Ratepayer Impacts of Arizona Public Service’s Gas Resources

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Executive Summary

Natural gas purchases to fuel Arizona Public Service (APS) power plants currently account for 5% of residential bills.

Gas prices can be impacted by external factors including global geopolitical events and domestic extreme weather events. Therefore, APS's reliance on gas resources exposes ratepayers to fuel price volatility risk.

- Gas price spikes could increase average residential customer bills by over $9 per month.

Data centers are driving up electricity demand in Arizona.

- Since its 2023 IRP, APS has increased its planned additions for 2030 by 4.6 GW to meet increased demand.

APS is responding by increasing its reliance on gas.

- APS plans to increase nameplate capacity of natural gas from 5.1 GW in 2023 to 7.8 GW in 2030, a 48% increase.
- Gas could make up 32% of the Company's generation mix, compared to 19% in 2023.

This will lock customers into increased bills for many years and increase ratepayer exposure to gas price risks.

Introduction

- Before the data center boom, APS and many other utilities were beginning to transition away from fossil resources and towards renewables. Resource plans showed increased deployment of solar, wind, and battery storage, and a reduction in utility reliance on gas and coal generation.
- Data center load growth has stymied this trend in many parts of the country. Utilities that previously planned a shift to renewable deployment are now keeping legacy fossil pants online and constructing new gas power plants. Although the gas plants are predominately to serve new large-load customers, the associated costs will burden all customers absent adequate protections.
- Gas is a global commodity; therefore, its supply and price are at the whim of both global and domestic market forces.
  - For example, stronger global demand for liquified natural gas (LNG) can increase U.S. LNG exports, increasing domestic demand for natural gas and putting upward pressure on U.S. natural gas prices.
- Gas is also hard to store and relies on complicated pipeline networks to move around the country. Because the price of gas is influenced by so many factors outside a utility's control, it can be volatile and pose risks to ratepayers.
- Increased reliance on gas generation will increase ratepayer exposure to fuel price volatility. This could result in unpredictable bill impacts for APS ratepayers as the company reconciles its fuel expenditures.
- In this analysis, we quantify how APS's reliance on gas resources has changed over time and the impacts of fuel price volatility on ratepayers.
- We also discuss how a fuel cost sharing mechanism can help to address these concerns.

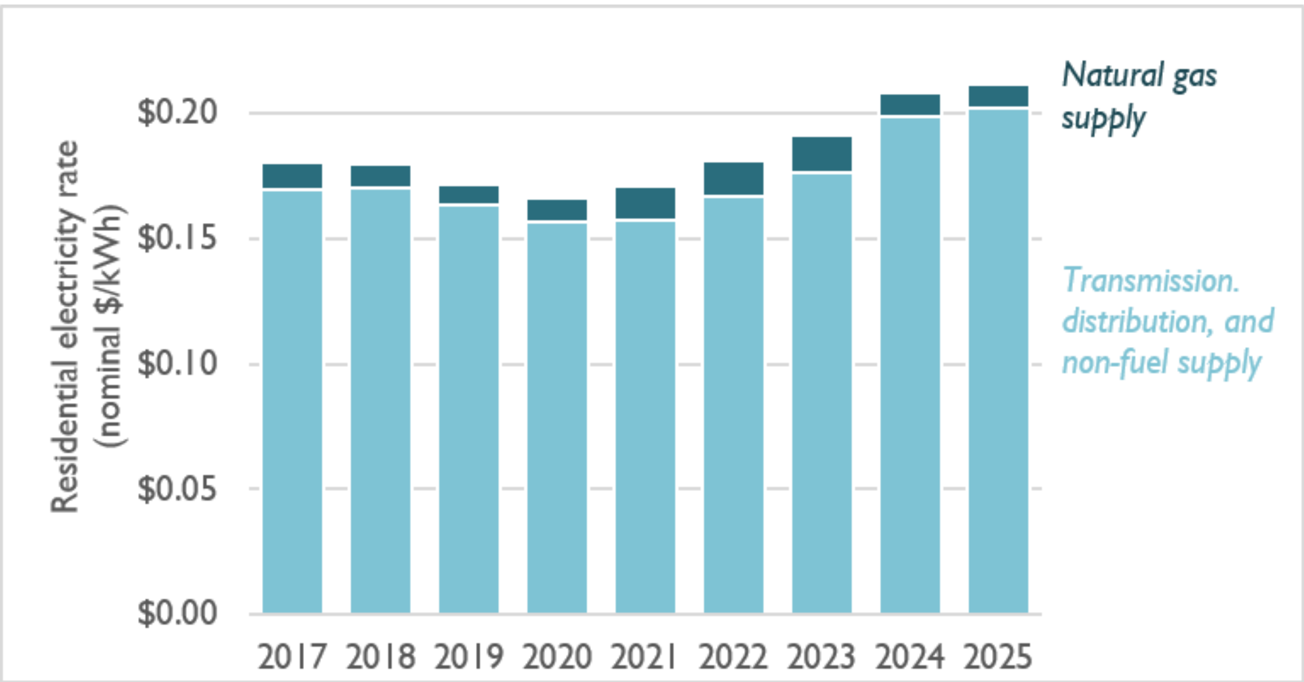
The Role of Gas in APS's Electric Bills

Currently, about 5% of the average APS residential customer's electric rate is from natural gas.

On the average residential bill, assuming around 1,000 kWh per month, this translates to about $10 per month in 2025.

APS's natural gas costs for an average residential customer have fluctuated from around $8 per month in 2019 to over $15 per month in 2023.

Figure 1. APS average residential electricity rate by component



Source: We estimated average annual residential electricity rates from monthly rate data for APS's Residential Schedule's RateAcuity database, available at https://rateacuity.com/. We assumed an average monthly residential energy consumption of 1,034 kWh, derived for APS from U.S. Energy Information Administration's Form 861, available at https://www.eia.gov/electricity/data/eia861/. We estimated average annual residential natural gas costs from FERC Form 1 Schedule 320 and annual energy from FERC Form 1 Schedule 401, available at https://docs.catalyst.coop/pudl/en/latest/data_sources/ferc1.html.

Reliance on Gas Brings the Risk of Price Volatility

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Gas prices can be volatile, with short-term price spikes caused by winter storms, and longer periods of elevated prices caused by geopolitical conflicts and other events (Figure 2).

When Henry Hub prices are high, APS pays more for gas and passes these costs directly onto its customers.

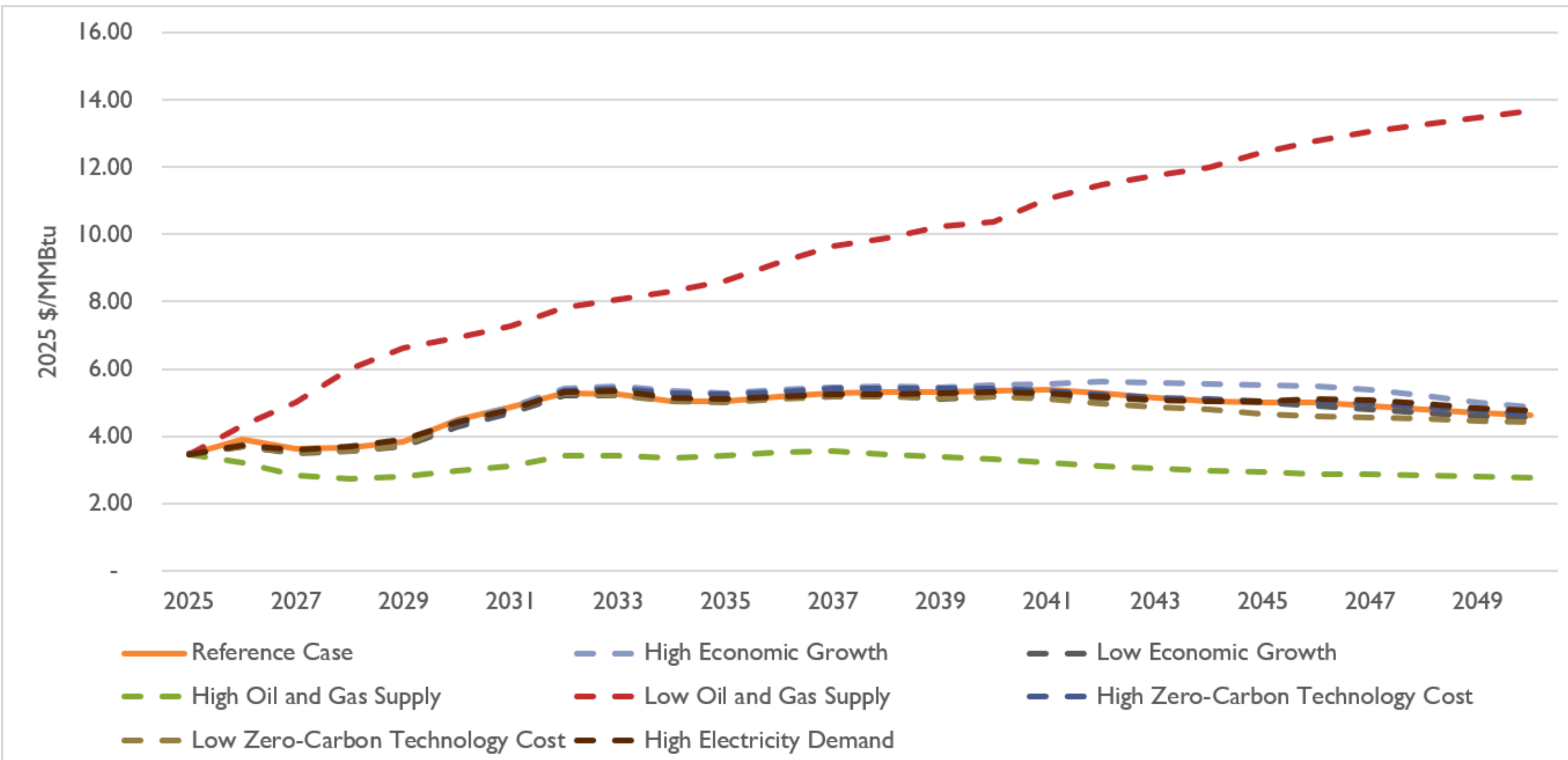
Figure 2. Historical Henry Hub natural gas spot price

Source: U.S. Energy Information Administration. Henry Hub Natural Gas Spot Price. Accessed March 15, 2026. Available at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

Future Gas Prices Are Uncertain

Gas price forecasts vary based on assumptions about future economic and technical conditions (Figure 3).

Figure 3. Projected Henry Hub natural gas spot price



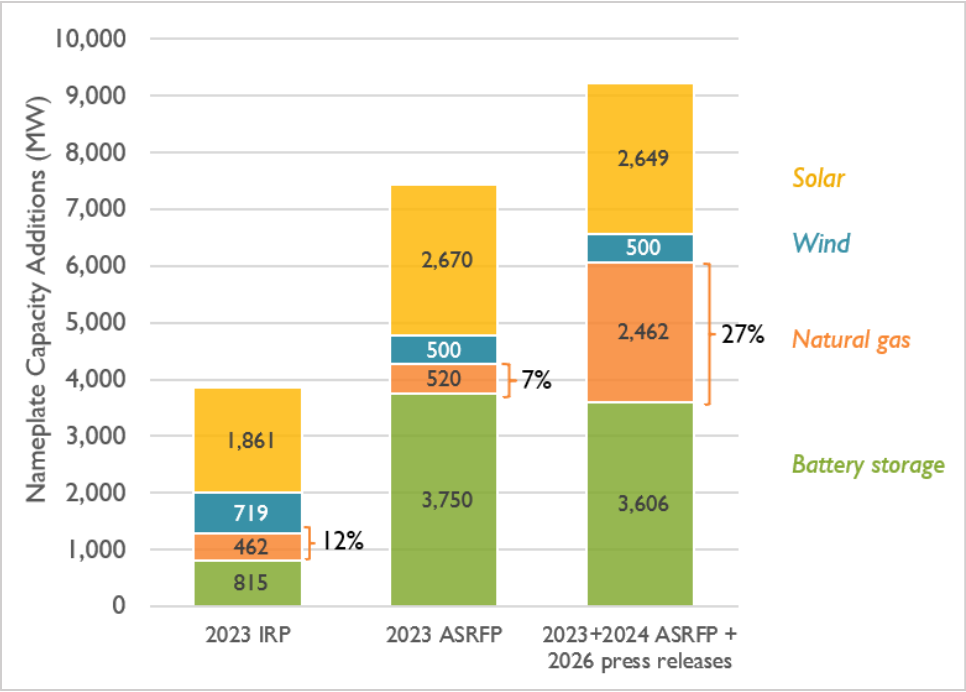
Source: U.S. Energy Information Administration. Annual Energy Outlook 2025. Accessed March 25, 2026. Available at: https://www.eia.gov/outlooks/aeo/.

Recent Trends in APS's Gas Reliance

APS's Response to Increased Demand Forecasts

- In its 2023 IRP, APS planned to add 462 MW of natural gas to its portfolio by 2030.
- In response to higher demand forecasts in 2023, APS increased plans by 520 MW of natural gas, with an online date of 2030. APS also increased storage and battery procurements beyond what it had planned in the 2023 IRP.
- In APS's current 2026 IRP proceedings, APS shared that through both 2023 and 2024 All-Source (AS)RFP procurements as well as July 2026 press release announcements, APS has plans to add 2,462 MW of natural gas capacity.

Figure 4. Projected 2023 IRP resource additions versus procurements (2026 - 2030)

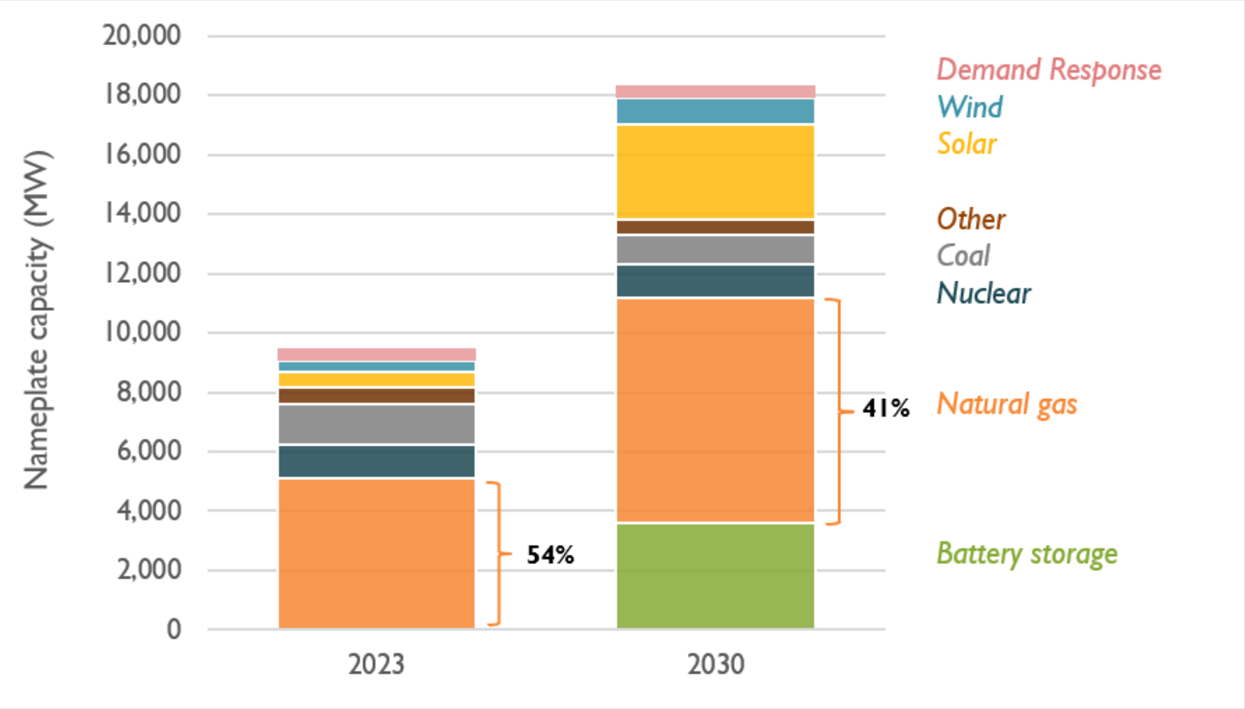


Since the 2023 ASRFP, APS has increased its planned gas capacity to meet additional demand, with 27% of new planned capacity coming from gas between now and 2030.

APS Capacity Mix

- In 2023, 54% of APS's total capacity mix was natural gas. In 2030, when including the procurements from APS 2023 ASRFP, 2024 ASRFP, and July 2026 press release announcements, APS projects that natural gas will account for 41% of its total capacity mix.
- The **nameplate capacity of natural gas will increase from 5.1 GW in 2023 to 7.8 GW** in 2030, a 48% increase.

Figure 5. APS projected energy contribution at peak by resource type

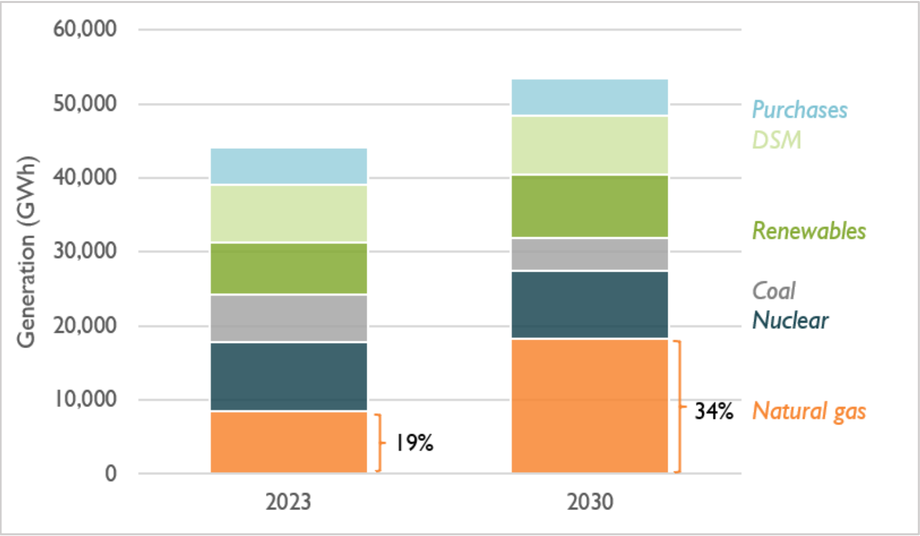


Other includes geothermal, biomass, demand response, biogas & microgrid.

APS Generation Mix

- In its 2023 IRP, APS projected that natural gas generation would account for 19% of total generation mix.
- By 2030, based on APS's most recently announced plans, we estimate that reliance on gas could increase such that 34% of the Company's generation will be from natural gas.
- The generation shown in Figure 6 assumes the same mix of combined-cycle (CC) and combustion-turbine (CT) gas generation as 2023, because APS has not published if its most recently-planned gas units are CCs or CTs.
- The share of natural gas generation would increase if APS procures CCs (which have a higher capacity factor) compared to CTs.

Figure 6. APS projected generation mix by resource type



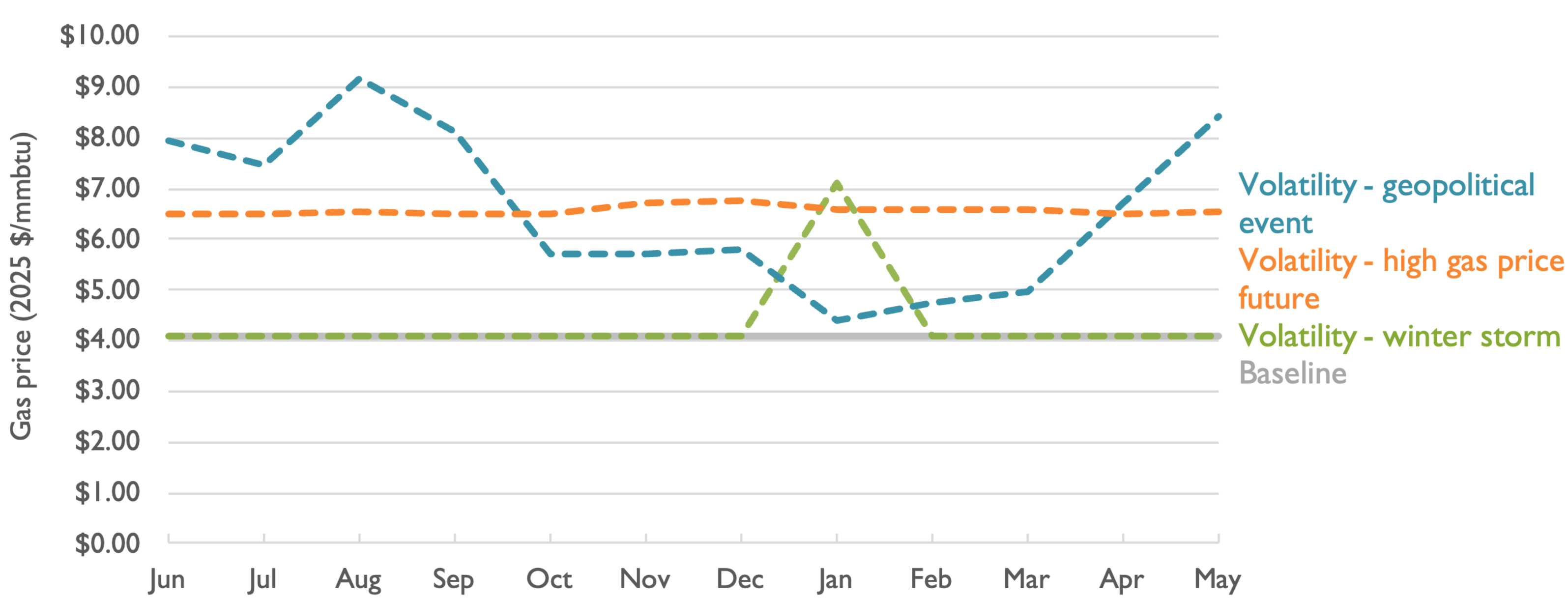
Note: Renewables include solar and wind. 2023 IRP generation mix from 2023 IRP. 2030 generation is based on 2023 capacity factors. Assumed purchases and DSM in 2030 equal to 2023 IRP. 2030 natural gas generation includes 2023 ASRFP, 2024 ASRFP, and July 2026 press release announcements.

Fuel Price Volatility

Impact of Future Volatility Event: Methodology

- As APS adds more gas resources to its system in the future, its exposure to gas price volatility will increase.
- We analyzed the magnitude of excess fuel costs APS would incur with its planned level of gas generation in 2030 under three gas price scenarios (Figure 7):
  1. A brief price spike caused by a winter storm in January.
  2. A year-long price increase caused by a geopolitical event, similar to that of 2022.
  3. Sustained high gas prices.

Figure 7. Gas price projections used in volatility analysis



Impact of Future Volatility Event: Results

- Table 2 summarizes the results of the volatility analysis. We found that residential customers could see monthly bill impacts of around $9.39.
- Costs may be even higher if gas prices surpass APS's fuel price projections. Any higher costs are passed directly onto ratepayers.

Figure 8. Increase in annual gas expenditures relative to baseline

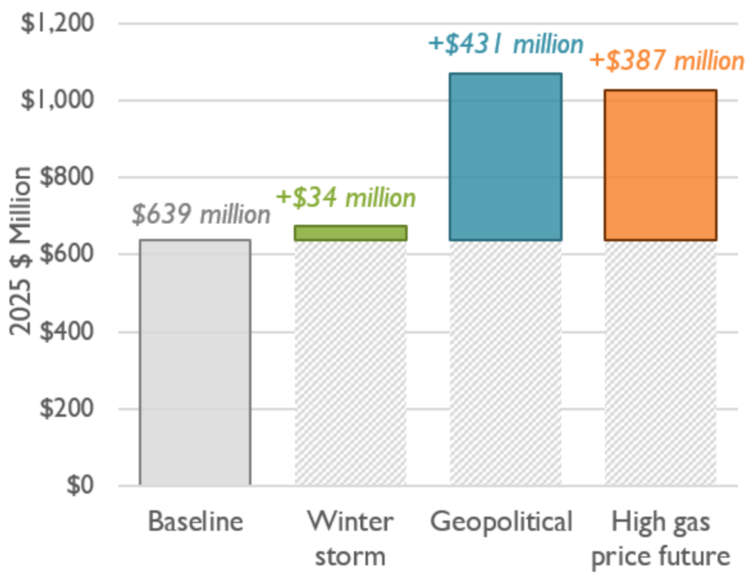


Table 1. Volatility analysis results: gas expenditures and bill impacts

Scenario	% increase in annual gas expenditures relative to baseline	Monthly average customer bill impact (2025$)
Baseline	-	-
Winter storm event	5%	$0.75
Geopolitical event	67%	$9.39
High gas price future	61%	$8.43

Note: This analysis reflects impacts on fuel prices only–if delivery price and fuel consumption were higher than projected, average customer bill impacts would likely be higher.

Historical and Projected Gas Resource Costs

Costs Associated with Gas Resources

APS and its ratepayers incur three main categories of cost from reliance on gas resources		
Capital costs to construct new resources	Operations and maintenance costs (fixed and variable) to maintain existing resources	Fuel costs to generate power—supply costs and fixed costs • Fixed costs: Pipeline costs including firm transportation and storage expenses, contract costs • Supply costs: Commodity cost of the fuel itself

The following slides discuss trends in new resource capital costs over time.

Gas Resource Capital Costs

- Public capital cost information is limited, but costs for other recent plants around the United States help to estimate the costs APS may be seeing for new projects.
  - In Virginia, Dominion constructed a CC unit that had capital costs of $1,127 per kW (2025$) (Table 1).
  - In Florida, Duke Energy constructed a CC that had $2,295 per kW in capital costs.
  - In Arizona, APS constructed a CT expansion that had $2,030 per kW in capital costs.
- Capital costs for gas resources are currently elevated due to surging demand across the country from utilities looking to serve data center load growth, paired with supply chain constraints, labor shortages, and tariff impacts.

Table 2. Capital cost of historical and planned gas additions

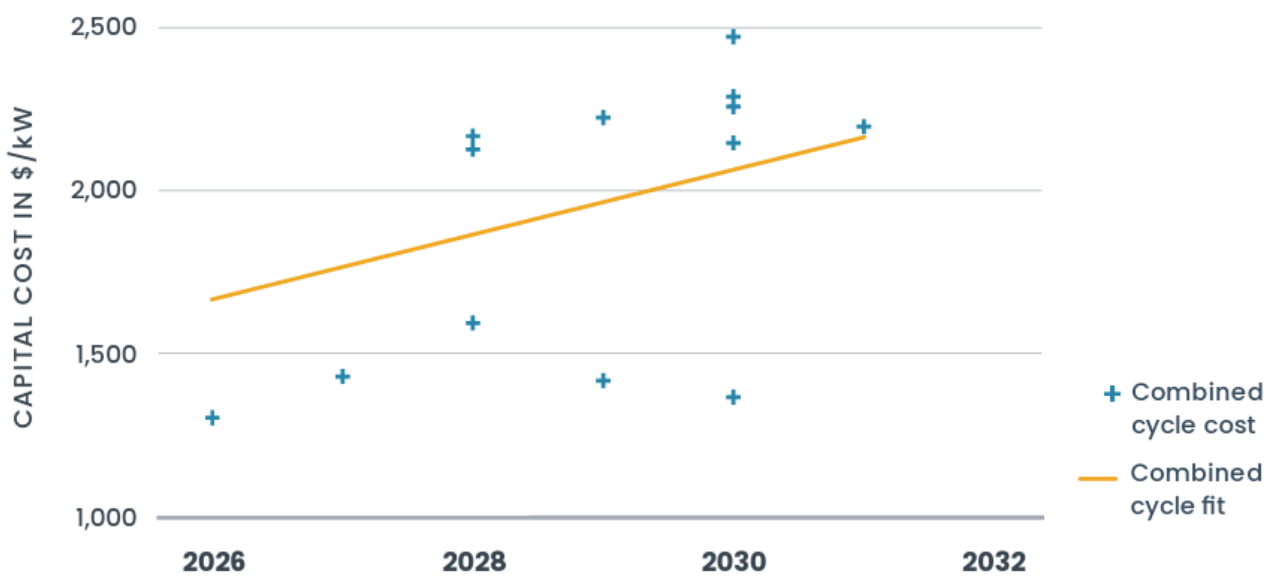
Plant Name	Type	State	Online Year	Nameplate Capacity (MW)	Capital Cost (2025$)	Capital Cost per kW (2025$ / kW)
Brunswick County Power Station	Combined cycle	VA	2016	1,376	$1.66 billion	$1,127
Citrus Combined Cycle Station	Combined cycle	FL	2018	820	$1.88 billion	$2,295
Sundance Power Station Expansion	Combustion turbine	AZ	2025	90	$182 million	$2,030

Sources: Virginia State Corporation Commission. 2013. Final Order in Case No. PUE-2012-00128; https://www.duke-energy.com/Our-Company/About-Us/New-Generation/Natural-Gas/Citrus-Natural-Gas; APS System Reliability Benefit Mechanism Stakeholder Meeting, February 2026, available at: https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/SRB/SRB_Q1_2026_Meeting_Presentation_022726.pdf.

Future Trends in Gas Capital Costs

- In the near term, capital costs for new gas resources are likely to continue increasing. APS's planned gas buildout risks locking ratepayers into these high capital costs for decades.
- A CC unit added in the early 2030s will have a capital costs over $2,000 per kW (Figure 9).
- If the cost of the new gas plants that APS constructs to serve data centers is higher than alternative resources such as wind and solar, this will increase costs for existing ratepayers.
- Ratepayers will pay for the capital costs of new gas resources over the lifetime of the plants. A gas plant lifetime is generally 40 to 45 years: much longer than the typical term of a data center contract.

Figure 9. CC cost as a function of operating year

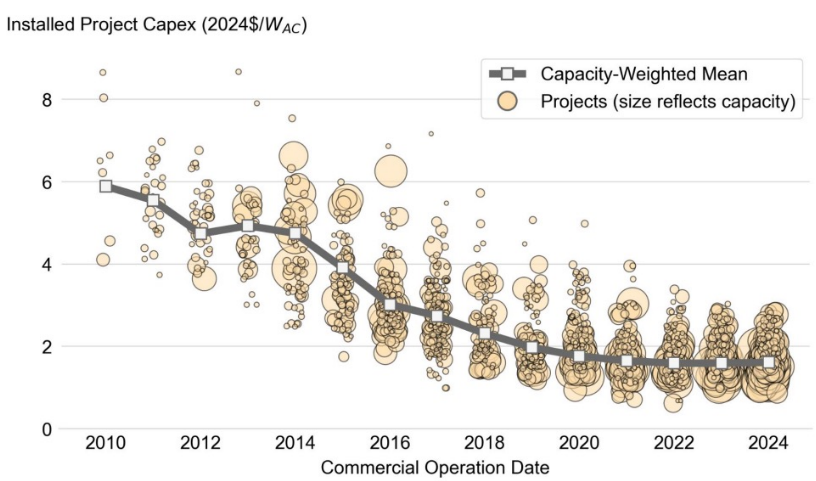


Source: GridLab, Energy Futures Group, and Halcyon. 2025. The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S. Available at: https://gridlab.org/gas-turbine-cost-report/.

Trends in Renewable Capital Costs

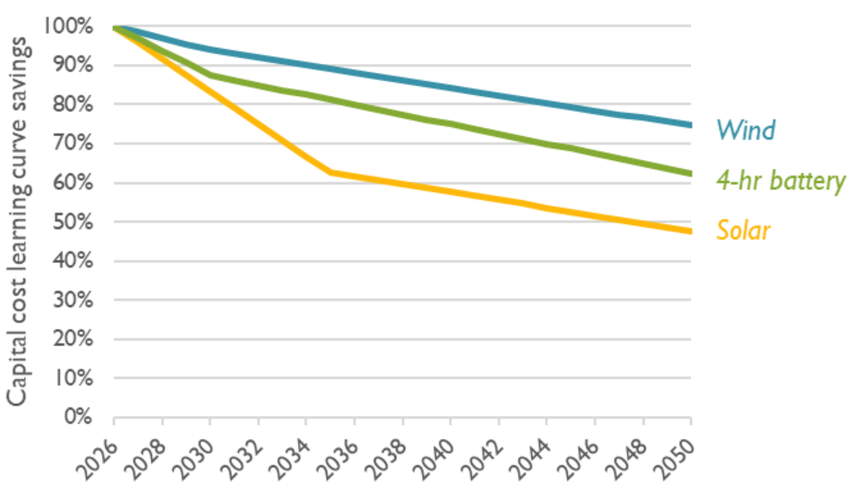
- Capital costs for renewables and battery storage have declined substantially over the past decade (Figure 10).
  - Solar, wind, and battery storage costs are expected to continue to decline in the future as the technology continues to mature and supply chains are expanded (Figure 11).
- In contrast, gas generation technology is relatively mature. While current price spikes are driven by a supply and demand mismatch, overall, costs are not expected to decline in the future due to technological advancements.

Figure 10. Historical capital costs for U.S. solar projects (2024$ / Watt)



Source: Lawrence Berkley National Laboratory. U.S. Utility-Scale Solar, 2025 Data Update. Available at: https://emp.lbl.gov/utility-scale-solar.

Figure 11. Projected decreases in renewable capital costs



Source: National Laboratory of the Rockies 2024 Annual Technology Baseline. Available at: https://atb.nrel.gov/electricity/2024/data.

Gas Pipeline Costs

- Gas pipeline costs represent the fixed costs of obtaining gas supply at a power plant, including transportation, storage, and contract costs.
  - APS pipeline costs are passed directly to ratepayers in the delivered price of natural gas.
- Gas transportation contracts may either be *firm* or *interruptible.* Firm transportation contracts ensure a utility has access to gas during periods of high demand.
  - Gas pipeline capacity is somewhat constrained in the Southwest, but APS pipelines have access to the Permian Basin gas fields in west Texas.
  - APS generally obtains firm transportation contracts for its gas fleet, including both CCs and CTs. CTs are also generally dual-fueled and burn oil when gas is constrained.
- It is unclear whether APS accounted for cost and availability of additional pipeline capacity in its IRP modeling of future CC additions.
  - There is a risk that all customers might see increased costs from pipeline expansion projects needed to provide firm gas to serve new power plants for data center load growth.
  - There is also a risk that customers would see higher costs if the timing of data center contracts does not align with the timing of gas and pipeline contracts.

Pipeline Development

- According to APS, existing gas pipelines in Arizona are **fully subscribed.** New pipeline capacity must be built to provide a firm gas supply for any new gas plants.[1]
- APS is the anchor customer for the **Desert Southwest Pipeline** expansion project, which would transport gas from the Permian Basin in Texas to Arizona to fuel gas plants, including APS's proposed Desert Sun Power Plant.
  - The Desert Sun plant is a CT set to replace the retiring Saguaro CT in 2031, partly driven by **data center load growth.**
- While APS has assured ratepayers that **plant costs** tied to large-load customers will be borne by those customers, **pipeline costs** are ultimately passed on to ratepayers.
  - According to the pipeline company, Desert Southwest Expansion project is expected to cost at least **$5.6 billion,** excluding allowance for funds used during construction (AFUDC).[2]
  - In July 2025, APS executed a 25-year agreement for long-term gas transportation, for **$7.3 billion** beginning in 2029.[3]
  - If the large-load customer contract were terminated early, publicly available information does not indicate what portion of the resulting costs would ultimately be borne by APS's other customers.

[1]Pinnacle West Capital Corporation Press Release. 2025. "Arizona Utilities Work to Lock in Critical Natural Gas Delivery to Power Growth." Available at: https://www.pinnaclewest.com/newsroom/company-news/news-release-details/2025/Arizona-Utilities-Work-to-Lock-in-Critical-Natural-Gas-Delivery-to-Power-Growth---/default.aspx.
[2]IEnergy Transfer Q4 Earnings Presentation. February 2026. Available at: https://www.plsx.com/finder/viewer.aspx?doc=113116&slide=3066205&v=0&utm#doc=113116&slide=3066205&
[3]Arizona Public Service Company. 2025. Securities and Exchange Commission. Form 10-Q. June 30. Available at: https://www.sec.gov/ix?doc=/Archives/edgar/data/0000764622/000076462225000072/pnw-20250630.htm.

Fuel Cost-Sharing Mechanisms

APS's Power Supply Adjustment Clause

- APS has a power supply adjustment (PSA) clause that automatically adjusts customer rates to recover eligible fuel and purchased-power costs, allowing APS to pass 100% of those costs through to customers.
- APS's PSA places all the fuel cost risk onto customers and none onto the utility. This includes:
  - Risk of volatility: storms, geopolitical events, etc.
  - Risk of rising market costs over time.
- PSAs pass costs onto consumers based on the assumption that utilities have little control over **prices.**
  - Because coal, gas, and oil prices are determined by larger market forces, including global markets and geopolitical events.
- However, there are many proactive ways utilities can control fuel **costs**.
  - Diversifying their resource mix to rely more heavily on clean energy resources such has wind, solar, batteries, and energy efficiency.
  - Purchasing fuel and/or generation using fixed-price contracts.
  - Purchasing other hedging instruments.

Additional Incentives Discouraging Fuel Efficiency

Incentives	Implications
Utilities earn profits primarily through returns on capital investments, such as power plants.	Utilities have clear incentive to invest in capital-intensive fuel-dependent power plants.
Utilities earn no return on fuel, but they also bear no risk associated with price volatility. Customers bear all fuel price risk.	As load grows over time (primarily due to data centers), the magnitude of fuel price risk being passed to customers grows.

Alternatives to the PSA

Eliminate the PSA

- Instead, recover all costs through base rates.
- When actual fuel prices are higher or lower than those assumed in rates, a portion or all of the difference would be recovered by the utility instead of ratepayers.
- This would provide the utility with the greatest incentive to minimize fuel costs.

Fuel efficiency performance incentive mechanism (PIM)

- The utility is given a target level of power plant efficiency, such as $/MWh or $/MMBtu, based on improvements over historical levels.
- The utility has an incentive to reduce fuel costs.
- PIMs can work so that upside potential savings in fuel costs are rewarded to customers, and the utility pays for downside fuel cost losses.
- PIMs can be combined with a fuel cost-sharing mechanism to bolster the incentive.

Fuel cost-sharing mechanism (addressed in more detail in subsequent slides)

- The PSA is modified so customers pay only a portion of the change in fuel price, while the utility pays for the remainder.

Fuel Cost-Sharing Mechanisms

- **Under fuel cost-sharing mechanisms, customers pay only a portion of the change in fuel price, while the utility pays the remainder.**
  - The portion paid by customers can be very large, e.g., 95%, or very small, e.g., 5%.
  - This is a more moderate option than eliminating the PSA altogether.
- **Requiring utilities to share a portion of fuel costs provides incentive to:**
  - Reduce reliance on fuel-dependent power plants.
  - Improve operating efficiencies of fuel-dependent power plants.
  - Manage fuel procurements, e.g., using fixed-price contracts, hedging options.
- **Common features include:**
  - Deadbands around expected fuel costs.
  - Additional bands around costs with different levels of cost-sharing.
  - Utility exposure to extreme cost increases.
- **Nine states have adopted some form of fuel cost-sharing:**
  - HI, ID, MO, MT, OR, UT, VT, WA, WI

APS's History of Fuel Cost-Sharing

- **From 2005 – 2011, APS had a 90% customer, 10% shareholder fuel cost-sharing mechanism in place for the PSA.**
  - The Commission approved the fuel cost-sharing mechanism due to "real and significant" disadvantages of the PSA from a customer standpoint.[1]
- **The fuel cost-sharing was removed in 2011.**
  - Due to lower gas prices at that time, Staff believed customers would benefit from the removal of the fuel cost-sharing mechanism.[1]
  - Importantly, the fuel cost-sharing mechanism was not removed because it was ineffective.[2]
- **When gas prices are lower than what APS contracted and projected APS has excess gas contracts to sell, customers benefit from the PSA. However, the opposite is also true when gas prices are higher than what APS purchased.**
  - If served with natural gas resources, data center load would be serviced through long-term gas contracts.
  - If the data center load were to depart ahead of its contracted timeline, APS customers could continue to pay for the fuel procured for the data center load. Additionally, without the large-load customer participating in APS, this would drive up customer bills.

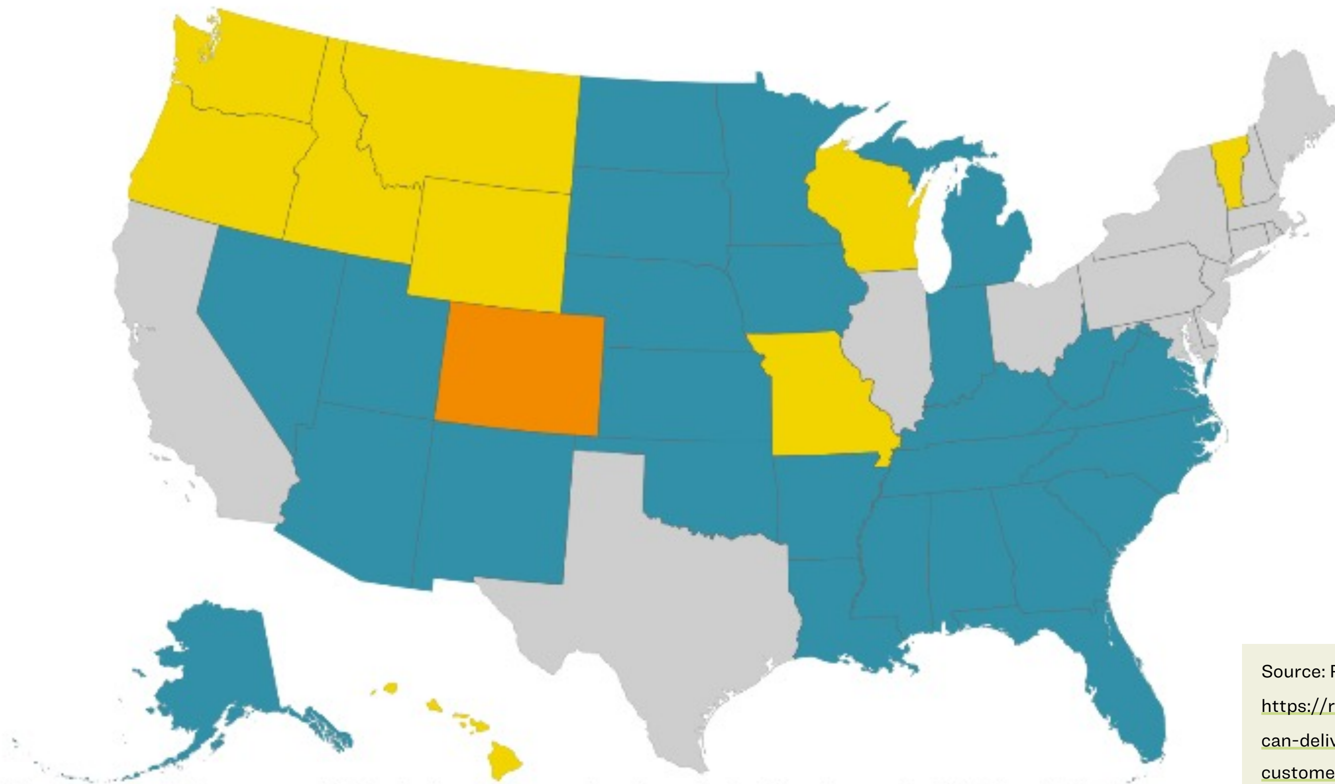
[1]Before the Arizona Corporation Commission, Decision 79293 - Docket E-01345A-22-0144 (Mar. 5, 2024).
[2]Ibid.

Fuel Cost Recovery Mechanisms in the U.S.

Fuel cost-sharing implementation

March 2026

Fuel Cost-Sharing In Place | Fuel Price Volatility PIM | No Fuel Cost-Sharing | Restructured state; regulated utilities not responsible for fuel procurement



Note: Generation in Tennessee and Nebraska is publicly owned and operated, so there is no option for fuel cost-sharing.

Source: RMI analysis

Source: RMI
https://rmi.org/how-fuel-cost-sharing-can-deliver-savings-for-utility-customers/

Appendix

Terminology

- **Capacity** measures the maximum electric output a generator can produce under specific conditions.
- **Nameplate capacity** is determined by the generator's manufacturer and measures the maximum output under reference conditions.
- **Generation** measures the amount of electricity that a generator produces during a specific period of time. The emissions from a given generator scale based on generation.
- The two most common types of new gas capacity are combined-cycle and combustion-turbine units:
  - **Combined-cycle units** (CC) have higher capital costs and higher efficiencies, so they are most economic as baseload resources that run for many hours of the year.
  - **Combustion-turbine units** (CT) have lower capital costs but are also less efficient and mainly run as peaking plants during periods of high demand.

Sources – Gas Reliance

- **APS capacity mix**
  - 2023 capacity: 2023 IRP
  - 2030 capacity: 2023 & 2024 ASRFP procurements, July 2026 press release announcements, and EIA-860 retirements.
- **APS generation mix**
  - 2023 generation: 2023 IRP
  - 2030 generation: Based on the capacities above and the following generation assumptions:
    - Wind and solar: average locational EIA 923 capacity factors
    - Nuclear: capacity factor assumed from 2023 IRP generation
    - Coal: capacity factor assumed from 2023 IRP generation
    - Natural gas: capacity factor assumed from 2023 IRP generation (Assumed the same mix of CT and CC resources in 2030 as in 2023)
    - Purchases and DSM: same generation as 2023 from 2023 IRP

Methodology – Fuel Price Volatility Analysis

- **Generation profile**
  - Assumed 2030 natural gas capacity as 2023 natural gas nameplate capacity (MW) from the APS 2023 IRP and additional capacity procured in its 2023 + 2024 All-Source RFP (Stakeholder meeting presentation)
  - Used average historical capacity factors of gas units to create generation shape which we then scaled to match calculated 2030 GWh gas generation (see previous slide for assumption made).
  - Used the same generation profile for all scenarios to isolate impacts of natural gas fuel price volatility.

- **Fuel consumption (MMBtu)**
  - Calculated 2030 weighted average heat rate for gas in Btu/kWh using *APS 2023 IRP - Attachment D.1(A)(3): Average heat rate*.
  - Calculated fuel consumption for future year 2030 by applying average heat rate to calculated generation profile.

- **Delivered fuel price ($/MMBtu)**
  - **Baseline:** Used projected 2030 delivered natural gas price from APS 2023 IRP (base case) and kept constant for entire year.
  - **Volatility event – Winter storm:** To model a price spike during a winter storm, we assumed the event would occur in January. For that month, we used Henry Hub natural gas spot price for the most recent winter storm price shock from January 2026, Winter Storm Fern. For the rest of the months, used the same price forecast as Baseline case.
  - **Volatility event – Geopolitical event:** To model the volatility impacts of a geopolitical event we used the 2022 Russian invasion of Ukraine as proxy. We used 2022 Henry Hub gas price and added the 2030 projected monthly delivery adder for the Permian Basin delivery point from EnCompass National Database.
  - **High Gas Price Future:** We used the projected 2030 Henry Hub natural gas spot price from the Annual Energy Outlook 2026 'Low Oil and Gas Supply' future and compared it to the Reference case future to calculate a scalar factor. This factor was applied to the Baseline fuel price.