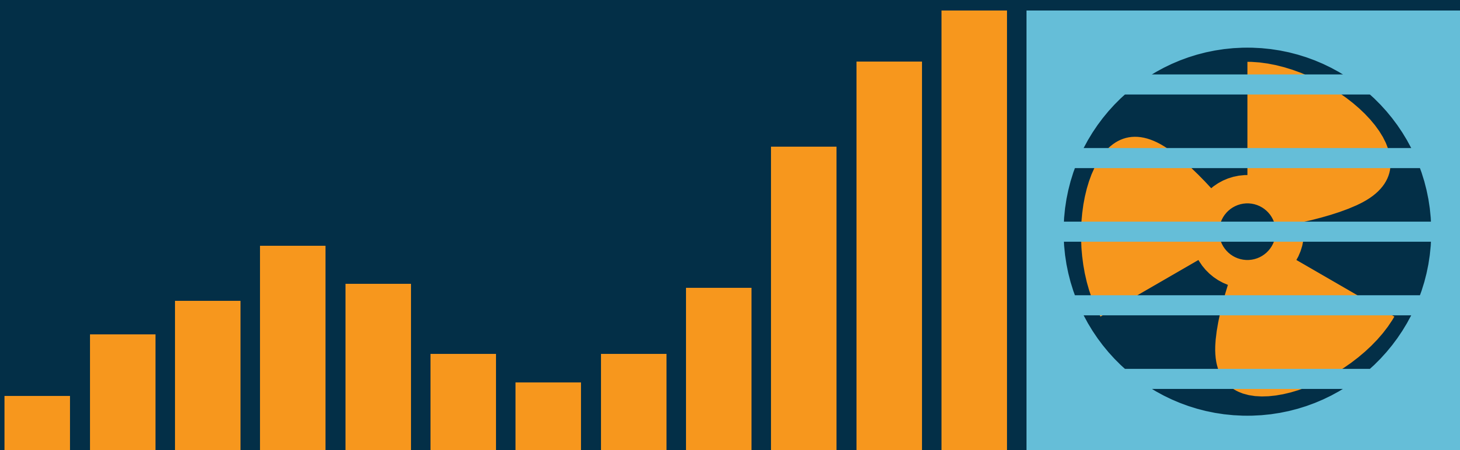
Heat Pump Rates in Rhode Island



Analysis of Fair Rates for Heat Pump Customers

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August 2026

About this report

WHO COMMISSIONED THIS REPORT?

This report was commissioned by the Conservation Law Foundation, Green Energy Consumers Alliance, Acadia Center, and Environmental Defense Fund.

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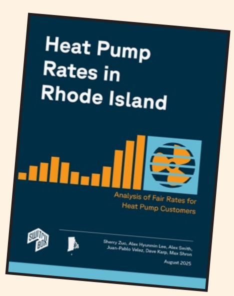

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Introduction

Rhode Island has committed to reducing greenhouse gas emissions 45% below 1990 levels by 2030, 80% by 2040, and achieving net-zero by 2050.[1] The state's 2025 Climate Action Strategy identifies the electrification of space heating — replacing fossil fuel furnaces and boilers with electric heat pumps — as a primary strategy for meeting these targets.[2]

Despite heat pumps being two to three times more energy efficient than fossil fuel heating systems — meaning households that switch will dramatically cut their energy *use* — most Rhode Island households would see their energy *bills* increase, not decrease. The result is a significant operating cost barrier to adoption: even when incentives cover the additional upfront cost of heat pump equipment, the prospect of higher monthly bills discourages homeowners from making the switch.[3]

But higher bills are not inherent to heat pumps. In fact, they are largely an artifact of how Rhode Island Energy (RIE) charges for the poles and wires that deliver electricity to homes. Most of these infrastructure costs are recovered through volumetric rates — per-kWh charges that grow with a customer's electricity consumption.[4] So when a home installs a heat pump and begins using more electricity for heating, its delivery bill jumps significantly — even though most of that new consumption falls in winter, when the grid has ample spare capacity and the cost of delivering electricity is low. The result is a cross-subsidy: heat pump customers **systematically overpay** for the grid, and the excess effectively subsidizes customers who heat with fossil fuels.

This problem is about to get much worse — or much better. Rhode Island is a participant in the New England Heat Pump Accelerator, a federally funded program that is making substantial upfront incentives available for heat pump installations across the state.[5] If the cross-subsidy is left in place, these incentives will funnel thousands of households into a rate structure that punishes them with inflated electricity bills — turning what should be a positive experience into a costly one, and undermining the word-of-mouth that drives market adoption. But if the cross-subsidy is corrected first, the same wave of installations would deliver genuine bill savings,

1 These targets were established by the 2021 Act on Climate, S0078A/H5445A (2021 Act on Climate).

2 See p. 78 of the Rhode Island 2025 Climate Action Strategy (RI 2025).

3 See p. 15 of NEEP's recent Modern Rate Design in the Northeast: Unlocking Efficiency, Affordability, and Electrification report (NEEP 2025).

Volumetric rates

A price per kWh of electricity consumed (e.g. 10 ¢/kWh). Can be used to pay for supply or delivery costs.

4 See this recent rate design paper from the Natural Resources Defense Council (Chhabra et al. 2024).

5 The New England Heat Pump Accelerator is funded through the Environmental Protection Agency's Climate Pollution Reduction Grant (CPRG) program.

building the kind of consumer confidence that accelerates the transition.

This report rigorously quantifies how much Rhode Island's heat pump customers are currently overpaying for the grid, by measuring their cost-of-service and comparing it to the delivery revenue RIE collects from them. We then propose a dedicated electric delivery rate for heat pump customers that would eliminate these overpayments. We find that this **heat pump rate** would transform the economics of heat pumps in Rhode Island, making it cheaper to heat with electricity than natural gas for the vast majority of households in the state.

Delivery costs

The cost to build, operate, and maintain the transmission and distribution network that delivers electricity to customers.

An earlier version of this report was used by the Conservation Law Foundation (CLF) to intervene in RIE's recent rate case.[6]

6 Rhode Island Energy, Application for Approval of a Change in Electric and Gas Base Distribution Rates, Docket 25-45-GE (RIE 2025b).

Executive Summary

This report analyzes the electric bills of heat pump customers served by Rhode Island Energy and finds that:

- **Under today's rates, most gas-heated homes would pay more after switching to heat pumps.** Only **21%** of natural gas-heated households would save on their annual energy bills after installing a heat pump — not because heat pumps are inherently expensive to run, but because electricity bills are inflated by RIE's outdated delivery rates.
- **Heat pump customers are overpaying for the poles and wires by $902 per year**, on average. Their delivery cost-of-service is only **29%** higher than that of fossil fuel-heated customers, but their delivery bills are **143%** higher — a direct consequence of volumetric delivery rates applied to customers who use more electricity.
- **RIE is overcharging heat pump customers by a total of $7.7 million per year** — money that heat pump customers are effectively transferring to customers who heat with fossil fuels.

- **The grid can handle the additional winter load.** Not a single one of RIE's local power lines is winter-constrained, and the median power line uses only 56% of its available capacity in the winter. Heat pump adoption is not triggering significant grid upgrades today — yet heat pump customers are being charged as if it were.
- **RIE should create a dedicated delivery rate class for heat pump customers** that reflects what these customers actually cost the system — rather than letting default volumetric rates collect far more than the cost of serving them. We propose a delivery rate that would charge heat pump customers 8.2 ¢/kWh rather than 14 ¢/kWh.
- **This heat pump rate would transform the economics of operating heat pumps.** Under it, **87%** of gas-heated households would save by switching to heat pumps (up from **21%** under default rates), and the share losing more than $1,000 per year would drop from **8%** to **0%**.
- **The impact on non-heat-pump customers would be minimal**: **$1.57** per month, on average.
- **Heat pump rates could also improve energy affordability for low-income households.** If low-to-moderate income (LMI) households installing heat pumps were enrolled in both the heat pump rate we propose and existing low-income discount programs, the share of highly energy-burdened LMI households would drop by **16 percentage points** compared to today.

Background

To follow along with this report, the reader needs to understand electric utility **costs**, **bills**, and **rates**. These concepts are introduced in this section.

Costs

The expenses a power sector companies incur to generate, transmit, and distribute electricity, including capital costs and operating costs.

Bills

The total amount a customer pays each month in order to cover their share of supply and delivery costs.

Rates

The regulated prices used to calculate customer bills. Includes fixed and volumetric charges.

COSTS: SUPPLY AND DELIVERY

To generate and deliver electricity to customers, power sector companies, including utilities, incur two kinds of costs:[7]

1. **Supply costs**: the money spent to build and operate power plants — as well as batteries and renewables — and burn fuel to generate the electricity.
2. **Delivery costs**: the money spent to build and operate the transmission and distribution network that delivers that electricity to customers.

7 Electric utilities in New England used to own and operate generation, transmission, and distribution. Now they only do the latter, while power producers handle generation, and Transmission Owners (Transcos) handle transmission.

BILLS: SUPPLY AND DELIVERY

Utility customers ultimately pay for these **costs** (and company profits) through their utility **bills**. Utility bills have a supply section, which pays for **supply costs**, and a delivery section, which pays for **delivery costs**.

COST OF SERVICE: SUPPLY AND DELIVERY

A customer's bill tells you how they are *actually* paying for these costs, but their **cost of service** tells you how much they *should* be paying. A customer's cost of service is their "fair share" of the utility's costs: in a given time period, every customer has a supply cost of service and a delivery cost of service — the total supply and delivery costs they impose on the utility in that period.

In theory, a customer's bill should equal their cost of service: the delivery bill should equal the delivery cost of service, and the same for supply. In practice, it rarely does.

RATES: FIXED AND VOLUMETRIC

That's because supply and delivery bills don't magically reflect a customer's supply and delivery cost of service; instead, they are calculated using rates. Rates are simply the regulated *prices* charged by the utility, and they are an imperfect proxy for the costs they are intended to collect.

For residential customers, rates mostly come in two flavors:[8]

- Fixed: a set monthly charge for being connected to the grid (e.g., $6 per month), similar to a rent or lease payment
- Volumetric: a per kWh charge for every unit of electricity consumed (e.g., 14¢/kWh), similar to pumping gasoline at a gas station

HOW FIXED AND VOLUMETRIC RATES RELATE TO SUPPLY AND DELIVERY BILLS

Supply bills are calculated largely with volumetric rates (¢/kWh) in Rhode Island — the utility reads the customer's meter to see how much electricity they consumed that month, and then charges the customer a certain number of cents for each of those kWh.

Delivery bills, on the other hand, are calculated using both fixed and volumetric rates:

- Every customer pays a fixed monthly charge, about $10 a month for Rhode Island Energy
- Volumetric delivery charges add about 14 cents per kWh, depending on utility, season, and (for some tariffs) usage tier — and for most customers, these volumetric charges make up the bulk of the delivery bill. The implication: if you consume more electricity, you don't just pay more for that electricity — you also pay more for the poles and wires that deliver it, regardless of whether you trigger the need for grid upgrades.

8 Rate design enthusiasts will be quick to point out the omission of demand charges, where customers pay for the highest kW of demand they use in a month — power instead of energy. Demand charges are out of scope for this report.

THE FAIRNESS PROBLEM

And therein lies the problem: heat pumps use significantly more electricity than the fossil heating systems they replace. Their supply cost of service goes up — they are consuming more electricity, after all — and their supply bill rises to match it.[9]

But because delivery bills are also largely calculated using volumetric rates, the amount they pay for poles and wires goes up significantly as well, even though their delivery cost of service only increases slightly — and in some cases actually decreases.[10]

As a group, heat pump customers' delivery bills are larger than their delivery cost of service, and the difference creates a cross-subsidy: heat pump customers are quietly lowering the electricity bills of their fossil-heating neighbors. We call this the fairness problem, and it is the central focus of this report.

In this report, we design a delivery rate that would solve the fairness problem for heat pump customers.

THE EFFICIENCY PROBLEM

The fairness problem is distinct from the efficiency problem, which is about whether price signals to customers when costs are high or low.

When rates are flat, customers have no reason to consume more electricity when it's cheap to produce or less when it's expensive — or to curb peak-hour consumption that drives new transmission and distribution (T&D) buildout. The result: underconsumption when electricity is cheap, overconsumption when it's expensive, and a bigger grid than we need — all of which makes supply and delivery rates more expensive for everyone.

The efficiency problem is usually addressed with time-varying rates, volumetric rates whose ¢/kWh price changes of time. Examples include time-of-use (TOU), critical peak pricing (CPP), and real-time pricing (RTP).

9 The opposite happens for **electric resistance** customers: heat pumps use significantly less electricity to produce the same heat, so supply cost of service goes down, and supply bill goes down to match it.

10 A residential customer's delivery cost of service only grows if they consume more electricity during the summer peak, which contributes to the need for new T&D capacity. Customers replacing central air conditioning with heat pumps will decrease their summer peak consumption, and therefore their delivery cost of service, because heat pumps cool more efficiently. Customers with partial or no cooling will increase their summer peak consumption, and therefore their delivery cost of service. However, these added costs are typically dwarfed by the larger delivery bills associated with winter heating — consumption that does not grow a customer's delivery cost of service.

Cross-subsidy

The systematic transfer of money between groups of utility customers. Occurs when rates overcharge one group of customers relative to their cost of service while undercharging another group.

Fairness problem

When the principle that a customer group's bills should match their overall cost of service is violated.

Efficiency problem

When the principle that rates should reflect underlying costs — rising when supply or delivery costs are high and falling when they are low — is violated.

Flat volumetric rate

Volumetric rates that charge the same price per kWh at all hours and seasons. Most default residential electricity rates in the U.S. are flat.

This report does not for on the efficiency problem, so we do not design and evaluate these rates. Moreover, time-of-use rates and other **time-varying rates** typically overcharge heat pump customers, so they are unable to fix the fairness problem without modification.

It is possible to design rates that address fairness and efficiency simultaneously. We do not focus on the min this report, but interested readers should consult Switchbox's Heat Pump Rates in New York report.

Time-varying volumetric rates

Volumetric rates where the price per kWh changes over time. Examples include seasonal rates and time-of-use rates.

Glossary

Bills: The total amount a customer pays each month in order to cover their share of supply and delivery costs.

Bill Alignment Test: Analytical framework that compares what each customer pays bills to their allocated cost of service. Used to measure cross-subsidies between customer groups

Capacity (infrastructure): The maximum electric current a piece of transmission or distribution equipment — a line, transformer, or substation — can carry safely without damaging the equipment. When demand approaches an asset's capacity, the utility must either upgrade it, or build new infrastructure to handle the load.

Capacity costs: The capital cost of an infrastructure project that increases the grid's capacity. Capacity costs are a kind of delivery cost, and they exist at every level of the grid: generation capacity costs (power plants), transmission capacity costs (high-voltage lines and bulk substations), and distribution capacity costs (feeders, transformers, secondary lines).

Costs: The expenses a power sector companies incur to generate, transmit, and distribute electricity, including capital costs and operating costs.

Cost allocation: The regulatory process of dividing a utility's total revenue requirement among the groups of customers it serves, in proportion to each group's cost of service. Typically applied to broad customer classes (residential, commercial, etc.); can also be performed for groups *within* a class (e.g. heat pump customers).

Cost-causation principle: The idea that utility costs should be paid for by the customers that cause them: the cost to generate electricity should be paid by those who consume it, the cost to build infrastructure to meet peak demand should be borne by customers who use the network during peak hours.

Cost of service: The costs associated with generating and delivering electricity to a particular customer or customer class. A customer's *delivery* cost-of-service is their fair share of delivery costs; *supply* cost-of-service is their share of supply costs.

Cross-subsidy: The systematic transfer of money between groups of utility customers. Occurs when rates overcharge one group of customers relative to their cost of service while undercharging another group.

Default rates: The electric supply and delivery rates a utility's customers are automatically enrolled in.

Delivery costs: The cost to build, operate, and maintain the transmission and distribution network that delivers electricity to customers.

Efficiency problem: When the principle that rates should reflect underlying costs — rising when supply or delivery costs are high and falling when they are low — is violated.

Economic burden: A customer's total marginal cost of service: the sum of their hourly consumption multiplied by hourly marginal energy and T&D capacity costs, during an entire year.

Electric resistance heating: A class of electric heating equipment — baseboard heaters, electric furnaces, space heaters — that converts electricity directly into heat by running a current through a resistive element.

Embedded costs: Costs that have already been incurred, and must be recovered from customers regardless of how much customer electricity they use, or when they use it. Mostly consists of the delivery costs associated with T&D infrastructure that has already been built.

Energy burden: The share of a household's annual income spent on home energy bills — electricity, natural gas, delivered fuels. A widely used indicator of energy affordability stress.

Fixed charges: A flat dollar amount per month that a customer pays regardless of how much electricity they use.

Flat volumetric rates: Volumetric rates that charge the same price per kWh at all hours and seasons. Most default residential electricity rates in the U.S. are flat.

Fairness problem: When the principle that a customer group's bills should match their overall cost of service is violated.

Headroom: The gap between a feeder's peak load and its normal capacity rating, expressed as a percentage. A feeder at 80% of capacity has 20% headroom — room for load to grow 20% before the feeder is fully loaded.

Load shifting: The practice of moving electricity consumption from one time of day to another without reducing total use, typically in pursuit of lower prices. Incentivized by TOU and other time-varying rates.

Marginal costs: The costs of generating or delivering the next unit of electricity. In other words, supply or delivery costs that are caused by customers choosing to consume an additional kWh at particular times.

Marginal energy costs: The operating cost of generating an additional kWh of electricity at a particular time. Marginal energy costs vary hour by hour with demand and the mix of generators running: they are low when abundant renewables are on the grid or demand is slack, and high when expensive peaker plants are running to meet peak load.

Marginal generation capacity costs: The capacity cost associated with triggering the construction of a new megawatt of generation capacity at a particular time. Zero most hours of the year, and high during system-wide peak hours.

Marginal T&D capacity costs: The capacity cost associated with triggering the construction of a new megawatt of transmission or distribution capacity at a particular time. Zero most hours of the year, and high during peak hours for the infrastructure component that is at capacity.

Operating costs: The ongoing expenses of running and maintaining the electric grid day-to-day. Operating costs recovered from customers in the same year they are incurred.

Peak hours: The hours in a year when a particular infrastructure component — be it a distribution line, transmission line, or the grid as a whole — experiences peak demand. If the component is at capacity, usage during these hours triggers the need for upgrades, which drives delivery costs up.

Rates: The regulated prices used to calculate customer bills. Includes fixed and volumetric charges.

Residual: The gap between a utility's total revenue requirement and the revenue that marginal-cost pricing alone would recover. It reflects embedded costs — depreciation, carrying charges, O&M — that are not captured by forward-looking marginal costs.

Revenue requirement: The total amount of revenue a utility is authorized to collect from a customer class (or subclass) over a given period, in order to cover its delivery costs. Determined during a rate case.

Rate design: The process of choosing the specific rate structure — the mix of fixed charges, volumetric charges, demand charges, and time-varying prices — used to calculate the bills of a particular group of customers. Many different rate designs can collect the same total revenue, but they differ in their secondary effects.

Seasonal rate: A volumetric rate whose per-kWh price differs between summer and winter but is constant within each season.

Supply costs: The cost to build and maintain power plants, renewables, and batteries, and to operate them to generate electricity. Dominated by energy costs, which vary hour by hour with demand and the mix of generators running.

Time-of-use (TOU) rates: A volumetric rate whose per-kWh price varies by time of day, typically higher during an "on-peak" window when the grid is more likely to be strained and electricity is most expensive to produce, and lower during "off-peak" hours.

Time-varying volumetric rates: Volumetric rates where the price per kWh changes over time. Examples include seasonal rates and time-of-use rates.

Volumetric rate: A price per kWh of electricity consumed (e.g. 10 ¢/kWh). Can be used to pay for supply or delivery costs.

Findings

WHAT HAPPENS TO HEATING BILLS WHEN HOUSEHOLDS SWITCH TO HEAT PUMPS?

Imagine a single-family home in Cranston, Rhode Island: a three-bedroom house built in the 1980s, heated by a natural gas furnace with central air conditioning. It pays $3,192 for electricity and natural gas every year — close to the median bill for gas-heated homes in the state.[11]

As with all homes in Rhode Island, when this household switches to an air-source heat pump,[12] its annual energy use plummets (Figure 1):

11 Specifically: a 1,698 sq ft, owner-occupied, single-story home with R-19 insulated concrete masonry walls, a 92.5% AFUE gas furnace, and SEER 13 central AC. The home is served by Rhode Island Energy (electricity and gas).

12 The heat pump modeled is a high-efficiency cold-climate air-source heat pump (ccASHP) with electric backup, rated SEER1 20 / HSPF1 11, sized to max load, with 90% capacity retention at 5°F.

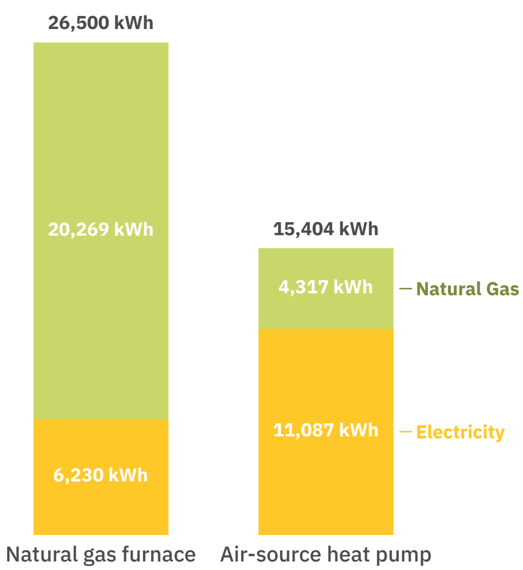


Figure 1: Annual energy consumption before and after switching to a heat pump, for a gas-heated home at the statewide median energy bill (among gas-heated homes with full baseline cooling).

This drop in energy use is due to the fact that heat pumps are two to three times more efficient than furnaces, so they only require a fraction as much energy input to heat a home to the same temperature.

However, while switching to heat pumps cuts a home's energy *use*, it often increases its energy *costs*, as is the case with this Cranston home (Figure 2).

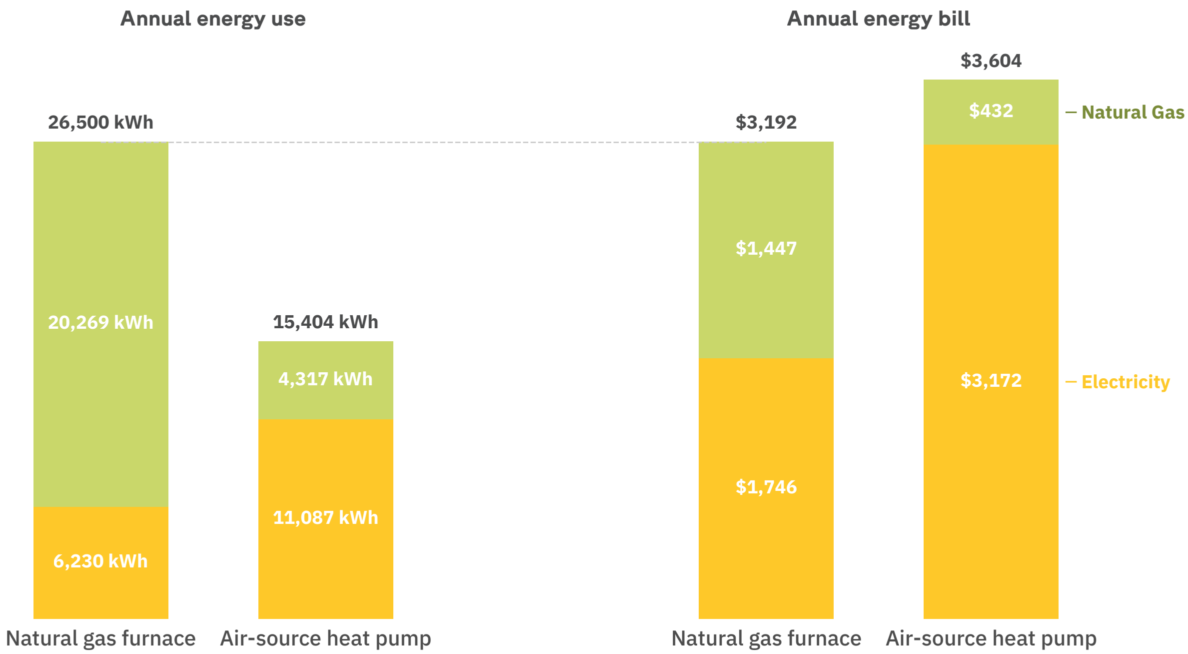


Figure 2: Annual energy consumption and energy bills before and after switching to a heat pump, for the gas-heated home at the statewide median energy bill (among gas-heated homes with full baseline cooling).

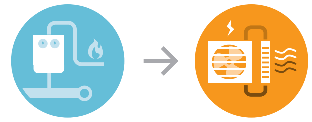
This is because electricity is more expensive than natural gas in Rhode Island: while it makes up only 24% of this gas-heated household's annual energy use, it accounts for 55% of its annual energy bill.

After this building replaces its gas furnace with a heat pump, its annual gas bill drops by $1,015.[13] But its annual electric bill jumps by $1,427.

The result: despite the heat pump's lower energy use, switching this home's heating fuel from natural gas to electricity causes its annual **combined energy bills** — which are near the statewide median — to jump by $412 per year.

In other words, under today's utility prices for electricity and gas, it costs more to heat this home with heat pumps than with natural gas. While this experience is fairly typical of what happens when gas-heated homes switch to heat pumps today, Rhode Island's building stock is diverse, so the full range of bill impacts varies widely (Figure 3).

13 The home in this example still uses some gas for cooking and hot water, which is why the gas bill doesn't drop to zero after the switch.



How bills would change for natural gas heated homes after switching to heat pumps (with current LMI discounts)

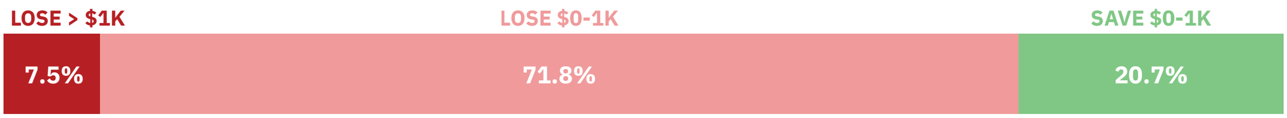


Figure 3: Bill impact of switching to heat pumps for natural gas-heated households (Assumes 32% of eligible LMI customers receive LMI discounts.)

While most natural gas-heated households that switch to heat pumps do see their bills go up, approximately 21% actually enjoy lower bills after the switch.[14]

Only 55% of RI households are heated with natural gas, however. The rest are heated with delivered fuels or electric resistance — both of which have more potential for bill savings than natural gas (Figure 4).

14 The homes most likely to save under default rates are those that start off with less efficient furnaces (they spend more on heating than a heat pump might) and those that already have central air conditioning (so they spend more on cooling than a heat pump would).

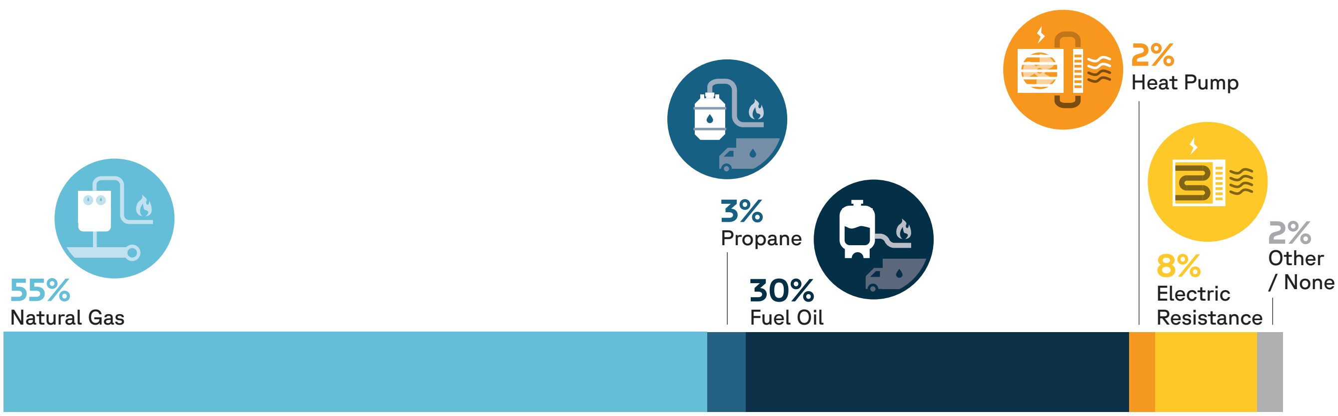


Figure 4: Percentage of households by primary heating fuel

Indeed, when households who heat with delivered fuels switch to heat pumps, their bills tend to go down (Figure 5).

How bills would change for fuel oil or propane heated homes after switching to heat pumps

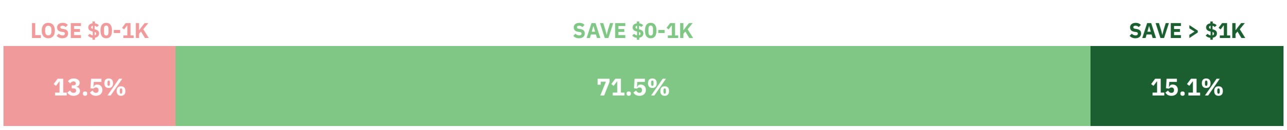
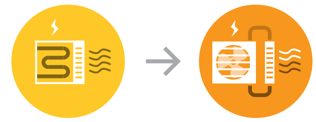


Figure 5: Bill impact of switching to heat pumps for oil/propane-heated households (Statewide)

Today, over 87% of oil and propane households lower their bills after switching, and 15% save more than $1,000 per year.

The story is similar for electric resistance-heated households (Figure 6).



How bills would change for electric resistance heated homes after switching to heat pumps

Figure 6: Bill impact of switching to heat pumps for electric resistance-heated households (Statewide)

For households that heat with electric resistance, 98% would see bill decreases after switching to heat pumps, and 57% would save more than $1,000 per year.

So why do heat pumps struggle to compete against natural gas in Rhode Island?

While natural gas prices are partly to blame, they are not the whole story. As we'll see in the next section, the main culprit is (artificially) high electricity prices: outdated **volumetric rates** are causing heat pump customers to pay more than their fair share for the poles and wires that deliver electricity to their homes.

> **Electric resistance heating**
>
> *A class of electric heating equipment — baseboard heaters, electric furnaces, space heaters — that converts electricity directly into heat by running a current through a resistive element.*

HEAT PUMP CUSTOMERS ARE CROSS-SUBSIDIZING NON-HEAT-PUMP CUSTOMERS

Why electric bills go up when heat pumps are installed

When a household with existing air conditioning switches to a heat pump, its annual electricity consumption goes up by roughly 31% to 98% — and much more for homes that gain cooling for the first time.[15] The electric bill goes up by approximately the same amount.

In the case of the Cranston home, its annual electricity use and its annual electric bill both grow by 1.8× (Figure 7).

15 The range shown is the weighted interquartile range (25th to 75th percentile) for fossil-fueled homes with full baseline cooling statewide. The increase depends on whether the home already had air conditioning.

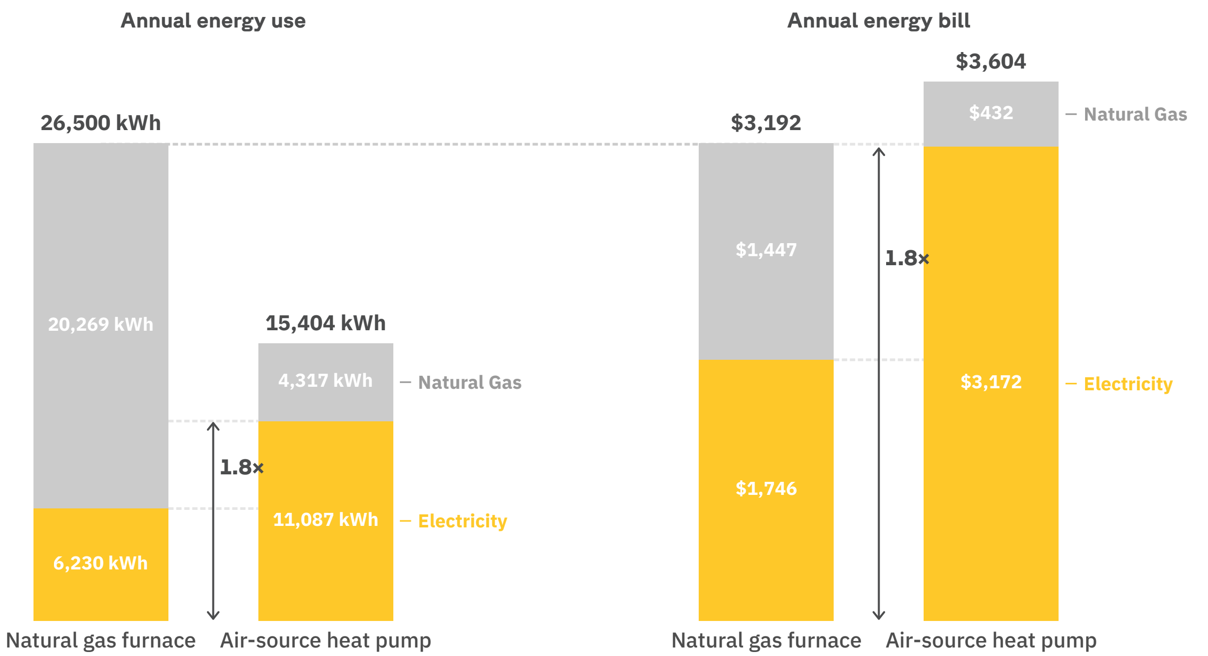


Figure 7: Electricity use and electric bills both roughly double after Cranston home switches to a heat pump. 1 kWh of gas = 3,412 BTU

To understand why this happens, we need to drill down into the electric bill's components (Figure 8).

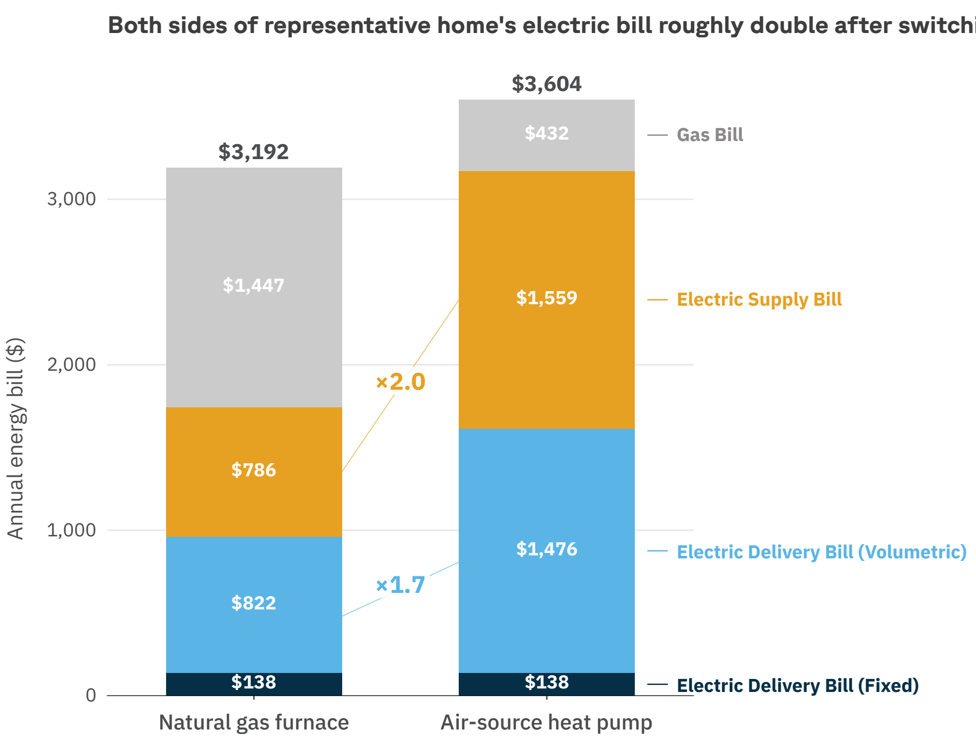


Figure 8: Median energy bill components for representative home

The home pays 2.0× as much for supply — the part of the bill that pays for the electricity itself, and for power plants to be available to generate it. This makes sense: after making the switch, the home consumes 1.8× as much electricity per year.

But upon turning on the heat pump, the home also starts paying 1.7× more for the same poles and wires that bring that electricity to its home.

This happens because delivery costs are largely recovered through volumetric charges, rather than **fixed charges**. The result: when a customer consumes more electricity, not only do they pay more for that electricity, but they also pay more for the grid itself — regardless of whether they trigger the need for grid upgrades.

Volumetric charges

A price per kWh of electricity consumed (e.g. 10 ¢/kWh). Can be used to pay for supply or delivery costs.

Fixed charges

A flat dollar amount per month that a customer pays regardless of how much electricity they use.

Is this delivery bill inflation fair?

Heat pump customers are overpaying for delivery

To be fair, a customer's **bill** must match the **costs** the customer imposes on the system.[16]

16 Goal 6 of the future electric system, adopted by the Rhode Island Public Utilities Commission in Order 22851 of Docket 4600, directs that rates should "appropriately charge customers for the cost they impose on the grid" (RIPUC 2017).

When a customer grows their electricity use after installing a heat pump, they grow their **energy costs** — power plants have to burn more fuel to generate that electricity, and so on. So it is fair that their supply bill also grows.

But a customer's delivery bill should only increase if they grow their **capacity costs**, also known as their delivery cost-of-service. And this only happens when their new electricity use triggers new upgrades to the grid's capacity — during the handful of "peak hours" of the year, when the grid as a whole (or their local distribution line) is most congested.

Delivery cost-of-service

The costs associated with delivering electricity to a particular customer, including their fair share of the existing grid, and any grid upgrades triggered by their usage.

If a customer's delivery bill exceeds their delivery cost-of-service, they are overpaying.

To illustrate, let's return to our Cranston home, which is served by Rhode Island Energy, and has an annual delivery cost-of-service of $1,019 per year (Figure 9).

When heated with natural gas, the home's annual electric delivery bill is $60 lower than its delivery cost-of-service — a good illustration of how most gas-heated homes actually *underpay* for delivery.

Peak hours

The hours in a year when a particular infrastructure component — be it a distribution line, transmission line, or the grid as a whole — experiences peak demand. If the component is at capacity, usage during these hours triggers the need for upgrades, which drives delivery costs up.

Delivery bill vs. cost of service — same home, before and after heat pump

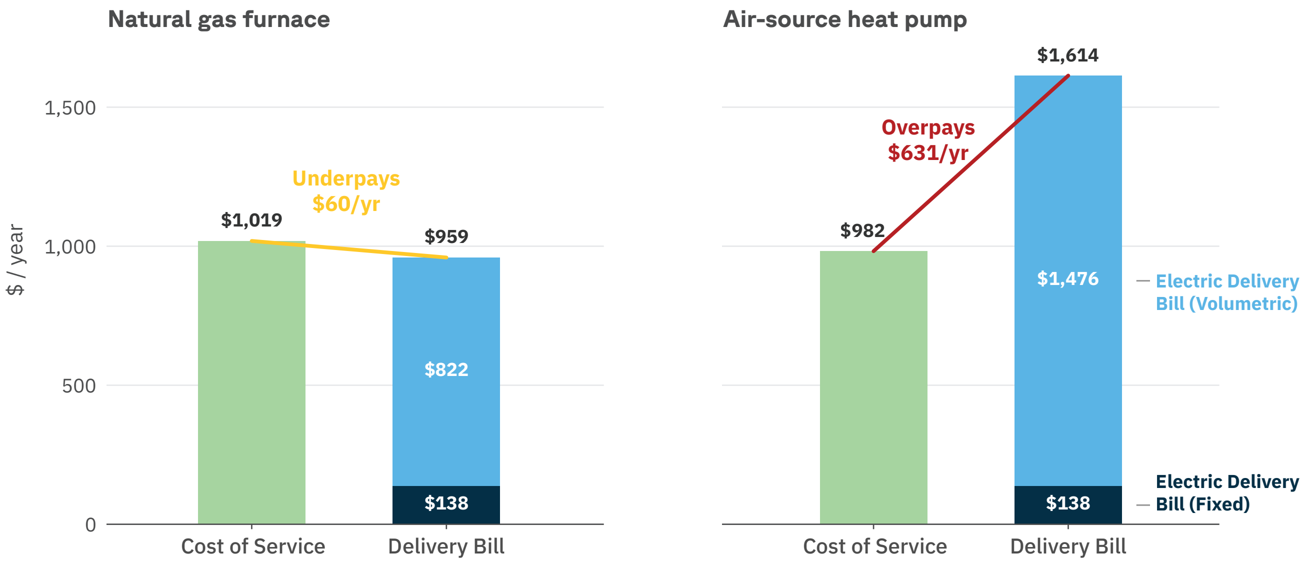


Figure 9: Annual electricity delivery bill vs. delivery cost of service for the representative gas-heated home, before and after switching to a heat pump.

After switching to the heat pump, its delivery cost-of-service actually decreases by $37 per year: because the heat pump cools more efficiently than their old central AC unit, the home's electricity use during the peak hours that drive grid upgrades actually goes down.[17]

But as we saw earlier — as a direct consequence of volumetric rates — the Cranston home's annual electric delivery bill grows to $1,614 per year, causing an overpayment of $631 per year. In other words: if Rhode Island Energy's delivery rates were fair, this home's *total* electric bill would shrink by 20%.

How widespread is this overpayment problem in practice?

We find that households with heat pumps are systematically paying more than their cost-of-service for delivery across all of Rhode Island.

Statewide, the delivery cost-of-service for fossil fuel customers is $1,080 per year, on average, compared to $1,395 per year for heat pump customers.

However, heat pump customers pay average delivery bills of $2296 per year, $1352 more than the bills of customers that heat with fossil fuels, despite costing only $315 more to serve.

17 The fact that the home's electricity use grew by 78%, but its delivery cost of service changed so little, reflects the fact that both the ISONE grid as a whole and Rhode Island Energy's local distribution system have ample winter headroom (see p. 23).

	Customers	% of customers	Avg. delivery bill	Avg. cost of service	Avg. cross-subsidy	Avg. cross-subsidy ÷ Avg. COS
Heat pump	8,563	2.00%	$2,296	$1,395	$902	64.70%
Electric resistance	35,348	8.40%	$2,020	$818	$1,202	147.10%
Natural gas	230,312	54.90%	$847	$975	−$128	−13.2%
Delivered fuels	137,002	32.70%	$1,107	$1,248	−$141	−11.3%
Other	8,123	1.90%	$1,078	$1,248	−$170	−13.6%
All customers	419,348	100.00%	$1,065	$1,065	$0	0.00%

Table 1: Average delivery revenue, cost of service, and cross-subsidy by residential subclass during the Test Year, 9/1/24 to 8/31/25.

Heat pump customers' average delivery cost-of-service is just **29%** higher than that of fossil fuel customers — but their average delivery bills are **143%** higher. As a result, Rhode Island's heat pump customers are overpaying for delivery by **$902 per year** every year, on average.

Moreover, households that heat with natural gas are *underpaying* for delivery by **$128 per year**, on average, while those with heating oil and propane are *underpaying* by **$141 per year**.

These findings are connected: part of what allows fossil fuel customers to pay less for delivery than their cost-of-service is precisely the fact that heat pump customers are overpaying, which creates a cross-subsidy to customers that heat with fossil fuels.[18]

18 Electric resistance customers are also overpaying, and are responsible for a substantial portion of the cross-subsidy to fossil fuel customers.

How overpayments create cross-subsidies

To understand how cross-subsidies arise, let's return to the single-family home in Cranston.

Before switching to a heat pump, let's assume its annual electricity use, and therefore its annual delivery bill, equals those of its natural gas-heated neighbors.

Cross-subsidy

The systematic transfer of money between groups of utility customers. Occurs when rates overcharge one group of customers relative to their cost of service while undercharging another group.

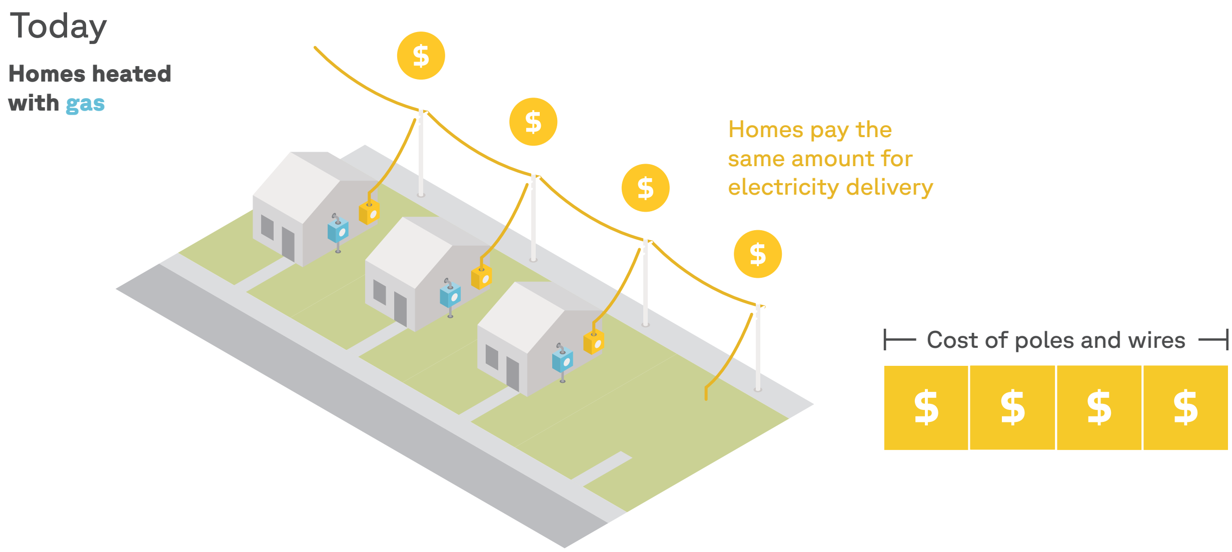


Figure 10: Homes pay the same amount for delivery.

The power line on this block was upgraded in recent years, and the cost of this upgrade is paid back by customers over decades. Every year, the cost of this upgrade is paid for by the homes on this block.[19]

As we've seen, after the home installs a heat pump, its annual electricity use (and therefore its annual delivery bill) both grow by 1.8×. But this new electricity use is highly concentrated in the winter:

19 In reality, these customers would also help pay for other power lines, and customers on other blocks would help pay for this one. This is a stylized example to illustrate the zero-sum dynamic: the utility's annual revenue requirement is fixed, so under volumetric rates, any customer who consumes more electricity pays a larger share of that fixed pot — and everyone else pays a smaller share, regardless of whether the actual cost of serving anyone changed.

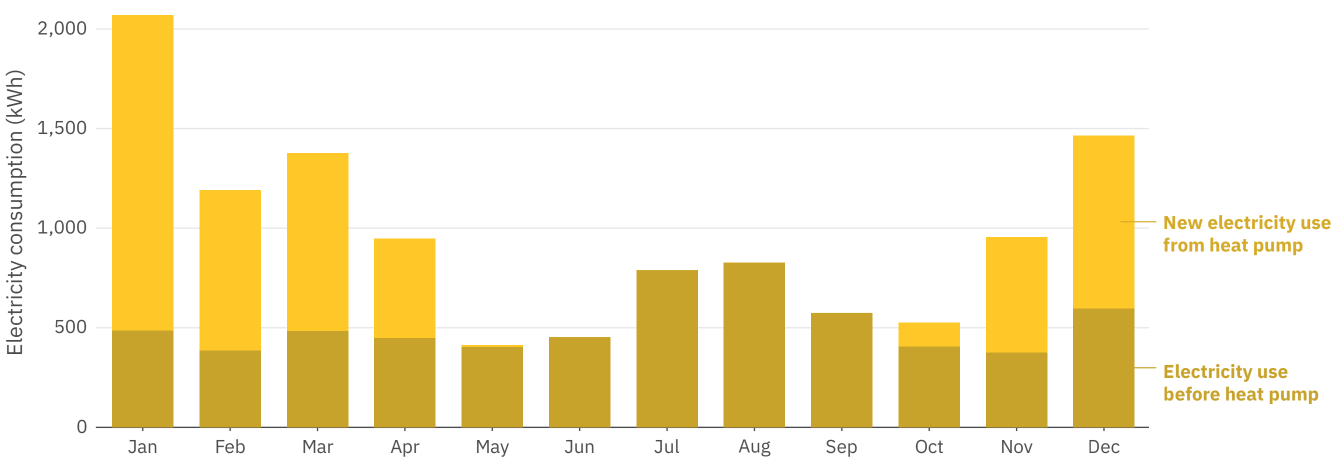


Figure 11: Monthly electricity consumption for a representative gas-heated home, before and after switching to a heat pump

Does the power line have enough capacity to accommodate this additional wintertime load?

If it does not, the electrical utility would need to upgrade the power line.

Capacity (infrastructure)

The maximum electric current a piece of transmission or distribution equipment — a line, transformer, or substation — can carry safely without damaging the equipment.

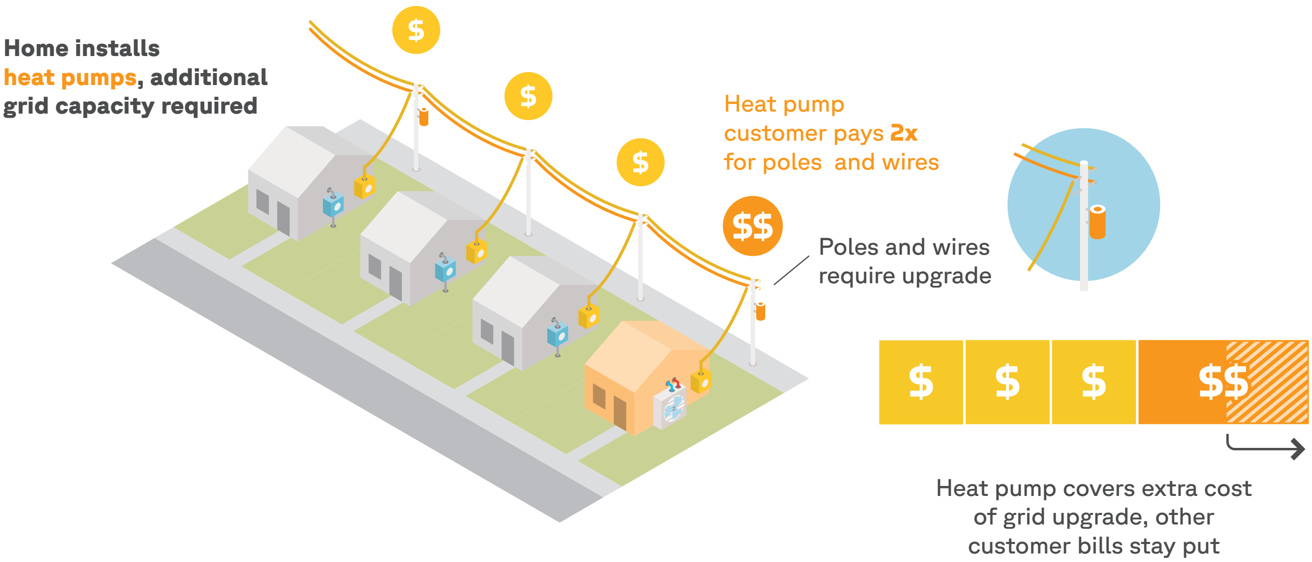


Figure 12: Heat pump customers pay 2x more for poles and wires, causes capacity upgrade.

These new capacity costs (represented by the growing rectangle in the diagram above) must now be recovered from the customers.

The costs were caused by the heat pump installation, so under the principle of cost-causation, they should be borne by that customer.

And, in this case, they are: the higher delivery bills resulting from volumetric delivery rates cover these new, or "marginal", capacity costs. The customer's delivery cost-of-service grows, but the delivery bill grows to match it. There's no underpayment or overpayment, and no impact on the other customers on the block.

But as we'll see in the next section, the overwhelming majority of Rhode Island's grid *does* have the capacity to accommodate this additional wintertime load. And that's what creates the cross-subsidy.

Capacity costs

The capital cost of an infrastructure project that increases the grid's capacity. Capacity costs are a kind of delivery cost, and they exist at every level of the grid: generation capacity costs (power plants), transmission capacity costs (high-voltage lines and bulk substations), and distribution capacity costs (feeders, transformers, secondary lines).

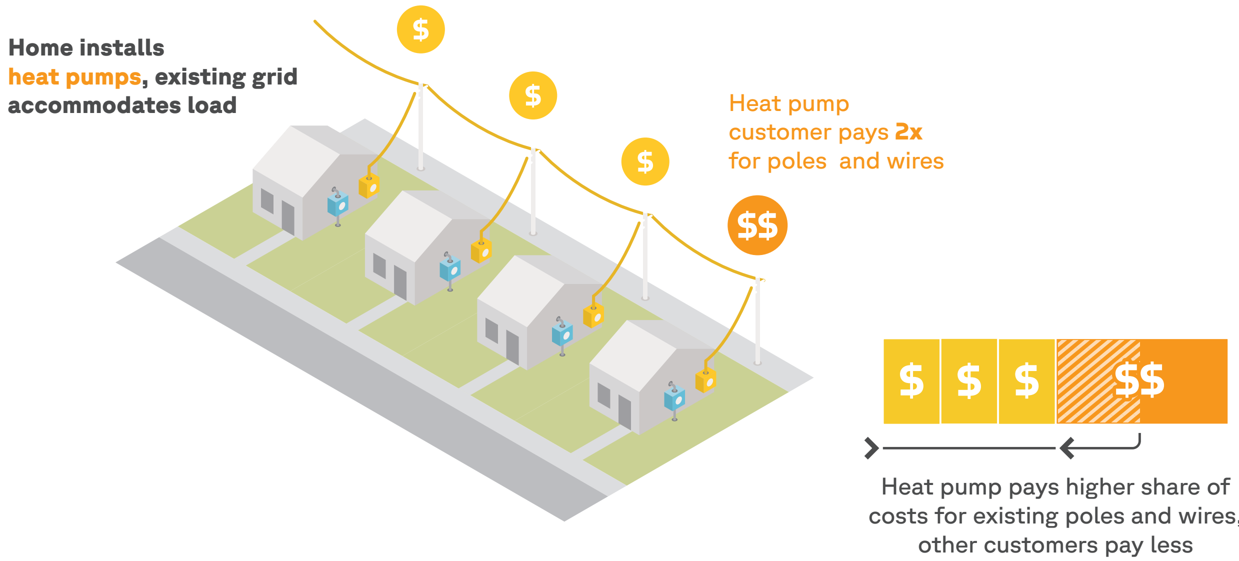


Figure 13: Heat pump customers pay 2x more for poles and wires, no capacity upgrade.

In this alternative scenario, the power line's spare winter capacity absorbs the heat pump's additional winter load. **Capacity costs** don't grow; they stay fixed.

Volumetric rates nevertheless cause the heat pump customer's delivery bill to rise, even though their delivery cost-of-service hasn't changed. The heat pump customer pays a bigger share of the fixed costs, which allows the other customers on the block to pay less.[20]

And this "no capacity upgrade" scenario is the one that prevails across most of the state today.

20 In practice, this doesn't happen instantaneously on a single block. When heat pump customers use more electricity, the utility collects more delivery revenue than it is authorized to keep. The excess is returned to all customers the following year through a lower per-kWh delivery rate, via revenue reconciliation adjustments (RRAs). Everyone's rate falls by the same amount — but customers who use less electricity (predominantly those heating with fossil fuels) see a bigger relative benefit than customers who use more (predominantly those with heat pumps). The net effect is a persistent transfer: heat pump customers' bills remain well above their cost-of-service, while fossil fuel customers' bills settle below theirs.

Why the grid can handle the additional load

How much headroom is currently available in Rhode Island Energy's distribution grid to accommodate heat pump adoption?

As of 2026, only 9% of RIE's local power lines, or feeders, are constrained during the summer peak (Figure 14). Of the 507,343 customers served by RIE's active feeders, 17% (85,576 customers) are on constrained feeders.

Headroom

The gap between a feeder's peak load and its normal capacity rating, expressed as a percentage. A feeder at 80% of capacity has 20% headroom — room for load to grow 20% before the feeder is fully loaded.

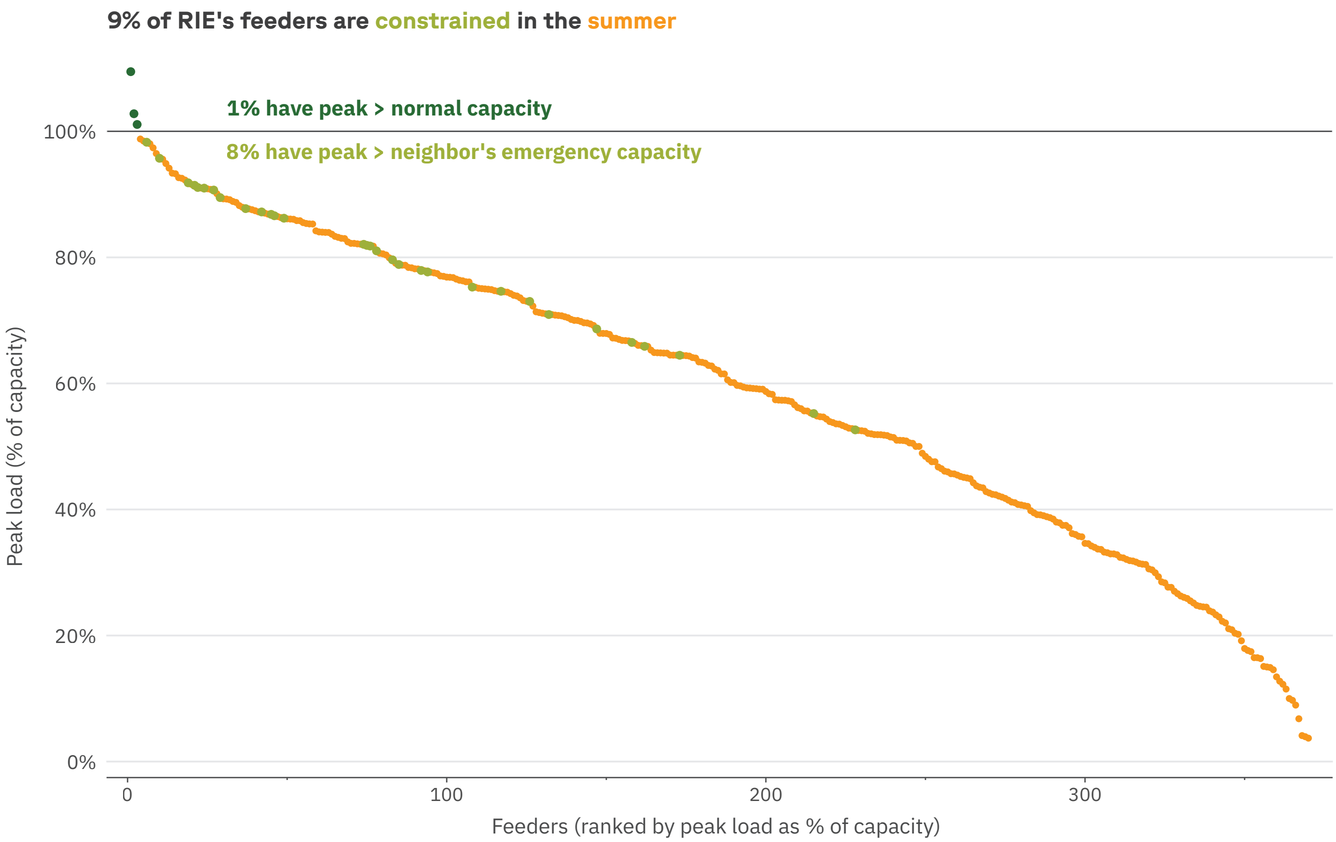


Figure 14: Summer peak load as a percent of summer normal capacity for every feeder on RIE's system, as forecasted in 2026. Feeders are ranked from most to least stressed. Green dots = contingency load-at-risk in MWh > 16 MWh. Dark green dots = peak exceeds summer normal rating. Source: Rhode Island Energy

The utility is already planning to upgrade the capacity of these constrainer feeders in the coming years.

As for the unconstrained feeders, nearly 79% have at least 20% headroom, and many have much more: the median headroom is 38%.

Note

What is a constrained feeder?

Rhode Island Energy considers a feeder to be **constrained** when...

- **Peak > normal capacity**: its highest annual load (or peak) exceeds its **normal capacity**, and the equipment risks overheating.[21] At present, this only occurs when the *summer* peak exceeds the *summer* normal capacity.[22]
- **Peak > neighbor's emergency capacity:** the feeder goes down during the summer peak, and the neighbors it is connected to don't have enough **emergency capacity**[23] to pick up and reroute 100% of its peak load, causing some customers on the downed feeder to lose power until crews complete the repair. Also known as an *N-1 contingency*.[24]

21 An electrical component's normal capacity rating is the load it can carry continuously without damage.

22 A feeder's normal capacity depends on the temperature, and therefore the time of year, because cold wires can carry more current than hot wires.

23 An electrical component's emergency capacity rating is the maximum load it can safely carry for 24 hours. During a contingency, neighboring feeders run (up to) this elevated rating while crews fix the problem.

24 Technically, RIE flags a feeder when the downed feeder's unservable load exceeds 16 MWh — equivalent to 4 MW's worth of customer load dropped for an entire 4-hour repair window. In this scenario, enough customers would be without power for long enough that the utility must evaluate infrastructure upgrades to reduce the load-at-risk. See (RIE 2011) for more details.

In other words, most of RIE's distribution network has plenty of spare capacity in the summer. What about in winter?

At present, RIE's distribution grid is so summer-dominated that the utility's planning engineers don't even measure the feeders' winter peaks.[25]

Instead, the utility's distribution planners estimate them by assuming each feeder's current winter peak is equal to 70% of its current summer peak.[26]

Using this same assumption, we can provide an estimate of the current winter headroom for each feeder on RIE's distribution grid (Figure 15).

25 In correspondence, RIE's Distribution Planning Manager, Ryan Constable, stated that "the Company estimates that the system and underlying components will not become winter-limited until the mid to late 2030s," Schedule JPV-6, Response 14, in (Velex 2026).

26 System-wide, RIE's winter peak is currently 70% of the summer peak (RIE 2024b), so this assumption is correct on average, but will tend to underestimate above-average winter peaks.

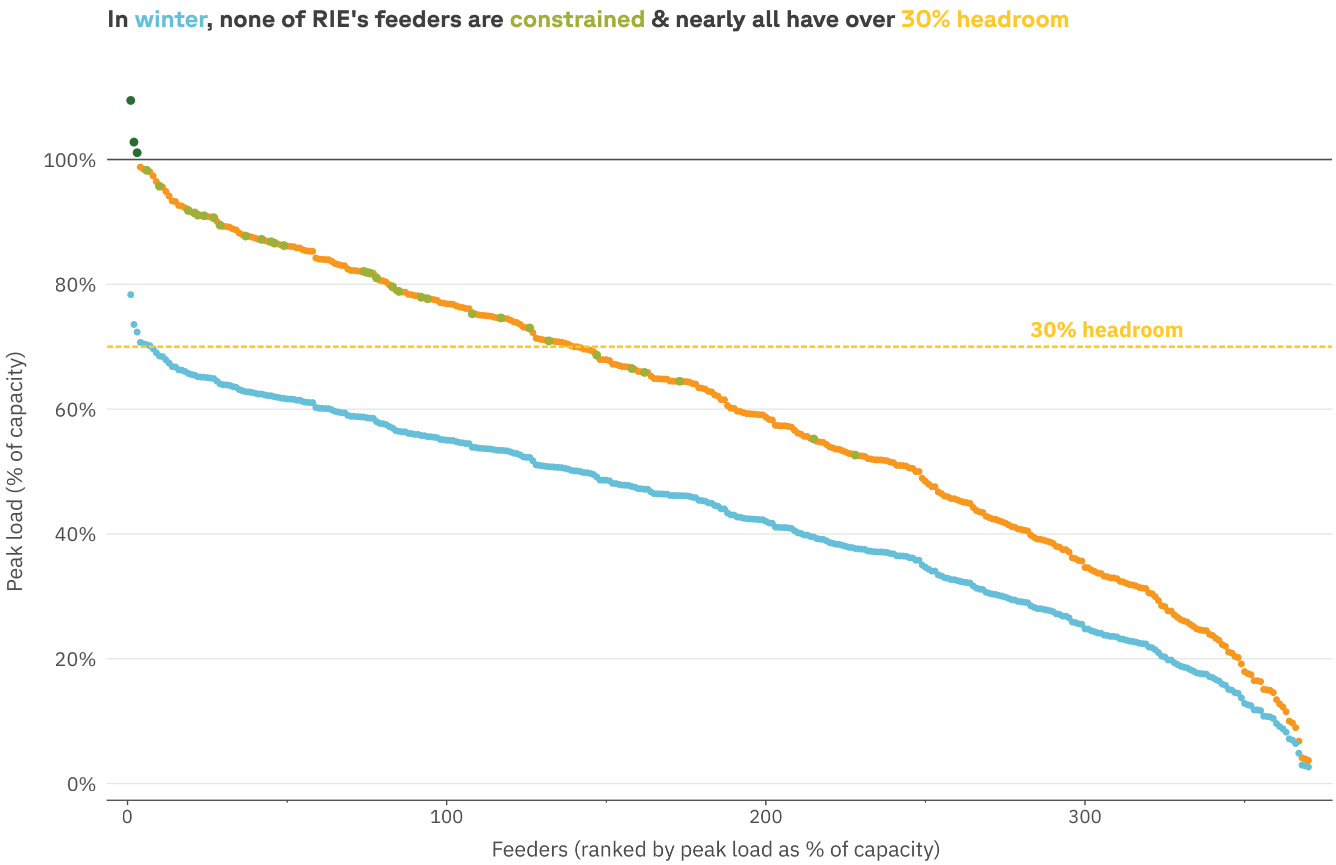


Figure 15: Summer and winter peak load as a percent of summer normal capacity, for every feeder on RIE's system as forecasted in 2026. Feeders are ranked from most to least stressed. Green dots = contingency load-at-risk in MWh > 16 MWh. Dark green dots = peak exceeds summer normal rating. Source: Rhode Island Energy

Bottom line, none of RIE's local power lines are constrained in winter. Far from it: 99% of feeders have more than 30% headroom. The median headroom is 56%.

At present, then, a household that installs a heat pump in Rhode Island imposes only modest costs on the grid during summer, if at all:

- During the winter, every distribution line in the state has ample capacity to accommodate the additional load.
- During the summer, the only households that would impose costs by installing heat pumps are those that lack central air conditioning *and* are served by one of the 34 feeders in Rhode Island that are currently constrained during the summer peak — all of which are already scheduled for capacity upgrades in the next few years.[27]

27 RIE's own load forecasts actually assume that heat pumps lower the summer peak, due to their increased efficiency over traditional air conditioning (RIE 2024c).

We've established that the grid's constraints are a summer phenomenon. But when, exactly, does using electricity cause new distribution and transmission costs? Figure 16 and Figure 17 show the cost of the next increment of grid capacity for every hour of the year. Each tile is one hour; darker tiles indicate higher cost.

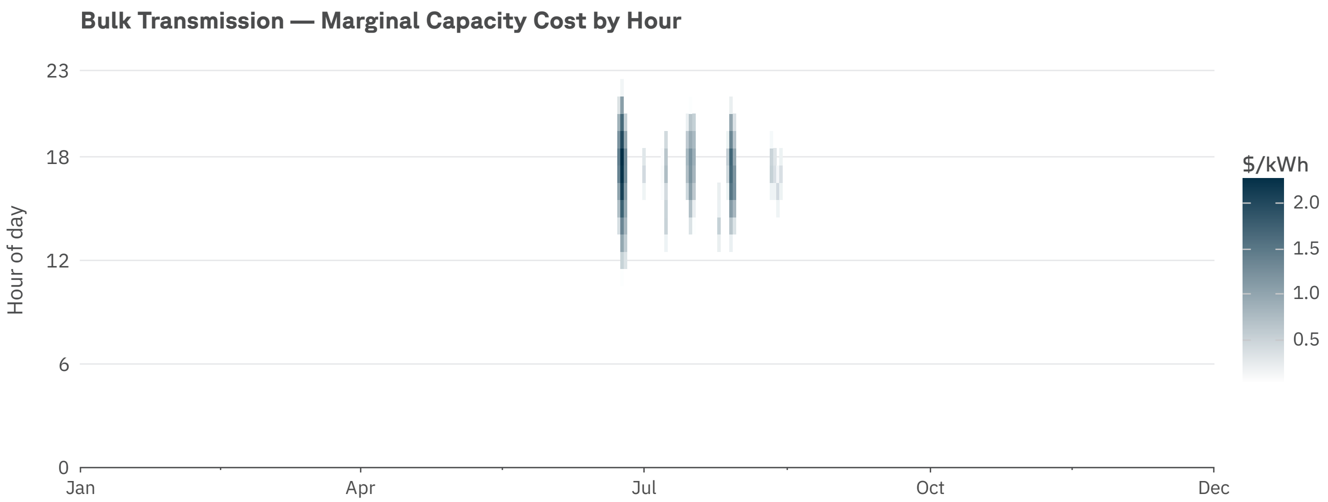


Figure 16: Hourly marginal bulk transmission capacity costs, 2025. Costs are concentrated in ~100 summer afternoon hours; every winter hour is zero.

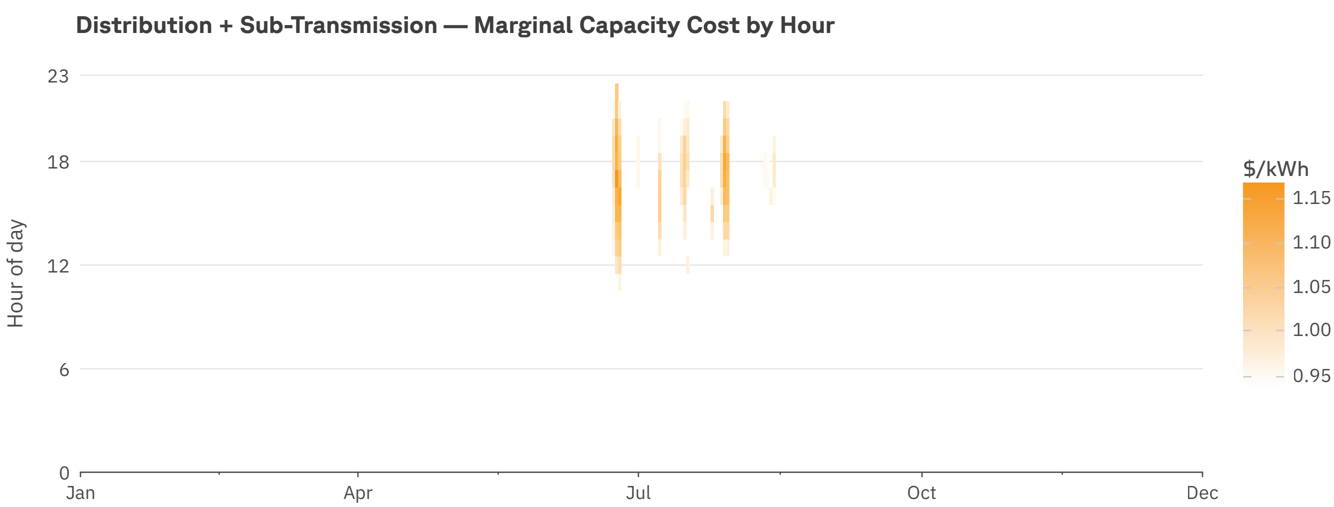


Figure 17: Hourly marginal distribution and sub-transmission capacity costs, 2025. Same summer-only pattern as bulk transmission.

The pattern is stark: the cost of new grid capacity is concentrated in a narrow band of summer afternoon and evening hours. Any customer who runs air conditioning during those peak summer hours — including heat pump customers who cool with their heat pump — does create real infrastructure costs. But the vast majority of the additional electricity a heat pump uses is for *heating*, which falls in winter, where every hour has zero cost. The grid absorbs their winter load at no incremental cost.

But how long will this period last, given that RIE's load forecasts show that heat pump adoption will grow rapidly in the coming years?[28]

28 See the heat pump adoption forecast in RIE's 2024 Peak Forecast report (RIE 2024c).

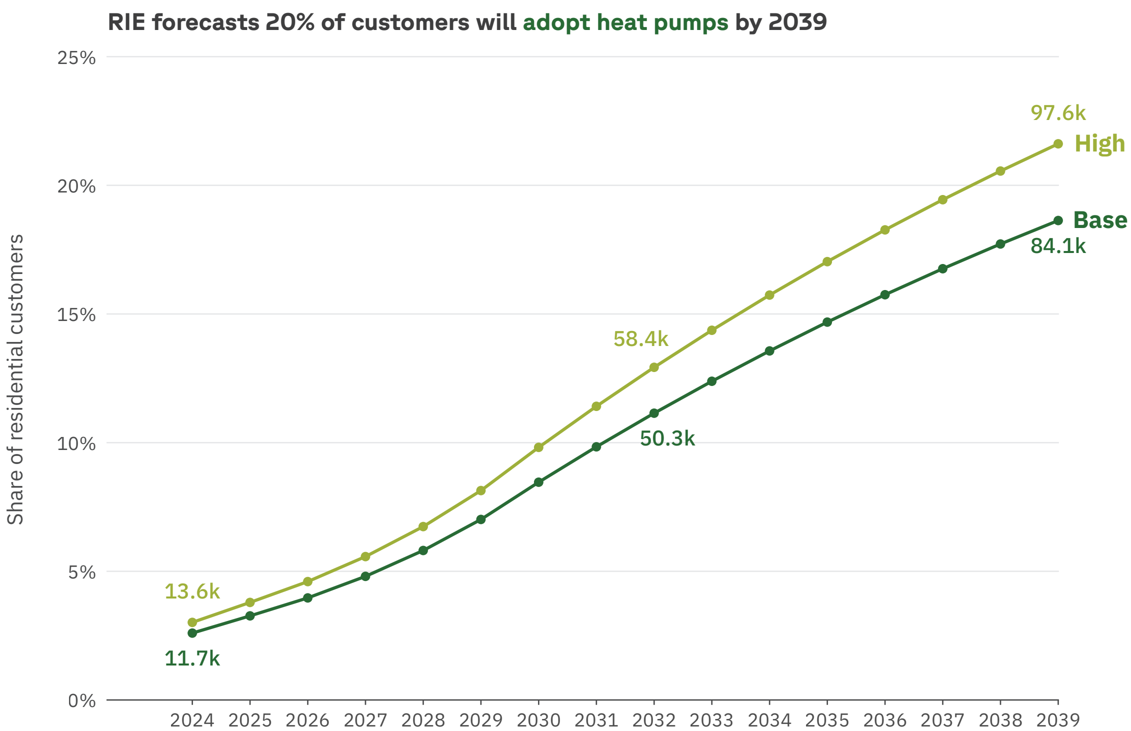


Figure 18: Cumulative heat pump adoption as a share of RIE residential customers under base and high scenarios. Source: Rhode Island Energy

RIE anticipates that between 19% and 22% of its customers will have heat pumps by 2039 (Figure 18). Each customer that electrifies their heat will bump up their feeder's winter peak.

Will this pace of heat pump adoption cause winter peaks to catch up with summer peaks, creating winter-constrained feeders and thereby imposing significant new costs on the system? (Figure 19)

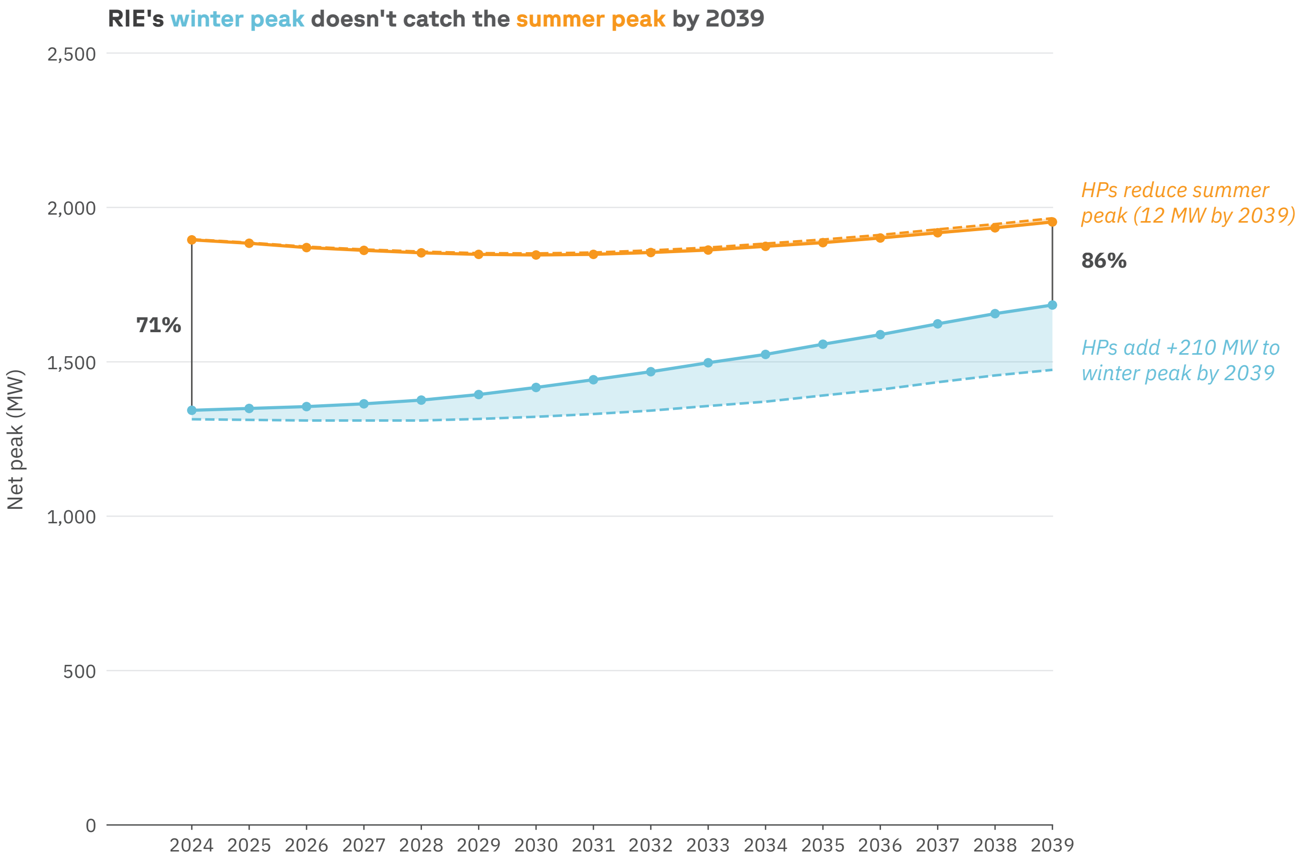


Figure 19: Rhode Island system-wide net peak forecast under 95/5 extreme weather. Solid lines show the base forecast (with heat pumps); dashed lines show the counterfactual without heat pumps. Source: Rhode Island Energy

While RIE's winter peak is expected to grow faster than its summer peak, the utility is not currently forecasted to become winter-peaking by 2039, when the system-wide winter peak is still only expected to be around 86% of the summer peak.[29]

Here is what the feeder headroom is expected to look like in 2039, according to RIE's own peak growth forecasts (Figure 20):

29 See the winter peak forecast on p. 31 of (RIE 2024c).

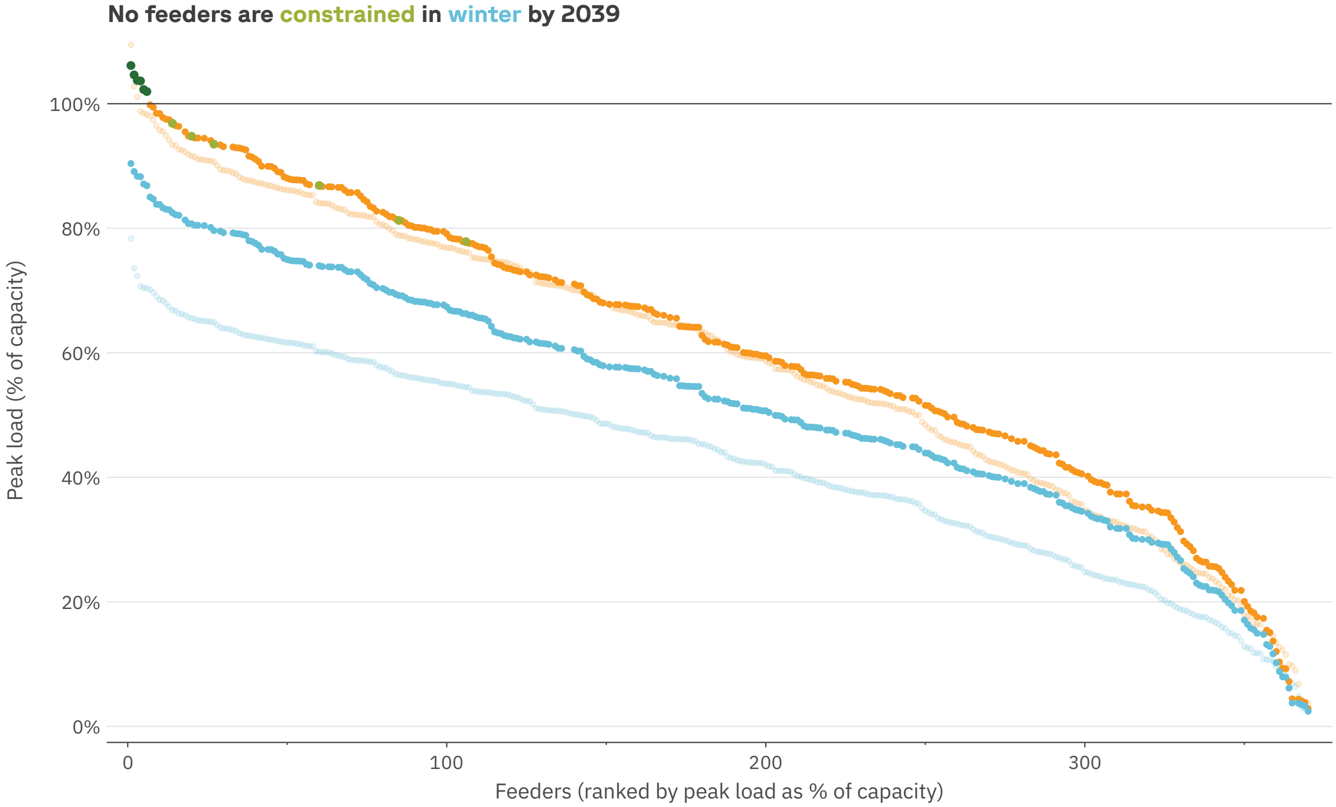


Figure 20: Feeder utilization, or summer (orange) and winter (blue) peak load as a percent of summer normal capacity, as forecasted in 2026 and 2039, under base and high HP adoption scenarios. Green dots = contingency load-at-risk in MWh > 16 MWh. Dark green dots = peak exceeds summer normal rating. Source: Rhode Island Energy

An additional 12 feeders are expected to become constrained due to *summer* peak growth by then, but none by winter peak growth — despite 19% of Rhode Island Energy customers installing heat pumps by then. So in addition to the 17% of customers that are on feeders constrained in the summer today, an additional 4% of customers (19,762) would be on summer-constrained feeders by 2039.

Moreover, 78% of feeders are expected to have more than 20% winter **headroom** in 2039 — a testament to the RIE distribution grid's significant spare winter capacity.

Indeed, RIE's substations have even more headroom than its feeders, both now and in 2039 (Figure 21).

No substations are constrained by 2039

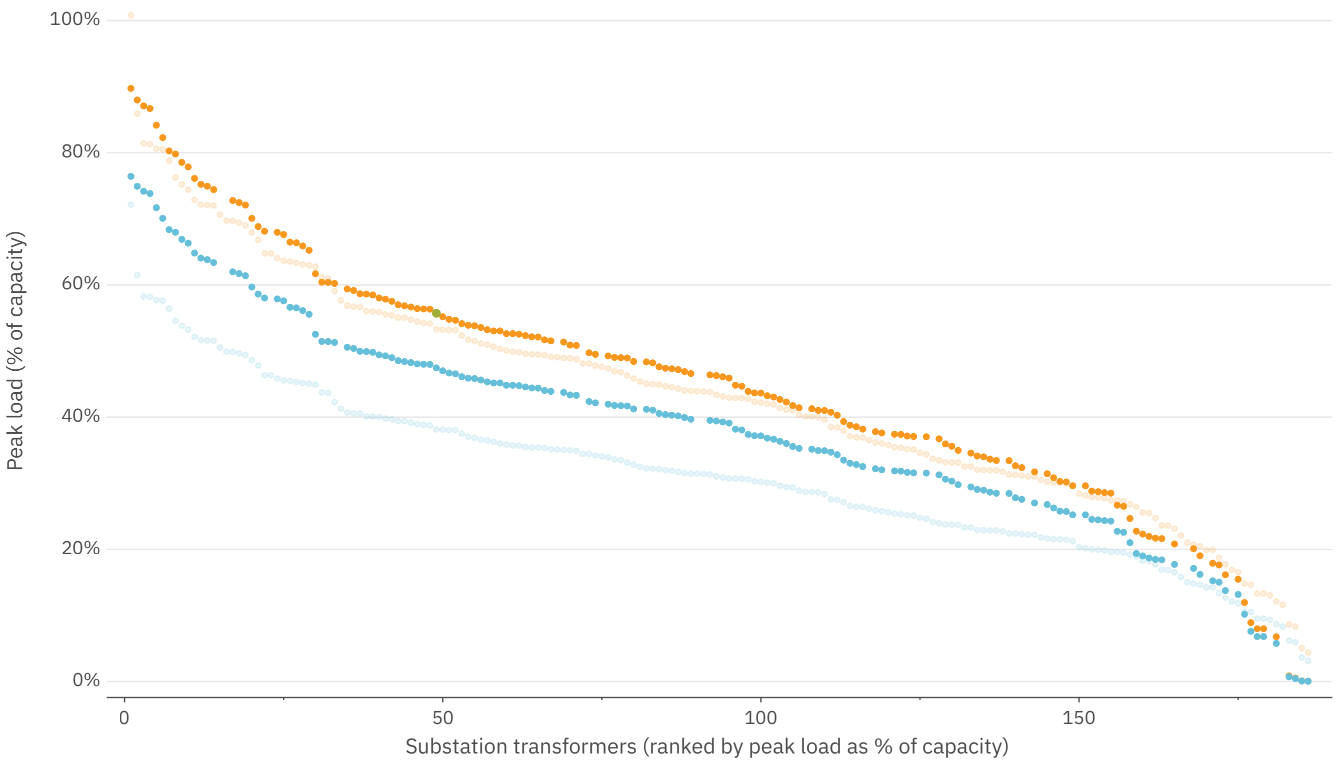


Figure 21: Transformer utilization, or summer and winter peak load as a percent of summer normal capacity, as forecasted in 2026 and 2039, ranked from most to least stressed. Green dots = contingency load-at-risk in MWh > 16 MWh. Dark green dots = peak exceeds summer normal rating. **Source**: Rhode Island Energy

Without rate reform, therefore, Rhode Island's heat pump customers will be forced to pay more than their fair share of historical grid costs for the next two decades.

FIXING THE OVERPAYMENT: THE COST ALLOCATION STEP

So far, we have examined the cross-subsidy problem one household at a time: the average heat pump customer overpays for delivery by **$902** per year. But what does this add up to across Rhode Island Energy's residential customer base?

To see, we need to start with the total delivery revenue that RIE collects from residential customers. In 2025, RIE collected $446,463,143 in total residential delivery revenue from 419,348 residential customers (Figure 22).

Cost allocation

The regulatory process of dividing a utility's total revenue requirement among the groups of customers it serves, in proportion to each group's cost of service. Typically applied to broad customer classes (residential, commercial, etc.); can also be performed for groups within a class (e.g. heat pump customers).

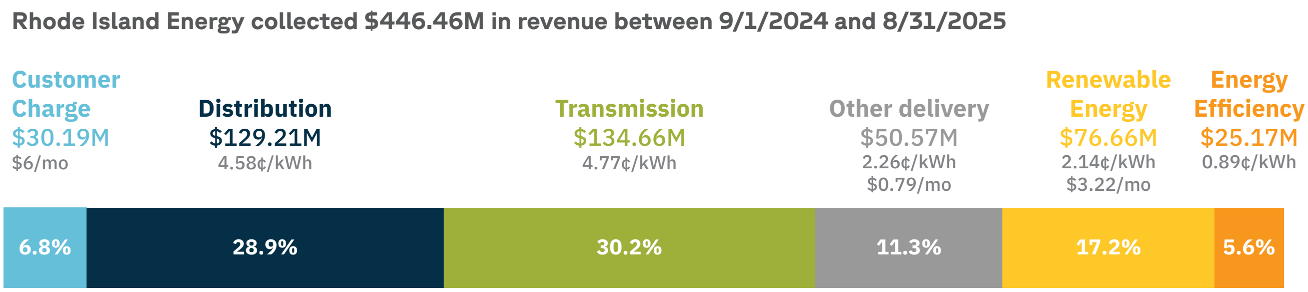


Figure 22: RIE delivery revenue collected during the test year (9/1/2024–8/31/2025), by classification of delivery charges. Bars show total revenue collected by charge, as well as total volumetric and/or fixed charges used to collect it. Source: Rhode Island Energy

This is all the money RIE collected from residential customers for delivery — including distribution, transmission, renewable energy, energy efficiency, and other programs.

Who are they collecting this revenue from? Heat pump customers make up just 2.0% of RIE's residential customer base. But during the test year, they accounted for 4.4% of residential delivery revenue (Table 2).

	Customers	% of customers	Consumption	% of consumption	Delivery revenue	% of revenue
Heat pump	8,563	2.0%	132.5 GWh	4.7%	$19,663,077	4.4%
Electric resistance	35,348	8.4%	477.6 GWh	16.9%	$71,396,828	16.0%
Natural gas	230,312	54.9%	1,192.8 GWh	42.3%	$194,999,178	43.7%
Delivered fuels	137,002	32.7%	962.8 GWh	34.1%	$151,647,018	34.0%
Other	8,123	1.9%	55.4 GWh	2.0%	$8,757,042	2.0%
All customers	419,348	100.0%	2,821.2 GWh	100.0%	$446,463,143	100.0%

Table 2: Breakdown of electricity consumption and revenue generated by residential customer subclasses during the Test Year (9/1/24 to 8/31/25).

Under the cost-causation principle — that rates should "appropriately charge customers for the cost they impose on the grid"[30] — for default rates to be fair, heat pump customers' share of delivery revenue should match their share of delivery costs. It does not.

Table 3 shows each residential subclass's delivery cost-of-service, juxtaposed with the revenue that RIE collected from them during the test year. As a subclass, heat pump customers' cost-of-service was $11.9 million, but they paid $19.7 million through their bills. While they made up only 2.7% of total delivery costs, they accounted for 4.4% of total delivery revenue.

30 Goal 6 of the future electric system, adopted by the Rhode Island Public Utility Commission in Order 22851 of Docket 4600 (RIPUC 2017).

Cost-causation principle

The idea that utility costs should be paid for by the customers that cause them: the cost to generate electricity should be paid by those who consume it, the cost to build infrastructure to meet peak demand should be borne by customers who use the network during peak hours.

Delivery revenue, cost of service, and cross-subsidy by residential subclass (9/1/24 to 8/31/25)

	Customers	% of customers	Consumption	% of consumption	Delivery revenue	% of revenue	Cost of service	% of cost	Cross-subsidy	Cross-subsidy ÷ COS
Heat pump	8,563	2.0%	132.5 GWh	4.7%	$19,663,077	4.4%	$11,940,871	2.7%	$7,722,206	64.70%
Electric resistance	35,348	8.4%	477.6 GWh	16.9%	$71,396,828	16.0%	$28,898,553	6.5%	$42,498,276	147.10%
Natural gas	230,312	54.9%	1,192.8 GWh	42.3%	$194,999,178	43.7%	$224,571,427	50.3%	−$29,572,249	−13.2%
Delivered fuels	137,002	32.7%	962.8 GWh	34.1%	$151,647,018	34.0%	$170,917,995	38.3%	−$19,270,977	−11.3%
Other	8,123	1.9%	55.4 GWh	2.0%	$8,757,042	2.0%	$10,134,298	2.3%	−$1,377,256	−13.6%
All customers	419,348	100.0%	2,821.2 GWh	100.0%	$446,463,143	100.0%	$446,463,143	100.0%	$446,463,143	100.0%

Table 3: Delivery revenue, cost of service, and cross-subsidy by residential subclass during the Test Year, 9/1/24 to 8/31/25.

Across the utility, heat pump customers are overpaying for delivery by a total of approximately **$7.7 million per year** — the gap between what the utility collects from them and what it actually costs to serve them. Because RIE's total delivery revenue requirement is fixed, every dollar of overpayment by heat pump customers is a dollar that other subclasses do not have to pay.

This gap points to a fix that is more fundamental than designing a new rate.

Utilities already perform cost allocation between customer classes — residential, commercial, industrial, and so on. For each class, the utility measures the cost of serving that group and assigns a revenue requirement: a target amount of revenue to collect from the customer group that matches the group's cost of service.

But utilities do not currently perform cost allocation at the level of customer *subclasses* within the residential class. All residential customers — whether they heat with gas, oil, or a heat pump — are lumped into a single group and charged the same default rate. Whatever revenue that rate happens to collect from each subclass is whatever it collects; RIE doesn't track whether it overshoots or undershoots any subclass's cost of service, because it has no reason to. Which is exactly what happens to heat pump customers: the default volumetric rate collects far more from them than it costs to serve them, and the utility has no visibility into the mismatch.

The fix is for the utility to create a **dedicated rate class for heat pump customers**. This would require the utility to

Delivery revenue requirement

The total amount of revenue that RIE collects from residential customers to cover all delivery costs. In our definition, this includes both total distribution costs — what is usually termed the revenue requirement in rate cases — as well as transmission, policy programs, and other costs.

Cost of service

The total cost a utility incurs to serve a customer or group of customers. This report looks at delivery cost-of-service only.

determine these customers' actual delivery cost of service and set a revenue requirement that reflects it — rather than the inflated revenue total it happens to collect when the default volumetric rate is applied to customers who use more electricity.

To eliminate the cross-subsidy, we follow a two-step process:

1. **Cost allocation**: determine the correct revenue to collect from heat pump customers, based on their cost of service.
2. **Rate design**: choose among the many rates that could collect this revenue. A lower flat rate, a higher fixed charge, a seasonal rate, a time-of-use rate — any rate calibrated to collect the revenue dictated by the cost allocation will, by definition, have eliminated the cross-subsidy and solved the fairness problem.

Rate design

The process of choosing the specific rate structure — the mix of fixed charges, volumetric charges, demand charges, and time-varying prices — used to calculate the bills of a particular group of customers. Many different rate designs can collect the same total revenue, but they differ in their secondary effects.

There's nothing novel about this process, this is how ratemaking already works: rate design is always based on cost allocation. First, the utility determines how much revenue to collect from a group of customers, based on their cost of service. Then, it chooses among rate structures that all collect this amount but may have different secondary effects — on equity across income levels, on economic efficiency, on incentives for conservation or distributed generation, on simplicity, on ease of implementation, and so on.

Cost allocation determines *how much* to collect. Rate design simply determines *how* to collect it. **Getting the cost allocation right is what eliminates the cross-subsidy.** The choice among rate designs, while important, is secondary.[31]

31 In other words, fairness is not an intrinsic property of a rate's structure — it comes from the subclass-specific revenue target the rate is calibrated to hit. A seasonal rate calibrated to the wrong revenue requirement wouldn't be fair at all.

PROPOSAL: FAIR RATE FOR HEAT PUMP CUSTOMERS

Having determined the correct delivery revenue requirement for heat pump customers — $11.9 million per year, reflecting their actual cost of service — the next question is how to collect it.

We propose a simple flat rate that would be guaranteed to lower the delivery bills of all heat pump customers, and could therefore be automatically applied to all known heat pump customers across Rhode Island. This rate would only be available to heat pump customers, and would only apply to the delivery side of the bill.

Flat volumetric rates

Volumetric rates that charge the same price per kWh at all hours and seasons. Most default residential electricity rates in the U.S. are flat.

During the test year, the total volumetric delivery rate was 14.08¢/kWh. Our proposal would reduce all volumetric delivery charges by a uniform 41.4%, bringing the total volumetric delivery rate for heat pump customers below the default rate. Per-customer fixed charges are unchanged.

Area	Default rate	Adj. default rate	Change
Distribution Charge	4.58¢/kWh	2.68¢/kWh	-41.40%
Transmission	4.77¢/kWh	2.80¢/kWh	-41.40%
Other Delivery	1.65¢/kWh	0.97¢/kWh	-41.40%
Renewable Energy	2.14¢/kWh	1.25¢/kWh	-41.40%
Energy Efficiency	0.89¢/kWh	0.52¢/kWh	-41.40%
Total	14.08¢/kWh	8.24¢/kWh	-41.40%

Table 4: Proposed HP delivery rate vs. current default rate, by delivery area.

As intended, these rates collect exactly the heat pump subclass's allocated cost of service, eliminating the cross-subsidy on average. But would that move the needle on operating costs?

Operating costs

The ongoing expenses of running and maintaining the electric grid day-to-day. Operating costs recovered from customers in the same year they are incurred.

BILL IMPACT OF HEAT PUMP RATE ON HEAT PUMP CUSTOMERS

If our fair rate were available, how would it affect what happens to annual energy bills when natural gas heated households switch to heat pumps? Let's revisit our earlier analysis.

First, let's revisit the post-heat pump bills for the Cranston home.

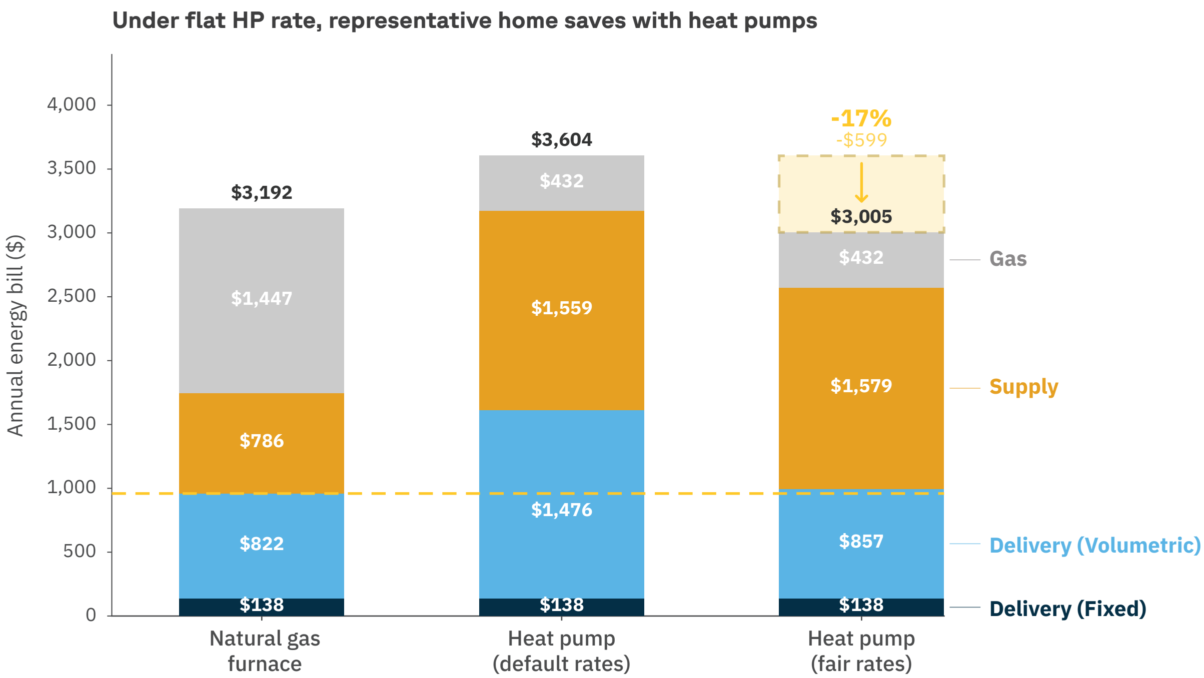


Figure 23: Annual energy bill for the representative gas-heated Cranston home: before heat pumps, after heat pumps at default rates, and after heat pumps at proposed HP flat rate.

Under fair rates, the Cranston home's post-heat pump annual electric bill would drop by **17%** — from $3,604 under default rates to **$3,005**.

The savings come entirely from the delivery (volumetric) component, which shrinks thanks to the lower rate we are proposing. Supply and gas bills are unchanged.

The dashed line marks the home's pre-heat-pump delivery bill. Under fair rates, the post-heat-pump delivery bill falls close to it — meaning the overpayment for delivery has been largely eliminated.

Bottom line: fair rates would allow this home to save $187 per year by switching from gas heating to heat pumps.

This is just a single home. Would we see similar outcomes statewide? Let's zoom out and see.

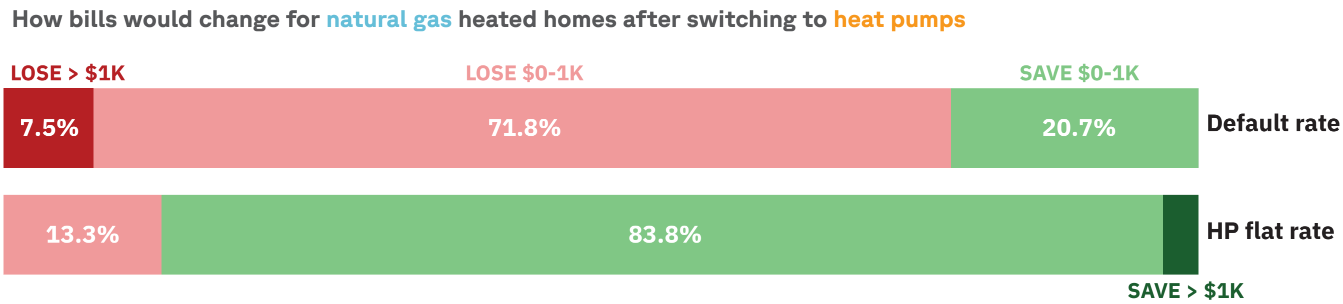


Figure 24: Bill change summary — natural gas homes switching to HP: default vs. HP flat rate (Statewide)

Yes — fair rates would transform the economics of heat pumps in Rhode Island.

Under default rates, only **21%** of gas-heated households would save by switching to heat pumps. But under fair rates, **87%** of gas-heated households would save. And the share of households losing over $1,000 per year would be eliminated.

The fact that most gas-heated households would save by switching to heat pumps if overpayments were eliminated proves **that heat pump operating costs struggle to compete against natural gas largely because of outdated volumetric delivery rates — not cheap gas supply**.

The pattern holds for oil and propane-heated homes. Under default rates, 87% of oil/propane households would save by switching to heat pumps. Under fair rates, **99%** would save.

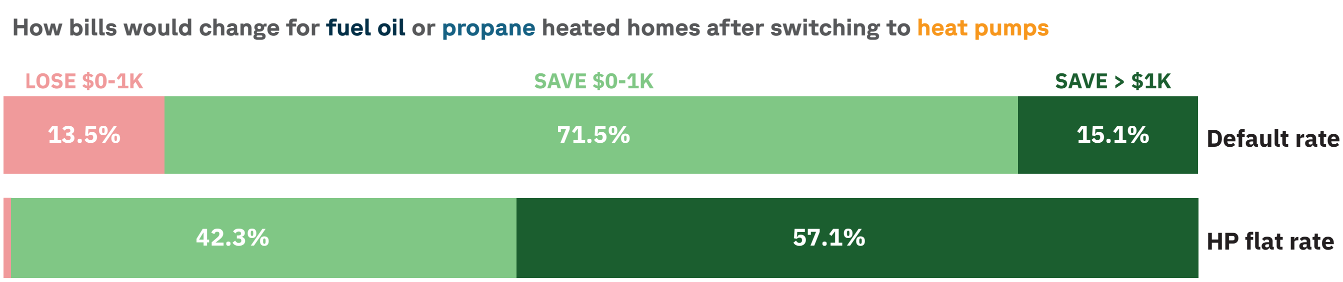


Figure 25: Bill change summary — oil/propane homes switching to HP: default vs. HP flat rate (Statewide)

Electric resistance homes see a similar improvement. Under default rates, 98% would save by upgrading to heat pumps. Under fair rates, **100%** would save.

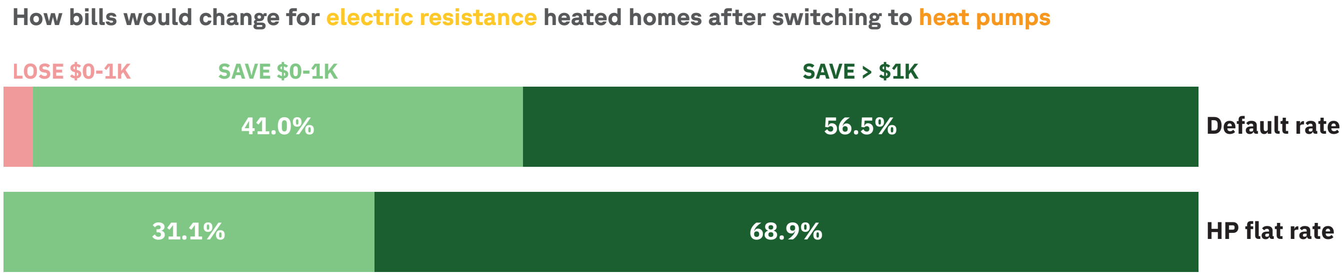


Figure 26: Bill change summary — electric resistance homes switching to HP: default vs. HP flat rate (Statewide)

EQUITY IMPACT OF HEAT PUMP RATE ON HEAT PUMP CUSTOMERS

While the bill impacts shown above reveal how the population at large would be affected by fair rates, they don't illuminate the equity impact on low- and moderate-income households. For that, we must zoom in on this population, and look at energy burdens.[32]

Today, 75% of Rhode Island's low- and moderate-income households that heat with natural gas pay more than 6% of their annual income on energy bills, and are therefore considered to be **highly energy burdened**. This figure reflects current LMI discounts for electricity and gas; only ~32% of eligible LMI households are currently enrolled.[33]

Energy burden

The share of a household's annual income spent on home energy bills — electricity, natural gas, delivered fuels. A widely used indicator of energy affordability stress.

Economic burden

A customer's total marginal cost of service: the sum of their hourly consumption multiplied by hourly marginal energy and T&D capacity costs, during an entire year.

32 Energy burden is defined as the percentage of a household's annual income spent on energy bills.

33 LMI is defined using the upper bound of the LIDR+ program, which is 250% of FPL.

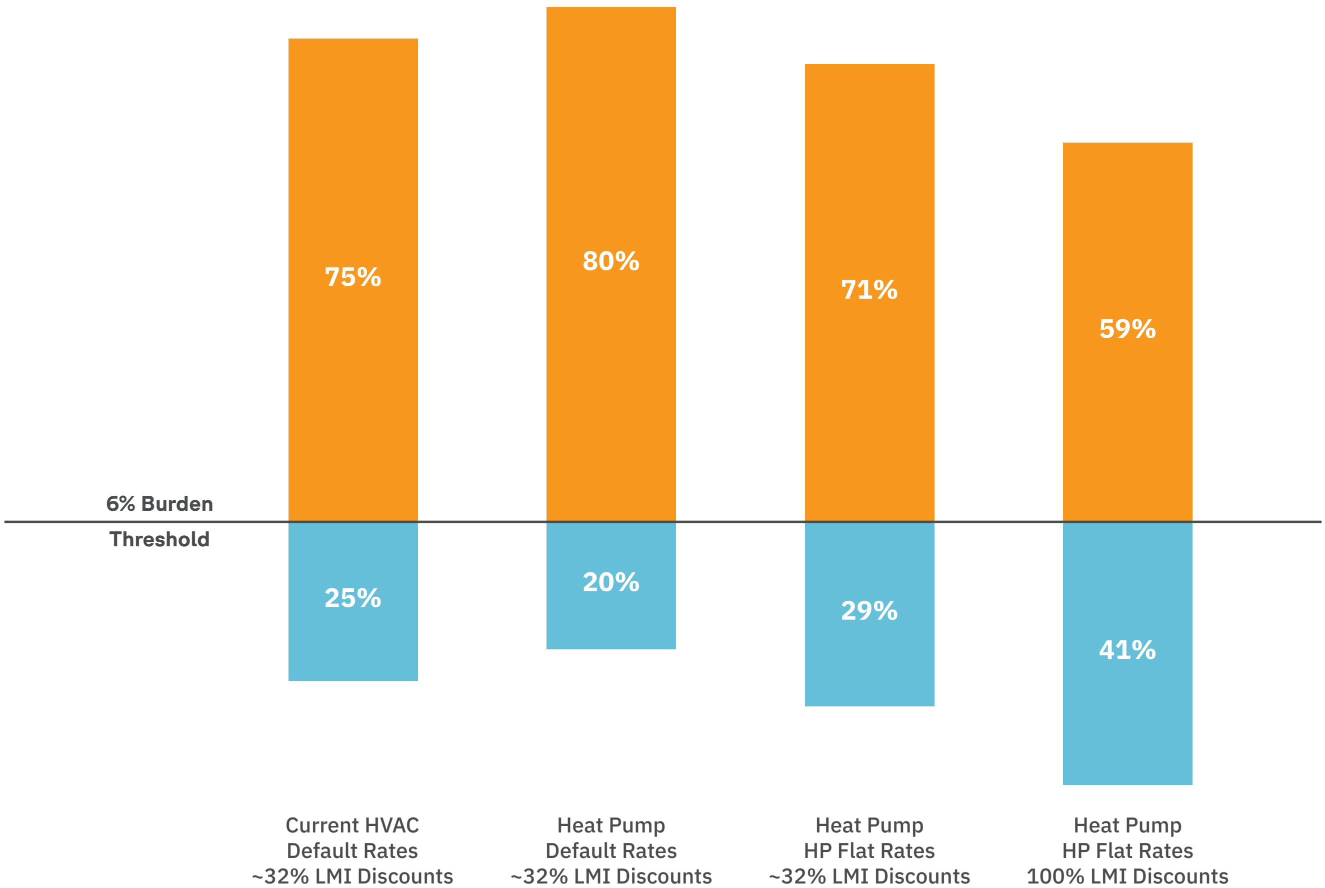


Figure 27: Share of low-income gas-heated households above the 6% energy burden threshold

After installing heat pumps under today's default rates, 80% of these households pay more than 6% of their annual income. This assumes that the same households that are already enrolled in LMI discounts remain enrolled after switching to heat pumps.

After installing heat pumps under the heat pump rates proposed in this report, 71% of these households would still be highly burdened. This assumes that LMI electrification is paired with opting households into the HP flat rates.

And as long as we're updating LMI electrification programs to include rate enrollment, what if these programs also ensured that all eligible LMI households were enrolled in the LMI electric bill discounts they're eligible for?

The final bar in Figure 27 shows what post-heat pump installation burdens would look like — under HP flat rates and 100% enrollment in LMI discounts. Under this scenario, the number of highly energy-burdened households would actually drop by 16 percentage points compared to today.

ADJUSTED RATES FOR NON-HEAT PUMP CUSTOMERS

The heat pump rate we proposed in this report is revenue-neutral at the residential class level: it reallocates delivery revenue responsibility within the residential class, but does not reduce total residential revenue. Heat pump customers' delivery revenue would decrease to match their cost of service, and the volumetric delivery rates for non-heat pump customers remaining on the default schedule would be adjusted upward to recover the difference.

The total volumetric delivery rate for non-heat pump customers would rise from 14.08¢/kWh to 14.37¢/kWh — a 2.0% increase.

Area	Default rate	Adj. default rate	Change
Distribution Charge	4.58¢/kWh	4.67¢/kWh	+2.0%
Transmission	4.77¢/kWh	4.87¢/kWh	+2.0%
Other Delivery	1.65¢/kWh	1.69¢/kWh	+2.0%
Renewable Energy	2.14¢/kWh	2.19¢/kWh	+2.0%
Energy Efficiency	0.89¢/kWh	0.91¢/kWh	+2.0%
Total	14.08¢/kWh	14.37¢/kWh	+2.0%

Table 5: Adjusted default delivery rate vs. current default rate, by delivery area.

As with the HP rate, the adjustment is a uniform percentage applied to all volumetric charges; per-customer fixed charges are unchanged.

BILL IMPACT OF HEAT PUMP RATE ON NON-HEAT PUMP CUSTOMERS

How would this small rate adjustment affect non-heat pump customers' bills (Figure 28)?

Monthly bill change for non-HP homes after cross-subsidy removal

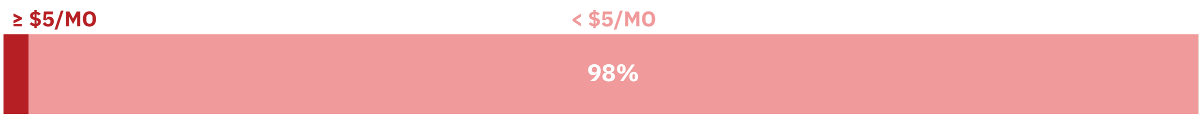


Figure 28: Average monthly bill change — all non-HP homes after cross-subsidy removal (Statewide)

It would raise them by **$1.57 per month**, on average.

And **98%** of non-HP households would see their monthly electric bill rise by less than $5 a month.

Importantly, this is **not a "rate hike"** on customers without heat pumps. Nor is it paying for handout to heat pump customers. On the contrary: the bills of non-heat pump customers would rise slightly precisely because heat pump customers are currently subsidizing *them*.

Offering dedicated rates to heat pump customers would therefore be significant step toward better aligning the delivery rates paid by *all* customers with their cost of service.

Why is the impact of unwinding the cross-subsidy so small?

Because heat pump customers only make up 2% of residential customers. The total cross-subsidy they generate is modest, around **$8 million per year**, and it gets spread across 411K non-HP households.

As a result, the benefit each non-heat pump household receives from the cross-subsidy is minuscule — but the cost each heat pump household bears is large, as we saw in Figure 24.

This shows how counterproductive this unintentional public policy of cross-subsidization really is: Rhode Island is actively trying to advance heat pump adoption, but its own volumetric rates are penalizing the customers who electrify — while delivering negligible savings to everyone else.

This asymmetry also points to why acting now is important. Heat pump customers currently make up just 2% of RIE's residential base, so the impact of unwinding the subsidy is small and easy to absorb. But as adoption grows — RIE forecasts 19% to 22% of customers will have heat pumps by 2039 — the aggregate cross-subsidy will grow, and the non-HP rate adjustment needed to remove it will grow with it.

Acting now, while the correction is small, *is* the gradual approach. Delay would not avoid it — it would make the eventual correction larger and less gradual, all while penalizing early adopters of the very technology the state is trying to promote.

ACHIEVING ENROLLMENT

The cross-subsidy will only be fully eliminated if all heat pump customers are enrolled in the proposed rate. An opt-in rate would take years to achieve meaningful enrollment, if it could be achieved at all. The solution is auto-enrollment — and Massachusetts has already shown how to do it.

The Massachusetts precedent

Massachusetts is the first state to offer a dedicated electric rate for heat pump customers. The three investor-owned utilities — Eversource, Unitil, and National Grid — began offering the rate on November 1, 2025. To achieve enrollment, the utilities automatically enrolled all customers who had received a qualifying heat pump rebate, or who currently live at a location that received one, through Mass Save — the state's ratepayer-funded energy efficiency program — since January 1, 2019.[34]

The auto-enrollment was not a one-time event. All customers who receive a new heat pump incentive are automatically enrolled once their Mass Save rebate is fully processed.[35] Customers wishing to opt out can do so by contacting their utility. Those installing heat pumps without going through Mass Save can manually enroll.

34 The Massachusetts Department of Public Utilities maintains an overview of the seasonal heat pump rates and enrollment procedures for all three IOUs at (DPU 2025).

35 National Grid MA describes the ongoing auto-enrollment process and opt-out procedures in its Residential Heat Pump Rate FAQ (NGrid 2025).

How Rhode Island could do the same

For existing heat pump customers, RIE would auto-enroll all customers who have received a heat pump incentive through Clean Heat RI, the Home Electrification and Appliance Rebate (HEAR) program administered by Rhode Island's Office of Energy Resources, or RIE's own Residential Electric Heating and Cooling Rebate program. For new heat pump customers, every customer receiving an upfront incentive through these programs — and through the recently launched New England Heat Pump Accelerator — would be automatically enrolled.

Why auto-enrollment is appropriate

Auto-enrolling heat pump customers into an opt-out rate has obvious advantages for eliminating the cross-subsidy at scale. But such a strategy could be inadvisable if the rate caused adverse bill impacts or bill volatility for some heat pump customers.

By design, our proposed flat rate would cause neither. Because it uniformly reduces all volumetric delivery charges, the rate results in lower bills for all heat pump customers in every month of the year. There is no scenario in which a customer would be worse off on the heat pump rate than on the default — which is precisely what makes auto-enrollment appropriate and opt-in unnecessary.

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Appendix

FIXING OVERPAYMENTS BY REDESIGNING THE DEFAULT RATE

This report diagnoses the overpayments faced by heat pump customers in Rhode Island, and proposes a practical solution: tech-specific rates. However, this is not the only possible fix to the fairness problem: the cross-subsidy could also be eliminated by redesigning the default residential rates that the vast majority of RIE customers are already on.

Default rates

The electric supply and delivery rates a utility's customers are automatically enrolled in.

The default residential rate has two components: a small fixed per-customer charge and a flat volumetric charge. Because the fixed charge is small — currently $6 per month — the vast majority of delivery revenue comes from the volumetric charge. That is what produces the cross-subsidy: heat pump customers consume far more kWh than average, mostly in winter, so flat per-kWh charges collect far more delivery revenue from them than their cost-of-service warrants.

Fixed charges

A flat dollar amount per month that a customer pays regardless of how much electricity they use.

Eliminating the cross-subsidy within this two-component structure would require raising the fixed charge dramatically, making the volumetric rate seasonal, or both — and none of these works without radical disruption.

Seasonal rate

A volumetric rate whose per-kWh price differs between summer and winter but is constant within each season.

Raising the fixed charge sufficiently would shift cost-recovery away from volumetric charges, reducing the overcollection from high-use customers. But the customer charge would need to increase more than *tenfold* — from $6 per month to approximately **$64 per month**.[36] In Docket 4770, nearly every intervenor opposed National Grid's proposal to increase the customer charge from $5 to $8.50 — a 1.7× increase — on the grounds that it would be regressive and weaken incentives for energy efficiency and distributed generation.[37]

Adding seasonal differentiation — lower volumetric rates in winter, higher in summer — is insufficient on its own. Even charging 0¢/kWh for delivery in winter and concentrating all volumetric recovery in summer would still leave a residual cross-subsidy of $390,875 per heat pump customer per year — 5.1% of the current overpayment.[38] The reason is counterin-

36 The full calculation is in Schedule JPV-7 of (Velez 2026).

37 See Direct Testimony of John G. Athas on behalf of the Division of Public Utilities, Docket 4770, at 9 (Athas 2018); Pre-Filed Direct Testimony of Mark LeBel on behalf of Acadia Center, Docket 4770, at 23–25 (LeBel 2018); Prefiled Direct Testimony of Karl R. Rábago on behalf of New Energy Rhode Island, Docket 4770, at 34 (Rábago 2018).

38 The full calculation is in Schedule JPV-8 of (Velez 2026).

tuitive: heat pump customers also consume a larger share of summer kWh than their share of delivery costs, because heat pumps double as air conditioners. No seasonal rebalancing can offset an overcollection that persists in both seasons.[39]

Time-of-use rates — which the Commission may consider after advanced meter infrastructure (AMI) deployment — would improve demand management but cannot solve the structural overcollection any better than seasonal rates. Adding on- and off-peak differentiation within each season would incentivize load shifting within the day, but the underlying problem is the same: heat pump customers overconsume relative to their cost-of-service in both seasons, and no time-varying rate can fix that without also raising the fixed charge. And waiting years for AMI deployment means accepting continued unfairness for the very customers the state is trying to create.

In short, eliminating the cross-subsidy by redesigning the default rate would require a dramatic overhaul of the rate structure for all 419,348 of RIE's residential customers — a tenfold increase in the customer charge, or an extreme seasonal structure, or both — with significant bill shock and likely political opposition.

A technology-specific rate avoids all of this. It means auto-enrolling only the 2% of residential customers who have heat pumps into a rate where every one of them saves in every month of the year, while making a small adjustment to delivery rates for everyone else (see p. 40).

39 A zero winter delivery rate would obviously be undesirable in practice; the point is that even this extreme design fails to eliminate the cross-subsidy.

Time-of-use (TOU) rates

A volumetric rate whose per-kWh price varies by time of day, typically higher during an "on-peak" window when the grid is more likely to be strained and electricity is most expensive to produce, and lower during "off-peak" hours.

Load shifting

The practice of moving electricity consumption from one time of day to another without reducing total use, typically in pursuit of lower prices. Incentivized by TOU and other time-varying rates.

All modeling, bill calculation, and rate design was performed using Switchbox's open-source Rate Design Platform (RDP), built on top of NREL's CAIRO rate simulation engine.[40] The analysis notebooks that produced this report's figures and statistics are also open-source, in Switchbox's reports repository.

[40] The Customer Affordability, Incentives, and Rates Optimization (CAIRO) Model provides users with a framework to evaluate the impact of different regulatory and utility decisions on ratepayers (NREL 2026).

How we estimate energy bill changes after switching to heat pumps

The bill analysis covers three scenarios. First: switching from current heating equipment to a heat pump under **today's default rates** — the baseline showing how electrification costs interact with the current rate structure. Second: the same switch under the proposed **heat pump flat rate** (HP flat rate), a rate calibrated to eliminate the cross-subsidy between heat pump and non-heat pump customers (p. 62). Third: what happens to the bills of homes that **keep their current heating equipment** when heat pump customers move to the HP flat rate and the default rate is recalibrated accordingly (p. 62).

Cross-subsidy

When one group of customers pays more (or less) than their cost of service, the difference is effectively transferred to other customers. The overpaying group cross-subsidizes the underpaying group.

Energy bills are the product of two things: load curves (how much energy a home consumes, and when) and prices (the tariff rates applied to that consumption). To model energy bills, we need to understand how household energy consumption changes when they switch to a heat pump (p. 47). This allows us to determine the price customers pay on the bill, but in order to determine a fair heat pump rate we also need to understand the cost each customer imposes on the system. We use those costs to measure the cross-subsidy between heat pump and non-heat pump customers (p. 53).

Building stock simulations

We use NREL's ResStock 2024.2 End Use Load Profiles (EULP) dataset to model Rhode Island's residential building stock. The dataset uses simulated buildings to represent the existing U.S. housing stock as a statistical sample, by collectively matching the state's diversity of building types, sizes, ages, envelope characteristics, and heating equipment. The "baseline" set of virtual homes are meant to collectively represent the United States' residential housing stock. The EULP project adds several upgrade packages, which virtually "install" various combinations of weatherization, HVAC upgrades, and appliance electrification and recompute each homes' 15-minute energy consumption for each appliance. The 2024.2 release uses actual meteorological year 2018 (AMY 2018) weather data. The RI sample contains 1,910 modeled dwellings, each reweighted so the sum of weights equals the 419,348 residential customers in RIE's rate-case test year.[41]

ResStock outputs 15-minute end-use load profiles (electricity, gas, oil, propane) for each building; we aggregate to hourly resolution for bill calculation. We use two scenarios from this dataset:

- **Upgrade 0 (baseline)**: current HVAC equipment as distributed across the existing housing stock — natural gas furnaces, fuel oil boilers, propane heaters, electric resistance, or existing heat pumps.[42]
- **Upgrade 2 (heat pump)**: high-efficiency cold-climate air-source heat pump retrofit with electric backup.[43] Performance is modeled hourly as a function of outdoor temperature via NEEP ccASHP performance curves.

The load data (fuel consumption and end-use electricity, gas, oil, propane) from these 2 simulated datasets are used to calculate the difference between a home's total energy bills under Upgrade 0 and Upgrade 2, which is the estimated bill change from switching to a heat pump.

Load curve adjustments. We apply two corrections to ResStock load curves before running the bill analysis.

Multifamily non-HVAC electricity correction. We compared ResStock's weighted residential electricity totals to EIA-861 residential sales for each electric utility across New York and Rhode Island. The comparison revealed a systematic bias. ResStock overstated electricity consumption, and the overstatement grew with the utility's share of multifamily buildings. For Con Edison (81% multifamily), the gap was +29%; for RIE (41% multifamily), +8%. The adjustment is a portfolio-level correction targeting the dominant source of bias. It dramatically improves the worst cases — Con Edison drops from +29% to +8%, RIE from +8% to −1% — while modestly worsening a few low-multifamily utilities that were already

41 By default, each dwelling in the ResStock dataset (NREL 2024a) represents ≈ 252 real-world homes. We rescale the weights so that the weighted sum equals 419,348 — the number of residential customers in RIE's rate-case test year (RIE 2025c). This ensures bill totals aggregate correctly when computing utility-wide revenue requirements.

42 In the baseline scenario, existing heat pumps are a mix of ducted and non-ducted heat pumps. Air-source heat pumps (ASHP), have an efficiency range of SEER 10-15 and HSPF 6.2-8.5, and mini-split heat pumps (MSHP) are SEER 14.5 and HSPF 8.2.

43 The heat pump is a high-efficiency cold-climate air-source heat pump (SEER1 20 / HSPF1 11, 90% capacity retention at 5°F) with electric resistance backup, variable speed, sized to each dwelling's design heating load (NREL 2024b).

near the benchmark. The maximum absolute error across all eight utilities falls from 29% to 8%.

We traced the source to **non-HVAC end uses** — plug loads, lighting, appliances, and miscellaneous loads. In ResStock, multifamily buildings had non-HVAC electricity intensity (kWh per square foot) roughly 1.5–2.0× higher than single-family buildings. ResStock's simulated appliance and plug loads for multifamily units were too high relative to single-family homes, and since multifamily buildings make up a large share of some utilities' housing stock, the overstatement propagated to utility-level totals. HVAC intensity, by contrast, was roughly half that of single-family buildings — directionally sensible, since multifamily buildings have less exposed exterior surface area per dwelling unit.

We correct this by computing the mean non-HVAC electricity intensity (kWh/sqft, among buildings with non-zero consumption) for single-family and multifamily buildings separately, then dividing each multifamily building's non-HVAC end-use consumption by the multifamily-to-single-family ratio for that end use. Each end use gets its own ratio. **HVAC loads are left unchanged.** The same scaling factors are applied to both annual totals and hourly load curves, preserving each building's hourly shape while reducing the non-HVAC magnitude. This adjustment affects 780 of 1,910 RI buildings (all multifamily). Post-adjustment, weighted ResStock electricity totals are within 1% of EIA-861 residential sales for RIE.[44]

Utility	State	% MF	Before	After
RIE	RI	41%	+8%	−1%
PSEG LI	NY	19%	−4%	−6%
NYSEG	NY	22%	+1%	−2%
CenHud	NY	26%	+10%	+6%
RGE	NY	29%	+12%	+7%
NiMo	NY	30%	+9%	+4%
OR	NY	30%	+2%	−3%
Con Edison	NY	81%	+29%	+8%

ResStock − EIA % difference, before and after multifamily non-HVAC correction.

44 Non-HVAC adjustment implemented in RDP. Each adjusted building is flagged to prevent double-application. Validation script in RDP.

Non-HP multifamily HVAC approximation (upgrade 2 only). ResStock's upgrade 2 scenario converts most buildings to heat pumps, but a subset of large multifamily buildings (primarily 5+ unit, 8+ story) are left unconverted, their upgrade 2 load curves and heating type are identical to upgrade 0. To ensure these buildings are represented as heat pump customers in the upgrade 2 analysis, we approximate their heat pump load profiles using a k-nearest-neighbor method. For each unconverted multifamily building, we find the 15 buildings at the same weather station whose heating load curves are closest by root mean squared error (RMSE), then replace the target building's HVAC electricity, natural gas, fuel oil, and propane columns with the average of those neighbors' profiles. Metadata is updated to mark these buildings as heat pump customers. This affects 27 buildings in RI (26 large multifamily, 1 small multifamily).[45]

45 HVAC approximation implemented in RDP. Each approximated building is flagged.

Energy prices and tariffs

Electricity. We use Rhode Island Energy's **A-16** residential electric rate as of 2025. The tariff has two components: a **delivery** portion (a fixed monthly customer charge, other fixed surcharges, and a volumetric rate) and a separate **supply** portion (seasonal volumetric rates reflecting Rhode Island Energy's Last Resort Service filings). Electric tariff data was sourced from Genability's utility rate database and verified against RIE Tariff No. 2095 (delivery) and the Last Resort Service filing (supply).[46]

46 Supply rates validated against RIE's Last Resort Service filing (RIE 2026). Filed delivery tariff and supply tariff are committed in the RDP in standard URDB JSON format. Tariffs were set in Docket 4770: Order 23823 (RIPUC 2018). Rather than include the A-60 electric tariff we apply LIDR+ discounts after bills are calculated.

Natural gas. Homes that heat with natural gas are assigned Rhode Island Energy's **Rate 12** (Residential Heating) tariff as of 2025. The tariff has two components: a fixed monthly customer charge plus per-therm volumetric charges covering distribution, gas cost recovery, and a LIHEAP enhancement. Homes that use gas but not for space heating are assigned **Rate 10** (Residential Non-Heating), which carries a lower volumetric rate. Natural gas tariff data was sourced from RateAcuity.[47]

47 Filed gas heating tariff (Rate 12) and non-heating tariff (Rate 10) are committed in the RDP in standard URDB JSON format.

Delivered fuels. For homes that heat with heating oil or propane, we use EIA's monthly residential fuel price series for Rhode Island, applied to each building's modeled annual consumption.[48]

48 EIA Form EIA-877, Petroleum Marketing Monthly — 2024 monthly residential heating oil and propane prices for Rhode Island. Available from the EIA Petroleum Marketing Monthly. (EIA 2024).

	Fixed charge	Volumetric rate
Electricity — customer charge (A-16)	$6.00 /mo	—
Electricity — RE Growth + LIHEAP (A-16)	$4.01 /mo	—
Electricity — delivery (A-16)	—	14.06 ¢/kWh
Electricity — supply, winter (LRS, Jan–Mar)	—	17.25 ¢/kWh
Electricity — supply, summer (LRS, Apr–Sep)	—	10.67 ¢/kWh
Electricity — supply, fall (LRS, Oct–Dec)	—	15.38 ¢/kWh
Natural gas — Rate 12 (heating)	$14.79 /mo	$1.846 /therm
Natural gas — Rate 10 (non-heating)	$14.79 /mo	$1.665 /therm
Heating oil (EIA)	—	$3.48–$4.10 /gal (monthly prices)
Propane (EIA)	—	$3.44–$3.67 /gal (monthly prices)

Table 6: Energy tariffs used for bill calculations (Rhode Island Energy, 2025).

Assigning tariffs to buildings

All homes in the Rhode Island ResStock sample are assigned to Rhode Island Energy (RIE) for electric service. Homes with natural gas usage were assigned to RIE as gas utility. Gas tariff assignment distinguishes between heating and non-heating customers - homes with gas heating loads are assigned Rate 12 (Residential Heating), while homes that use gas but not for space heating are assigned Rate 10 (Residential Non-Heating). When a home installs a heat pump, it is moved from the heating rate to the non-heating rate. Homes with zero gas consumption receive no gas tariff and pay zero gas bills.

Computing bill changes under default rates

For each building, we apply the relevant tariffs to the building's hourly electricity load profile and annual fossil fuel consumption to calculate total annual energy bills.[49] We apply 12 months of electric fixed charges, and 12 months of gas fixed charges if they are a gas-heated building. Then, we apply the volumetric electricity, gas, heating oil, and propane rates to the amount of these fuels they consumed in each hour (few buildings consume all of them at once). The sum of these is the building's total annual energy bill.

We do this for all buildings under upgrade scenario 0, where their load profiles reflect their current HVAC system, and again for all buildings under upgrade scenario 2, where their load

49 Electric bills are computed by CAIRO, developed by The National Laboratory of the Rockies (formerly NREL). The RDP's master-bills builder decomposes delivery and supply portions; gas bills are computed independently by the RDP.

profiles reflect the removal of a furnace, boiler, or electric resistance heater for either a centralized heat pump, or mini-splits.

The **bill change from switching to a heat pump** is the difference between a building's total annual energy bill (electricity plus gas, oil, and propane) under its current heating equipment and after a heat pump retrofit, both on today's default rates. A negative change means the household would save; a positive change means bills would rise.[50]

50 Bill-change calculations and visualizations are in the report's analysis notebook.

All bill comparisons are **undiscounted**. Low-income discounts are handled separately in the low-income discount program (p. 63). Results are computed building-by-building, aggregated using ResStock sample weights, and broken out by baseline heating fuel type (natural gas, oil/propane, electric resistance).

How we measure the cross-subsidy between HP and non-HP customers

When we calculate the bills for each building under the default rates, we also compute their cost of service i.e., what they *should* pay based on the cost they impose on the system. A customer whose bill exceeds their cost of service is overpaying (cross-subsidizing others); a customer whose bill falls short is underpaying (being cross-subsidized). We use this measure to inform the design of a fair rate that eliminates the cross-subsidy.

Cost of service

The total cost a utility incurs to serve a customer or customer class — marginal cost (economic burden) plus the customer's allocated share of the residual.

The cross-subsidization analysis uses the Bill Alignment Test (BAT), developed by Simeone et al. (2023). The BAT compares what each customer pays in electric delivery charges against their delivery cost of service.

Bill Alignment Test

Framework (Simeone et al. 2023) that compares what each customer pays in delivery charges to their allocated cost of service. A positive BAT value means the customer is overpaying; a negative value means underpaying.

We apply the BAT at the **subclass level**: heat pump customers as one subclass, non-heat pump customers (fossil fuel and electric resistance) as the other. This lets us measure the total dollars flowing from one group to the other under default electric rates.

How we measure the cost of service for each customer

At the highest level of aggregation, each customer's cost of service has two parts:

$$\text{Cost of Service}_i = \underbrace{\sum_{h=1}^{8760} L_{i,h} \times MC_h}_{\text{Marginal cost (economic burden)}} + \underbrace{f(i,R)}_{\text{Residual share}}$$

where:

- $i \in \mathcal{C}$ — customer index (over all customers)
- h — hour of the year (1–8760)
- $L_{i,h}$ — customer i's electricity load in hour h (kWh)
- MC_h — system marginal cost in hour h ($/kWh)
- R — total residual ($/yr); the gap between the revenue requirement and total marginal cost revenue
- $f(i,R)$ — customer i's allocated share of the residual ($/yr)

The **marginal cost** (or **economic burden**) captures the incremental cost that a customer's hourly load pattern *causes* the system to incur.[51] The gap between the revenue requirement and the sum of all customers' economic burdens is the **residual**, R — discussed on p. 59.

Marginal costs

The forward-looking cost of serving the next unit of electricity — the incremental cost of generation, transmission, and distribution capacity needed to meet one additional kWh or kW of demand.

Economic burden

A customer's total marginal cost of service — the sum of hourly marginal costs weighted by that customer's hourly consumption. Used in the Bill Alignment Test to measure what a customer "should" pay before residual allocation.

51 A home that uses 10 kWh during a summer peak hour when the marginal cost is $0.25/kWh contributes $2.50 to its economic burden in that hour. A home that uses the same 10 kWh at 2 a.m. when marginal cost is $0.03/kWh contributes only $0.30. Repeat that calculation for every hour of the year — multiplying each hour's consumption by that hour's marginal cost — and sum the results: that total is the customer's annual economic burden.

Why there is a residual

We call this **marginal capacity** to distinguish it from the short-run energy and ancillary costs already defined above. In practice, we measure this long-run marginal capacity cost (LRMC) using the **First-Year Levelized Investment Cost (FLIC)** approach: the near-term projects in the utility's capital plan serve as a proxy for what it costs to expand the system at the margin. Interpreted this way, the **total marginal cost** signal roughly represents the *newest tranche* of capital on the revenue requirement — the costs that marginal load is currently triggering. (FLIC is not the only way to estimate LRMC; replacement cost and avoided cost methods are alternatives, but FLIC is grounded in actual planned investment.)

Residual

The gap between a utility's total revenue requirement and the revenue that marginal-cost pricing alone would recover. It reflects embedded (sunk) costs — depreciation, carrying charges, O&M — that are not captured by forward-looking marginal costs.

But utilities don't only charge customers for costs they are triggering now. They also need to recover the cost of everything already built: carrying charges on past capital investments, operations and maintenance on sunk assets, the regulated return on the rate base, and customer-related administrative costs. These are real costs that customers must pay, but they were caused by past consumption decisions — not by any individual customer's choices today. See p. 59 for more details.

Where the marginal costs come from

Our hourly marginal cost signal has five components, each derived from publicly available regulatory and market data:

	What it captures	Data source
Energy	Short-run cost of generation, congestion, and transmission losses in each hour. Contributes to the marginal cost of supply.	ISO-NE real-time LMPs for the RI zone (hourly, 2025)
Generation capacity	Cost of the next MW of generation to meet demand during scarcity/binding capacity hours. Contributes to the marginal cost of supply.	ISO-NE FCA clearing prices for the SENE capacity zone (RI + southeastern MA), blended across FCA 15 and FCA 16 for calendar year 2025; peak hours from SENE aggregate load (2025)
Ancillary services	Cost of two frequency regulation sub-markets: regulation service (energy dispatched by AGC in real time) and regulation capacity (capacity reserved for AGC response). Contributes to the marginal cost of supply.	ISO-NE regulation clearing prices for the RI zone (hourly, 2025)
Bulk transmission	Cost of the next MW of regional transmission capacity. Contributes to the marginal cost of delivery.	AESC 2024 avoided PTF cost ($69/kW-yr); peak hours from all-New-England system load (8 zones summed, 2025)
Sub-TX + distribution	Cost of the next MW of local delivery capacity. Contributes to the marginal cost of delivery.	AESC 2024 avoided distribution cost ($80.24/kW-yr in 2019$, CPI-adjusted to $101.05/kW-yr in 2025$); peak hours from RIE utility load (EIA hourly demand, 2025)

Table 7: Components of the hourly marginal cost signal used in the Bill Alignment Test.

How marginal costs are allocated throughout the year

In order to calculate the marginal cost for each customer, we need to know the total system marginal cost for each hour of the year. Each component produces a separate 8,760-hour signal. The signals differ in which hours carry non-zero costs.

The five components combine into two cost categories **supply** and **delivery** which are modeled as separate CAIRO runs:

$$MC_h^{\text{supply}} = MC_h^{\text{energy}} + MC_h^{\text{gen cap}} + MC_h^{\text{anc}}$$

$$MC_h^{\text{delivery}} = MC_h^{\text{bulk tx}} + MC_h^{\text{dist}}$$

The total **marginal cost** in each hour is the sum of both:

$$MC_h = MC_h^{\text{supply}} + MC_h^{\text{delivery}}$$

Each customer's **economic burden** is computed by multiplying their hourly consumption by the marginal cost in that hour and summing across all hours of the year:

$$EB_i = \sum_{h=1}^{8760} L_{i,h} \times MC_h$$

where:

- EB_i — customer i's annual economic burden ($/yr)
- $L_{i,h}$ — customer i's electricity load in hour h (kWh)
- MC_h — system marginal cost in hour h ($/kWh), the sum of all five components above

Customers who consume more electricity during peak hours — the hours when energy or capacity costs are non-zero — bear a larger economic burden than customers whose load is concentrated in off-peak hours.

Marginal cost components

Here we describe the methods used to generate the five components that make up marginal cost.

The capacity and transmission components use **exceedance weighting** to concentrate costs in peak hours. Throughout, we use the top $N = 100$ hours. Both exceedance weighting and the probability-of-peak method (used below for distribution) serve as proxies for the probability that a given hour is a capacity-binding peak, differing only in how sharply they concentrate costs.

Given the top N hours by load, each hour's **exceedance** and **weight** are:

$$e_h = \max(L_h - T,\ 0), \qquad w_h = \frac{e_h}{\sum_{h'} e_{h'}}$$

where:

- L_h — aggregate system load in hour h for the relevant load zone (specified separately for each component below)
- T — load threshold: the load of the hour immediately below the N-th highest
- e_h — exceedance of hour h above the threshold (zero for hours outside the top N)
- w_h — normalized weight assigned to hour h (zero outside the top N)

This formula is used for generation capacity and bulk transmission, each applied to a different load profile and annual cost.

Energy. Every hour receives a non-zero value equal to the ISO-NE real-time locational marginal price for Rhode Island Energy's zone:[52]

$$MC_h^{\text{energy}} = \text{LMP}_h$$

The signal varies continuously throughout the year, reflecting the changing fuel cost and congestion of the marginal generator in each hour.

Generation capacity. ISO-NE holds annual Forward Capacity Market (FCM) auctions, each clearing capacity obligations roughly three delivery years in advance. The auction pays generators and demand resources to be available during peak periods. The clearing price sets the annualized cost of keeping one kW of capacity online. We convert that to a single $/kW-year value C_{FCA} by blending the two overlapping auction periods that cover each calendar year. That cost is then spread across the top 100 hours of the year by aggregate load in the RI and southeastern Massachusetts capacity zone (the zone whose clearing prices apply to Rhode Island) using exceedance weights:[53]

Marginal energy costs

The operating cost of generating an additional kWh of electricity at a particular time. Marginal energy costs vary hour by hour with demand and the mix of generators running: they are low when abundant renewables are on the grid or demand is slack, and high when expensive peaker plants are running to meet peak load.

52 Hourly LMPs drawn from the ISO-NE Web Services API (ISO NE 2025c). Hourly energy MC signals are built by the RDP's supply energy MC generator.

Marginal generation capacity costs

The capacity cost associated with triggering the construction of a new megawatt of generation capacity at a particular time. Zero most hours of the year, and high during system-wide peak hours.

53 Forward capacity auction clearing price P_m from (2ISO NE 2024); system hourly loads used to identify peak hours from (2ISO NE 2025a). Hourly capacity MC signals are built by the RDP's supply capacity MC generator.

$$MC_h^{\text{gen cap}} = w_h \times C_{\text{FCA}}$$

where:

- w_h — exceedance weight (p. 56), computed from aggregate load in the Southern New England (RI + south-eastern MA) capacity zone
- C_{FCA} — annualized FCM clearing price ($/kW-yr), blended across the two overlapping auction periods covering the calendar year

The result is exactly 100 non-zero hours per year, concentrated in the hours when the regional grid is under the most stress.

Ancillary services. ISO-NE procures frequency regulation through a real-time market that clears every five minutes. We aggregate the regulation service clearing price and regulation capacity clearing price to hourly resolution: [54]

$$MC_h^{\text{anc}} = P_h^{\text{reg svc}} + P_h^{\text{reg cap}}$$

where:

- $P_h^{\text{reg svc}}$ — ISO-NE regulation service clearing price in hour h ($/MWh)
- $P_h^{\text{reg cap}}$ — ISO-NE regulation capacity clearing price in hour h ($/MWh)

Ancillary costs are non-zero in every hour. They represent the continuous cost of maintaining grid frequency balance.

Bulk transmission. The AESC 2024 study provides the avoided Pool Transmission Facility (PTF) cost C_{PTF} ($/kW-yr). We allocate it to the top $N = 100$ hours by all-New-England system load (the sum of all eight ISO-NE load zones) using exceedance weights: [55]

$$MC_h^{\text{bulk tx}} = w_h \times C_{\text{PTF}}$$

where:

- w_h — exceedance weight (p. 56), computed from aggregate all-New-England system load (sum of all eight ISO-NE load zones)
- C_{PTF} — avoided Pool Transmission Facility cost ($/kW-yr) from the AESC 2024 study

54 Hourly regulation service and regulation capacity clearing prices from the ISO-NE Web Services API (ISO NE 2025b), summed to produce an ancillary cost signal ($/MWh). Hourly ancillary MC signals are built by the RDP's supply ancillary MC generator.

Marginal T&D capacity costs

The capacity cost associated with triggering the construction of a new megawatt of transmission or distribution capacity at a particular time. Zero most hours of the year, and high during peak hours for the infrastructure component that is at capacity.

55 The AESC study (Synapse 2024) is the New England standard for avoided transmission costs; all six New England states use AESC values for energy efficiency program screening, and Rhode Island's PUC benefit-cost framework (Docket 4600) draws directly from it. Hourly bulk-TX MC signals are built by the RDP's bulk transmission MC generator.

Non-zero hours are concentrated around the annual system peak, currently summer-dominated for ISO-NE.

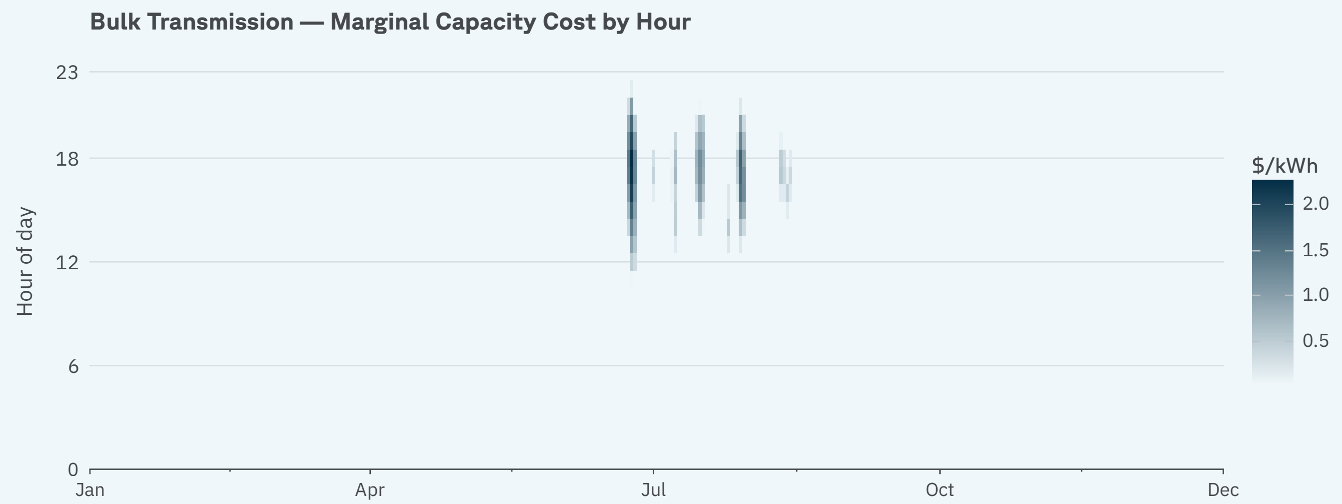

Figure 29: Hourly marginal bulk transmission capacity costs, 2025. Costs are concentrated in ~100 summer afternoon hours; every winter hour is zero.

Sub-transmission and distribution. The AESC 2024 study also provides an avoided distribution capacity cost ($\overline{MC}^{\text{dist}}$ = \$80.24/kW-yr), which represents the system-wide cost of reducing peak demand by one kW. The AESC value was in 2019 dollars. We adjusted it to 2025 dollars using the Consumer Price Index (CPI) to get \$101.05/kW-yr. Effectively this is the avoided cost of a distribution capacity upgrade, diluted to reflect the fact that most feeders are not constrained.[56] That cost is allocated to the top 100 hours of RIE's system load (EIA Form 930) using a **probability-of-peak** (PoP) method. Each peak hour's weight is proportional to its absolute load rather than its exceedance above a threshold:[57]

$$MC_h^{\text{dist}} = \frac{L_h}{\sum_{h' \in \text{top } 100} L_{h'}} \times \overline{MC}^{\text{dist}}$$

where:

- L_h — RIE's hourly system load in hour h (from EIA Form 930)
- $\overline{MC}^{\text{dist}}$ — avoided distribution capacity cost (\$/kW-yr) from the AESC 2024 study

56 Sub-transmission and distribution marginal cost drawn from the AESC 2024 avoided distribution capacity cost (Synapse 2024). The AESC value of \$80.24/kW-yr (2019 dollars) is adjusted to 2025 dollars using the CPI-U All Items index (U.S. Bureau of Labor Statistics 2025), yielding \$101.05/kW-yr. The \$/kW-yr input value is committed in the RDP; the hourly PoP allocation is performed by the RDP's utility TX/DX MC generator.

57 RIE system load from the EIA Hourly Electric Grid Monitor (Form 930) (EIA 2025) — hourly demand by balancing authority, used to identify the top 100 peak hours for allocating sub-transmission and distribution marginal costs.

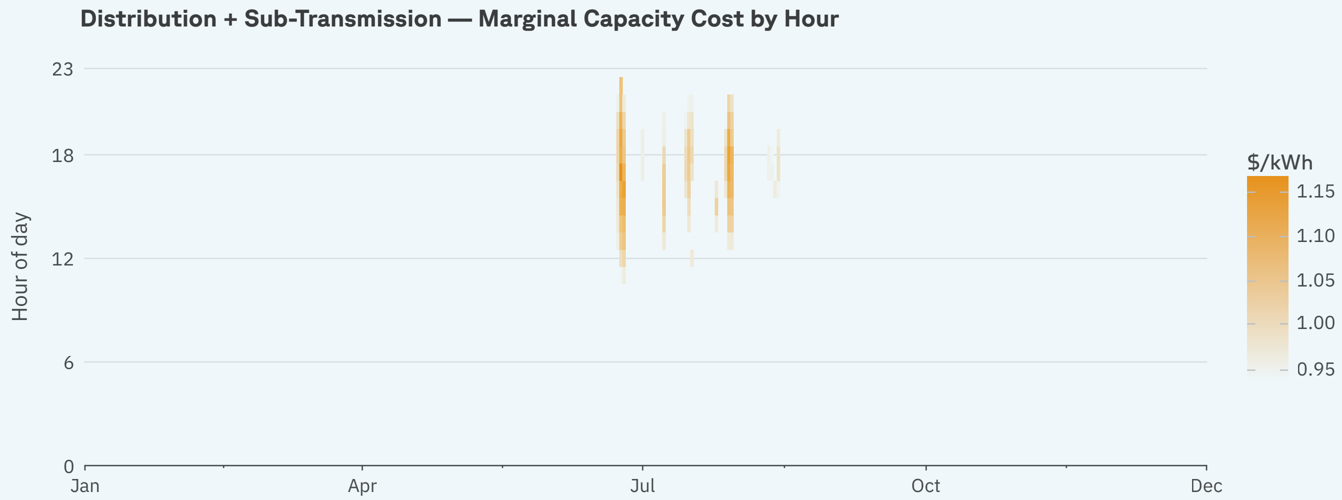

Figure 30: Hourly marginal distribution and sub-transmission capacity costs, 2025. Same summer-only pattern as bulk transmission.

How we allocate the residual

The gap between the utility's total revenue requirement and the revenue that marginal cost pricing alone would generate is the residual. For Rhode Island Energy, the delivery residual is 86% of total delivery revenue. Only 14% of what customers pay for delivery reflects the forward-looking cost of new infrastructure.[58] The table below shows the full breakdown of delivery charges and revenue during the rate-case test year.

58 The total delivery revenue requirement is established before the CAIRO run by the RDP's revenue-requirement calculator, reading rate-case inputs committed in the RDP.

Area	Charge	Rate	Revenue	Revenue (derivation)
Customer Charge	Customer charge	$6/mo	$30,193,044	$6.00/month * 5,032,174 bills
Distribution Charge	Core delivery rate	4.58¢/kWh	$129,212,677	$0.0458/kWh * test_year_residential_kwh
Transmission Charge	Transmission charge	4.71¢/kWh	$132,908,498	
	Transmission uncollectible	0.06¢/kWh	$1,749,167	
Other Delivery Charge	Capex revenue	0.83¢/kWh	$23,472,696	
	Storm fund replenishment	0.79¢/kWh	$22,231,351	
	Low-income discounts	0.25¢/kWh	$6,562,821	
	O&M	0.23¢/kWh	$6,404,209	5,935,300 + 468,909 (includes O&M reconciliation)
	System reliability plan	0.16¢/kWh	$4,598,617	
	LIHEAP enhancement	$0.79/mo	$3,975,417	
	EE & SRP uncollectible	0.01¢/kWh	$366,761	
	Arrears recovery	0.01¢/kWh	$169,274	
	Transition / restructuring	0.00¢/kWh	$28,213	
	Performance incentive	0.00¢/kWh	$0	
	Revenue Decoupling Rdm	($0.00272)/kWh	−$7,673,766	$0.00272 * test_year_residential_kwh
	Pension adjustment	($0.00339)/kWh	−$9,563,995	
Renewable Energy	Net metering	1.46¢/kWh	$41,105,430	
	Long-term contracting	0.66¢/kWh	$18,507,318	
	Renewable energy growth program	$3.22/mo	$16,203,601	
	Renewables charge	0.03¢/kWh	$846,371	
Energy Efficiency	Energy efficiency programs	0.89¢/kWh	$25,165,439	

Table 8: Residential delivery revenue requirement by program area and line item (Test Year, 9/1/24 to 8/31/25).

Source for Rate and Revenue on Customer and Distribution Charges: RIE Book 21, p. 14 of PRB-1-ELEC exhibit; Source for Rate and Revenue on Transmission Charges, Other Delivery Charges, Renewable Energy, and Energy Efficiency: RIE Book 21, p. 7 of PRB-1-ELEC exhibit

Because the residual represents sunk costs that are not attributable to any customer's current behavior, the choice of how to split it is a normative decision, not a strictly economic one (Borenstein 2016). The main options are:

- **Volumetric markup** — add a uniform $/kWh surcharge; each customer's share is proportional to their consumption. This is the dominant practice in U.S. rates. It is simple and feels equitable, but it distorts consumption decisions because customers face a price above marginal cost.

- **Flat fixed charge** — divide the residual equally across all customers ($/customer/month). This is the most economically efficient option — it creates no incentive to change consumption — but can be regressive, since the same dollar charge weighs more heavily on low-usage households.
- **Proportional to marginal cost causation (EPMC)** — each customer's share is proportional to their share of total system marginal costs.

We use equi-proportional marginal cost (EPMC) allocation: each customer's residual share is proportional to their share of total system marginal costs. If a subclass causes 3% of total marginal costs, it bears 3% of the residual. This is equivalent to scaling all marginal-cost-based rates by a uniform factor

EPMC

Equi-proportional marginal cost — a method for allocating the residual so that each customer's share is proportional to their share of total system marginal costs. Equivalent to scaling all marginal-cost-based rates by a uniform factor until the revenue requirement is met.

$$K = \frac{TRR}{EB_{\text{total}}}$$

where:

- K — the EPMC scaling factor
- TRR — total delivery revenue requirement
- EB_{total} — total system economic burden (sum of all customers' economic burdens, $\sum_{i \in \mathcal{C}} EB_i$)

so that total revenue equals the revenue requirement. This is the standard reconciliation method used in California (NARUC 1992).

This mirrors the logic of RIE's own embedded cost-of-service study (ECOSS): use a metric that measures each subclass's current cost-causation, then divide the revenue requirement accordingly. We use hourly marginal costs rather than non-coincident peak (NCP) as the cost-causation metric. It is a more granular signal, but the same allocative principle.

Under EPMC, the BAT reveals how the current delivery rate redistributes costs between customer groups. Heat pump customers, who consume more electricity (especially in winter, when capacity marginal costs are low), pay a disproportionate share of the delivery revenue requirement relative to the cost they impose on the system.[59]

How we designed the proposed fair rate

The cross-subsidy analysis (p. 52) identifies the problem: under today's flat delivery rates, heat pump customers systematically overpay for delivery. The fair rate is designed to eliminate this overpayment. The process has two steps: **first**, allocate costs to the HP subclass to determine its revenue requirement; **then**, design a rate that recovers that amount.

Step 1: Cost allocation

Under EPMC, each subclass's share of the total delivery revenue requirement is proportional to its share of total system economic burden. The HP subclass revenue requirement is:

$$RR_{\text{HP}} = K \times EB_{\text{HP}} = \frac{TRR}{EB_{\text{total}}} \times EB_{\text{HP}}$$

where:

- TRR — total delivery revenue requirement
- EB_{HP} — sum of economic burdens for all HP customers ($\sum_{i \in \text{HP}} EB_i$)
- EB_{total} — sum of economic burdens for all customers ($\sum_{i \in \mathcal{C}} EB_i$)
- $K = TRR / EB_{\text{total}}$ — the EPMC scaling factor (defined on p. 52)

This is the HP subclass's fair share of total delivery costs. The same formula applies to the non-HP subclass, and $RR_{\text{HP}} + RR_{\text{non-HP}} = TRR$ by construction.

Step 2: Rate design

Given the HP subclass's revenue requirement, many rate structures could recover it — a flat volumetric rate, a time-of-use rate, a demand charge, or some combination. We use the simplest: a **flat volumetric delivery rate for heat pump customers**, set lower than the current default rate. Rhode Island Energy gets a single HP delivery rate reflecting its territory's cost structure.

59 BAT values per-customer economic burden and cross-subsidy are computed by CAIRO during the run (via the RDP's scenario runner). The RDP's subclass revenue-requirement allocator then applies the EPMC split between HP and non-HP subclasses. BAT results are consolidated across utilities by the RDP's master BAT builder.

$$r_{\mathrm{HP}} = \frac{RR_{\mathrm{HP}} - FC_{\mathrm{HP}}}{Q_{\mathrm{HP}}}$$

where:

- RR_{HP} — HP subclass revenue requirement (the EPMC-allocated share of the total delivery revenue requirement; see p. 52)
- FC_{HP} — fixed-charge revenue already collected from HP customers
- Q_{HP} — total HP kWh delivered

By construction, this rate collects exactly the HP subclass's allocated cost of service.[60] Non-HP customers remain on a slightly recalibrated default rate that absorbs the revenue previously cross-subsidized by HP customers.

60 The fair flat delivery rate is derived by the RDP's subclass revenue-requirement allocator.

Bill comparisons under the fair rate

Once the fair rate is calibrated, we compute two additional sets of bill comparisons (using the same building-by-building, undiscounted methodology described above):

- **HP customers switching under the fair rate.** We compare each building's total energy bill under its current heating equipment on default rates (upgrade 0, default rate) against its bill after a heat pump retrofit on the HP flat rate (upgrade 2, HP flat rate). This captures the combined effect of electrification and rate reform.
- **Non-HP customers after cross-subsidy removal.** If HP customers move to the fair rate, the default rate is recalibrated for remaining customers. We compare non-HP customers' bills before and after this recalibration. Same homes (upgrade 0), same heating equipment, only a slight rate adjustment.

Low-income discount program

The current program: LIDR. Rhode Island Energy's existing Low-Income Discount Rate (LIDR) provides a 25% or 30% discount on the total monthly bill for qualifying customers — electric customers on the A-60 rate and gas customers on Rates 11 and 13. Discounts are tied to participation in categorical assistance programs: households enrolled in SNAP, LIHEAP, or SSI receive a 25% discount; those on Medicaid, Rhode Island Works, or Public Assistance receive a 30% discount.[61]

[61] Current LIDR program rules from the PUC's LIDR order (RIPUC 2024); see also the A-60 tariff schedule (RIPUC 2020).

The proposed redesign: LIDR+. In November 2025, Rhode Island Energy filed a proposed Low-Income Discount Rate Plus (LIDR+) in its base distribution rate case (Docket 25-45-GE).[62] LIDR+ applies to electric service only and replaces categorical program enrollment with income-based tiers. Three tiers are defined by household income as a share of the Federal Poverty Level (FPL):

[62] DeSousa et al. direct testimony describing the proposed LIDR+ program (RIE 2024a); tier discounts from Table 7 of Blazunas testimony in the same docket (RIE 2025c).

	Household income	Electric discount
Deepest	≤ 75% FPL	60%
Middle	76–150% FPL	30%
Smallest	151–250% FPL	10%

Table 9: Proposed LIDR+ electric discount tiers by household income (Federal Poverty Level), filed in RIE Docket 25-45-GE.

Gas service remains on the flat LIDR unchanged from the current program.

Our definition of "LMI household." Throughout the energy burden analysis, we define a low-and-moderate-income (LMI) household as any household at or below 250% FPL (the outer eligibility limit of LIDR+). This is a broader definition than the current LIDR program, which in practice reaches households up to roughly 185% FPL (the SNAP/LIHEAP income ceiling). We use the 250% FPL boundary because it reflects the full population that a reformed LMI program could serve, and to show what full LIDR+ uptake would mean for the entire eligible population.

Energy burden

The percentage of a household's annual income spent on energy bills. A household is considered energy-burdened when this share exceeds 6%.

Participation. As of July 2024, approximately 36,320 households were enrolled in the A-60 electric discount rate. We estimated that to be roughly 32% of estimated eligible households.[63] We use this estimated 32% figure as our baseline participation scenario for both electric and gas discounts. Under the partial participation scenario, we sample 32% of eligible households uniformly. All households participating in the gas discount program were also assigned the electric discount program. We also model a 100% enrollment scenario to reflect bills under automatic enrollment.

[63] 36,320 A-60 enrollees as of July 2024 per (RIE 2024a). Roughly 114,000 RI households estimated eligible per (Johnson 2025); 32% ≈ 36,320 ÷ 114,000.

Because ResStock does not include program enrollment data, we use percent of FPL as a proxy for discount eligibility. For electric bills we apply the LIDR+ tier structure (10%/30%/60% by FPL band). For gas bills we apply the flat LIDR, proxied by percentage of FPL. Households at or below 138% FPL receive the 30% discount (likely Medicaid-enrolled), households between 138% and 185% FPL receive the 25% discount (SNAP/LIHEAP range), and households above 185% FPL receive no gas discount.[64,65]

Computing energy burden. A household's energy burden is the share of annual income spent on energy. We define a household as **energy-burdened** if this share exceeds 6%.[66] For each ResStock building we compute:

$$\text{Energy burden}_i = \frac{\text{Electric bill}_i + \text{Gas bill}_i}{\text{Annual household income}_i}$$

Because ResStock's household income is in 2019 dollars while the bills are priced at current tariff rates (2025 dollars), we inflate income to the bill year using the BLS CPI-U (U.S. Bureau of Labor Statistics 2025) before computing the ratio. We focus on a cohort of LMI gas-heated households, those flagged as low-or-moderate income who heat with natural gas in the baseline scenario, and track their energy burden across three rate scenarios:

1. **Current HVAC, default rates** — the status quo before electrification.
2. **Heat pump, default rates** — electrified, but on the standard flat delivery rate.
3. **Heat pump, HP flat rate** — electrified on the proposed fair rate.

For each scenario we compute the share of the cohort above and below the 6% burden threshold. We run this comparison under two LMI discount enrollment assumptions: **current enrollment** (~32% of eligible households receiving discounts) and **full enrollment** (100% of eligible households receiving discounts). This lets us isolate the separate effects of rate reform and discount take-up on low-income energy affordability.[67]

64 ResStock's household income data reflects income in 2019 dollars. Before computing FPL percentages and energy burden ratios, we inflate income to 2025 dollars using the BLS CPI-U (U.S. Bureau of Labor Statistics 2025), series CUUR0000SA0). This ensures income and bill dollars are in the same year.

65 LMI tier assignment and discounts are applied by the RDP's LMI discount module, using shared tier logic, tier definitions, and FPL guidelines committed in the RDP.

66 The 6% threshold is a commonly used benchmark in energy affordability research. We apply it to total energy costs (electric + gas), not electricity alone. We focused on gas-heated households because there is no discount for delivered fuels.

67 Energy burden analysis is in the report's analysis notebook (section "Energy burden for low-income gas-heated households").

How we assessed winter headroom on Rhode Island Energy's distribution system

A key question for heat pump policy is whether the grid can physically handle increased winter electricity demand as more homes electrify. We assess this by examining Rhode Island Energy's distribution feeders and substation transformers against their rated capacity in winter, across three HP adoption scenarios and through 2039.

Current headroom (2026 snapshot)

Data source. Rhode Island Energy provided feeder- and transformer-level peak demand projections in a workbook covering 2021–2035. Each row is a distribution feeder (a medium-voltage line carrying power from a substation to homes and businesses) or a substation transformer, which steps voltage down from the transmission level to distribution voltage. Columns contain forecasted summer peak load (in amps, a measure of current flow) for feeders, and MVA (megavolt-amperes, a measure of apparent power) for transformers for each year, the asset's nameplate summer rating (the maximum load it is designed to carry continuously under normal conditions), and two years of N-1 contingency load-at-risk assessments (2026 and 2035).[68]

Deriving winter loads. The feeder data is summer-only. RIE does not currently measure feeder-level winter peaks and does not forecast how those peaks will evolve at the feeder level.[69] We estimated winter headroom ourselves using RIE's recommended method. Current winter demand is estimated from summer demand using a scaling ratio of 0.70 (the system-wide winter/summer peak ratio as of 2024, per RIE's distribution planners). This ratio is held fixed for the 2026 current-state snapshot. Winter rated capacity is assumed equal to summer nameplate rating which is a conservative assumption, since thermal limits do not degrade in winter.

Defining constrained assets. A feeder or transformer is classified as **constrained** if its peak exceeds 100% of nameplate rating, or N-1 contingency = "yes". Headroom for a given asset is $1 - \text{utilization}$, where utilization is the ratio of peak demand to rated capacity.[70]

68 The N-1 contingency standard requires that the grid remain operable after any single component failure. A feeder flagged as "contingency load-at-risk" is one whose neighbors could not safely absorb its load if it went offline. In other words, the feeder can fail the N-1 screen even at modest utilization if adjacent feeders are themselves heavily loaded.

69 RIE's Distribution Planning Manager confirmed that "the RI system is currently summer limited" and that "the Company concentrates on summer analysis for efficiency reasons," adding that "a winter analysis would provide no useful information to determine system sufficiency." Schedule JPV-6, Responses 6 and 12, in (Velez 2026).

Headroom

The gap between a feeder's peak load and its normal capacity rating, expressed as a percentage. A feeder at 80% of capacity has 20% headroom — room for load to grow 20% before the feeder is fully loaded.

70 Headroom analysis is in the report's feeder peaks notebook.

Forward-looking headroom (2039 projection)

Data source. We draw system-wide peak MW projections from Rhode Island Energy's *RI Peak Report 2024*,[71] specifically the **95/5 extreme weather** scenario. We selected the 95th-percentile summer temperature (unusually hot, maximizing cooling peak) and the 5th-percentile winter temperature (unusually cold, maximizing heating peak). We do not use these system-wide totals as absolute demand forecasts. We use them only as ratios to capture how quickly winter peaks grow relative to summer peaks as heat pump adoption rises. Feeder-level demand in any given year is still anchored to RIE's actual base feeder data. The Peak Report also provides year-by-year electric heating (EH) contribution forecasts and cumulative heat pump adoption counts under Base and High scenarios.

71 Rhode Island Energy, *2024 Electric Peak Report* — system-wide summer and winter net peak MW forecasts through 2039, including electric heating contributions and HP adoption scenarios (Base and High). (RIE 2024b).

Projecting feeder loads. Summer demand for each feeder is projected forward by applying the system-wide summer peak growth rates from the Peak Report. Winter demand uses a separate method, because winter and summer system peaks grow at different rates as heat pump adoption rises. The RIE Peak Report projects both summer and winter system peaks through 2039. Rather than fixing the winter-to-summer ratio at 0.70 for the full forecast period, we let it change each year in proportion to how the two system-wide peaks evolve relative to their 2024 baselines. Concretely, if winter system load grows faster than summer system load in a given year (because more heat pumps are added), the feeder-level winter-to-summer ratio rises accordingly:

$$\text{winter demand}_i(y) = \text{summer demand}_i(y) \times \frac{W_{\text{NET}}(y)/W_{\text{NET}}(2024)}{S_{\text{NET}}(y)/S_{\text{NET}}(2024)} \times W_0$$

where:

- i — feeder (or transformer) index
- y — projection year
- $W_{\text{NET}}(y)$ — system-wide winter net peak in year y (extreme weather scenario)
- $S_{\text{NET}}(y)$ — system-wide summer net peak in year y (extreme weather scenario)
- $W_0 = 0.70$ — 2024 baseline winter-to-summer demand ratio

Utilization for 2036–2039 is extrapolated from 2035 by applying the Peak Report's year-over-year growth rates.

Heat pump adoption scenarios. We model three scenarios by scaling each feeder's demand using unitless adjustment factors derived from the Peak Report's EH forecasts and HP adoption counts:

- **No heat pumps** — The EH contribution is removed:

$$\mathrm{adj}_y = (N_y - EH_y)/N_y$$

where:

- adj_y — unitless demand scaling factor for year y
- N_y — system net peak in year y
- EH_y — electric heating contribution to the net peak in year y
- **Baseline** — No adjustment; demand follows RIE's base forecast.
- **High heat pump adoption** — The EH contribution is scaled up by the ratio of High to Base cumulative HP adoption counts:

$$\mathrm{adj}_y = (N_y + EH_y \times (r_y - 1))/N_y$$

where:

- $r_y = \mathrm{HP}_{\mathrm{high}}(y)/\mathrm{HP}_{\mathrm{base}}(y)$ — ratio of cumulative High to Base HP adoption counts in year y
- N_y, EH_y — as defined above

Feeders already constrained in 2026 are excluded from the 2039 assessment — they are assumed to be upgraded before heat pump adoption stress arrives. For the remaining feeders, the same two constraint criteria apply (peak exceeds normal capacity, or N-1 contingency flag), with feeders rated "border-line" in 2035 also counted as constrained to capture assets approaching their limit.

ASSUMPTIONS

- **Actual meteorological year (AMY 2018) weather.** All load profiles use actual meteorological year 2018 weather data. While ResStock also provides a composite typical meteorological year (TMY) scenario, we use the AMY year to preserve weather-driven coincident peaks. TMY composites splice months from different years, which can smooth out the extreme weather events that drive the system peak hours central to our marginal cost allocation.
- **Static tariffs and fuel prices.** Bills are computed at 2025 tariff rates. Natural gas and delivered fuel prices use 2024 EIA data; the model does not incorporate price escalation or fuel-switching dynamics.
- **No behavioral response to rate changes.** The model does not capture price elasticity — a household's hourly load profile is the same under the default rate and the proposed HP flat rate. In practice, time-varying price signals could shift load away from peak hours, which would reduce delivery cost-of-service for responsive customers.
- **EPMC residual allocation.** The residual — the gap between the total delivery revenue requirement and total system marginal cost — is allocated to subclasses via equi-proportional marginal cost (EPMC) scaling. This is the standard approach in marginal cost-of-service studies but is ultimately a normative choice; per-customer equal allocation is an alternative. The residual represents embedded costs of existing infrastructure that are not attributable to any customer's current load pattern.
- **Winter feeder peaks estimated from summer.** RIE does not compile or forecast feeder-level winter peaks.[72] Winter demand for each feeder is derived from its summer peak using the system-wide winter-to-summer ratio of 0.70, per RIE's recommended method. This is correct on average but may underestimate above-average winter feeders.
- **Aggregate system load as proxy for feeder stress.** RIE does not publish feeder-level 8,760-hour load profiles, and confirms that the hour of each feeder's peak "is not

72 RIE stated in discovery that "the RI system is currently summer limited" and that "the Company concentrates on summer analysis for efficiency reasons," adding that "a winter analysis would provide no useful information to determine system sufficiency." Schedule JPV-6, Responses 6 and 12, in (Velez 2026).

tracked as it is not necessary to current distribution planning practices."[73] We allocate distribution marginal costs using the top 100 hours of aggregate RIE system load. If feeder-level hourly data were available, costs would spread across more hours (since different feeders peak at somewhat different times) with lower per-hour values; the aggregate approach concentrates costs in fewer hours, which if anything overstates the cost assigned to any individual peak hour.

- **ResStock as building stock proxy.** Load profiles come from NREL's ResStock physics-based simulations, not metered household data. Each simulated building represents approximately 252 real homes. Results are statistically representative in aggregate but should not be interpreted as describing any individual household.
- **HP adoption scenarios from RIE's Peak Report.** The forward-looking headroom analysis (see p. 66) uses RIE's own Base and High adoption scenarios from the 2024 Electric Peak Report,[74] rather than a Switchbox-derived adoption scaling.

73 RIE confirmed in discovery that "the hour of peak is not tracked as it is not necessary to current distribution planning practices focused on peak level analysis." Schedule JPV-6, Response 4, in (Velez 2026).

74 Rhode Island Energy, *2024 Electric Peak Report* — system-wide summer and winter net peak MW forecasts through 2039, including electric heating contributions and HP adoption scenarios (Base and High). (RIE 2024b).

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