	**IEPR AAFS** Scenarios 1-6

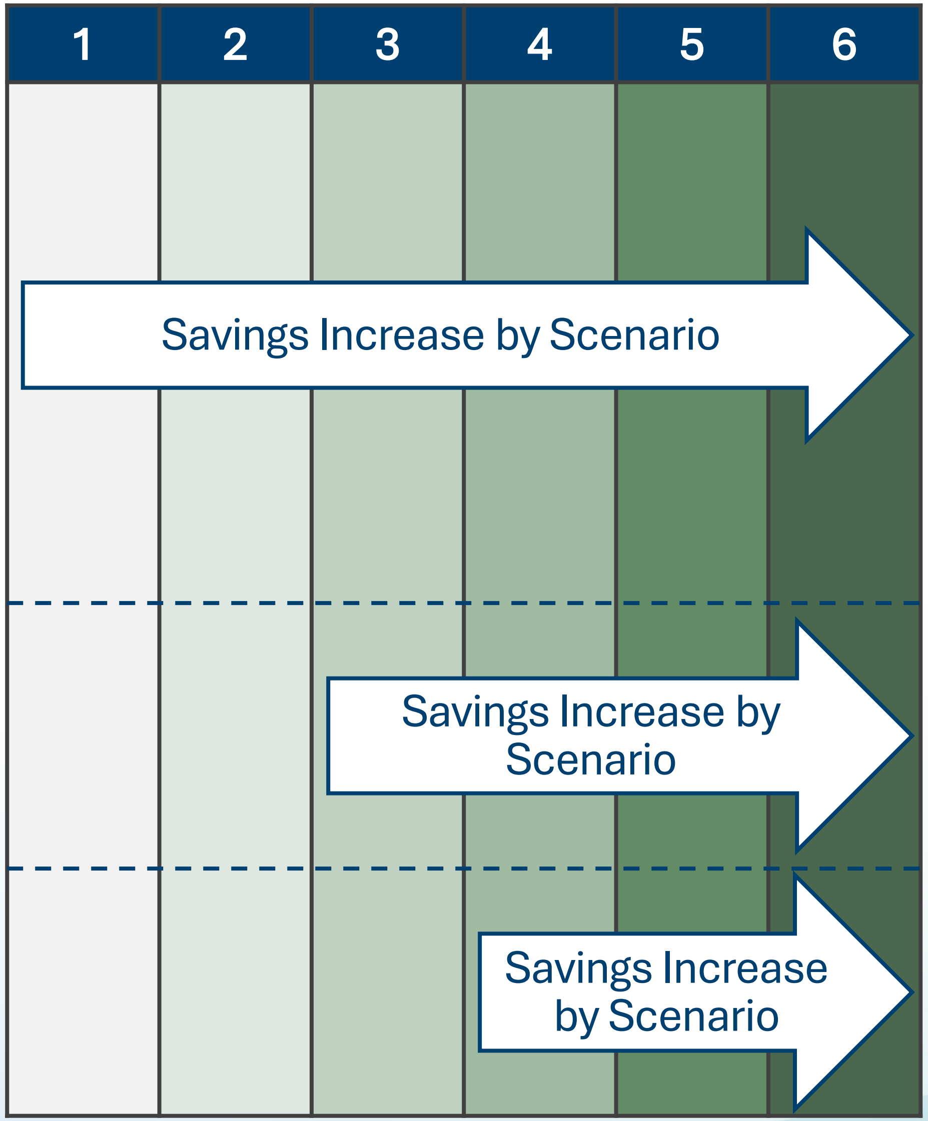
IEPR AAFS Gas Scenario = Baseline + f(PiCS AAFS + FSSAT AAFS + PiCS AAEE)

IEPR Gas Demand Scenarios

Characterization and Results of 2023 and 2024 AAFS Scenarios

2023 IEPR	CARB Scoping Plan	2024 IEPR
• 2023 Baseline • GT AAFS (“AAFS 2.5”) • AAFS 3 (“Planning”) • AAFS 4 (“Local Reliability”)	Proposed Scenario • Gas only • Gas, Hydrogen, and Biogas	• **2023 Baseline** • **AAFS 2** • **AAFS 3 (“Planning”)** • **AAFS 4 (“Local Reliability”)**
Market impacts presented at the June 6 IEPR Gas Price Outlook Workshop	Market impacts presented at the June 6 IEPR Gas Price Outlook Workshop	**Market impacts will be presented today by Anthony Dixon**

AAEE Modeled in 2023



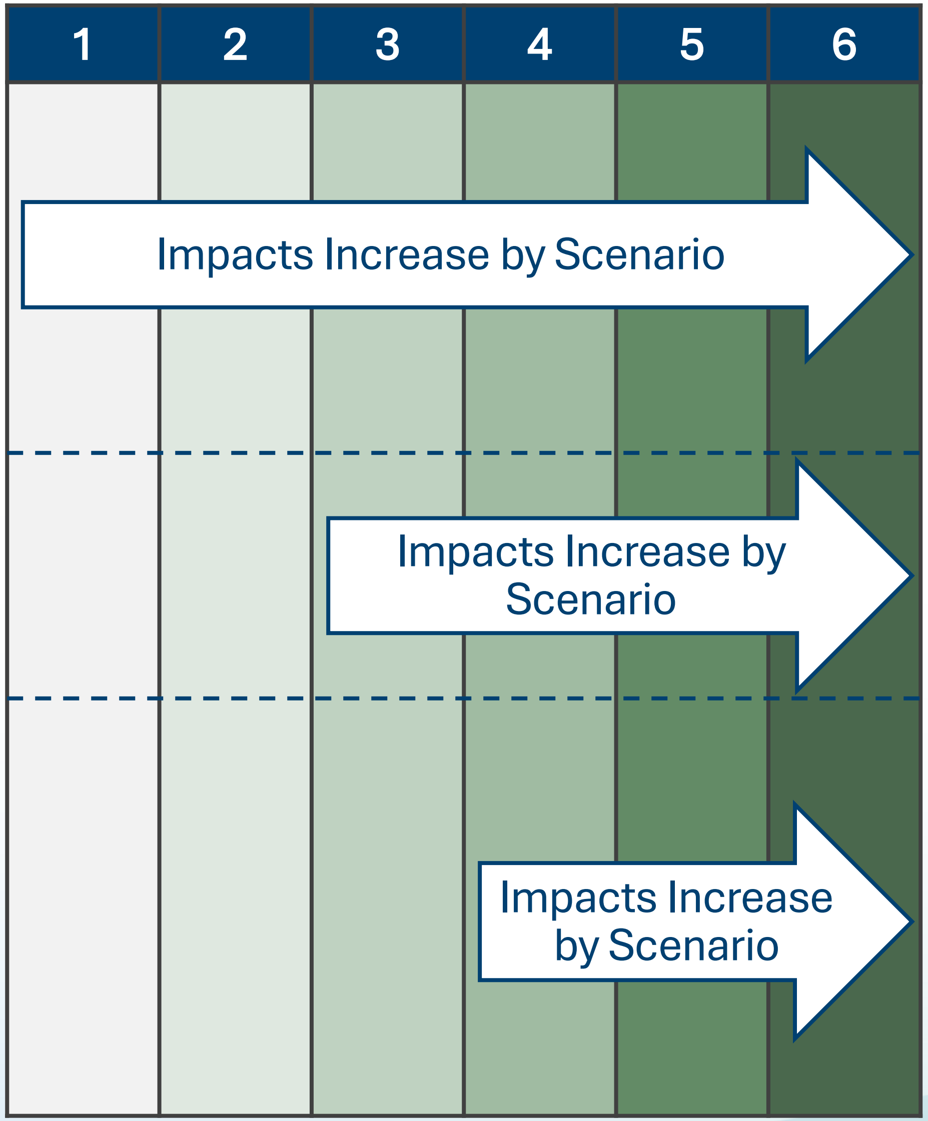
← AAEE Scenarios

- **IOU energy efficiency programs**
- **POU energy efficiency programs**
- CCA/RENs
- **Title 24 Res and Non-Res NC and A&A**
- **Building Initiative for Low-Emissions Development (BUILD)**
- **Local Government Ordinances**
- Greenhouse Gas Reduction Fund LI Weatherization
- Energy Conservation Assistance Act (ECAA) Financing
- Property Assessed Clean Energy (PACE) Financing

- **Federal Appliance Standards**
- **Home Efficiency Rebates (HOMES) IRA Incentive Program**
- Energy Asset Rating
- Smart Meter Data Analytics

- **Title 20 State Appliance Standards**
- Industrial and Agricultural Potential
- Clean Energy Reliability Investment Plan (CERIP)
- Conservation Voltage Reduction

PiCS AAFS Modeled in 2023



← AAFS Scenarios

- **IOU fuel substitution programs**
- **POU fuel substitution programs**
- CCA/RENs
- **Title 24 Res and Non-Res NC and A&A**
- Targeted Electrification
- Affordable Housing and Sustainable Communities

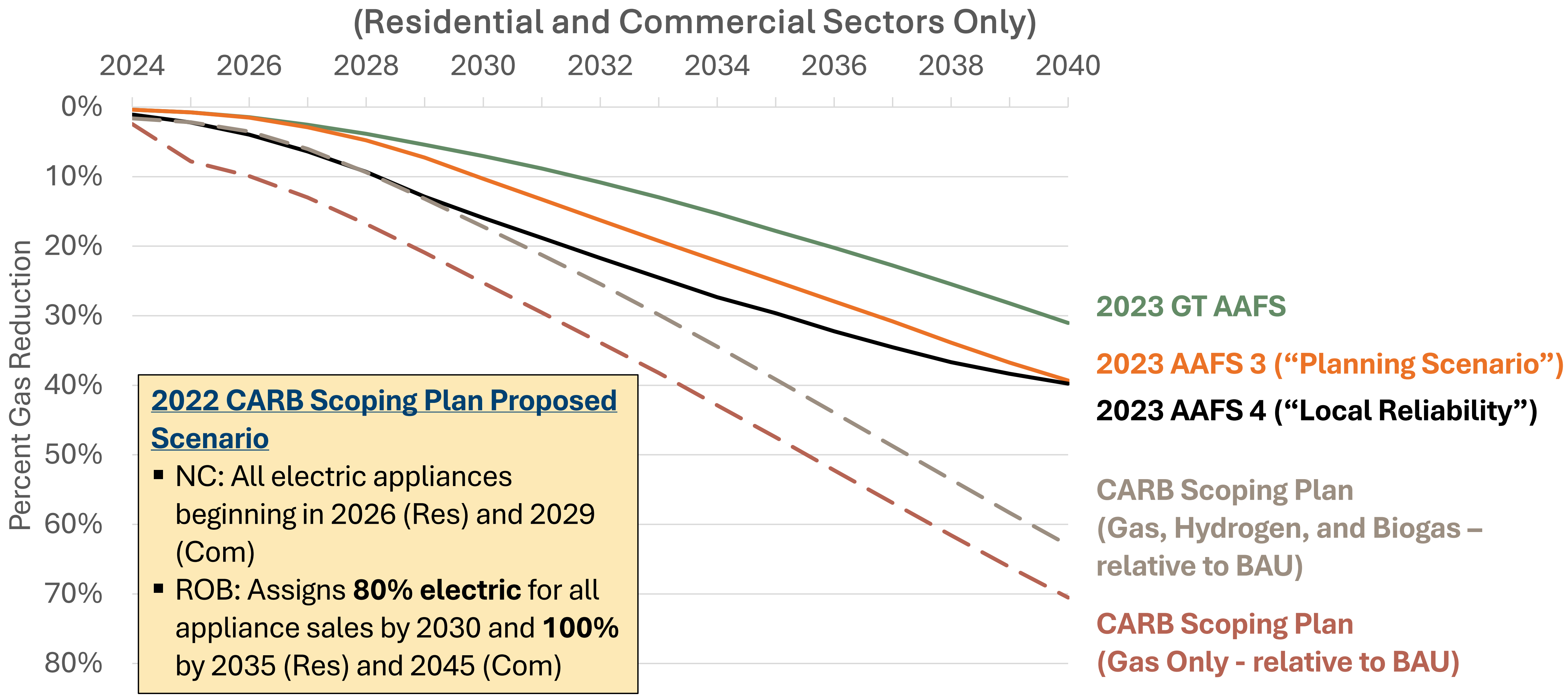
- **TECH Clean California**
- California Electric Homes Program
- Wildfire and Natural Disaster Resiliency Rebuild

- **Equitable Building Decarbonization (EBD)**
  - **IRA Incentive Program**
  - **CEC's EBD Program Direct Install & Tribal Direct Install**
  - **EBD Non-IOU TECH**
- Food Production Investment Program
- Self-Generation Incentive Program HPWH
- Local Governments Challenge

Summary of FSSAT AAFS characterizations

IEPR	IEPR AAFS Scenario	PiCS Scenarios	ZE Appliance Statewide Adoption Description (All include NC adoption and various AQMD zero-NOx regulations)
2023	GT AAFS ("AAFS 2.5")	AAEE 3 PiCS AAFS 3	100% by 2040 ROB adoption rate
2023	AAFS 3 ("Planning")	AAEE 3 PiCS AAFS 3	CARB's concept of 2030 ZE SH and WH appliance standards (with a slower ramp-up rate to 2030)
2023	AAFS 4 ("Local Reliability")	AAEE 2 PiCS AAFS 4	CARB's concept of 2030 ZE SH and WH appliance standards
2024	**AAFS 2**	**AAEE 2 PiCS AAFS 2**	**100% by 2040 ROB adoption rate**
2024	**AAFS 3 ("Planning")**	**AAEE 3 PiCS AAFS 3**	**Earlier and staggered compliance date schedule for CARB's concept of ZE SH and WH appliance standards**
2024	**AAFS 4 ("Local Reliability")**	**AAEE 2 PiCS AAFS 4**	**Earlier and staggered compliance date schedule for CARB's concept of statewide ZE SH and WH appliance standards**

Comparing 2023 IEPR and CARB Scoping Plan

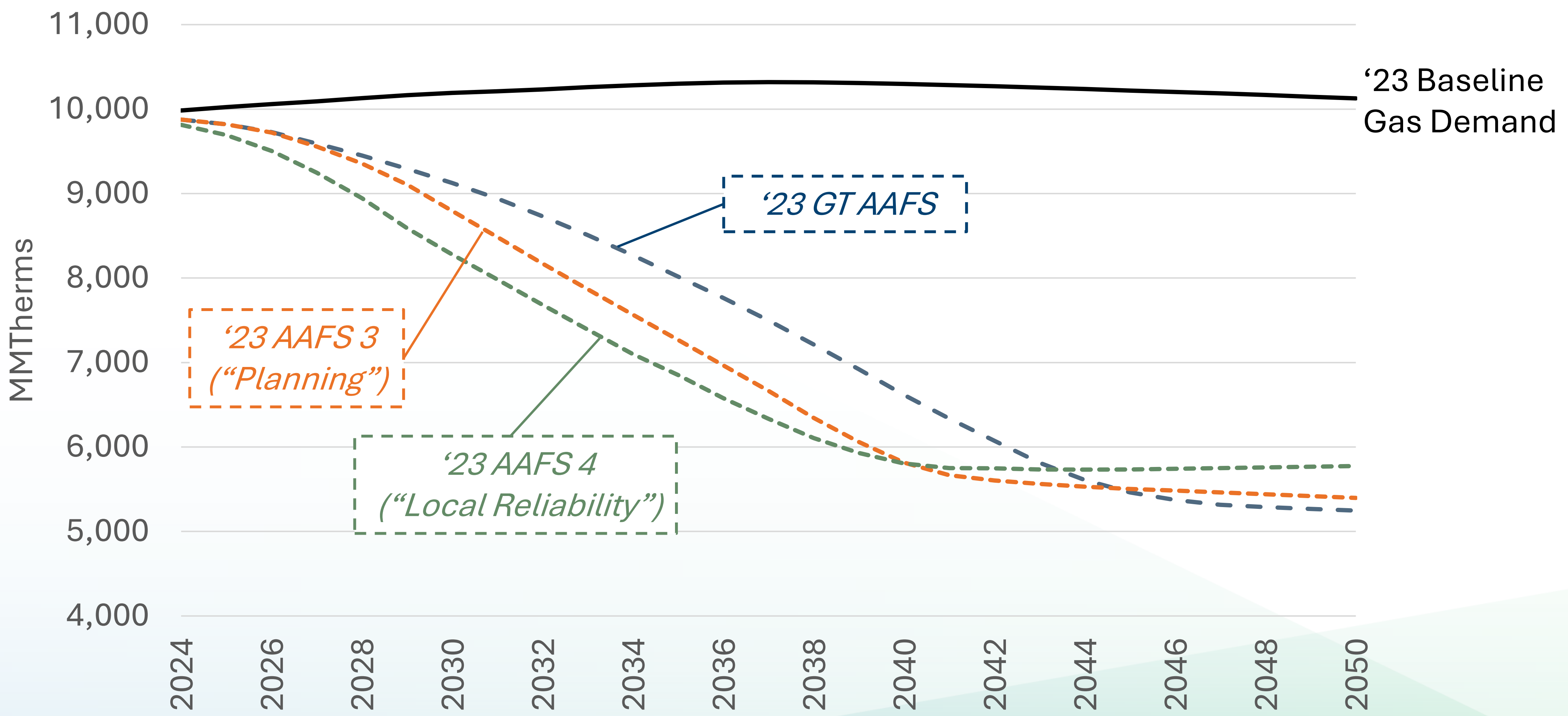


2022 CARB Scoping Plan Proposed Scenario

- NC: All electric appliances beginning in 2026 (Res) and 2029 (Com)
- ROB: Assigns **80% electric** for all appliance sales by 2030 and **100%** by 2035 (Res) and 2045 (Com)

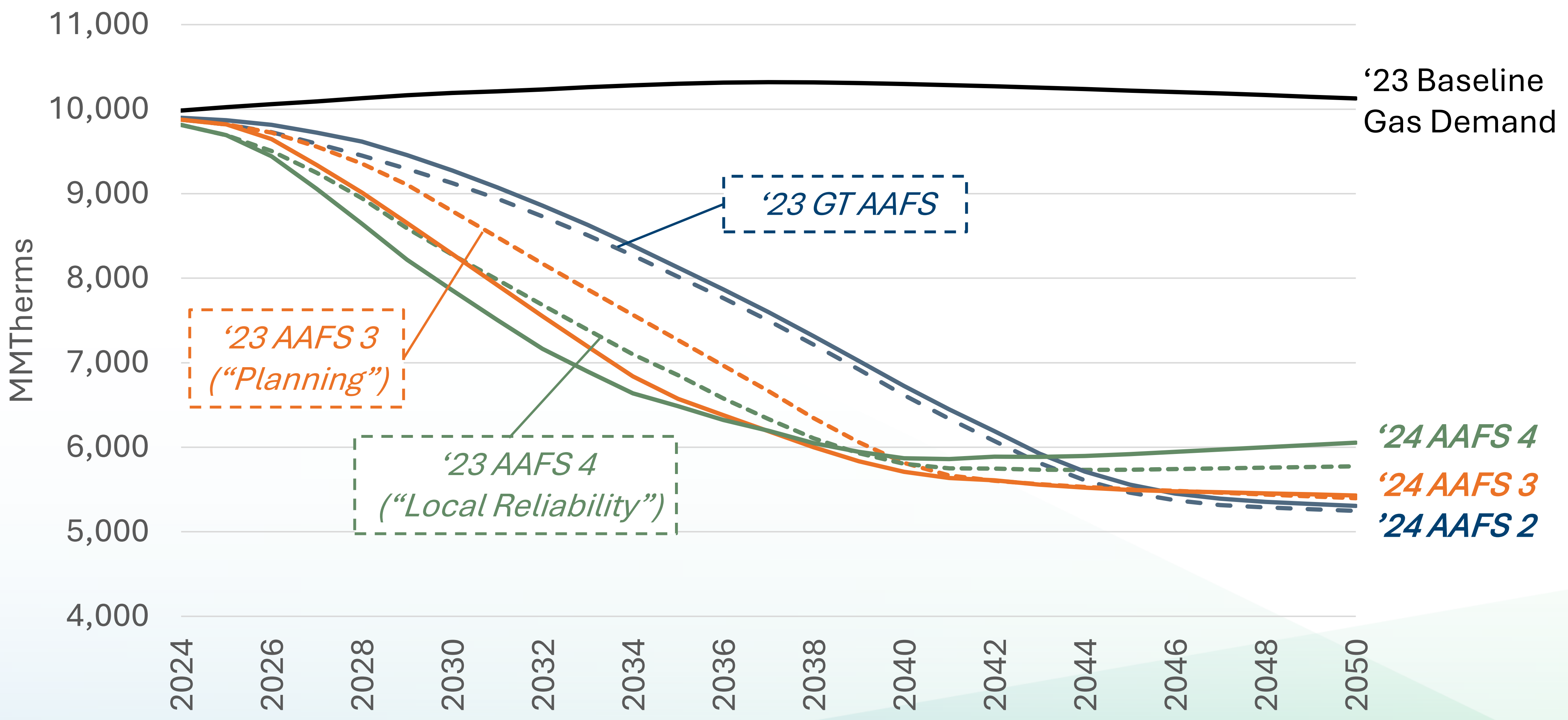
Source: CEC Staff

2023 AAFS Gas Demand Scenarios



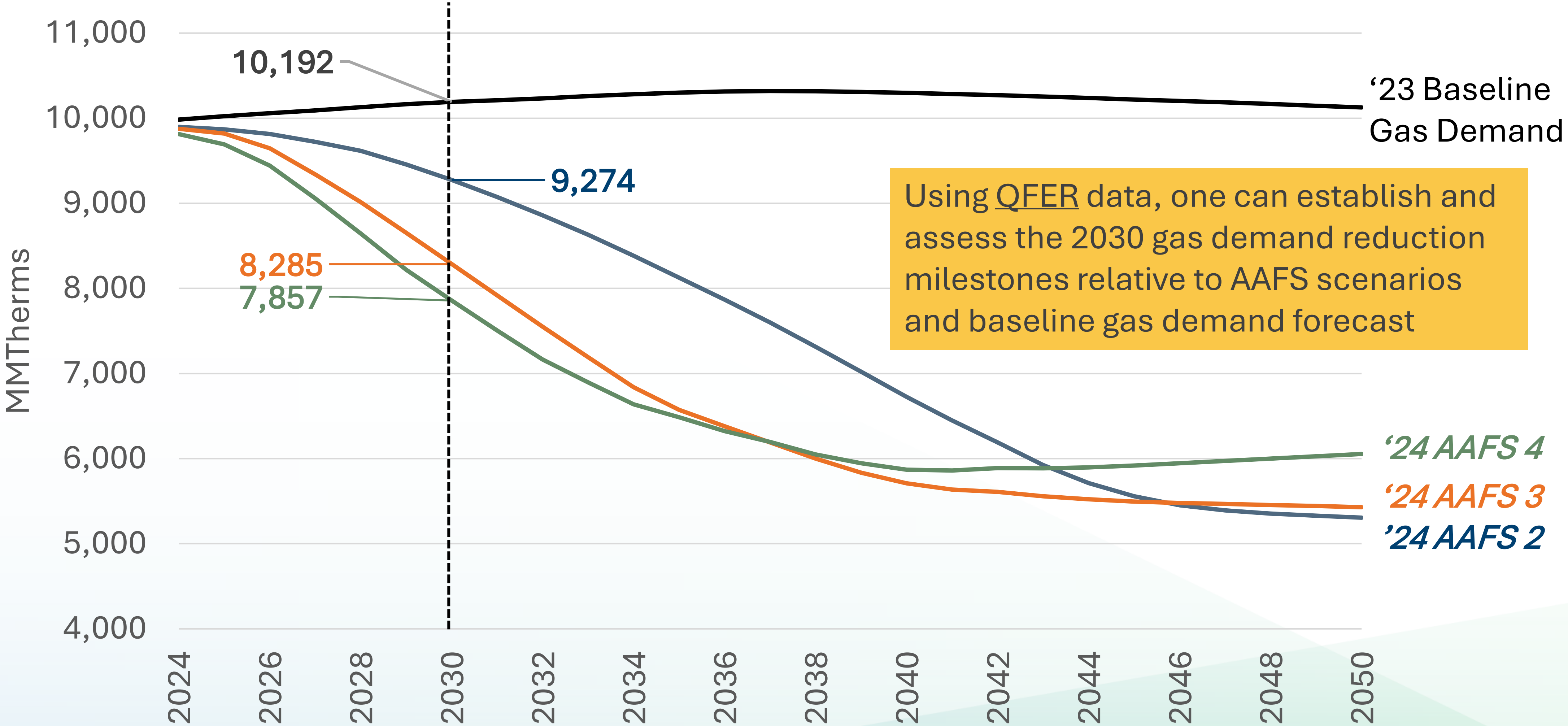
Source: CEC Staff

2023 & 2024 AAFS Gas Demand Scenarios



Source: CEC Staff

2030 Gas Demand Reduction Milestones Based on 2024 AAFS Gas Demand Scenarios



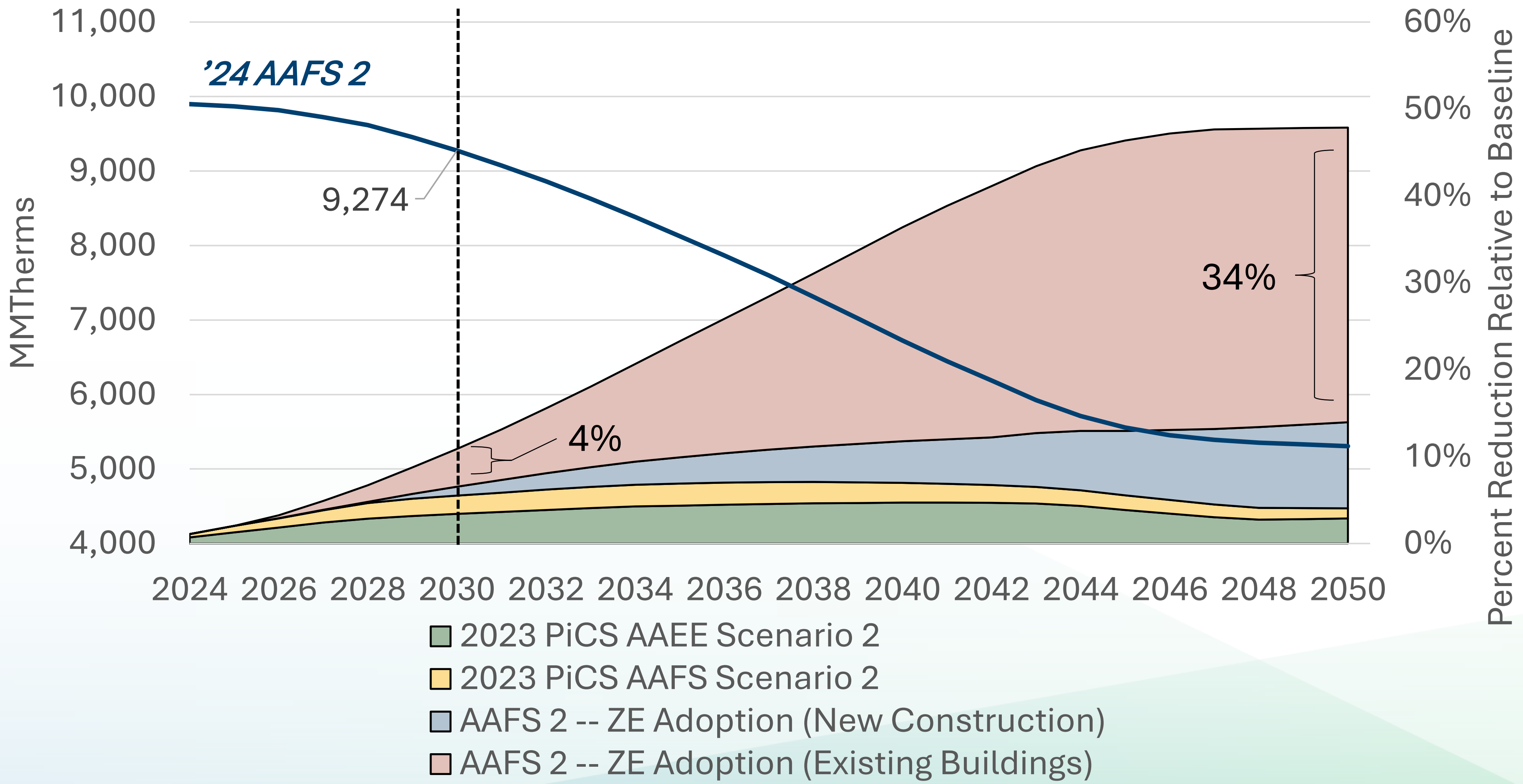
Using QFER data, one can establish and assess the 2030 gas demand reduction milestones relative to AAFS scenarios and baseline gas demand forecast

Source: CEC Staff

2030 Gas Reduction Milestones: Pair with CEC's Heat Pump Tracking Efforts

- CEC staff currently has an unofficial estimate as of Q2 2025
- Increasing agency-wide efforts in tracking equipment, particularly heat pumps
  - Existing available data sources
  - Energy Data Collection Phase 3 – Space Conditioning And Water Heating Equipment Data Tracking
  - AMI data
- Dashboard in development with planned quarterly updates
- Latest estimate in 2025 IEPR analysis

The Major Gas Reduction Components: 2024 AAFS Sc. 2 (100% ROB adoption by '40)

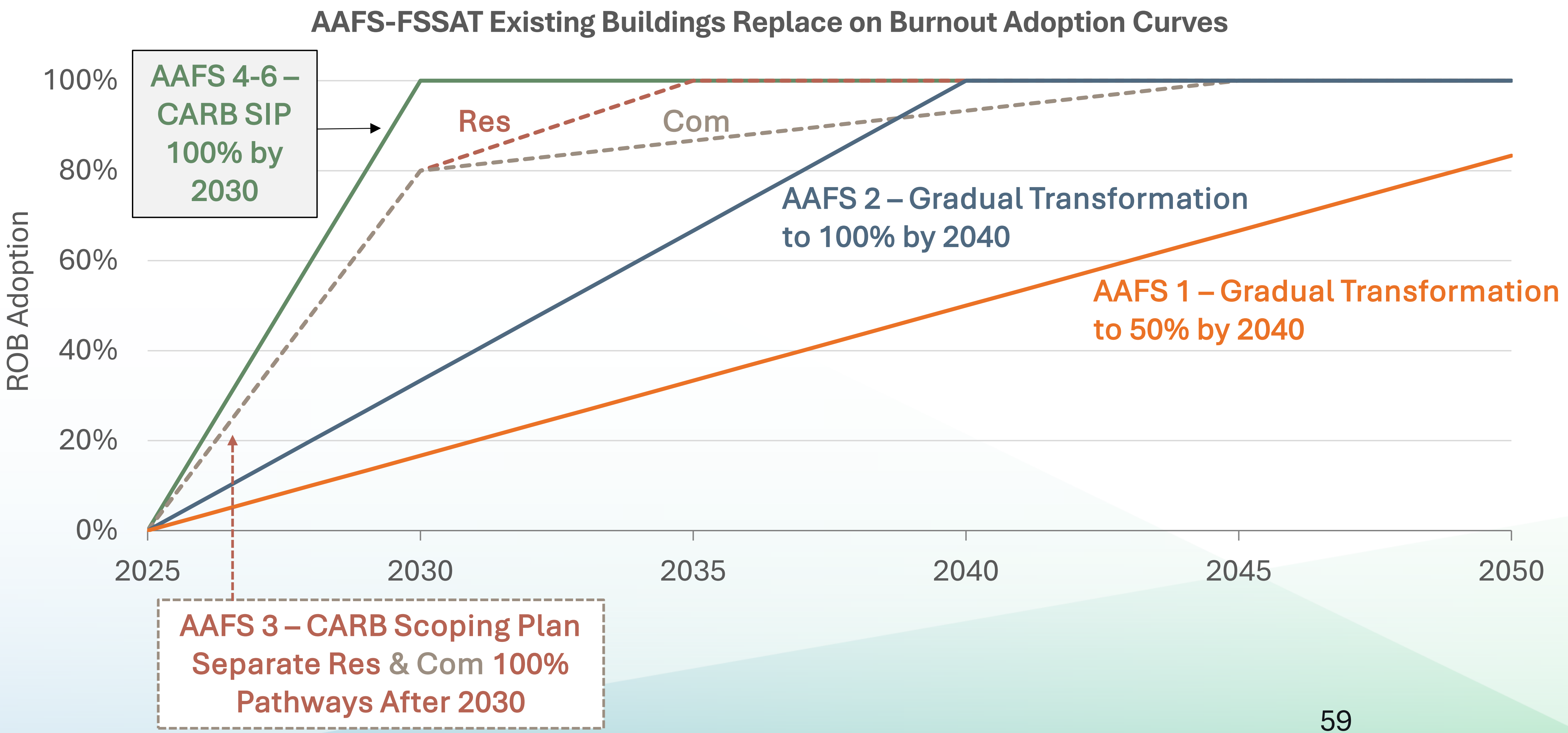


Source: CEC Staff

2025 IEPR Gas Demand Forecast

Draft Characterization of 2025 AAFS Scenarios

Proposed 2025 AAFS Scenario Replace-on-Burnout Adoption Curves



Thank You!

Nicholas Janusch, Ph.D.
Program and Project Supervisor
Advanced Electrification Analysis Branch
nicholas.janusch@energy.ca.gov

Appendix

Helpful AAEE/AAFS Resources

Reference	Description
2023 AAEE and PiCS AAFS Workbooks	A detailed workbook of AAEE and AAFS PiCS characterizations is available here: 2023 AAEE & PiCS AAFS Scenario Characterization Workbook. TN# 262297. Docket Number 24-IEPR-03. March 21, 2025.
2024 FSSAT AAFS Assumptions	A detailed workbook of FSSAT AAFS Assumptions used for 2024 IEPR Update is available here: FSSAT AAFS Assumptions used for 2024 IEPR Update. TN# 260687. Docket Number 24-IEPR-03. December 12, 2024.
2025 IEPR Demand Forecast	For the 2025 IEPR California Energy Demand Forecast Proceeding, please go here.

California Energy Commission

Fossil Gas Total Customer Rates

Presenter: Anthony Dixon, Energy Assessments Division

Date: September 22, 2025

Fossil Gas Resource Planning and Reliability Analysis

Gas Market Assessments

- Tracking national and international market developments
- Forecasting total customer rates
- Tracking revenue requirements

Gas System Assessments

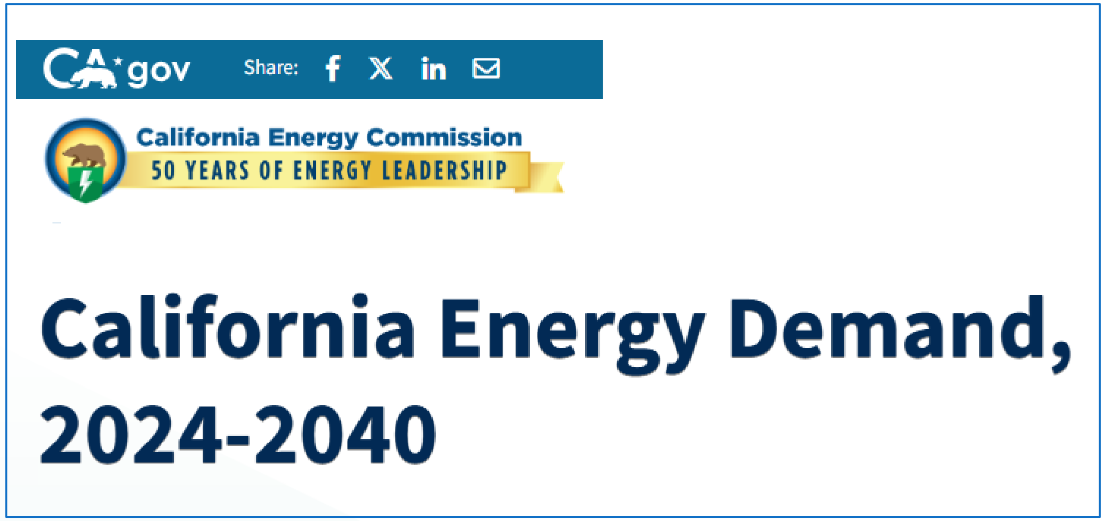
- Tracking gas system operations
- Assessing system reliability
- Assess long-term gas planning scenarios

Further Analysis, Information, and Support

- Daily tracking and reporting of gas system operations
- Assessing future pathways for low-carbon fuels
- Technical support during emergencies

Purpose

- Total Customer Rates modeling process
- California total customer rates with CED Fossil Gas Demand Forecast



Total Customer Rates

Transportation Rate
- Cost to deliver gas from pricing hub to end users

+

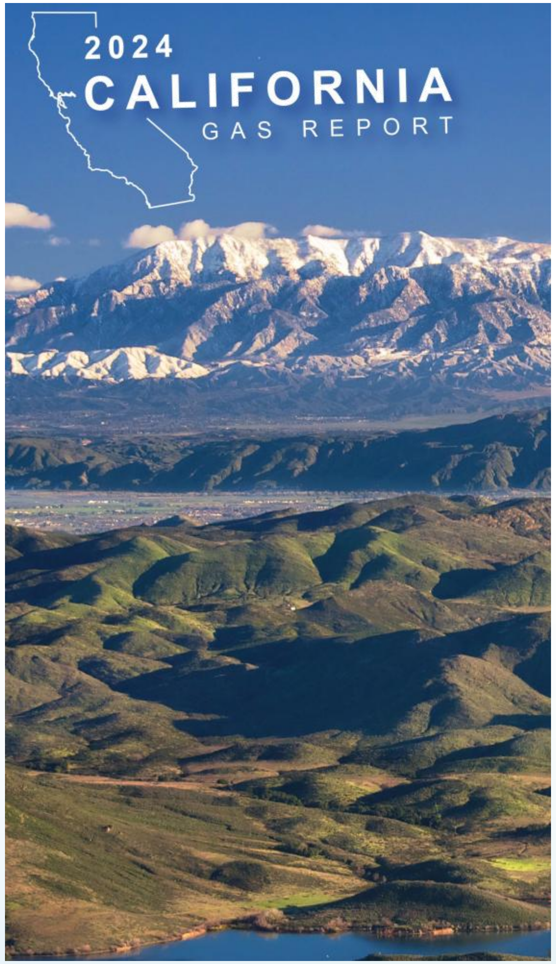
Commodity Price
- Wholesale, pass-through cost
- North America-wide market

=

Total Customer Rate

Final price customer pays for gas
- Electric Generators
- Residential
- Commercial
- Industrial

Total Customer Rates Users



State Energy Entities

- CEC
- CPUC
- California ISO

Outside Stakeholders

- Gas Utilities
- Western Electricity Coordinating Council
- Northwest Public Power Association
- Environmental Groups
- Universities and Consultants

California Utilities Transportation Rate Model

Revenue Requirement × Class Allocation ÷ Demand = Transportation Rate

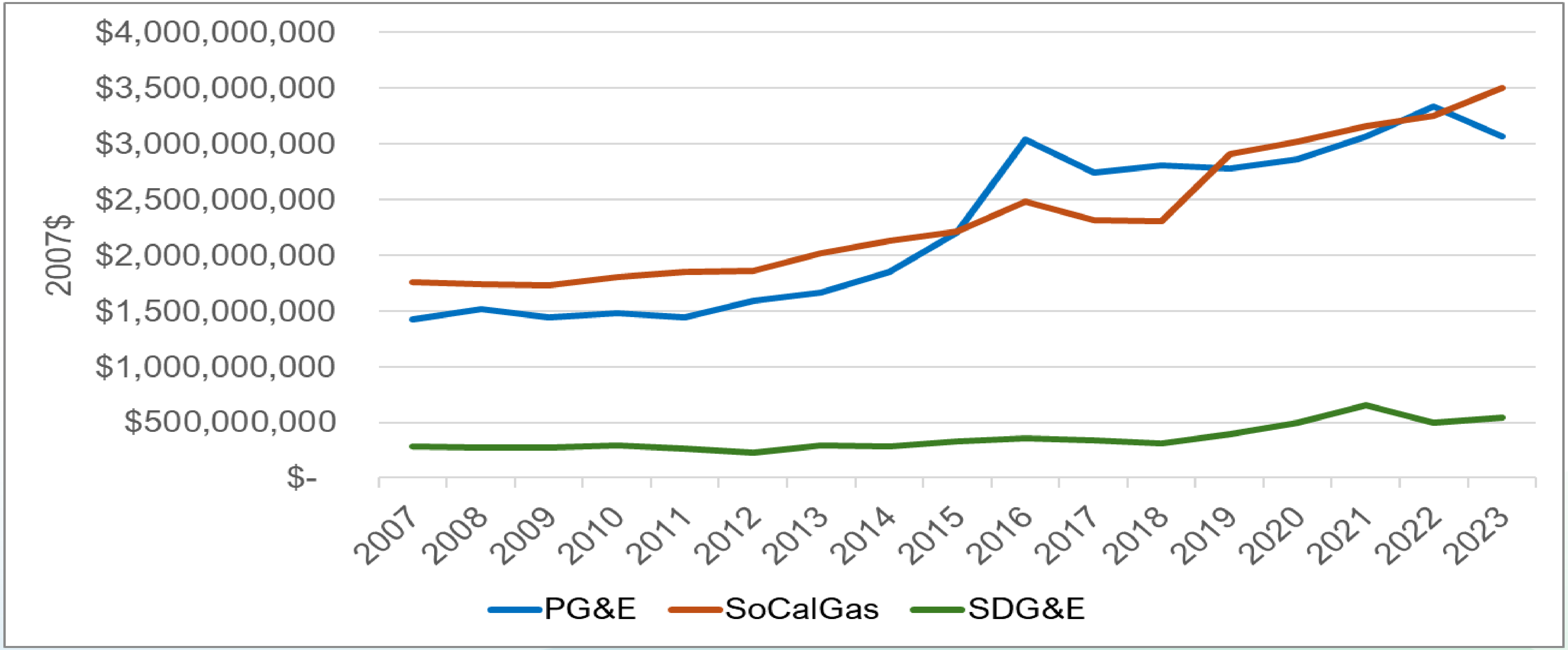
Transportation Rates Approach

Revenue Requirement (RR) x Class Allocations / Demand = Transportation Rate

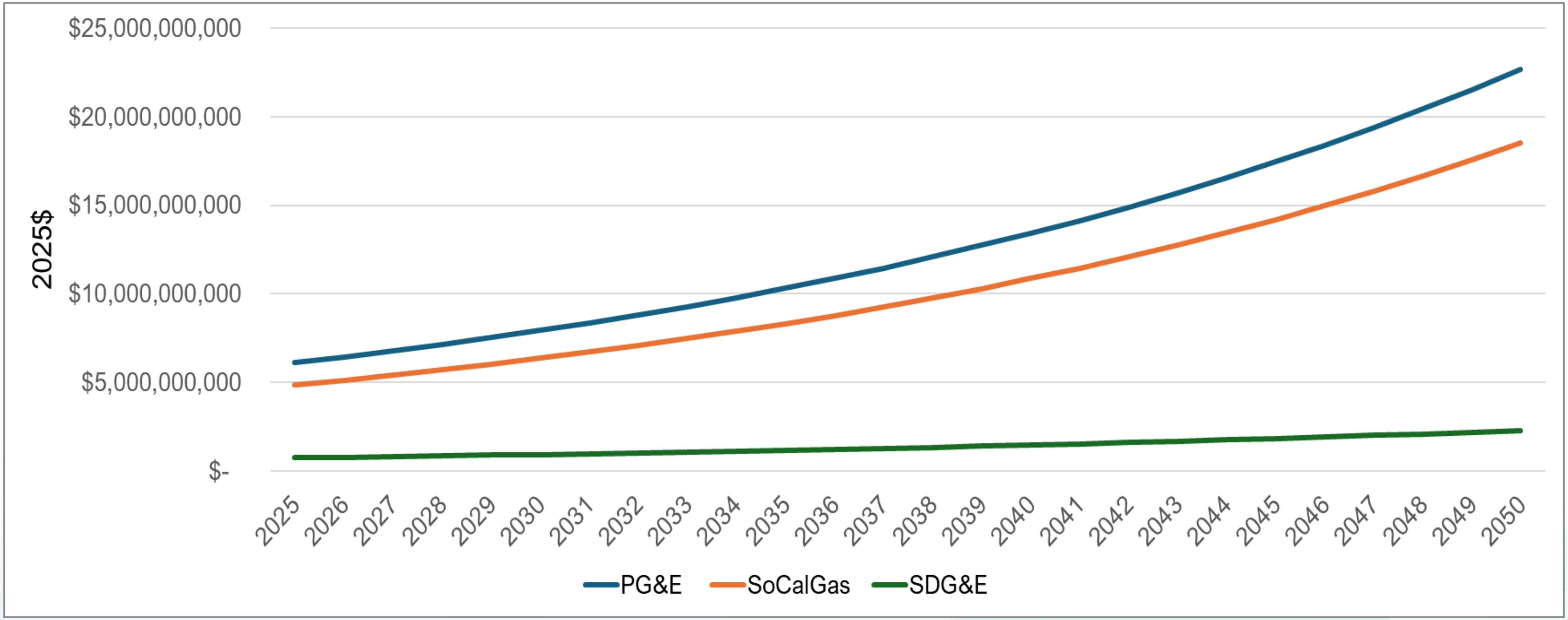
- Revenue Requirement – amount of money a utility needs to operate their fossil gas system.
  - Includes operation and maintenance (O&M), capital investments, administration costs, taxes, interest, profits.
  - Comes from utilities' January of modeling year, 2025 in this case, advice letters
  - Modeled using base year amount (see above) and constant growth rate
- Class Allocations - portion of the total RR that each class pays.
  - Comes from utilities' January of modeling year, 2025 in this case, advice letters
  - Held constant
- Demand is the 2023 CED Base Demand Case, and the three 2024 CED forecasts (AAFS, Planning Are, Local Reliability)

Historical Revenue Requirements

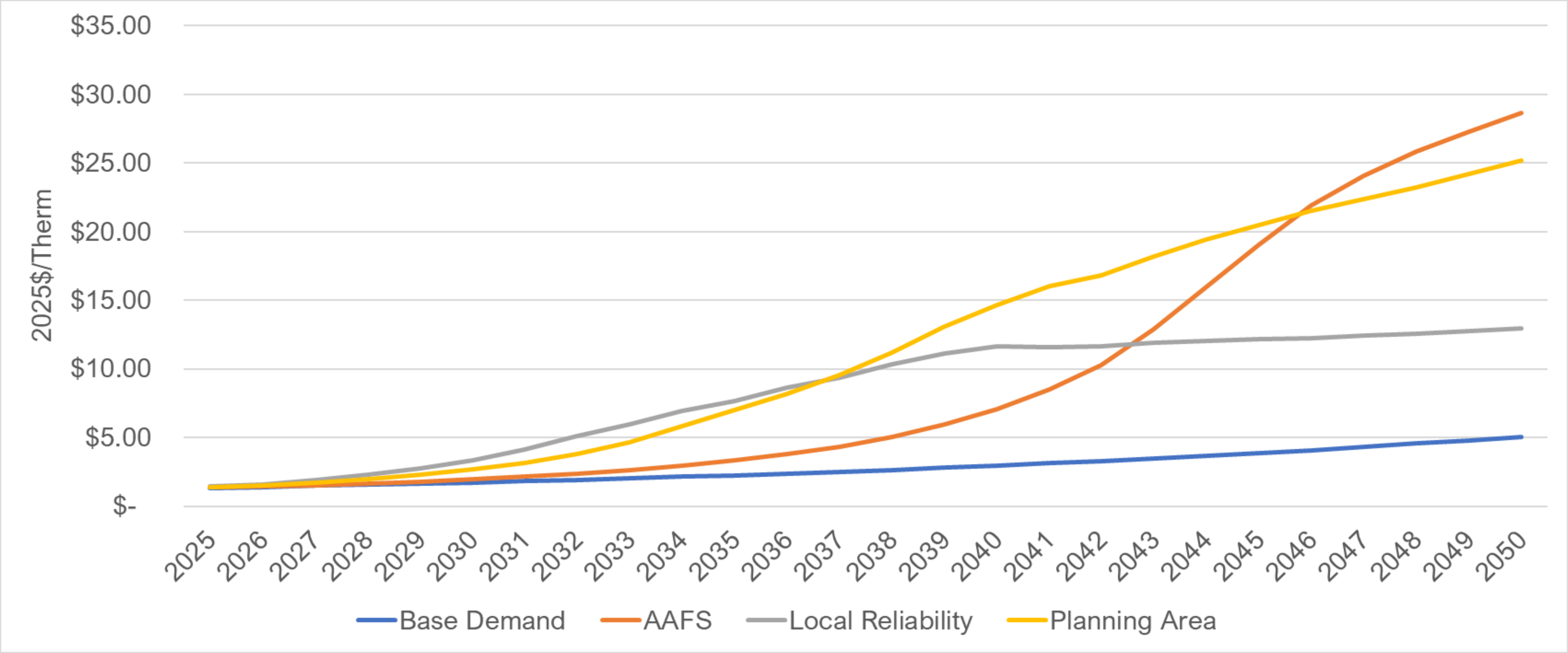
Historical Revenue requirement for the three major CA gas utilities (2007-2023):



Revenue Requirements: Constant Growth



CUTR: Residential Transportation Rates Results for SoCalGas



FGCP Modeled Pricing Hubs

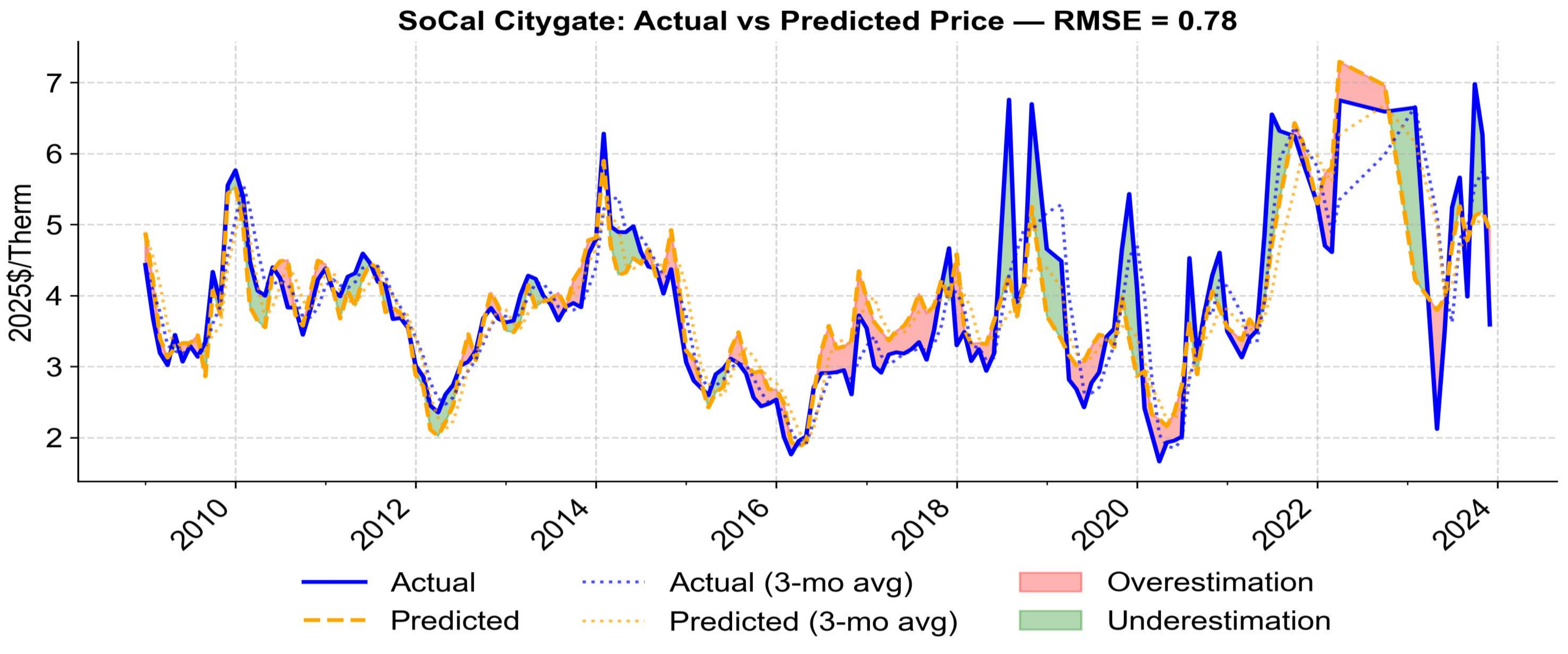
FGCP: Data Used

Data	Data Source	Description	Function in model
Henry Hub spot price	Energy Information Administration (EIA)	• National benchmark for fossil gas prices • Historical monthly data on prices, volumes, and deals • Yearly forecasted price data	The Henry Hub price serves as the benchmark for U.S. natural gas and is linked to multiple interstate and intrastate pipelines. The model uses it to constrain hub price predictions within a reasonable range.
Natural Gas Trading Volume	Natural Gas Intelligence (NGI)	• Historical Daily Hub Data	Volume reflects the 'hub' attribute, enabling the model to capture hub-specific traits, enhance prediction accuracy, and produce more representative forecasts.
Nationwide electricity retail price	EIA	• Historical state-level monthly data • National yearly forecasted price data	The model uses it to represent the 'state' attribute of various hubs, enabling differentiation of commodity price trends across states during prediction.

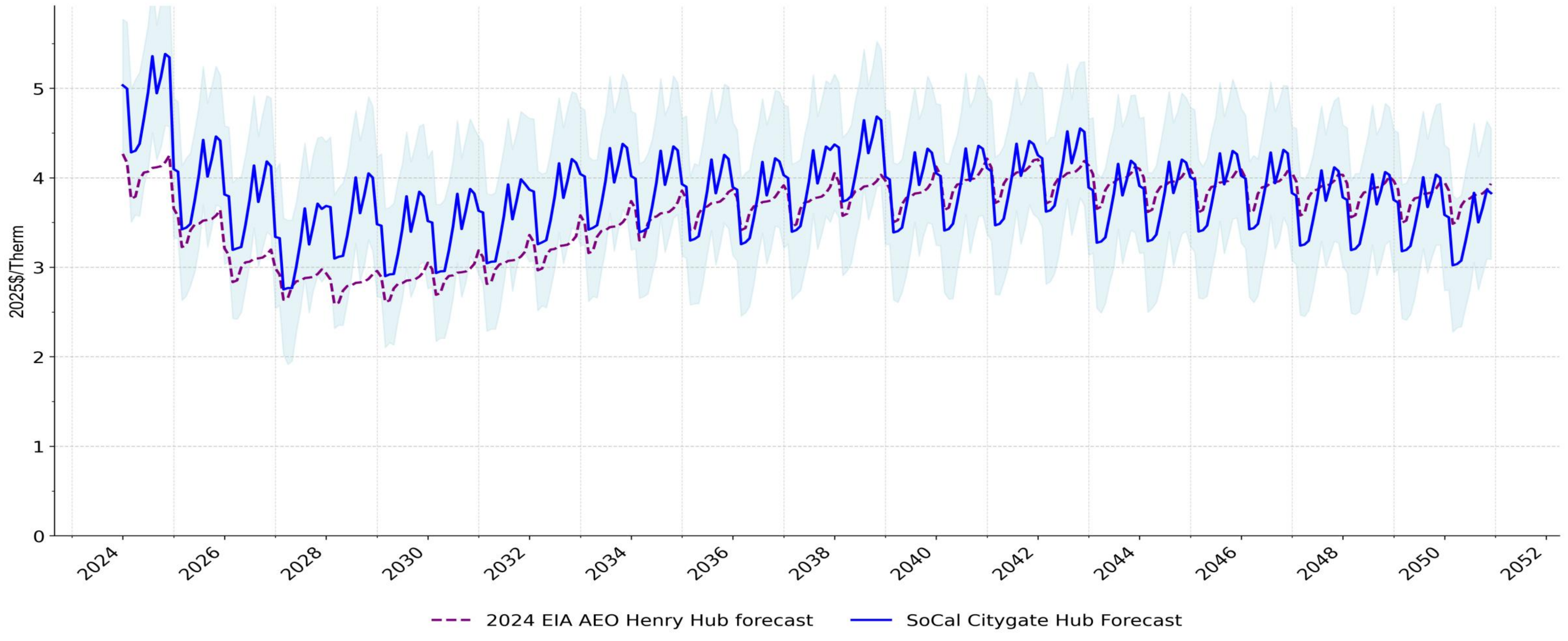
FGCP: Data Used Continued

Data	Data Source	Description	Function in model
Electricity generation from NG	EIA	• Historical state-level yearly data	Serves the same function as the 'Nationwide Electricity Retail Price'.
Renewable energy consumption	EIA	• Historical national monthly data • National yearly forecasted price data	Renewable energy consumption influences natural gas prices by affecting demand, helping the model generate more realistic price predictions.
Heating and cooling degree days	National Ocean and Atmospheric Administration (NOAA)	• Historical state-level yearly data	Functions similarly to the 'Nationwide Electricity Retail Price' and 'Renewable Energy Consumption' regressors.

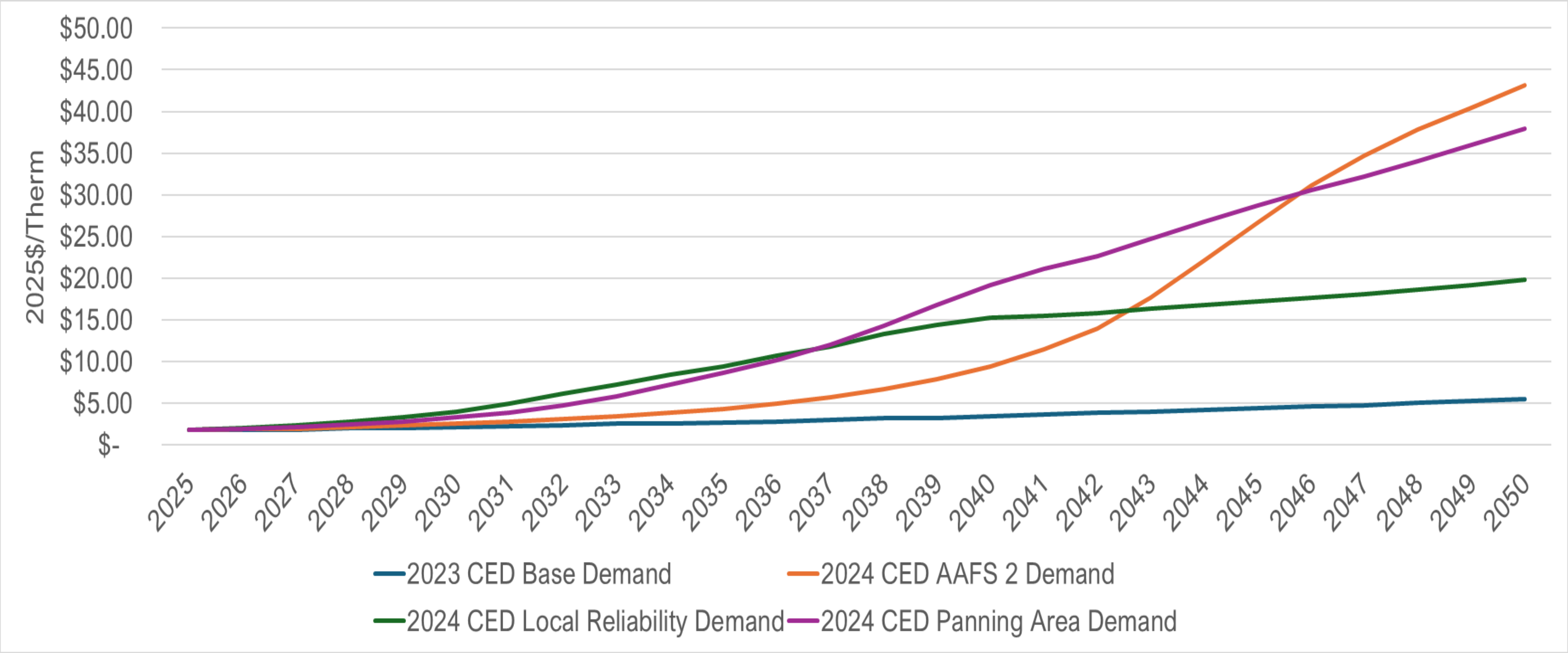
FGCP: Verifying Model's Accuracy



FGCP: Results for SoCal Citygate



Total Customer Rates: SoCalGas Residential



Fossil Gas Total Customer Rates

Thank You!

Questions?

Gas Distribution Infrastructure Replacement

Identifying Cost-Effective Decarbonization Opportunities

CPUC Energy Division Staff Presentation

Eileen Hlavka

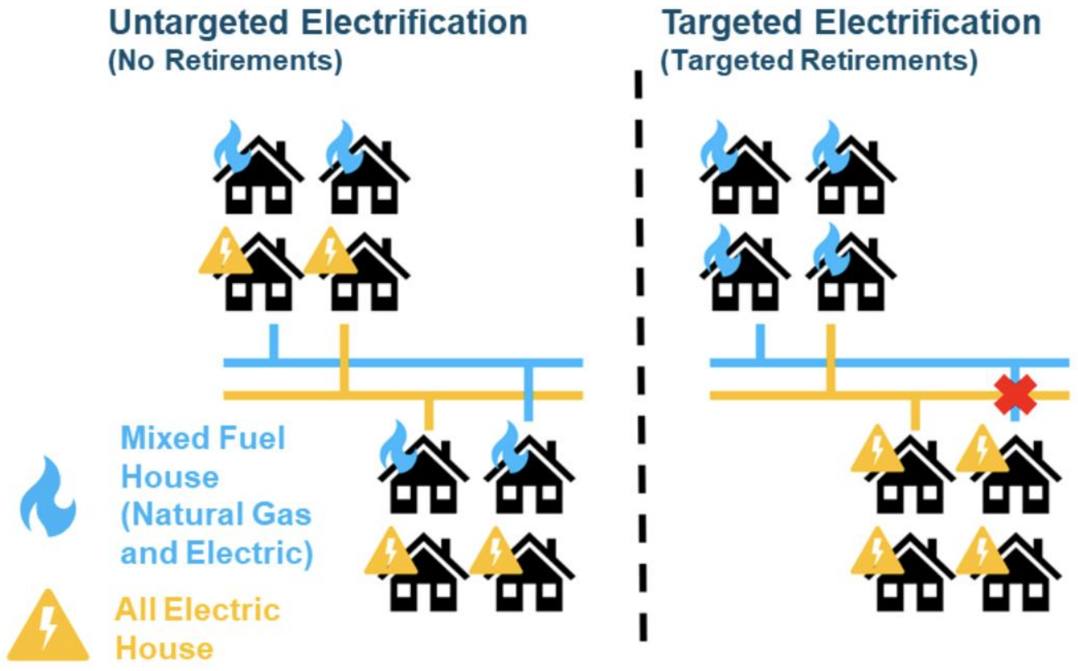
September 22, 2025

California Public Utilities Commission

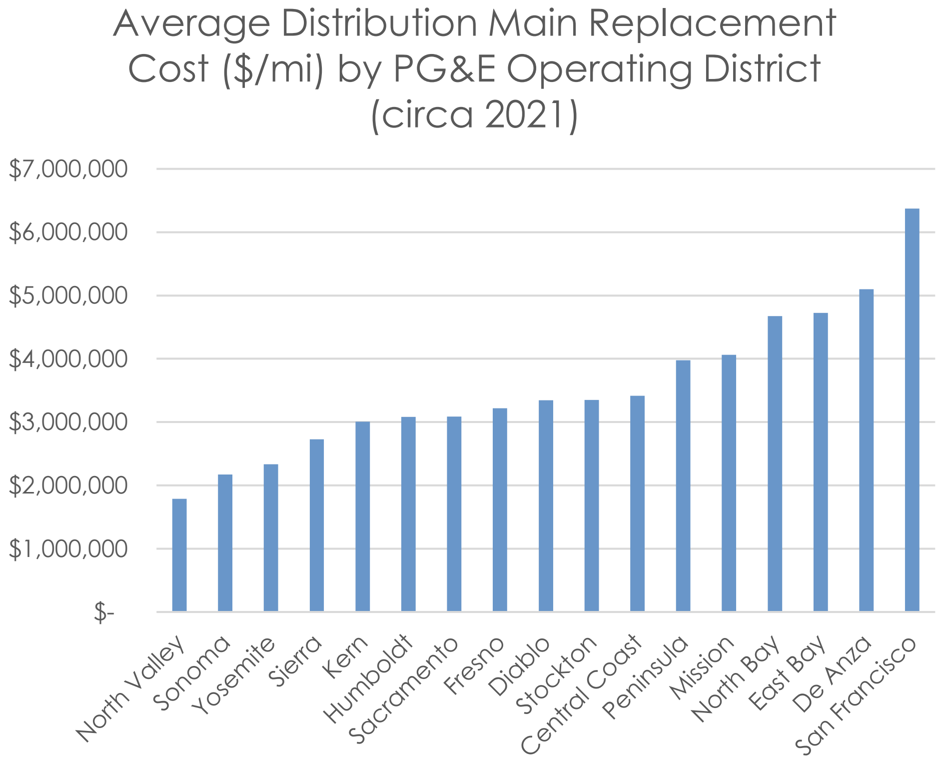
Agenda

- Context
- Major Gas Distribution Infrastructure Replacement Activities
- Distribution Mains and Services Replacement
  - Overview
  - Site Selection
  - Customer and Jurisdiction Consent
  - Cost Estimation
- Services-Only Replacement
- Regulator Station Replacement

Prior Discussions Identify Neighborhood Decarbonization as Cost-Savings Opportunity



Source: E3



Source: PG&E census tract data submitted in proceeding

Major Gas Distribution Replacement Programs

Infrastructure Replaced	GRC Rate Codes			Units of Work
	PG&E	SoCalGas/SDG&E	Southwest Gas	
Mains and Services	14A (Aldyl-A), 14D (aging steel), 50A (other)	VIPP (Aldyl-A) and BSRP (aging steel) in 277, other (252, 253, 255, 267, 278)	TPRP (plastic) and VSP (aging steel) in 9636 and 9605	Work order, aka site
Services Only	50B	256, 257, 258, 260	COYL (customer-owned) Program	Work order, aka site
Regulator Station Replacement	50C	Rebuilds within 265	NA	Regulator station

Mains and Services Replacement Process

What is gas distribution mains and services pipeline replacement?

- **Routine replacement of gas distribution main pipelines, and usually, the services connected to them**
- New pipe laid alongside existing pipe, connected at project endpoints, old pipe disconnected. Also includes site access and restoration (repaving etc.)
- Occupational hazards mitigated: noise, gas exposure, explosion risk

Mains and Services Replacement Aspects

- Each utility conducts an iterative review of its distribution pipelines to identify and replace the highest-risk segments
  - Process initiated **annually** by some utilities or at their discretion up to every four years;
  - Site completion is **staggered**: each work order may occur one to four years later, depending on site-specific factors
- A single “work order” or site may be hundreds of feet to thousands of feet long

Caveat to upcoming timing slides: Timelines for each step may vary from project to project as well as utility to utility, and steps may overlap.

Key Mains and Services Replacement Steps

Utility Action	Approx Time Before Breaking Ground
Site Selection: Prioritization by Calculated Risk	**1-2 years, up to 4 years**
Site Selection: Prioritization by Observation	**1-2 years, up to 4 years**
Initiation: Site Selection: Site Boundary Adjustment and Mapping	12-18 months (6-9 months for SWG)
Initiation: Consider Contacting Agencies and Landowners	12-18 months
Initiation: Scheduling	12-18 months
Execution: Apply for Permits	3-6 months
Execution: Landowner Contact for Consent	0-6 months
Execution: Customer Informational Alert	1-2 weeks
Execution: Online Public Alert (Southwest Gas only)	1-2 weeks
Execution: Construction and Restoration	0
Completion	2-12 weeks after beginning construction
Reconciliation	4-28 weeks after construction

Key Steps: Site Selection

- Sites typically selected at least 1-2 years in advance of target completion date, for risk-based programs
  - Some projects are delayed by months or years based on consent and feasibility
- Can be selected farther in advance using same software
  - SB 1221 maps show just that
- Project boundaries are routinely adjusted
  - Thus implying some adjustment is also acceptable for decarbonization

Key Steps: Customer and Jurisdiction Consent

- Consent processes already exist but do not apply to most customers or incorporate discussion of non-gas options
- Landowner consent, if needed, occurs on multiple timelines and pathways
- Local jurisdictions have permitting authority over projects
- While landowner consent may be required, in many cases it is not, so most customers are not notified well in advance
- Online mapping of upcoming sites is conducted by Southwest Gas only

Key Steps: Cost Estimation

- Cost estimates available early based on project definition
  - Utilities typically have equations for conducting these estimates at two different levels of granularity
- Precise costs not known until after project is completed

Services-Only Replacement

- Funded by dedicated General Rate Case codes
- Replaces only gas services, one at a time
- Follows similar procedures and costs to mains and services replacement
- May have shorter timelines due to fewer customers per site
- PG&E 2023 General Rate Case decision redirected funds disallowed for service replacement ($10.3 million in 2023) to be used for its Alternative Energy Program (AEP)

Note: PG&E's Alternative Energy Program, which fully funds electrification in selected sites of up to 5 customers where large gas investments can be avoided, requires customers to identify their own electrification vendors and typically takes 4-6 months from customer contact to completion.

Gas Distribution Regulator Station Replacement

- One or more gas distribution regulator stations serve a group of customers on interconnected mains and services called a "pressure district" by reducing pressure from upstream lines to mains and services that reach customer meters
- Not to be confused with larger upstream regulator stations
- **Replaces most major equipment** at station: piping and valves for flow control, measurement, and release, and may relocate station nearby
- **Constitutes an additional cost-saving opportunity** if can be avoided

Gas Distribution Regulator Station Replacement Process

- Stations are typically inspected annually and scheduled for replacement based on assessed risk ranking
- PG&E and SoCalGas/SDG&E together replaced about 25 stations per year in 2021-2024 (excluding High-Pressure Regulator or HPR-type stations)
- On average, it takes more than two years from identification for replacement to breaking ground

For more information:

eileen.hlavka@cpuc.ca.gov

Reference Slide: Site Selection

Utility Action	Details
Site Selection: **Prioritization by Calculated Risk**	Use utility-specific DIMP software to identify sites for **aldyl-A and aging steel replacement programs**.
Site Selection: Prioritization by Observation	Use leak surveys, observation to ID sites for other main and service replacement programs.
Initiation: Site Selection: Site Boundary Adjustment and Mapping	Propose site boundary/scope of work order by potentially **adjusting initial boundaries**, including changes based on cost, grouping nearby sites, and reduction of environmental impacts.

- Sites typically selected at least 1-2 years in advance of target completion date, for risk-based programs
  - Some projects are delayed by months or years based on consent and feasibility
- Can be selected farther in advance using same software
  - SB 1221 maps show just that
- Project boundaries are routinely adjusted
  - Thus implying some adjustment is also acceptable for decarbonization

Reference Slide: Customer and Jurisdiction Consent

Utility Action	Approx Time	Communication Details
Initiation: Consider Contact	**12-18 months**	Contact landowners or permitting agencies **in complex cases**, e.g., mobile home park or creek crossing.
Execution: Apply for Permits	3-6 months	Apply to site city and county for construction permits. Seek any environmental permits.
Execution: Landowner Consent	3-6 months	Landowners only contacted for consent (easement, ROW) if they are not the customers, e.g., a service passes through neighboring land.
Execution: Customer Info Alert	1-2 weeks	Customers alerted of work at their location via **door hangers, mailers or forums**
Execution: Online Public Alert (**SWG only**)	1-2 weeks	Post to online map, https://www.swgas.com/en/construction-projects.

- Consent processes already exist but do not apply to most customers or incorporate discussion of non-gas options
- Landowner consent, if needed, occurs on multiple timelines and pathways
- Local jurisdictions have permitting authority over projects
- While landowner consent may be required, in many cases it is not, so most customers are not notified well in advance
- Online mapping of upcoming sites is conducted by Southwest Gas only

Reference Slide: Cost Estimation

Utility Action	Approx Time	Site Costs
Site Selection: Prioritization	1-2 years, up to 4 years	**Estimate costs** defined by main pipeline length, # services, and service density, by operating district. Estimate using last 3 years of historical data. Serves as a target to keep costs, on average, at GRC allocation level.
Site Boundary Adjustment and Mapping	12-18 months (6-9 months for SWG)	**Estimate precise costs** based on scope of work, incl pipeline length, diameter, material, depth, valve count, paving and prelim envl requirements, site operating district, and other work characteristics, aka unit costs. Costs also depend on whether done by utility or contracted out. Sites will cost this amount unless something changes.
Execution: Construction and Restoration	0	Actual costs incurred. **Costs may change** from estimates if unexpected site conditions discovered (e.g. groundwater).
Completion	2-12 weeks later	Contractors paid most costs.
Reconciliation	4-28 weeks later	**Final costs recorded** and contractors paid.

- Cost estimates available early based on project definition
  - Utilities typically have equations for conducting these estimates at two different levels of granularity
- Precise costs not known until after project is completed

Reference Slide: Key Main and Service Replacement Steps

Utility Action	Approx Time Before	Details	Site Costs
Site Selection: Prioritization by Calculated Risk	1-2 years, up to 4 years	Use utility-specific Distribution Intregity Management Program software to rank potential sites based on main risk. Identifies sites for aldyl-A and aging steel replacement programs.	Estimate costs defined by main pipeline length, number of services, and density of services, by operating district. Estimate using last 3 years of historical data. This estimate serves as a target to keep costs, on average, at the level allocated for in GRCs.
Site Selection: Prioritization by Observation	1-2 years, up to 4 years	Identify additional potential sites based on leak surveys and other in-person observation. Applies to other main and service replacement programs.	Estimate costs defined by main pipeline length, number of services, and density of services, by operating district. Estimate using last 3 years of historical data. This estimate serves as a target to keep costs, on average, at the level allocated for in GRCs.
Initiation: Site Selection: Site Boundary Adjustment and Mapping	12-18 months (6-9 months for SWG)	Propose final mix of sites balancing risk, cost and labor resources. Propose final site boundary/scope of work order by potentially adjusting initial boundaries, including changes based on cost, grouping nearby sites, and reduction of environmental impacts. Identify affected services.	Estimate precise costs based on scope of work, including pipeline length, diameter, material, depth, valve count, , paving and prelim environmental requirements, site operating district, and other work characteristics, aka unit costs. These costs also depend on whether done by utility or contracted out. Sites will cost this amount unless something changes.
Initiation: Consider Contacting Agencies and Landowners	12-18 months	Contact landowners or permitting agencies in complex cases, e.g., mobile home park or creek crossing.	
Initiation: Scheduling	12-18 months	Identify target construction month (subject to change).	
Execution: Apply for Permits	3-6 months	Apply to site city and county for construction permits. Apply for any applicable environmental permits.	
Execution: Landowner Contact for Consent	0-6 months	Landowners only contacted for consent (easement, right of way) if they are not the customers, e.g., a service passes through neighboring land.	
Execution: Customer Informational Alert	1-2 weeks	Customers alerted of work expected at their location via door hangers, mailers or forums, depending on site or program. On-site gas tanks mean work usually does not interrupt their gas flow. No broader public notification.	
Execution: Online Public Alert (Southwest Gas only)	1-2 weeks	Post to online map, https://www.swgas.com/en/construction-projects.	
Execution: Construction and Restoration	0	New pipe laid alongside existing pipe, connected at project endpoints, old pipe disconnected. Also includes site access.	Actual costs incurred. Costs may change from estimates if unexpected site conditions discovered (e.g. groundwater).
Completion	2-12 weeks after beginning construction	New gas service in operation	
Reconciliation	4-28 weeks after construction	GIS mapping of completed project, quality control review, cost reconciliation, payment of remaining costs and closeout of work order.	Final costs recorded and contractors paid.

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Non-Pipeline Alternatives:

What we can learn from other jurisdictions

Sarah Steinberg, Managing Director

September 22, 2025

New York

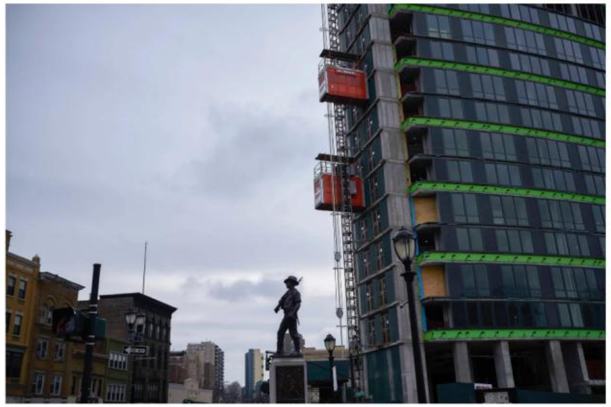
New York's NPA journey began as a tool to address supply and delivery constraints

They have been more recently recognized as a tool for cost-containment and clean energy policy compliance

The New York Times

Con Ed Cuts Off New Gas Hookups in New York Suburb

Share full article 114



Residential buildings in Yonkers, one of the cities and towns in Westchester County where Con Edison, the main utility, has imposed a moratorium on new natural gas hookups. John Taggart for The New York Times

By Debra West

March 21, 2019

https://www.nytimes.com/2019/03/21/nyregion/con-ed-natural-gas.html

Commission Directs Central Hudson to Take Additional Action to Reduce Natural Gas Demand, Advancing Goals to Maintain Gas System Reliability and Reduce Greenhouse Gas Emissions

July 17, 2025

…Specifically, the Commission directed the company to develop and propose pilot demand response programs and pursue non-pipes alternatives for at least two locations in its service territory.

"The Commission's natural gas planning procedures bring greater transparency to how our gas utilities provide safe, adequate, and reliable service while striving to meet the State's greenhouse gas emissions reduction targets," said Commission Chair Rory M. Christian. **"This process is critical to ensuring reliability and affordability, while advancing State clean-energy policies to combat climate change."**

https://dps.ny.gov/news/groundbreaking-process-continues-advance-gas-system-reliability-and-planning-transparency

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Early NPAs used competitive solicitations to build portfolios of projects to serve specific gas system needs

conEdison

Projects

SOUNDVIEW DISTRIBUTION SYSTEM REINFORCEMENT

PORTCHESTER DISTRIBUTION SYSTEM REINFORCEMENT

WHOLE BUILDING ELECTRIFICATION SERVICES

NYSEG NPA process (2019-2021)

2019: NYSEG found that growth on gas distribution system led to too-low delivery pressures during peak conditions in Lansing, NY

December 2019: NPA RFP for innovative solutions to defer or avoid the need for construction of a Reinforcement Gas Pipeline Project via demand reduction or equivalent supply

March 2020: 16 proposals received, including: heat pumps (air, ground, water, community loop); efficiency measures; hydrogen injection; thermostat DR; industrial heat recovery; CNG and RNG

August 2020: NYSEG petition at the NY PSC proposing 7 projects from the RFP responses: **1) residential heat pumps; 2-3) commercial GSHP; 4) community GSHP; 5) efficiency at two schools; 6) industrial heat recovery; 7) education and outreach**

June 2021: NY PSC approved the petition (with modifications), allowing NYSEG to proceed with contract negotiations

https://www.nyseg.com/ourcompany/reliableservice/reliability-projects/non-pipe-alternatives

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Later programs offer electrification solutions to customers to replace pre-1972 service lines and avoid leak prone pipe replacement

Consolidated Edison's Energy Exchange Program: eliminates replacement of gas services installed pre-1972 by providing customers with electric alternatives for existing gas end-uses (not including space heating) to facilitate their disconnection from the gas system

- ~38,500 buildings identified
- Limited to the first 100 service lines and associated customers that elect to participate in the program

As of November 2024, **three customers are onboarded; one customer has completed gas disconnection.**

Consolidated Edison's Electric Advantage Program: eliminates replacement of leak prone gas mains by providing customers with electric alternatives for all existing gas end-uses to facilitate their disconnection from the gas system

- 2022-2024: 108 projects were feasible and cost effective; 2024 filing: 24 new projects identified

As of November 2024, 30% of projects are in progress (70% have had customer participation challenges)

14 buildings had been electrified on 9 mains.

- **3 mains have been abandoned**
- **2 main abandonments in progress**
- **Partial electrification is complete on 5 additional mains**

Company recruiting at 92 more locations.

ConEdison: Electric Advantage and Energy Exchange BCA framework

Energy Exchange BCA

Table 1: Service Replacement Portfolio and BCA summary

Portfolio Size (# of service replacements avoided)	Total Energy Savings (MMBtu /year)	Total Benefits (NPV to 2024)	Total Costs (NPV to 2024)	BCA SCT Score	Con Edison Investment (NPV 2024)[4]	Customer Portion of Net Benefit (70% of Net Benefits)	Performance Incentive[5] (30% of Net Benefits)
100	2,309	$2,761,110	$1,982,648	1.39	$2,272,912	$544,923	$233,539

Electric Advantage BCA

Costs	Benefits
Additional program participant incentives	Avoided gas consumption in dekatherms and customer savings
Incentive costs from other efficiency and electrification programs	Avoided peak day gas capacity and customer savings
Administration and implementation planning, marketing, reporting, payments to independent contractors for quality control, evaluation, and M&V	An increase in MWh of electric consumption and a decrease in MW in peak electric system load (can be + or -)
	Avoided oil consumption and customer savings
	Net avoidance of CO2 emissions reductions and benefits in dollars
	Avoidance of the traditional solution in dollars

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https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=67367&MNO=22-G-0065 (7/23/2024 BCA filings and 11/18/2024 NPA Annual Report)

Colorado

Colorado comes to NPAs via gas system planning and a desire to contain infrastructures costs while meeting state decarbonization goals

2021: The Commission hosted a "miscellaneous" docket to review gas utility regulation (21M-0395M)

2021: The Colorado legislature passes SB 264 establishing Clean Heat Plans for gas utilities and HB 1238 modifying gas demand side management programs and the Commission opens 21R-0449G to implement rules

2022: Commission finalizes rules after receiving 300+ comments, hosting various public comment sessions, and redlining versions of draft rules

Rules include requirement for NPA analyses for all "new business" and "capacity expansion" projects included in the plan (minimum cost threshold of $3 million for projects *and* sets of interrelated projects).

2023: Public Service Company of Colorado files its first (non-adjudicated) Gas Infrastructure plan (23M-0234G)

Commission decision on April 3, 2024 "strongly encourage[s]" the Company to include NPA analyses for system safety and integrity projects

2024: Commission opens an M-docket to focus on utility forecasting, mapping, and **NPA CBA** to improve 2025 filing (24M-0261G)

Creation of a CBA Handbook with stakeholder input; decision acknowledging factors beyond the CBA: stranded asset risk, commodity cost uncertainty (particularly in extreme weather), locational characteristics, unquantified health impacts

2025: Public Service Company files its second (adjudicated) Gas Infrastructure Plan (25A-0220G) and **Mountain Energy NPA CPCN** (25A-044EG)

Public Service Company’s NPA Development Process starts with GIP project identification.

STEP ONE: Identify projects by category and timeline

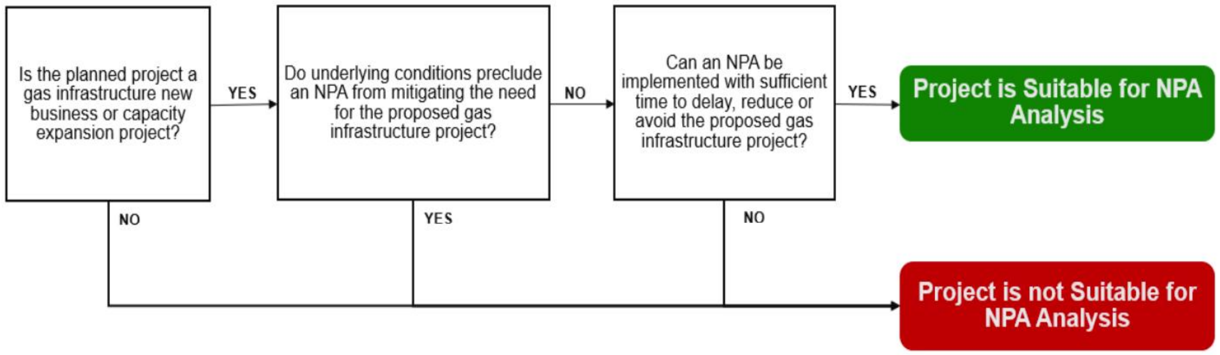
Table 4:
2025 GIP Planned Projects ($/Millions)

	Action Period				Informational Period						
Planned Project Category	**2025**	**2026**	**2027**	**No. of Planned Projects**	**2028**	**2029**	**2030**	**No. of Planned Projects**	**Total No. Planned Projects**	**Est. Total Planned Project GIP Period CapEx**	**Est. Total Planned Project CapEx***
System Safety & Integrity	$67.0	$88.4	$77.5	30	$76.3	$65.4	$32.9	21	51	$407.5	$425.8
Capacity Expansion	$13.1	$75.6	$33.7	2	$0.6	$2.0	$2.6	3	5	$127.5	$135.0
New Business	$25.7	$6.3	$5.4	6	$0.0	$0.0	$0.0	0	6	$37.4	$30.7
Mandatory Relocation	$0.0	$0.0	$0.0	0	$0.0	$0.0	$0.0	0	0	$0.0	$0.0
Planned Projects Total:	**$105.8**	**$170.3**	**$116.6**	**38**	**$76.9**	**$67.4**	**$35.5**	**24**	**62**	**$572.5**	**$591.6**

* Includes capital expenditures for included Planned Projects before GIP Total Period.

STEP TWO: Screen eligible projects

Figure 9: NPA Initial Suitability Criteria Framework



STEP THREE: Evaluate alternatives

Criteria Used to Rank or Eliminate Alternatives

- Technical Potential
- Achievable Potential
- Cost Benefit Analysis
- Best Value Employment Metrics

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The under-review Mountain Energy NPA is the largest NPA to date, impacting over 33,000 customers

PSCo was planning an LNG Hub and Spoke project to serve increasing gas demand in their mountain system.

This traditional project costs up to $328 million.

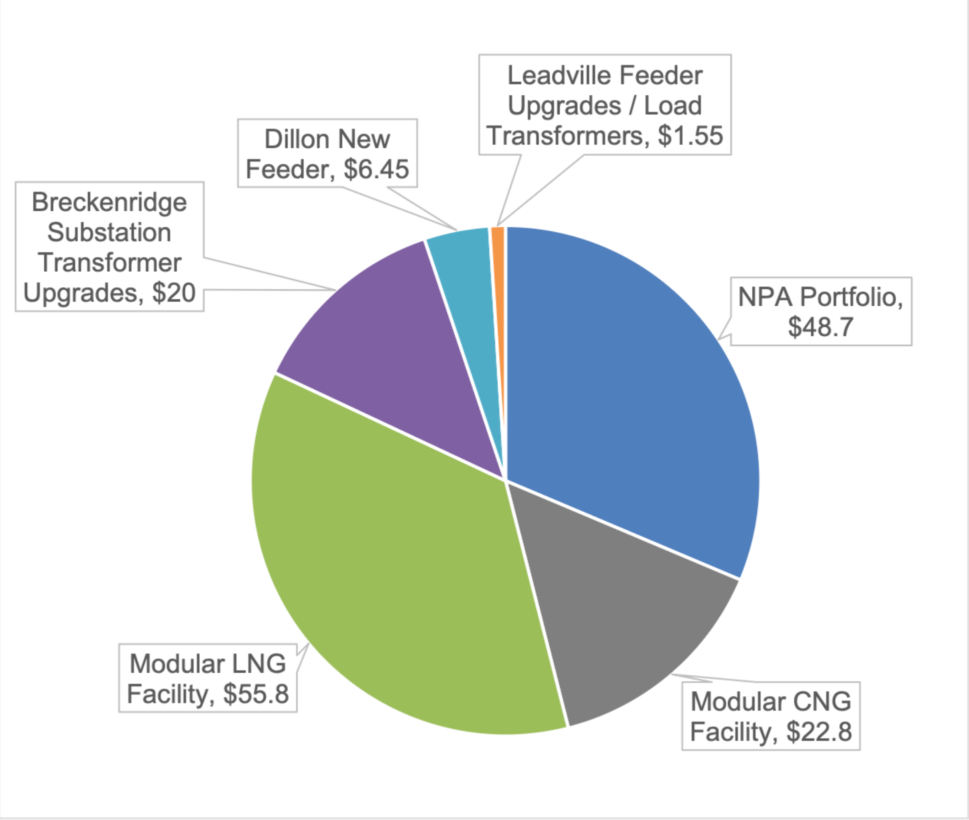
They are seeking approval of an NPA portfolio that include building electrification, demand response, energy efficiency, and smaller CNG and LNG facilities.

The NPA is projected to cost $155 million.

Table 3-1: ME NPA Residential Participation by Type of Measure and Year

ME NPA Residential Measure Type	2025 (Premises)	2026 (Premises)	2027 (Premises)	Totals (Premises)
Energy Efficiency - Non-Equipment	821	1,022	1,271	**3,114**
Energy Efficiency - Home Energy Reports[2]	~6,000	~6,000	~6,000	**~6,000**
Energy Efficiency - Equipment	325	413	514	**1,252**
Building Electrification	54	70	92	**216**
Demand Response[3]	-	~16,000	~21,000	**~21,000**

Figure GKJ-D-3:
Hybrid Portfolio Cost Estimates, By Component ($ in millions)



Public Service Company's CBA Framework

PSCo primarily uses the "Expanded, Modified Total Resource Cost" test (EMTRC)

Societal Impact	EMTRC
Incremental Generation Emissions Cost	Included and Quantified
Avoided Methane Leakage Benefit	Included and Quantified
Avoided CO2 Emissions Benefit	Included and Quantified
Incremental Generation Methane Leakage Cost	Included, Not Quantified
Air Pollutants	Included, Not Quantified
Land and Water Impacts	Not Applicable
Workforce Impacts	Not Applicable

Utility Impact	EMTRC
Program Incentive Cost	Not Applicable
Participant Cost	Included and Quantified
Administrative Cost	Included and Quantified
Generation Capacity Cost	Included and Quantified
Transmission Capacity Cost	Included and Quantified
Distribution Capacity Cost	Included and Quantified
Electric Commodity Cost	Included and Quantified
Incremental Line Losses	Included and Quantified
Ancillary Services Cost	Included and Quantified
Winter Mitigation Cost	Included and Quantified
Incremental Gas Infrastructure Cost	Included and Quantified
Avoided Gas System O&M Cost	Included and Quantified
Non-Energy Benefits	Included and Quantified
Net Revenue Impact	Not Applicable
Electric Reliability Cost	Included, Not Quantified
Reliability Benefit	Included, Not Quantified
Higher Utilization of Underutilized Assets	Not Applicable
Avoided Line Extension Subsidies	Not Applicable

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Massachusetts

ADVANCED ENERGY UNITED™

The DPU flipped the paradigm, requiring NPAs to be non-viable in order to get cost recovery on traditional gas system investments

- Order 20-80-B in Future of Gas Docket (No. 20-80) (December 6, 2023)

  “Going forward, the Department states that as part of future cost recovery proposals, **LDCs will bear the burden of demonstrating that NPAs were adequately considered and found to be non-viable or cost prohibitive to receive full cost recovery**”

- Order modifying Gas System Enhancement Program (24-GSEP-03) (April 20, 2025)

  “[The DPU will allow] spending in excess of the newly established 2.5 percent revenue cap **up to 3.0 percent for non-pipeline alternatives**, i.e., NPAs, which will encourage gas companies to consider solutions that avoid additional investment in fossil fuel infrastructure”

Lessons learned

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Key learnings from other states

- NPAs can be a valuable cost-containment mechanism!
- Be expansive in what *types* and *sizes* of projects can become NPAs. Think both ***big*** (Mountain Energy NPA) and ***small*** (Electric Advantage and Energy Exchange)
- ***Early systematic project identification*** is key, whether in the context of an infrastructure plan or by finding projects with similar sets of characteristics
- Competitive solicitations can help utilities identify the lowest-cost solutions, but often require pre-application engagement and then hands-on post-application joint utility-vendor work
- Look for creative ***portfolios of solutions***; don't get too boxed into pre-defined solutions
- Where possible, get stakeholders and the utility on the same page early (outside of litigated dockets)
- Construct CBAs thoughtfully. There is a high risk of double counting electric distribution system costs.
- ***Get started!*** Anything we create now will need iteration, but we'll learn by doing. The CPUC can jumpstart the process by addressing key regulatory hurdles *for now.*

ssteinberg@advancedenergyunited.org

Thank you.

Policy Options to Facilitate Non-Pipeline Alternatives

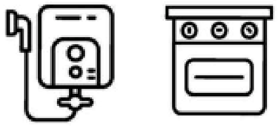
Jalal Awan, Ph.D.

THE UTILITY REFORM NETWORK

Preliminary Questions & Definitions

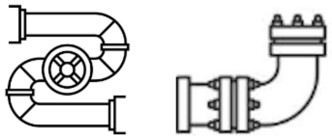
❑ <u>What</u> is a Non-Pipeline Alternative (NPA)?

- **Demand-side measures only** (partial/full electrification, EE, DR)*



❑ <u>How</u> to define (gas) "projects" for evaluation?

- **Contiguous pipeline segments** (mains/services)
    - Normalized by a common unit of analysis (e.g. per mile cost and/or risk)

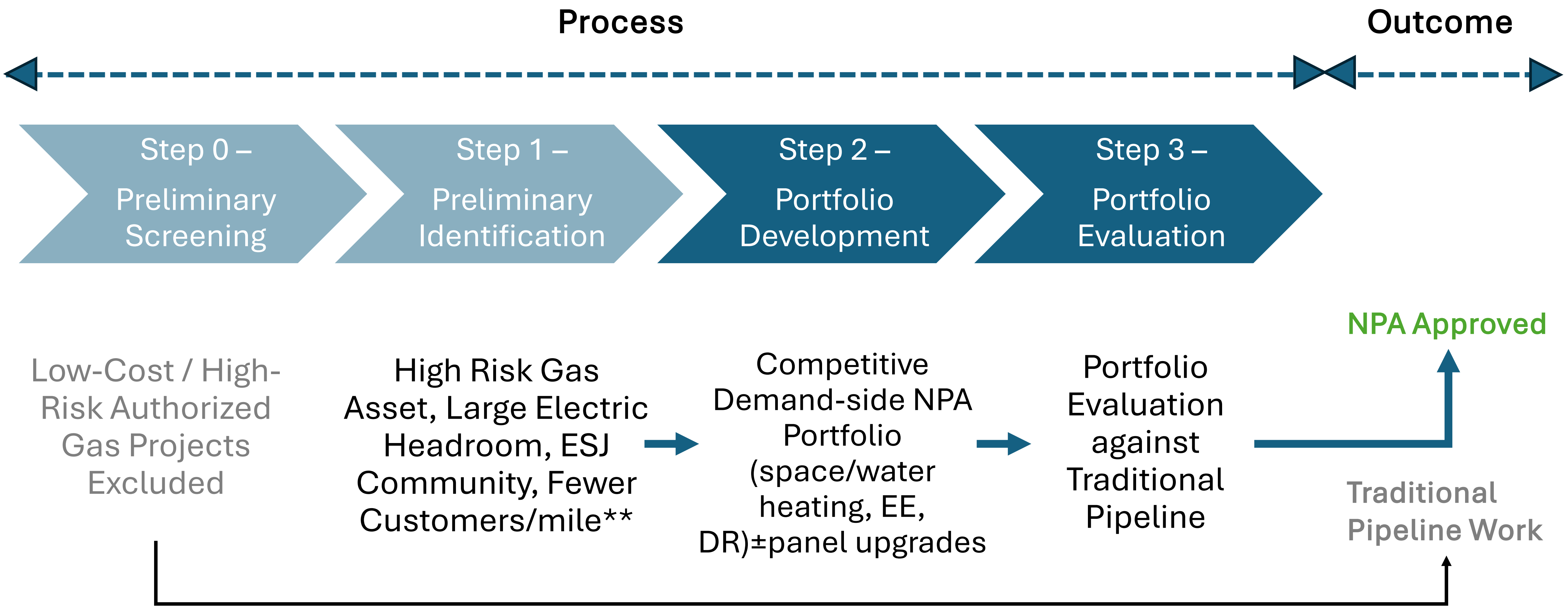


❑ <u>Which</u> risk metrics for 10-year foreseeable replacements?

- **DIMP Risk Ranking** (likelihood * consequence)
- Top X% of mains by DIMP score
- RSE scores
- Others?

**Supply-side NPAs such as hydrogen blending or biomethane are the subject of separate Commission proceedings (A.22-09-006 and R.13-02-008, respectively)*

Framework for Benefit-Cost Analysis (BCA)*



**This is an illustrative work-flow for a transparent BCA framework. Actual data from IOUs would determine various threshold values.*

*** Lower density sites i.e. fewer customers/mile of gas main exhibit better cost-effectiveness for electrification (E3 / Gridworks)*

Framework for Benefit-Cost Analysis (BCA)

Process

Step 0 – Preliminary Screening

Step 1 – Preliminary Identification

Low-Cost / High-Risk Project Screening

- GRC-approved and/or required by Compliance
- Safety vs. Non-Safety indicator
- *Cost* < *$X* threshold & *Timeline* < *Y* months

Data Source(s): DIMP, GRC/CPCN Applications

High Risk Gas Asset, Large Electric Headroom, ESJ Community

- Top X percentile by DIMP Risk Score (10-year foreseeable)
- Available Load Capacity (ALC) avoids dist. upgrades

Data Source(s): DIMP, ICA Maps, “Project-level” IOU data, CalEnviroScreen 4.0

Framework for Benefit-Cost Analysis (BCA)

Process (contd.)

Step 2 –

Portfolio Development

Step 3 –

Portfolio Evaluation

Competitive Demand-side NPA Portfolio (space/water heating, EE, DR)

IOU-proposal

Competitive RFP

Data Source(s): CPUC DEER, TECH, BUILD databases

Portfolio Evaluation against Traditional Pipeline

- Use NPV of RRQ w/ avoided gas costs (benefits) vs. total electrification costs*

$$\boldsymbol{Benefit/Cost}_{Net\ Present\ Value} = \frac{\sum_{t=0}^{40}\left[\frac{(Avoided\ Pipeline\ CapEx_t + Pipeline\ O\&M_t)}{(1+0.078)^t}\right]}{2 * \sum_{t=0}^{20}\left[\frac{(Utility\ Investment_t + Participant\ Costs_t + Admin\ Costs_t\ )}{(1+0.078)^t}\right] - \sum_{t=0}^{40}\left[\frac{(Social\ and\ Environemntal\ Benefits_t)}{(1+0.03)^t}\right]}$$

Data Source(s): TURN recommends using Appendix IV in E3 report on BCA of 11 sites in the Bay Area (2023)

**TURN notes that threshold issues, including but not limited to, cost recovery, BTM treatment may be addressed on an ongoing basis and should not delay the BCA framework.*

Recommendation

TURN recommends that the Commission:

1) Address open definitional questions from this workshop as a priority.
2) Direct Utilities to provide all underlying data to enable risk-based Priority Neighborhood Decarbonization Zones (PNZs) as part of Track 2.
3) Adopt of a uniform BCA framework for both SB-1221 and non-SB-1221 NPA evaluations.

A Staff Proposal addressing these recommendations, followed by intervenor comments, may provide the most efficient path forward.

Policy Options to Facilitate Non-Pipeline Alternatives

Kiki Velez, Equitable Gas Transition Lead

September 22, 2025

NRDC

Quick Background

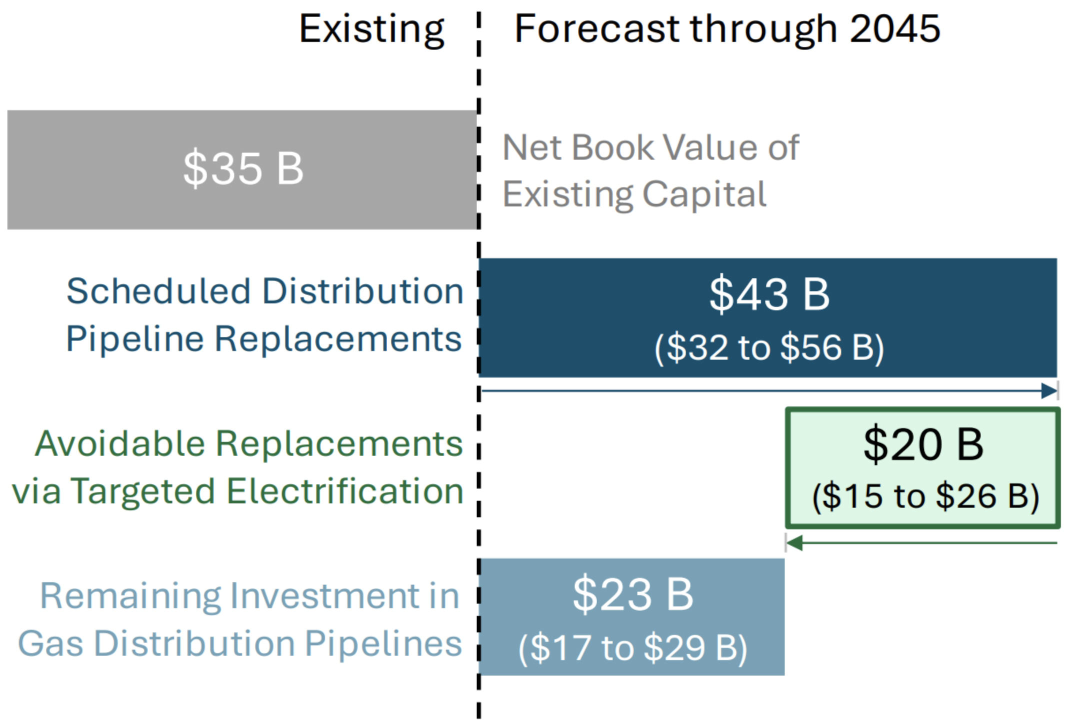


Figure 4: Historical investments in the gas utility system, estimated costs for scheduled pipeline replacement, and estimated avoidable pipeline replacement costs.

- Analysis shows targeted electrification could save Californians **more than $20 billion** in gas pipeline costs by 2045.

Source: Energy + Environmental Economics for NRDC

Recommended Next Step:

Issue a **Commission Decision** addressing threshold issues for NPA implementation.

Commission Should Resolve:

1. **NPA Definition**

Commission Should Resolve:

1. **NPA Definition**

Recommendation: NPA = Any project or portfolio of projects that avoids a planned gas investment, including:

- *Zero-Gas NPAs*
- *Demand Reduction NPAs*
- *Pipeline Re-lining*

Commission Should Resolve:

1. NPA Definition
2. **Benefit-Cost Analysis**

Commission Should Resolve:

1. NPA Definition

2. **Benefit-Cost Analysis**

Recommendation: Compare net-present value of a planned gas project with an NPA, including all associated utility earnings.

- *Consider the CEC's proposed BCA as a starting point.*

Commission Should Resolve:

1. NPA Definition
2. Benefit-Cost Analysis
3. **Cost Recovery**

Commission Should Resolve:

1. NPA Definition

2. Benefit-Cost Analysis

3. **Cost Recovery**

Recommendation: NPA behind-the-meter costs should be recovered as a gas regulatory asset.

- *Adopt preliminary framework for next 5-10 years; can revise after that point.*
- ***Other states do this**: In NY, utilities recover NPA costs over 20 years + receive 30% of the NPA savings*

Commission Should Resolve:

1. NPA Definition
2. Benefit-Cost Analysis
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- ***Other states do this:*** *In NY, utilities recover NPA costs over 20 years + receive 30% of the NPA savings*

Next slide shows NRDC analysis →

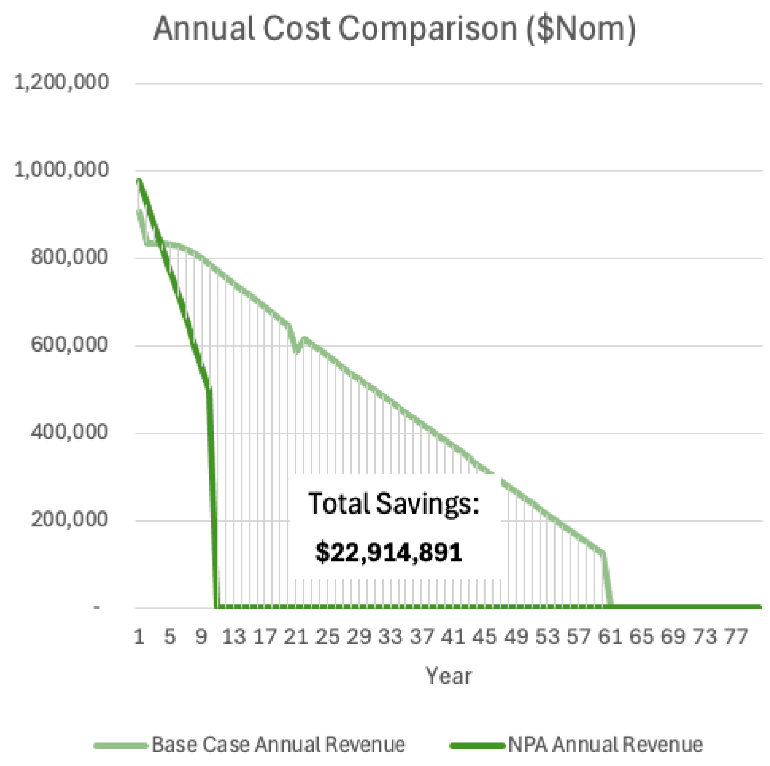
Tradeoffs of Different NPA Cost Recovery Options

1. Regulatory Asset, 15 Years

Year 1 NPA Bill Impact: - 0.15 cents

NPV Savings: ~$5.2 M

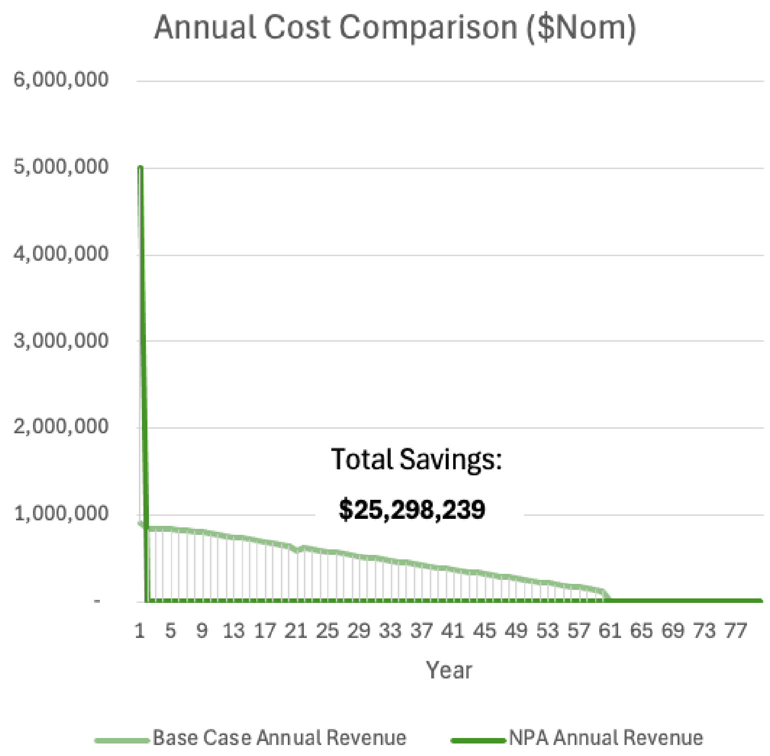
2. Regulatory Asset, 10 Years



Year 1 NPA Bill Impact: 0.14 cents

NPV Savings: ~$5.5 M

3. No Regulatory Asset

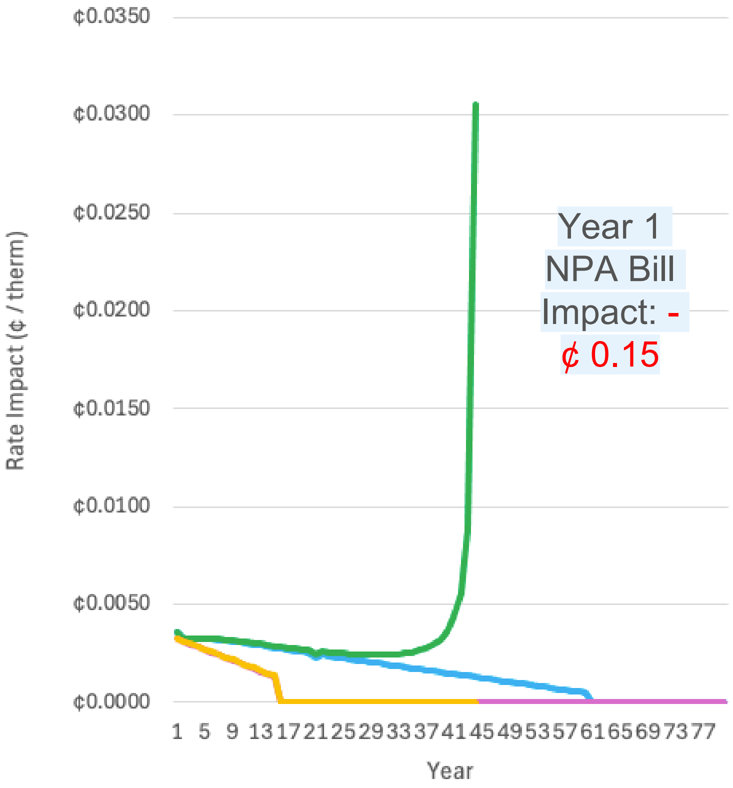


Year 1 NPA Bill Impact: 8 cents

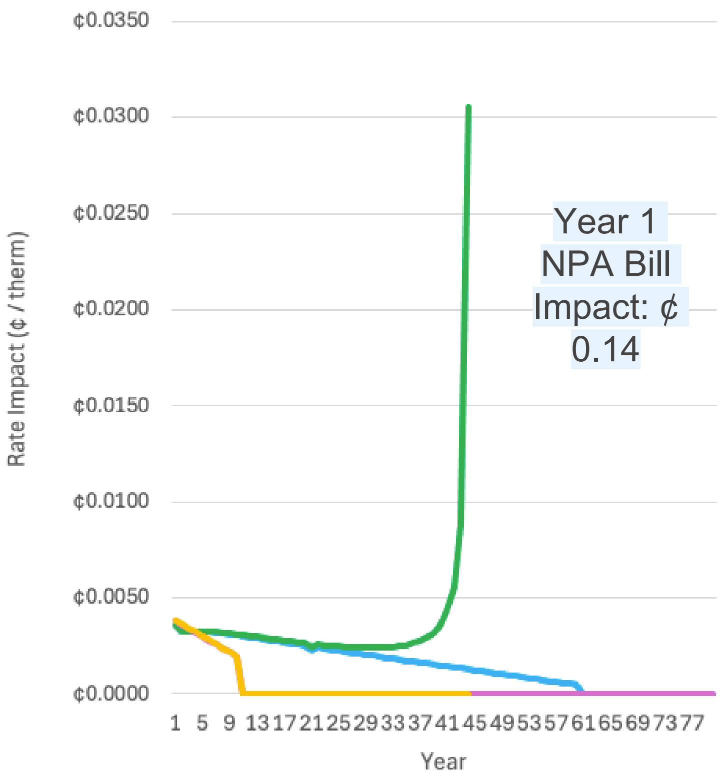
NPV Savings: ~$6.4 M

Comparing NPA Cost Recovery Options: **Rate Impacts**

1. Regulatory Asset, 15 Years



2. Regulatory Asset, 10 Years



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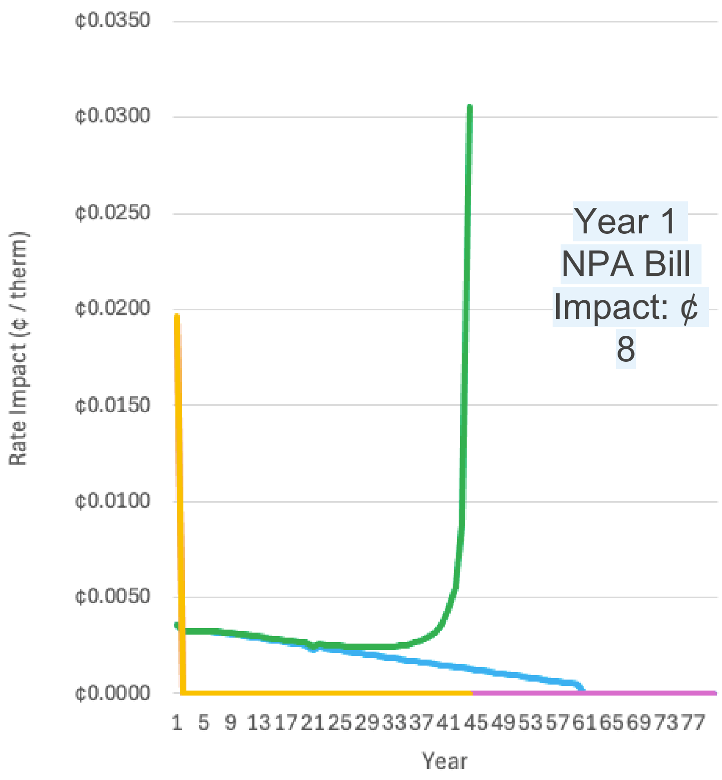


Base Case (BAU Scenario) | Base Case (Gas Transition Scenario)
NPA (BAU Scenario) | NPA (Gas Transition Scenario)

Recap - Commission Should Resolve

1. NPA Definition
2. Benefit-Cost Analysis
3. Cost Recovery

And after that...

- **NPA Identification Framework**

And after that…

- **NPA Identification Framework**

Recommendation: Develop a transparent, streamlined process to identify and prioritize NPAs, including:

- *Additional **mapping** needs*
- *Role of 3rd-party review (e.g., for hydraulic assessment)*
- *Low-hanging fruit opportunities (e.g., gas service line NPAs)*

Thank you!

Contact information: Kiki Velez, kvelez@nrdc.org

Happy to take any additional questions via email.

Appendix Slides

Expanded Recommendations for Commission NPA Decision

and Discussion of NRDC Analysis

Presentation Roadmap

Quick Background

Recommended Objective

Concrete Next Steps

Quick Background

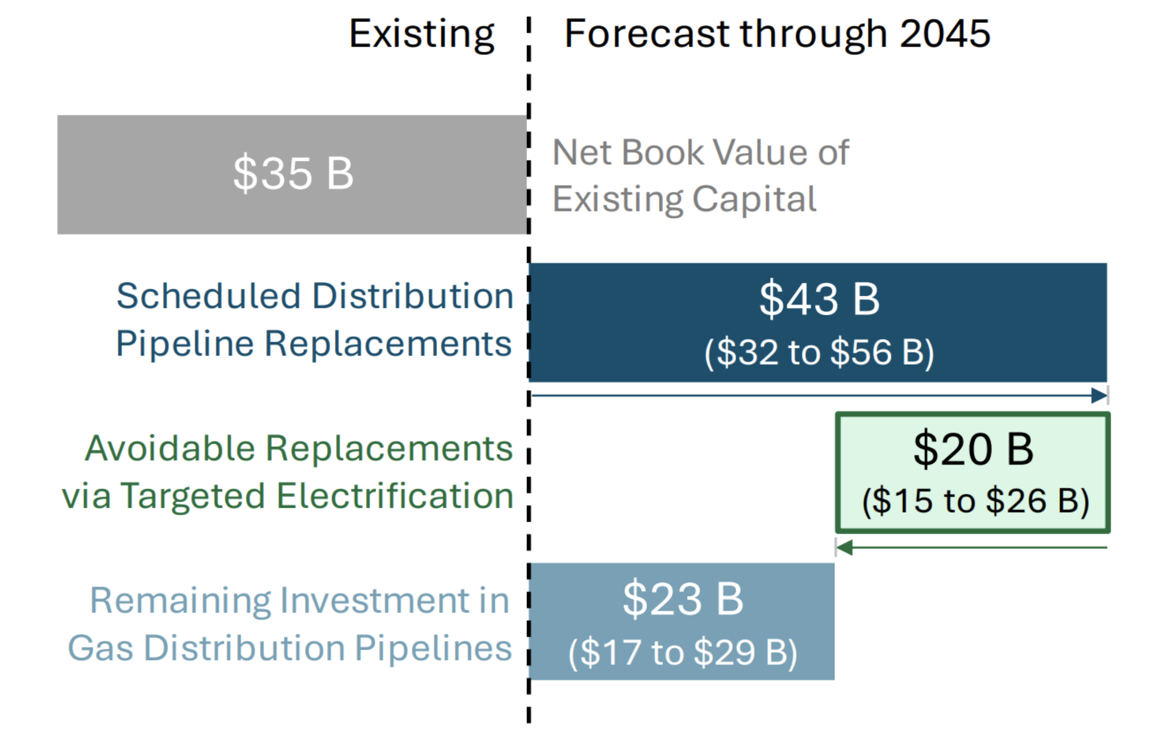


Figure 4: Historical investments in the gas utility system, estimated costs for scheduled pipeline replacement, and estimated avoidable pipeline replacement costs.

- Analysis shows targeted electrification could save Californians **more than $20 billion** in gas pipeline costs by 2045.

Source: Energy + Environmental Economics for NRDC

Proposed Objective

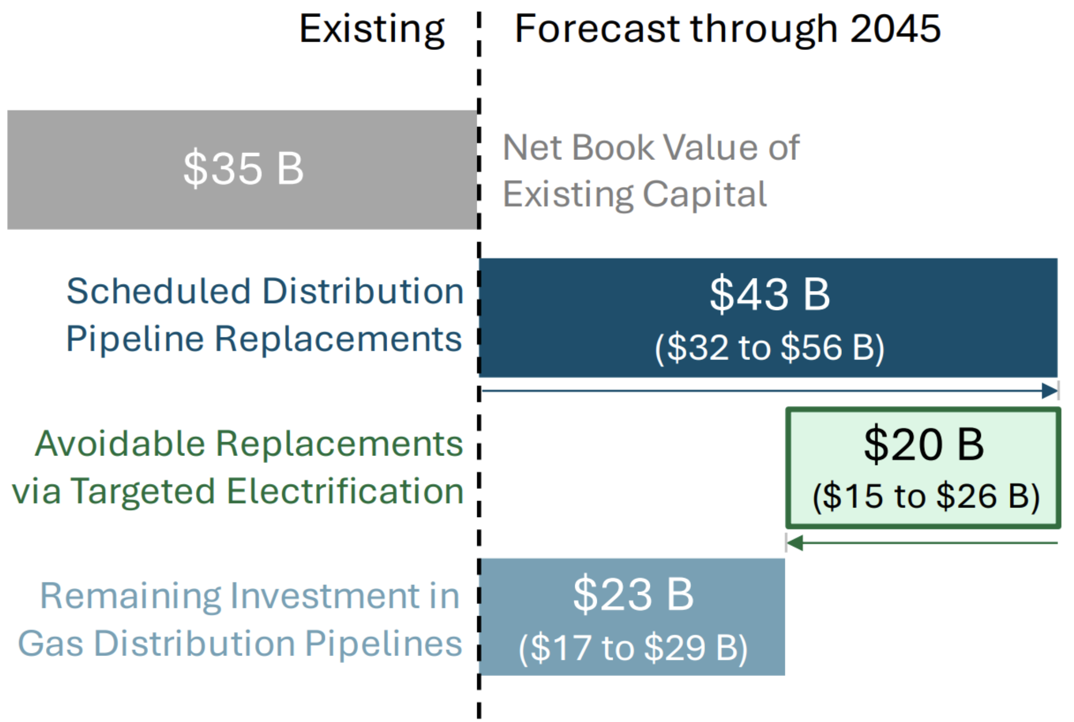


Figure 4: Historical investments in the gas utility system, estimated costs for scheduled pipeline replacement, and estimated avoidable pipeline replacement costs.

1. Require **NPA review** for all planned gas projects.
2. If a cost-effective, feasible NPA exists, do not guarantee gas investment cost recovery.

Commission Should Resolve:

- Key NPA questions, including:

1. NPA Definition
2. Benefit-Cost Analysis
3. Cost Recovery

Do these first...

And then:

4. Process for Identifying and Prioritizing NPAs

1. NPA Definition

Need: Stakeholders need clarity around what qualifies as an NPA.

Recommendation: NPA = Any project or portfolio of projects that avoids a planned gas investment.

- *Definition must include neighborhood electrification that enables pipeline retirement, but should also include novel solutions like pipeline relining & NPAs that **deploy sufficient demand-side resources*** *to avoid capacity expansion or pressure betterment projects.*

** E3 has published a helpful article describing this concept in more detail.*

2. Benefit-Cost Analysis (BCA)

Need: To streamline NPA implementation, it is necessary to adopt a consistent BCA framework.

Recommendation: BCA framework should define cost-effectiveness from the utility customer perspective and should compare the NPVs of a planned gas project with an NPA project, including all associated utility earnings.

- *The Commission can put forth an existing framework for comment, such as the California Energy Commission's proposed BCA.*
- *Societal costs & benefits could be used to prioritize NPAs*

3. Cost Recovery

Need: Disagreement and uncertainty around cost recovery was a key barrier to implementation of the CSU Monterey Bay project. Resolution is needed to streamline NPA cost-effectiveness calculations and implementation.

Recommendation: NPA behind-the-meter costs should be recovered as a gas regulatory asset.

- *Any associated electric system costs should be recovered from electric ratepayers in the usual manner.*
- *Adopt preliminary framework for next 5-10 years; can revise after that point in response to shifting gas system considerations.*
- ***Other states do this**: In NY, utilities recover NPA costs over 20 years + earn a 30% shared-savings mechanism.*

3. Cost Recovery – Analysis Tools

NRDC is developing **two analysis tools** to weigh the benefits and drawbacks of different NPA cost recovery methods:

1. An internal spreadsheet tool to compare the gas system cost and rate impacts of gas projects vs. NPAs on a project- or portfolio-level.
2. A web-hosted model developed by Switchbox to compare the systemwide gas and electric system impacts of paying for NPAs under different scenarios at a large scale.

3. Cost Recovery – Analysis Tools

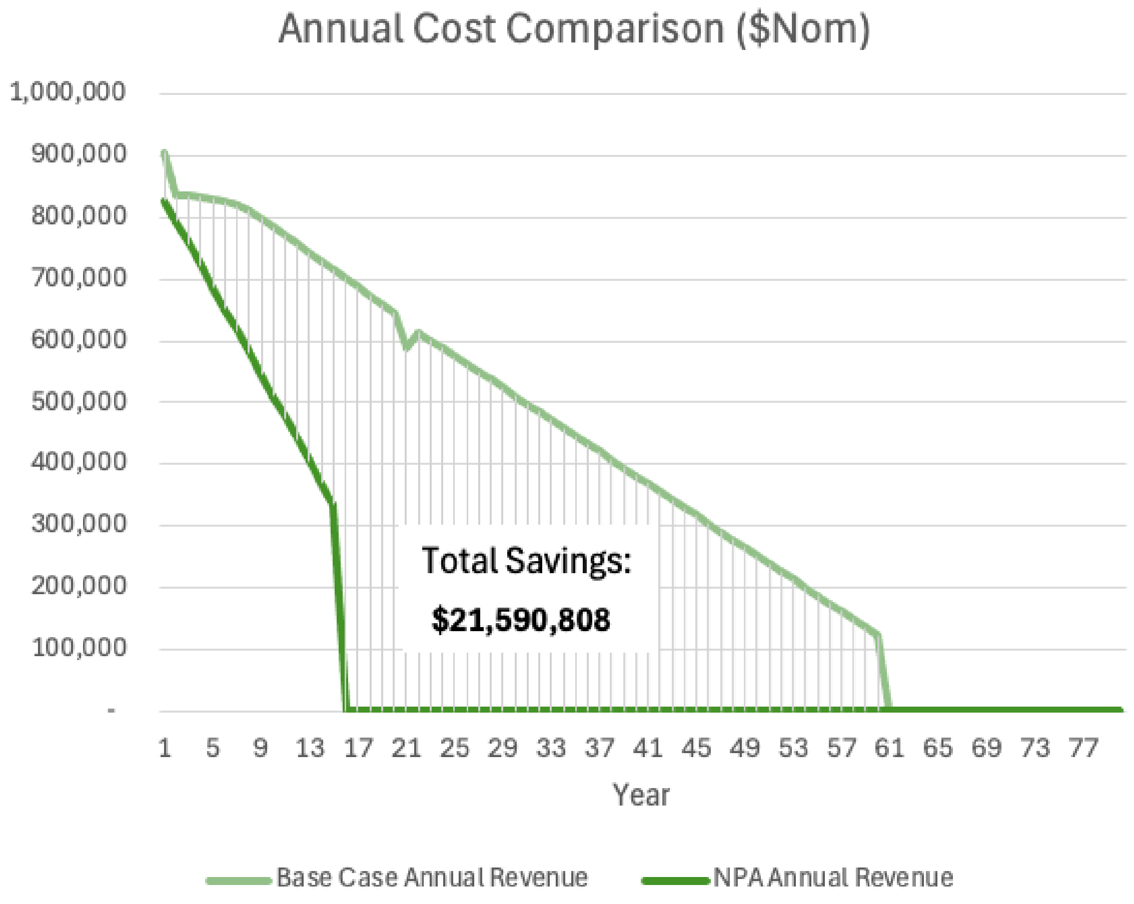
Assumptions for this Run:

- $36,650 / gas project,* 60-year depreciation
- $25,000 / NPA project, 15-year depreciation
- 200 projects completed

Results

- 530,000 kg CO_2 avoided/year
- **NPV Savings: ~$5,150,000**

**This is PG&E's rounded average cost to replace a gas service line, per Sierra Club discovery requests.*



Comparing Different NPA Cost Recovery Options

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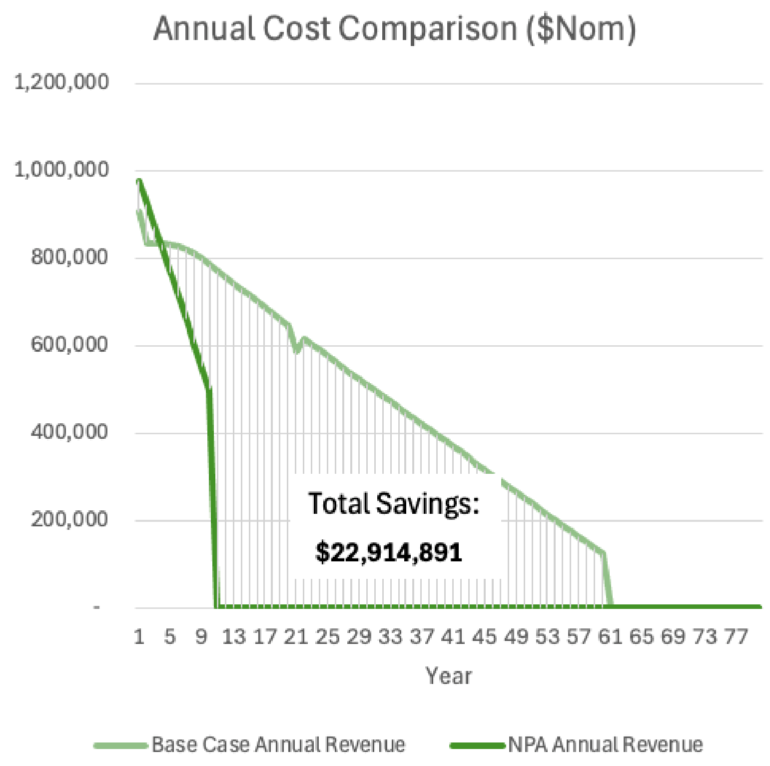
Year 1 NPA Bill Impact: - 0.15 cents

NPV Savings: ~$5.2 M

2. Regulatory Asset, 10 Years



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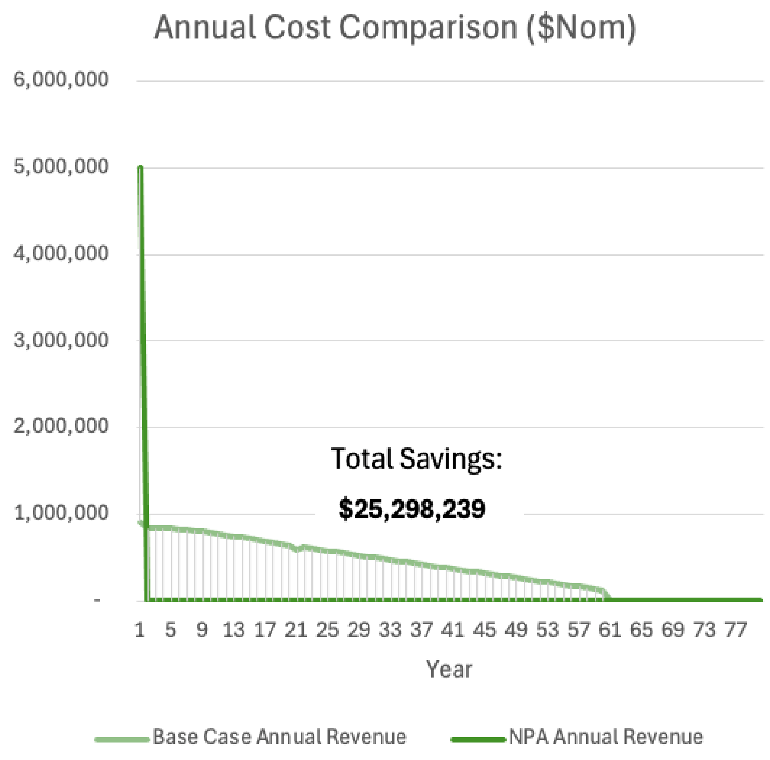
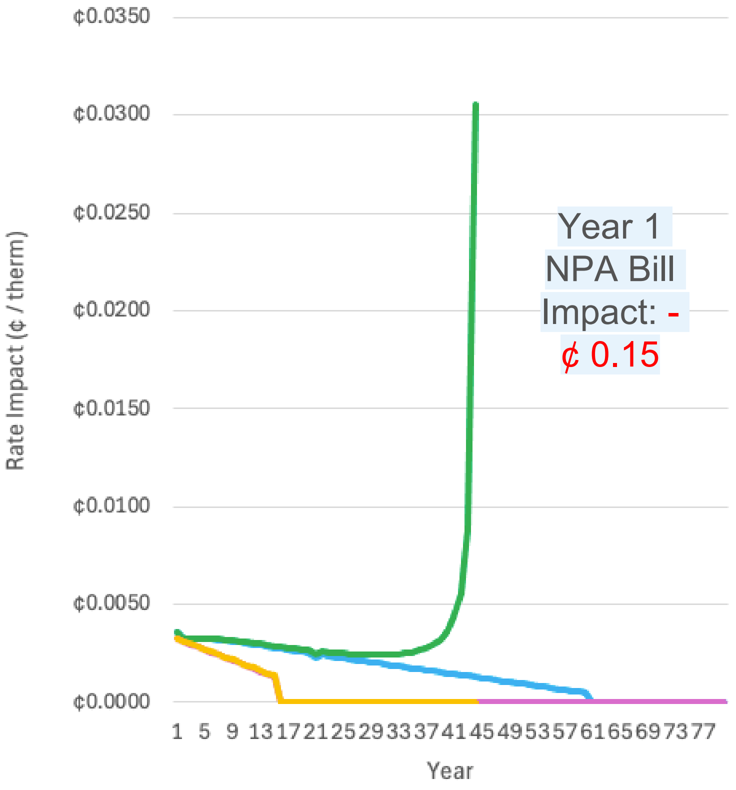


Year 1 NPA Bill Impact: 8 cents

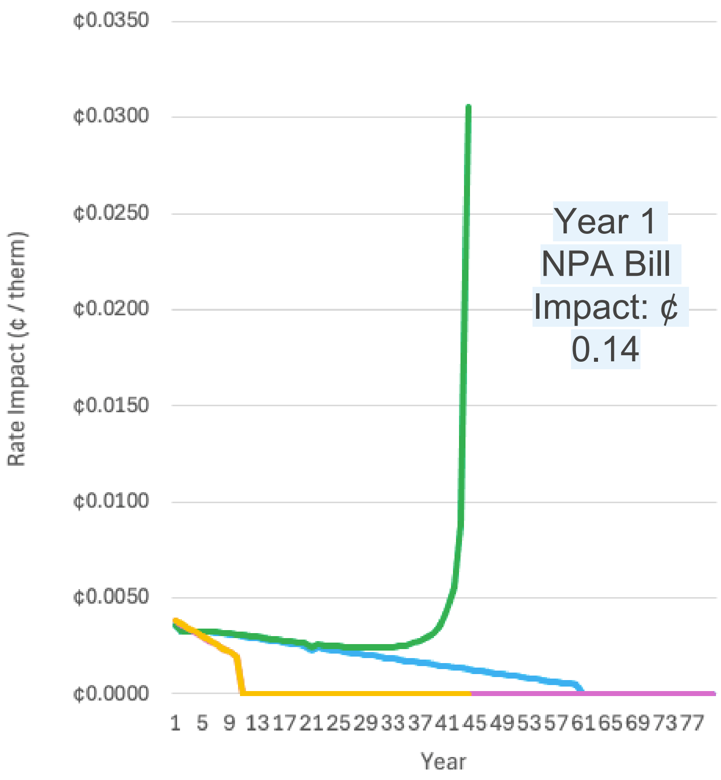
NPV Savings: ~$6.4 M

Comparing NPA Cost Recovery Options: **Rate Impacts**

1. Regulatory Asset, 15 Years



2. Regulatory Asset, 10 Years



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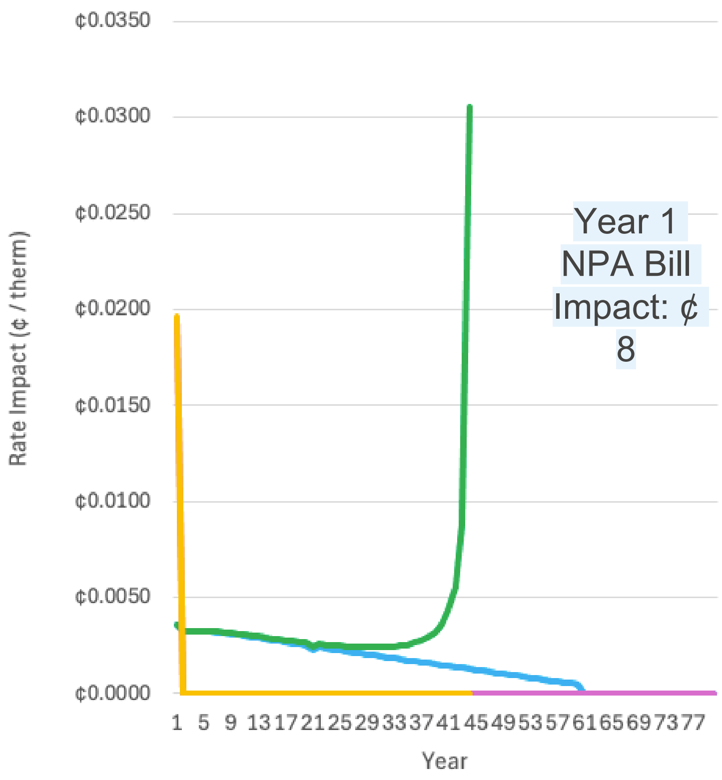


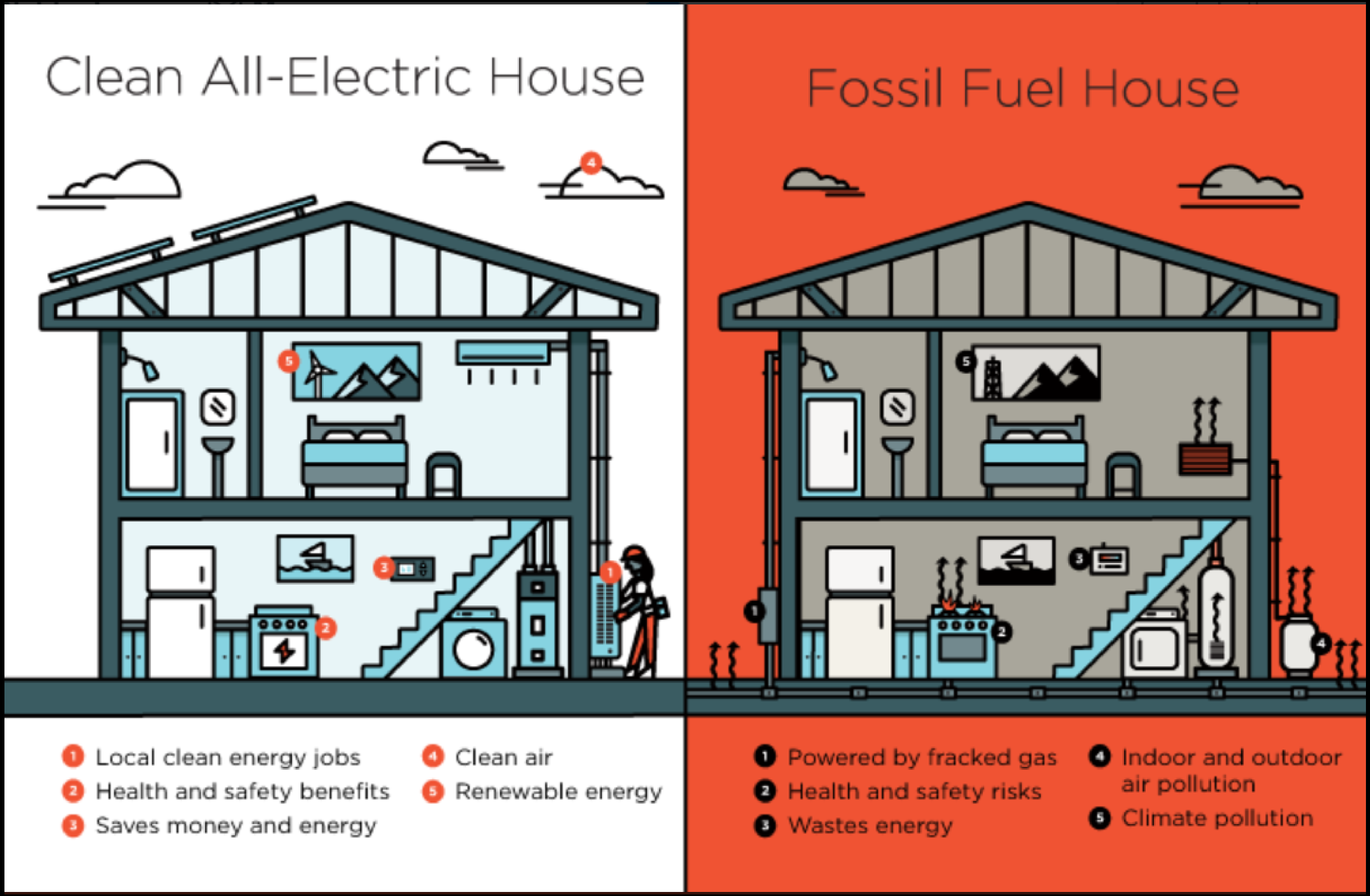
Base Case (BAU Scenario) | Base Case (Gas Transition Scenario)
NPA (BAU Scenario) | NPA (Gas Transition Scenario)

4. NPA Identification Process

Need: There is no transparent, streamlined process to identify and prioritize NPAs.

Recommendation: Staff Proposal should outline:

- Additional **mapping** needs
  - Where are individual projects planned to take place?
  - How many customers do they serve?
  - What type of customers do they serve?
  - Preliminary hydraulic feasibility: Is it a terminal branch? Connecting segment? Other?
- Role of 3rd-party review (e.g., for hydraulic assessment)
- Low-hanging fruit opportunities (e.g., NPA to gas service line replacements)

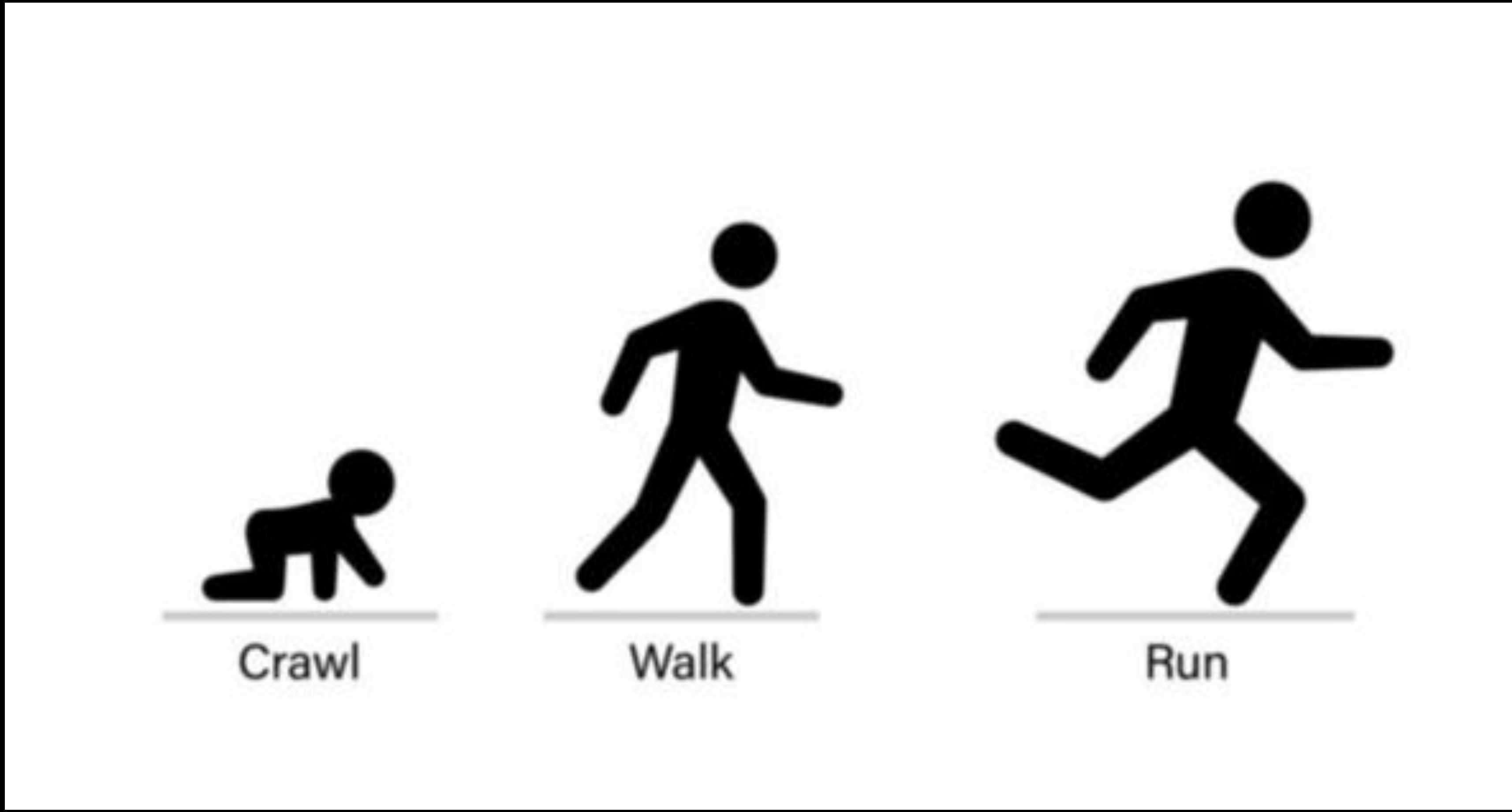


EARTHJUSTICE

Policy Options to Facilitate Non-Pipeline Alternatives

Matt Vespa, Senior Attorney, Earthjustice, on behalf of Sierra Club
mvespa@earthjustice.org

1. Interim Actions
2. Service Line Replacement NPA program



Questions in Need of CPUC Resolution

- **Should NPAs be funded by gas or electric ratepayers?**

  Gas ratepayers are customers that would otherwise pay for gas investment. Should pay for NPA. (Though any IFOM electric upgrades responsibility of electric ratepayers)

- **How Should Utilities Recovery Costs from BTM investments?**
  - **SB 1221 Projects – Pub. Util. Code Sec. 663**
    - (8) A requirement that gas corporations recover costs related to the pilot projects that are deemed just and reasonable and ***a requirement that prohibits*** a gas corporation from recovering behind-the-meter costs associated with the pilot projects ***as capital costs that are afforded a rate of return.***
    - (9) ***The appropriate rate of return and recovery period that a gas corporation is eligible to receive for its costs to implement a zero-emission alternative…***
  - **Non-SB 1221 Projects**

    Regulatory asset treatment with 10-year cost recovery. Utilities should have *at least* as much incentive to implement climate friendly alternatives to fossil fuel infrastructure.

- **How should NPA cost-effectiveness be evaluated?**

ACR teeing up questions in need of further record development, followed by Commission decision.

NPA for Service Line Replacement:
Low-Hanging Fruit in Gas System Transition

- Vast majority connect to single meter
- Avoids complications of projects involving multiple customers
- Hydraulic feasibility not issue
- NPAs can be standardized
- Begin to prune system
- Participation can be voluntary

Service Line NPAs

conEdison

Energy Exchange Program

Provides up to $20,000 in incentives to remove and replace gas appliances with new electric equipment

Building Type	SINGLE-FAMILY	2+ UNITS	SMALL BUSINESS + NONPROFIT	COMMERCIAL + INDUSTRIAL
BASE INCENTIVE	up to $10,000	up to $15,000	up to $10,000	up to $10,000
ENHANCED INCENTIVES FOR DISADVANTAGED COMMUNITIES*	up to $15,000	up to $20,000	up to $15,000	up to $15,000

https://www.coned.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-residential-customers/energy-exchange

Service Line NPAs

conEdison

Energy Exchange Program

- Targets customers connected to pre-1972 services
- Customer can choose among pre-approved contractors
- Contractor does site visit, works with customer to select appliances, submits application, which Con Ed uses to determine if need electric service line upgrade
- After installation customer, customer must close out gas account and requires gas service disconnection
- Follow-up survey for feedback to improve program

Con Edison, Non-Pipes Alternative Implementation Plan (2024)

Implementing a Service Line NPA Program in California

PG&E has both stand-alone service line replacement programs and replacements included in larger projects.

Service Line Only:

- *Reliability Service Replacement Program (MAT 50 B)*
  - 87+ percent connect to single customer
  - Average cost
    - $32,651 for residential
    - $53,222 for commercial

	Core Residential[(a)]	Core Commercial[(a)]	Single Customer	2 - 5 meters	>5 meters
2022	536	33	499	67	4
2023	540	23	489	77	2
2024	487	23	452	62	1
TOTAL	*1,563*	*79*	*1,440*	*206*	*7*

- *Single Distribution Service Replacements (MAT 50G/M)*
  - MAT 50G is for single service replacements
  - Average cost (MAT 50G)
    - $21,512 for residential
    - $24,900 for commercial
  - This is leak replacement program
    - Less complicated that MAT 50B
    - Average time from detection to replacement for residential service line is 270 days

Customer Type by MAT	2022	2023	2024
Residential	992	890	723
50G	970	866	708
50M	22	24	15
Commercial	103	67	61
50G	97	63	55
50M	6	4	6
Industrial	12	9	8
50G	11	9	8
50M	1		
Grand Total	1107	966	792

Implementing a Service Line NPA Program in California

Bulk of service line replacements part of larger replacement projects that include gas main

- Costs to replace service line as part of larger project currently not tracked, would likely be lower than individual replacements due to implementation efficiencies
- Could offer a certain amount (e.g., up to $15,000) with larger amount if entire project avoided

Program	Year	Total Services Replaced[a]	Core Residential Meters	Core Commercial Meters	Industrial Meters	Noncore Meters	Single meter Services[b]	2-5 meter Services[b]	>5 meter Services[b]
GPRP (MAT 14A)	*2022 - 2024*	*6,106*	*8,299*	*679*	*2*	*1*	*5,170*	*1,013*	*118*
Plastic Pipe Replacement (MAT 14D)	*2022 - 2024*	*35,827*	*44,383*	*1,392*	*2*	*1*	*32,282*	*3,802*	*422*
Reliability Pipe Replacement (MAT 50A)	*2022 - 2024*	*2,563*	*3,931*	*159*	*0*	*0*	*1,951*	*477*	*78*

(a) Excludes counts where a service was unable to be correlated with the meter class data.
(b) Total services replaced varies slightly as data availability for count of meters per service varies from meter class data.

Implementing a Service Line NPA Program in California

Additional Implementation Questions

- Outreach
  - How offer communicated to potential customers
  - How involve interested local governments, CCAs, CBO
- Contractors – use of defined list (e.g. TECH)?
- Gas/Electric utility coordination where panel/service line upgrade needed
- Equity
  - Con Ed program provides additional outreach/higher incentives for projects in DACs
  - How can other programs/non-ratepayer programs be leveraged to do same here
- Reporting/Feedback
- Proceeding coordination – Long-Term Gas Planning/General Rate Case

Questions?

UTILITY PERSPECTIVES ON PROCEDURES FOR FACILITATING NON-PIPELINE ALTERNATIVES

Interim Actions Workshop

Gas Planning OIR (R.24-09-021)

September 22, 2025

SoCalGas™

Key Considerations Around NPA Integration

- **Safety**
  - Safety is a leading driver for gas infrastructure investments, and is the primary driver for potential projects on July 1 SB 1221 maps
  - NPA integration must not delay or otherwise negatively impact these safety investments. Streamlining qualified NPA project approval will be crucial to successful integration
- **Reliability**
  - NPA deployment must not impact gas system reliability
  - Customer energy reliability must be considered
- **Affordability**
  - Appropriate cost-effectiveness testing, cost recovery mechanisms, customer education and engagement, and other program execution controls must be established to ensure NPAs don't negatively impact affordability for any ratepayers – thoughtful program design will be critical to protecting ratepayers and informing future policies
  - Energy affordability for impacted customers must also be considered
- **Enhanced Need for Coordination**
  - SoCalGas does not have access to data or expertise to assess electric grid capacity
  - ICA data in July maps may help, but likely is not conclusive without further review
  - Shared service territory with all major IOUs and ~20 POUs
    - POU levels of interest and resources for NPA support are likely varied
    - POU participation not directed by CPUC
- **Reporting**
  - Documentation and reporting of successes, failures, costs, challenges, and other key performance criteria will be crucial to support the development of a sustainable program

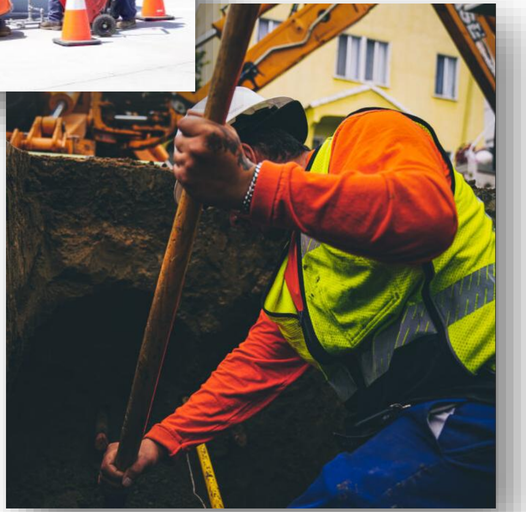
Long Beach Perspective on Non-Pipeline Alternatives

September 22, 2025

LONG BEACH Utilities
Water · Gas · Sewer

About Long Beach

- 7^{th} largest city in California
- Charter City formed in 1897
- 500,000 in population
- Municipal Planning and Permitting
- Publicly Owned Utilities
  - Water, Gas, Sewer
- Committed to Climate Adaptation



Long Beach's Climate Commitment

Long Beach's **Climate Action and Adaptation Plan** (LB CAP) was adopted in August of 2022 as a Qualified Climate Action Plan per CEQA Guidelines.

The LB CAP demonstrates the City's commitment to reducing emissions, preparing for climate change and mitigating its current and future impacts.

Climate Action Baseline and Goals

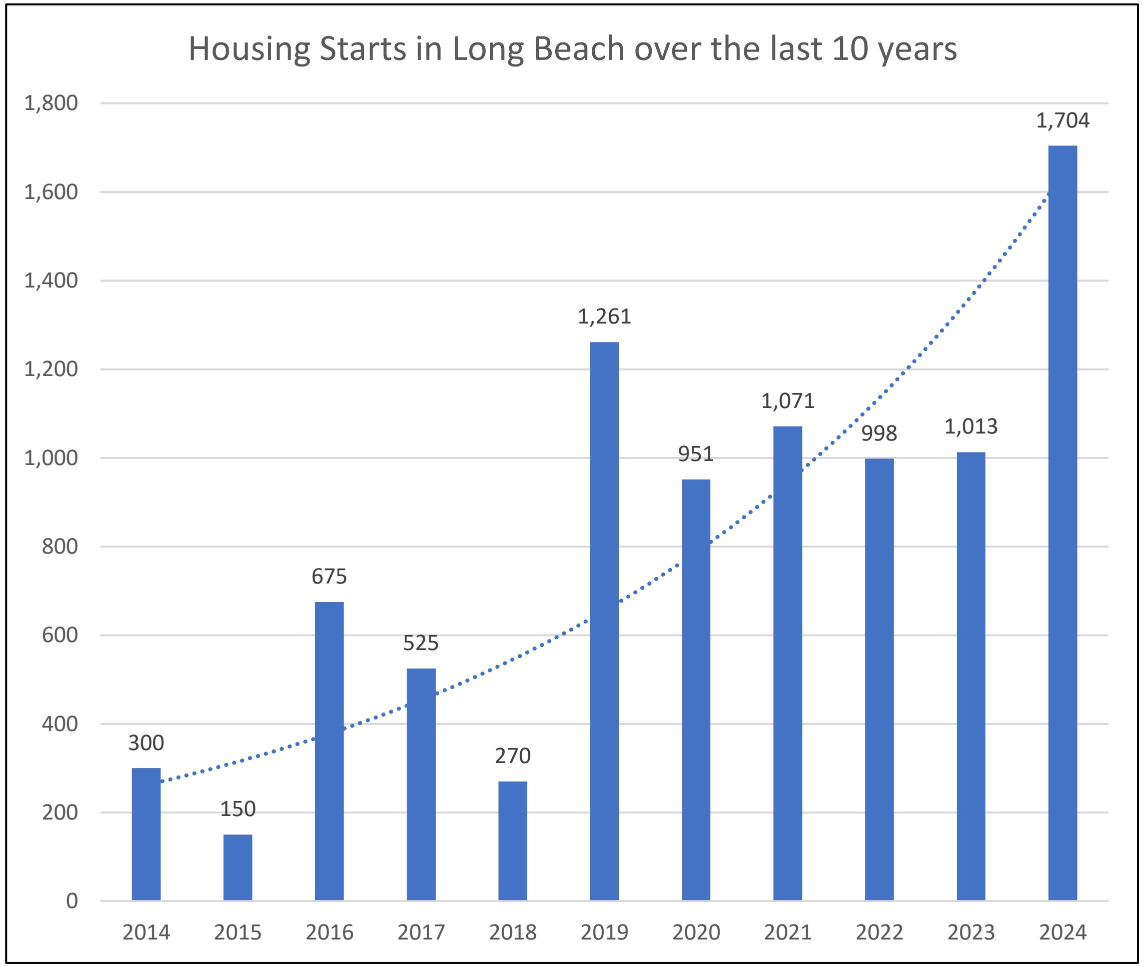
Sector	MT CO2e	% of Total
Stationary Energy	1,377,291	49.20%

Target Year	State Target	Corresponding Legislation	Status
2020	1990 GHG levels by 2020	AB 32, Global Warming Solutions Act (2006)	California met this target Statewide
2030	40% below 1990 levels by 2030	AB 32, Global Warming Solutions Act (2006)	LB CAP is a plan for Long Beach to meet this target by 2030
2045	Carbon neutrality by 2045	Executive Order B-55-18 of 2018	Aspirational for Long Beach
2050	80% below 1990 levels by 2050	Executive Order S-3-05 of 2005	LB CAP's plan horizon is to 2030

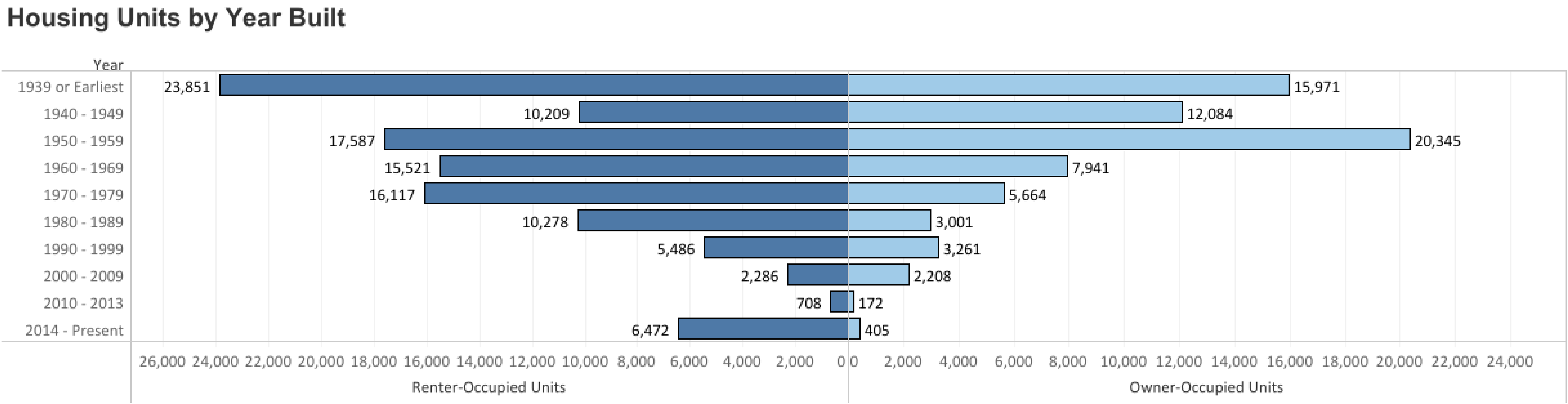
Stationary Energy Sector

Buildings and Energy

- LB CAP provides for a flexible approach with individual control mechanisms that change over time.
- Electrification was included in the LB CAP, and is still being pursued for new development within existing constraints:
  - CRA v Berkeley
  - AB 170
  - Availability of green power
- Electrification currently applies to residential units in buildings with 50 or more units, 100% affordable projects and other discretionary approvals.
- Electrification on smaller projects (such as ADUs) is encouraged but not required.

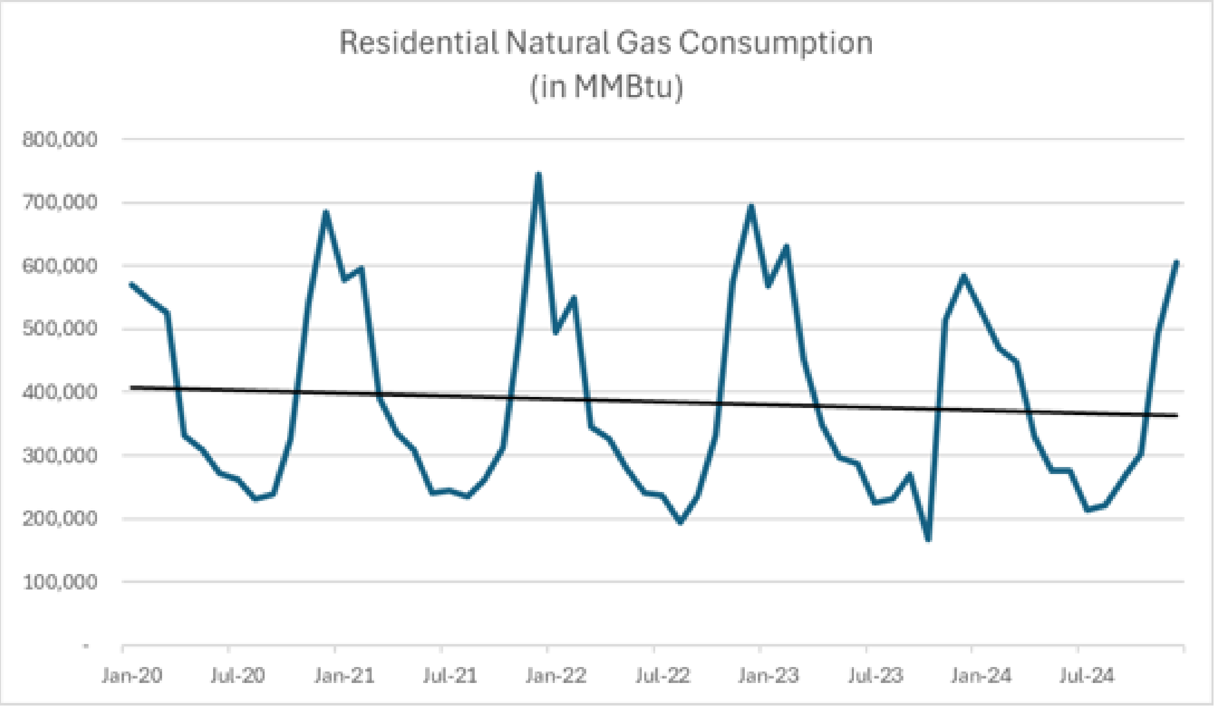


Long Beach Housing Stock



Long Beach Natural Gas Utility

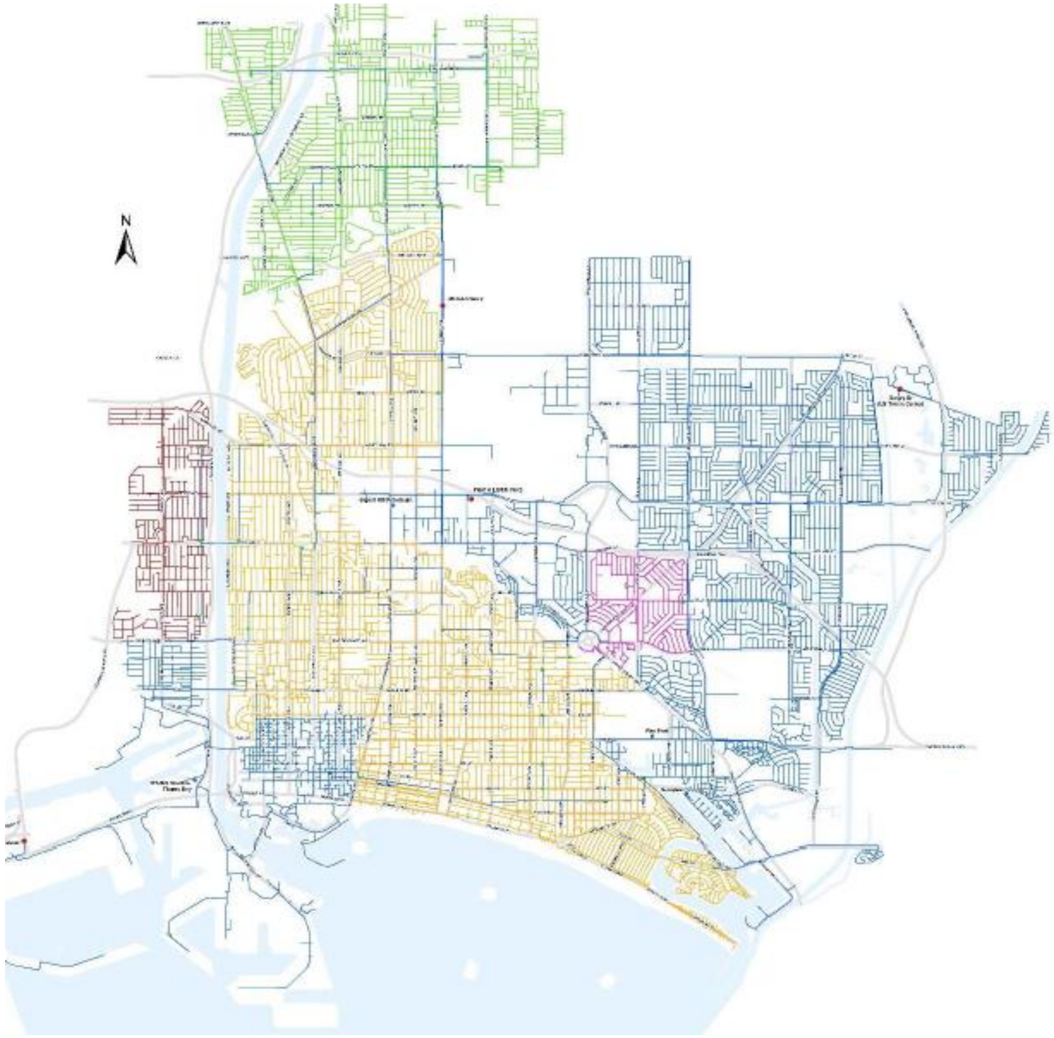
- **Long Beach's publicly owned natural gas distribution system supports 150,000 customer accounts**
  - **90% of accounts are residential** – making up 50% of gas consumption
  - 10% of accounts are commercial, industrial – making up the remaining 50% of consumption
- **1,900 miles of pipeline**



In the last 5 years, there has been a consistent decline of approximately 1% per year

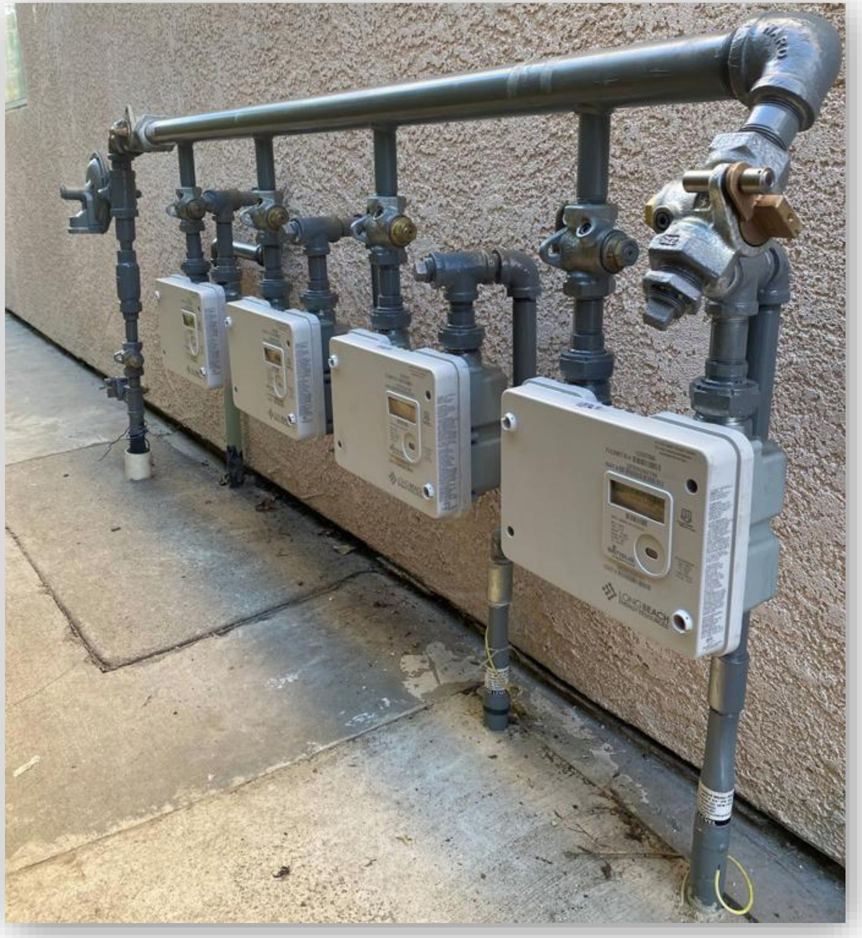
Utilities Participation in Statewide Solutions

- Alignment with State and City Climate Action Plan goals, to:
  - Avoid 'replace-in-place' when cleaner, lower-cost options exist
  - Target decarbonization where it counts, i.e.: end-of-life mains, pipeline corridors with high operations and maintenance costs
- Actively engaging in energy climate adaption projects
  - Interested in exploring NPAs with SCE for Zonal Electrification



Non-Pipeline Alternatives

- Preliminarily gathering data to assess **place-based electrification** for end uses
  - Space heating, water heating, cooking
- **Goal: Understand emerging energy opportunities to protect safety, reliability, affordability for our customer base.**



Non-Pipeline Alternative Study

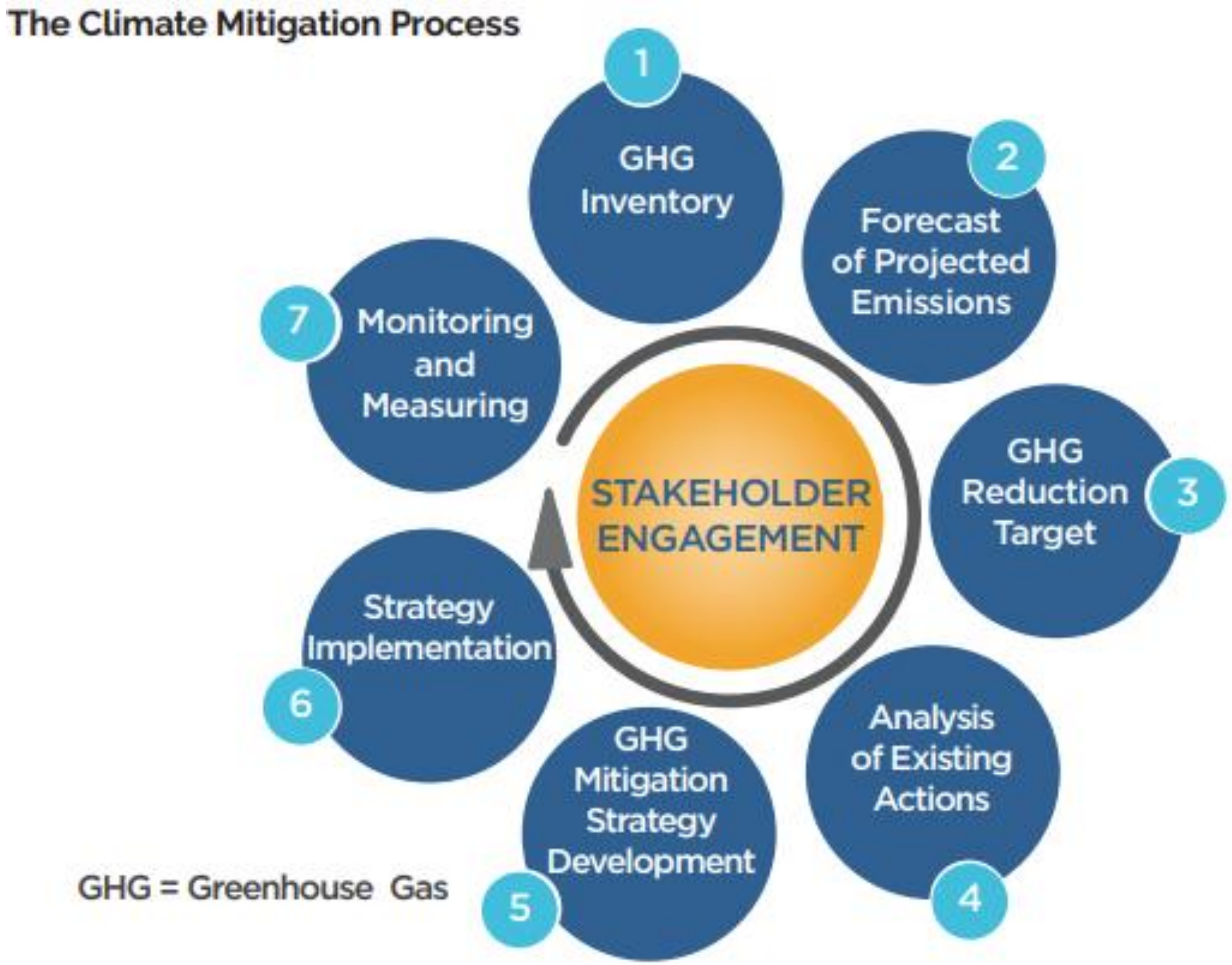
- Joint planning with Southern California Edison
  - Energy currently provided by natural gas, electric capacity
- Project purpose
  - Assess up to two pilot micro-zones (locations still to be identified)
  - Assess energy resources impacting emission reductions
  - Understand the customer journey
    - Incentive programs
    - Customer infrastructure and appliances
      - Initial electrification costs
      - Ongoing monthly bills

LONG BEACH Utilities
Water · Gas · Sewer

SOUTHERN CALIFORNIA EDISON®
Energy for What's Ahead®

Understanding Non-Pipeline Alternatives

- Risk-benefit
  - Electric readiness
  - Customer readiness
  - Cost / affordability
  - Emissions reduction
  - Stranded energy assets (gas and electric)
  - Reliability
  - Safety



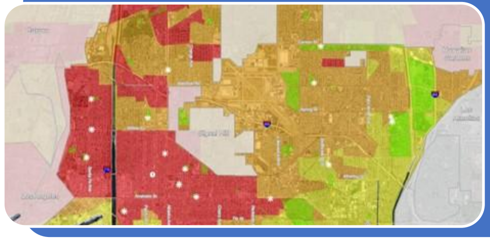
Clean Energy Considerations

Mitigation

- Implementation occurs at both city and state level (siting EV charging stations and updating building codes and zoning to incentivize electrified buildings, for example, require local leadership)
- LB CAP identifies local GHG reduction measures for implementation

Adaptation

- State emissions reduction target does not prepare Long Beach for the impacts of climate change that are happening today
- LB CAP helps increase resilience for current and future threats (extreme heat, poor air quality, sea level rise, etc.)



Equity

- State emissions reduction targets do not ensure that climate issues are equitably addressed
- LB CAP helps address environmental justice and can help steer climate finance opportunities to communities most impacted by climate change

Conclusion

The City of Long Beach and Long Beach Utilities are ready to partner with CPUC, SCE, communities, and other stakeholders to turn good theory into good practice—carefully, transparently, and affordably.

SMALL CHANGE BIG IMPACT

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LONG BEACH

Utilities

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Utility Perspectives on Procedures for Facilitating Non-Pipeline Alternatives

Exploring strategies for energy infrastructure innovation

September 22, 2025

Mike Kerans, Sr. Director, Gas Regulatory and Risk
Rachel Wittman, Building Electrification and EE Strategic Analyst, Principal

PG&E

Purpose of Presentation

- Establish a **shared definition** of an NPA and identify the **necessary actions** the CPUC must take to support the successful large-scale implementation of NPAs.
- Summarize **key insights** gained from current programs and emphasize the significance of **engaging** customers and communities.
- Offer a **set of recommendations** for the CPUC to incorporate into the Interim Actions Proposed Decision for scaling up NPA implementation.

Definition and Scope of NPAs

Definition of NPAs

A Non-Pipeline Alternative (NPA) is a strategy used to address infrastructure needs—such as new pipeline construction, capacity expansion, or pipeline replacement—through alternative solutions that **avoid or defer traditional gas investments**. These alternatives typically include electrification, fuel switching to non-regulated fuels (e.g., propane), and infrastructure retirement or decommissioning.

Scope Limitations

NPAs exclude minor pipeline repairs (such as sleeve installation or valve replacement), near-term high-risk pipe replacement, and O&M.

Importance of Clear Boundaries

Defining NPA boundaries helps utilities focus on projects with cost savings and environmental benefits.

Actions Needed from CPUC

Cost-Effectiveness	Streamlined Process	Safety
Cost-Effectiveness Framework A clear cost-effectiveness framework at the program level ensures consistency and eliminates ambiguity. **Funding Mechanisms** Adequate non-ratepayer funding is crucial for supporting before-the-meter and behind-the-meter expenses including home upgrades and appliance replacements.	**Streamlined Processes Needed** Streamlined decision-making and processes are necessary to avoid delays that could compromise safety timelines and project success. Authorizing portfolio budgets allows projects to be implemented without individual approvals, speeding up program deployment. **Customer Consent** We need procedures to ensure customer consent and support for NPA projects.	**Quick Decision-Making** Timely decisions are critical to maintaining safety when managing assets with known risks. Delays can slow down critical safety work and put projects at risk. Fast decisions mean we can act quickly, fix issues, and stay ahead of potential hazards. **Importance of System, Customer and Worker Safety** Maintaining safety standards during the broader transition to NPAs is essential to ensure reliable and secure utility service for customers and the public.

Existing PG&E Programs & Lessons Learned

Zonal Program Highlights

- The **Alternative Energy Program (AEP)** and **Zonal Equity Electrification Program (ZEEP)** aim to retire gas infrastructure by promoting electrification to support cleaner energy transitions.

- On average, ~25% of customers engaged by AEP and ZEEP have agreed to retire their gas service.

Non-Zonal Program Highlights

- PG&E administers several building electrification programs in its Energy Efficiency and Income Qualified Programs Portfolios that are not NPAs.
- These programs experience similar lessons learned as NPA programs.

Lessons Learned

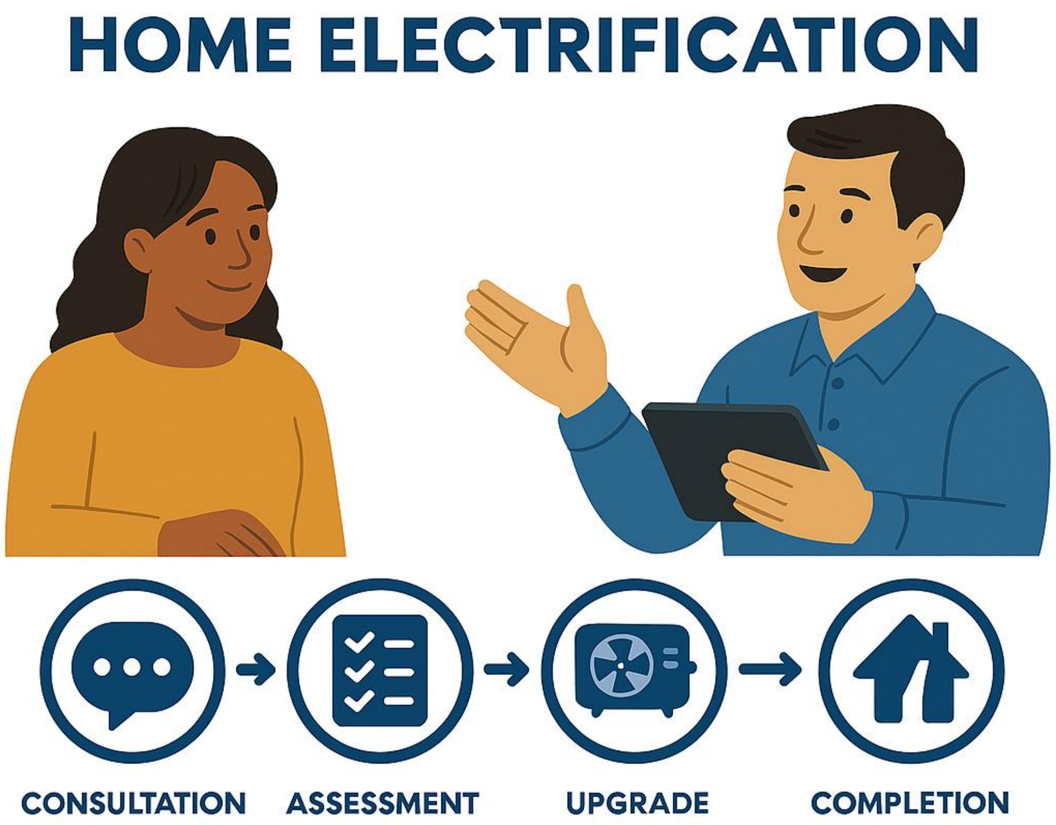
- **Flexible program design** and **proactive customer & community engagement from trusted messengers are critical** to driving adoption and overcoming barriers.

- **Engagement must be customized to local neighborhood needs** for effectiveness, including method, frequency, and timeline.

- **Customer reluctance to electrify** often stems from **personal circumstances** in addition to cost or preference.

- AEP and ZEEP have not yet had success convincing customers to electrify who firmly oppose.

Importance of Early Customer Engagement



Customer Engagement Importance

Engaged customers inspire greater adoption of non-pipeline alternatives, boosting their success and community acceptance. Especially when there is local government and partner support.

Utility Support Role

Utilities provide essential infrastructure and guidance to support and facilitate customer-driven energy initiatives.

Empowerment and Ownership

Customer-driven programs foster empowerment and ownership, leading to more effective and sustainable energy solutions.

Recommendations to Accelerate Long Term Gas Transition

Cost Recovery

Utilities must be allowed to capitalize and recover decarbonization costs, including financing costs, over a sufficiently long period to mitigate rate and bill impacts on customers.

Cost-Effectiveness

The framework should focus on removing risks and emissions associated with the gas system in a cost-efficient manner.

Funding Mechanisms

Whenever possible, funding sources outside of ratepayer contributions should be utilized to maintain affordable utility rates for these initiatives.

Streamlined Process

A rapid decision-making structure within the CPUC and the IOUs with clear program-level approvals is critical to achieving state climate objectives on schedule.

JOINT CCA PERSPECTIVES ON NON-PIPELINE ALTERNATIVES

September 22, 2025

Kate Ziemba, Senior Environmental Program Manager, San José Clean Energy/City of San José

Sonoma Clean Power

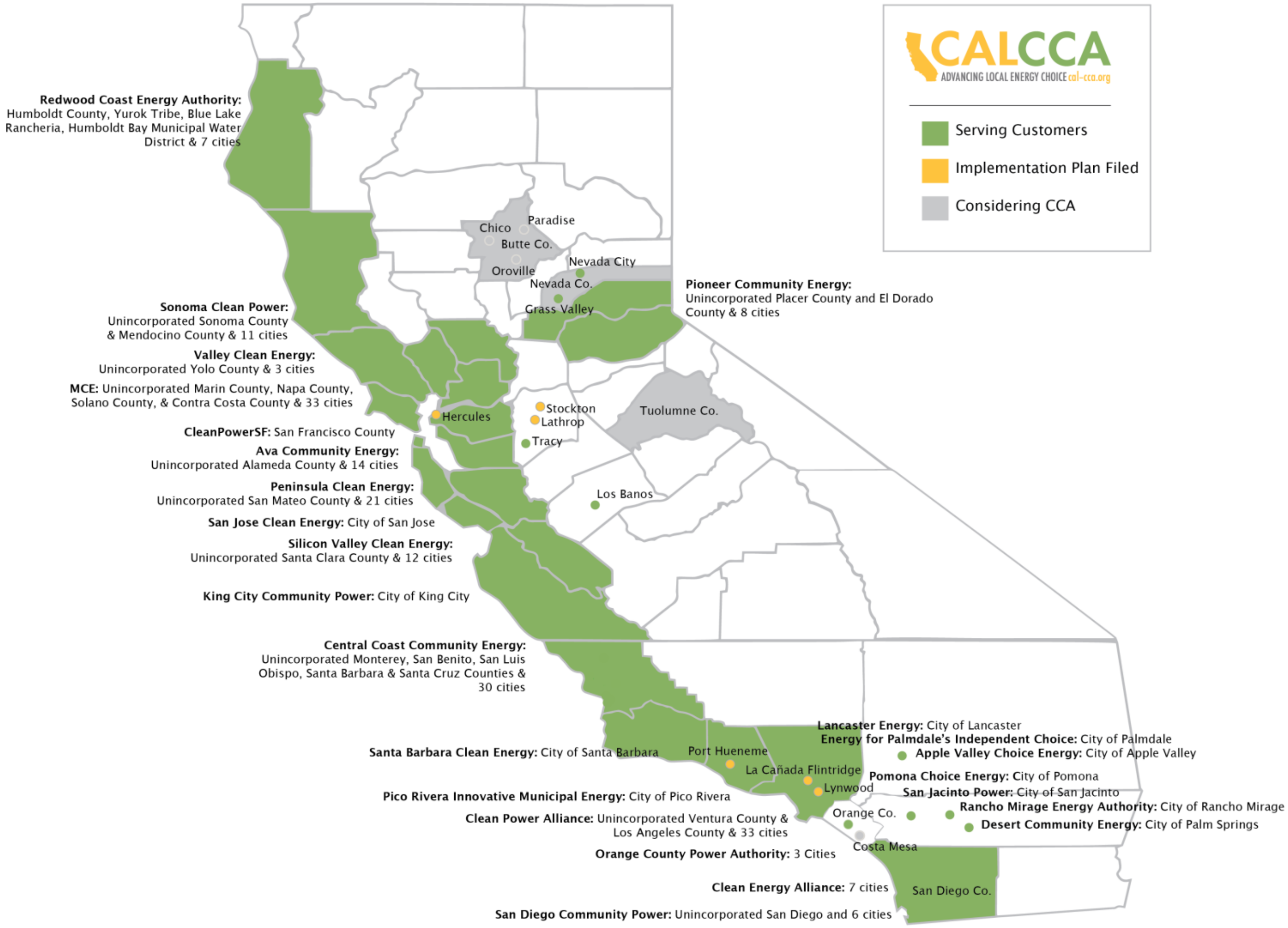
SAN JOSE CLEAN ENERGY

A Program of the City of San José

CCA MOVEMENT

- 25 Community Choice Aggregators in CA serving 14 million customers in 200+ cities and counties
- Urban and rural
- Local control over electricity options and programs
  - Values: affordability, GHG reductions, equity

CALIFORNIA CCAs



SAN JOSE CLEAN ENERGY (SJCE)

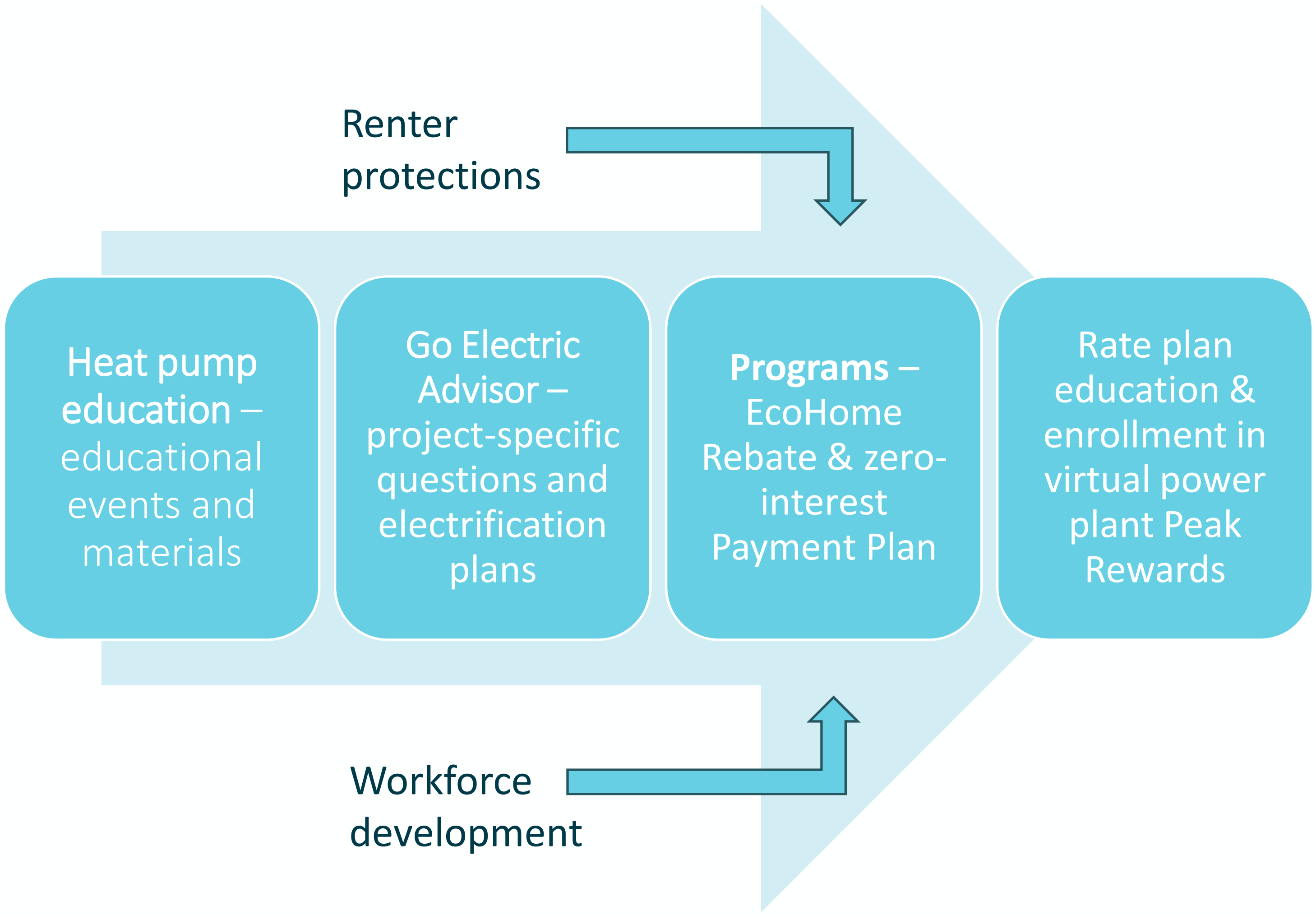
- Largest single-jurisdiction CCA
- Governed by City Council
- Operated by City of San José Energy Department
  - Partner departments: Housing; Office of Racial and Social Equity; Planning, Building, & Code Enforcement

SAN JOSE CLEAN ENERGY

CCA BUILDING ELECTRIFICATION PROGRAMS

- Many supportive programs: direct install, rebates, financing, work force development, education
- Focused on an equitable transition
  - Higher incentives, renter protection policies
- Each CCA approaches BE based on community and governance needs

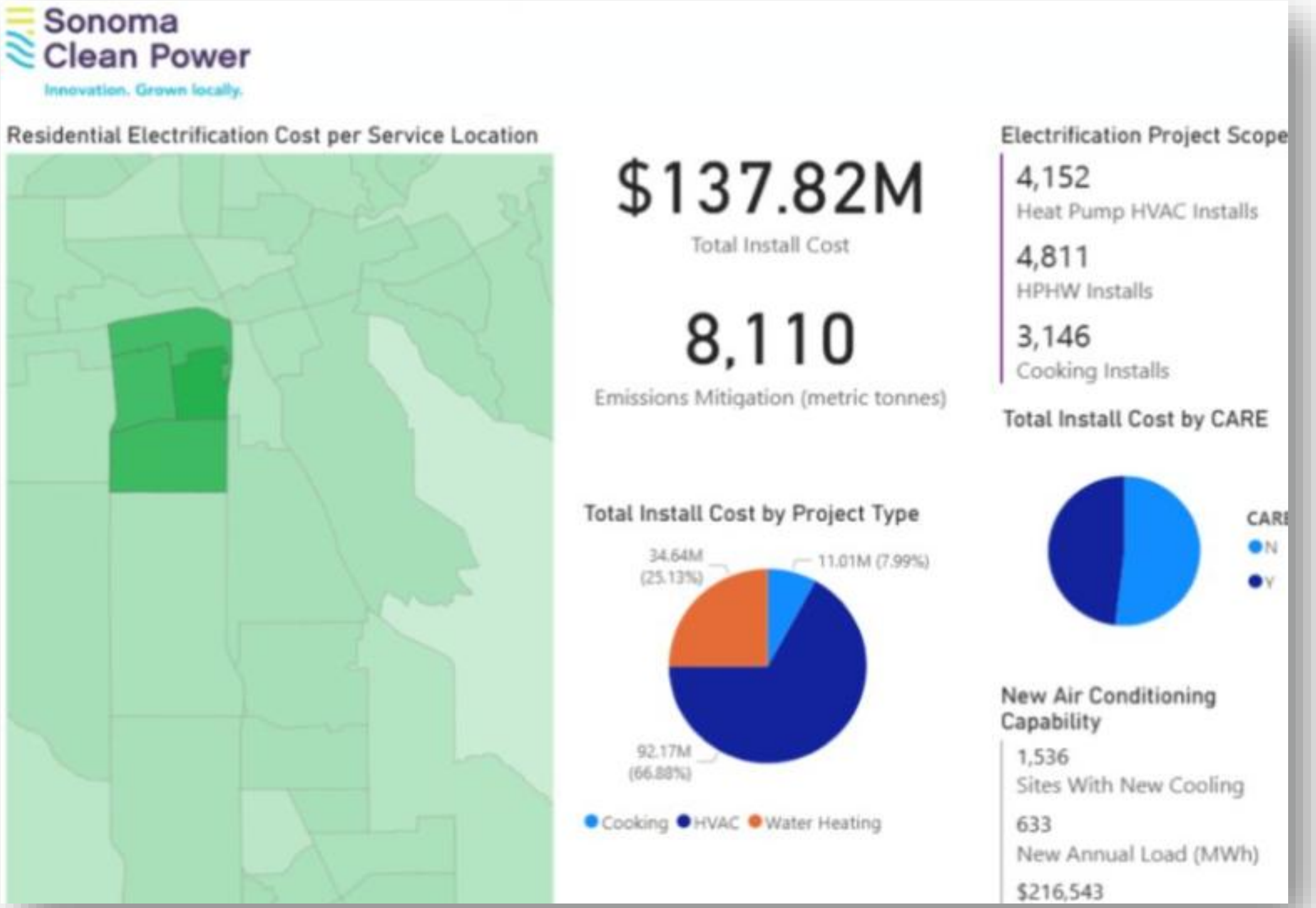
SJCE'S BUILDING ELECTRIFICATION APPROACH



SAN JOSE CLEAN ENERGY

CCA INTEREST IN NON-PIPELINE ALTERNATIVES

- Opportunity to align incentives
- Sonoma Clean Power and UCSB researching zonal decarbonization feasibility, impacts, and scale



SAN JOSE CLEAN ENERGY

CCAS ARE IDEAL PARTNERS

- Connected to communities
  - Relationships with community-based organizations, neighborhood groups, elected officials
- Already work collaboratively with communities to design programs
- Can navigate social, economic, and political feasibility

SAN JOSE CLEAN ENERGY

PROCESS INSIGHTS AND RECOMMENDATIONS

- Consensus building and community willingness is going to be large effort
  - It takes time, but CCAs can serve as accelerators
- Choosing communities requires trusted conversations and leaders who are willing to champion – this can't be rushed
- Using confidential gas system information for PNZ identification is helpful for LSEs – nomination based on this data should also be protected by a discrete process respecting the NDA

SAN JOSE CLEAN ENERGY

Questions?

California Public Utilities Commission