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Natural Gas Price Volatility Study

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Executive Summary

Fuel price volatility analysis and its impact on the cost to produce electricity is a critical component of an integrated resource plan. Price volatility stems from a real or perceived supply – demand imbalance caused by disruptions to the delivery network, extreme weather events, geopolitical issues and other factors. Rather than relying on a single forward curve to model future fuel prices it is critical to evaluate a variety of scenarios such that potential price changes are factored into the resource plan creating a more robust analysis.

Siemens used a two-part approach consisting of a qualitative assessment of factors that could influence the regional gas market and a quantitative assessment of the impact of price volatility on PNM's gas requirements. The qualitative analysis was completed to assess the potential for fundamental shifts in energy price behavior due to changes in the underlying market structure. The study considered the potential commodity and basis pricing impacts from the following factors:

- Gas production and supply
- Pipeline capacity and infrastructure changes
- Liquified Natural Gas (LNG) exports
- Weather
- Inflation

The quantitative assessment was split into a long-term market simulation to create a series of future potential price paths. Those price paths were then tested against the forecasted gas supply requirement to estimate the potential variance in annual gas expense. Due to the long-dated nature of the simulation, the impact of short duration price spikes is muted. To account for this, Siemens used a historical price analysis that identified the magnitude, duration, frequency and financial impact of short-term basis price disruptions and the associated impact on gas load.

Energy markets are dynamic and constantly evolving with the shifting and conflicting priorities of low cost, reliability, and sustainability. Our analysis found that while there will be many changes in the desert Southwest gas markets in the next 20 years, we do not believe the net impact will significantly alter the regional market structure and therefore historical prices can be used to simulate future prices. Basis price spikes will continue to occur; however, they will be short duration, and tools exist to mitigate the impact. Lastly, long-dated market simulation indicates that price volatility will continue to exhibit similar patterns with annual cost variances in the $0.14 to $1.09/MMBtu range. This is a meaningful number however, similar to basis risk, the impact of long dated volatility on a rolling 2 – 5-year horizon can be effectively, and cost efficiently reduced to a tolerable level thereby reducing impacts to rate payers.

Fundamental considerations

Background and analysis inputs

PNM, formally known as Public Service Company of New Mexico, is the largest electric utility in the state of New Mexico, serving approximately 540,000 customers across a service territory that includes Albuquerque, Santa Fe, and surrounding communities in central and northern New Mexico. Founded in 1917, PNM has been a cornerstone of the state's energy infrastructure for over a century. The utility operates as a regulated investor-owned utility under the jurisdiction of the New Mexico Public Regulation Commission and is a subsidiary of PNM Resources, which also owns Texas-based utility Texas-New Mexico Power (TNMP).

PNM's generation portfolio has historically included a mix of coal, natural gas, nuclear, and renewable resources. The utility was a significant participant in the San Juan Generating Station, a large coal-fired power plant near Farmington, New Mexico, which was retired in 2022 as part of the state's broader energy transition efforts driven by the Energy Transition Act of 2019. PNM has been actively replacing retired coal capacity with solar, wind, and battery storage projects to meet the ETA targets. PNM continues to navigate the challenges of grid modernization, integrating distributed energy resources, managing wildfire risk, and maintaining reliability while transitioning to a cleaner energy portfolio in one of the sunniest and most wind-rich states in the country.

PNM’s 2026 IRP will be filed in September 2026 and as part of that process PNM agreed to perform a natural gas volatility study from the comments provided in the 2023 IRP process. For this 2026 IRP, PNM examined three planning cases, High Economic Growth (HEG), Low Economic Growth and the Current Trends and Policy (CTP) reference case.

PNM provided forecasted gas load data that was extracted from the CTP reference case. Graphical representation of that data is found in Figure One on page 7.

For the purpose of this analysis, Siemens evaluated the cost variability stemming from the generation profile and associated gas load as shown in the charts below.

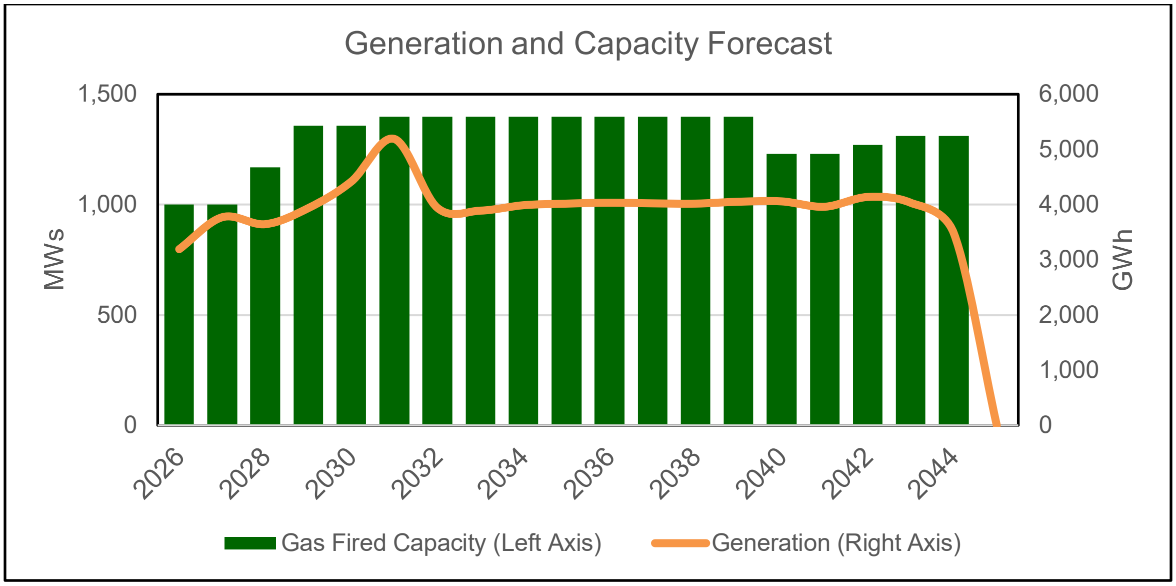

Figure 1 Generation and Capacity Forecast

(Capacity is reported in MWs, annual generation is in GWh)

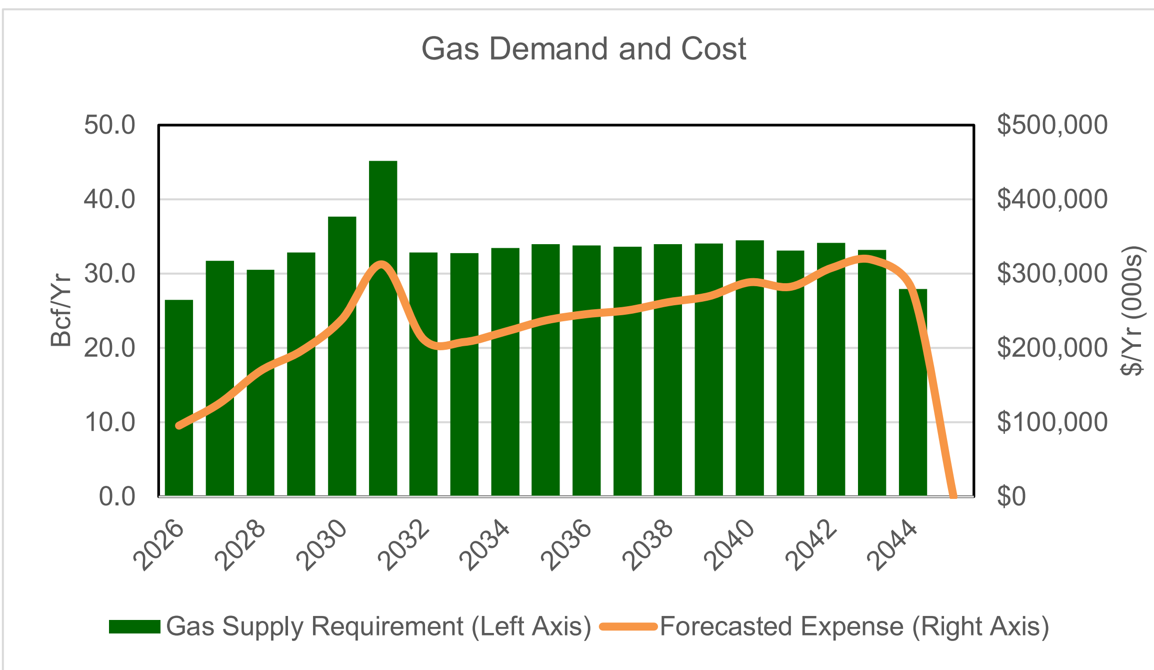

Figure 2 Gas Demand and Cost

The above volumes and associated costs were tested for sensitivity to market volatility using 3 years of historical data and then bifurcating NYMEX Henry Hub risk from basis risk into four different basis locations. PNM purchases the majority of its gas based on the El Paso San Juan or Keystone Pool indices however, for the sake of thoroughness Siemens evaluated several adjacent markets and then tested for correlation to confirm the impact of basis price spikes in adjacent markets on prices for PNM. Those results are presented in the conclusions section of the quantitative analysis results.

The US natural gas market is very dynamic and rapidly evolving. The impacts of fracking, changes to the IRA, new pipeline builds, increased LNG, data center growth and numerous other factors will move the market in different directions as those competing factors try to reach equilibrium. Many of the assumptions used in this analysis are based on years of experience in the market and represent the best estimate of the future direction of price and volatility.

Domestic supply and production analysis

Natural gas production in the western United States is expected to continue growing over the next several years, driven by both legacy Rockies output and strong gains in associated gas from oil plays such as the Permian in west Texas and southeast New Mexico. Federal forecasts indicate U.S. marketed gas will reach new record highs in 2026–2027, with a disproportionate share of incremental volumes coming from western basins and the Gulf Coast corridor. In the broader North American context, tight gas plays in the Rockies and gas focused activity in parts of the Permian and Mid Continent are expected to mature but still contribute to net growth into the 2030s.

Within the Permian Basin itself, natural gas output is forecasted to rise steadily as oil directed drilling continues and gas oil ratios climb in maturing fields. EIA's latest outlook shows Permian marketed gas reaching roughly 25.8 Bcf/d in 2026, after adding about 1.9 Bcf/d in 2024 and another 1.0 Bcf/d in 2025, making the basin a major driver of U.S. supply growth. Recent revisions to Permian shale play mapping also lift estimated 2026 shale gas output by about 0.8 Bcf/d, underscoring how new zones and productivity gains are reshaping the basin's gas profile.

Longer term Permian forecasts suggest continued expansion in both associated and non-associated gas as drilling technology improves, and more gas focused development becomes economic relative to other basins. Some private forecasts see Permian gas focused production growing from around 4 Bcf/d in the early 2020s to roughly 5 Bcf/d by the early 2030s and to more than 9 Bcf/d by 2040, supported by rising initial well productivity and gradual increases in well count. At the same time, pipeline expansions out of the basin, including new late decade projects, are expected to alleviate constraints and allow higher flows to Gulf Coast LNG terminals and western demand centers.

As reflected in the chart below, US natural gas production is forecasted to continue to rise through 2045 in all but the low case scenario where production is seen to decline.

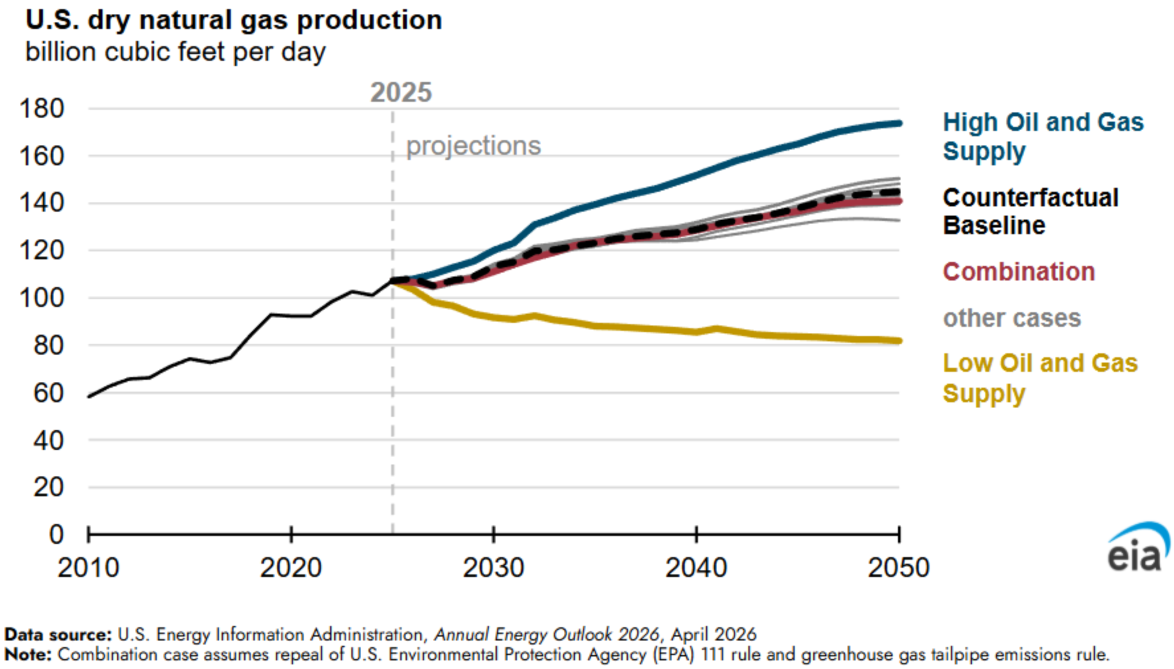

Figure 3 US Natural Gas Production

For western U.S. markets, these production trends imply increasing reliance on Permian and other western basin supplies to meet growing power burn, industrial demand, and export linked calls on gas. As more Permian gas moves east and south toward LNG and petrochemical hubs, western states will need to balance in region Rockies output, imports from Canada, and competition for Permian molecules, with infrastructure build out and price spreads determining how much of the new supply actually clears into West Coast and desert Southwest hubs. From a trading and risk perspective, the interaction between Permian associated gas growth, periodic capacity bottlenecks, and seasonal western demand will remain a central factor in basis behavior and volatility across western U.S. hubs.

Specifically in the case of PNM, rising Permian and New Mexico gas production generally improves physical supply security but does not eliminate exposure to regional basis and price shocks. New Mexico is now the third largest U.S. gas producer with about 8% of national output and Permian side growth in the state, plus Texas, provides ample molecules that can flow toward the Four Corners/San Juan interfaces and into the desert Southwest. That backdrop lowers long run scarcity risk but increases dependence on how well pipeline projects and interconnections keep up with supply and demand shifts across the West.

In the near term, congestion at Waha and along key westbound and northbound routes means PNM remains moderately exposed to volatility in regional gas prices even if the basin is in a long physical supply position. Episodes of negative or very weak Waha pricing contrast sharply with potential spikes at downstream Southwest and Rockies hubs when weather, outages, or maintenance bind capacity, creating sizable basis moves that can flow through to PNM's delivered gas cost for generation. Future projects like the proposed Transwestern Desert Southwest expansion (Texas–New Mexico–Arizona) aim to add about 1.5 Bcf/d of capacity by around 2029 which would improve PNM adjacent routing options but also tighten the link between PNM's region and Permian dynamics. In conclusion, natural gas supply is adequate and will not be a major diver of price volatility over the long term.

Weather analysis

Weather can impact natural gas price volatility in the U.S. Southwest primarily by driving power sector demand. Extended hot spells across Texas, New Mexico, Arizona, and Southern California push cooling loads higher and force gas fired generators to ramp, especially when solar output fades in late afternoon and evening peaks. In recent years, summer power burn has reached record levels over 50–60 Bcf/d nationally, and the Southwest tends to experience heat waves earlier in the cooling season often extending into the post summer shoulder season, so early or extreme heat waves can quickly tighten regional balances and lift hub prices and basis. Conversely, milder than expected shoulder season weather depresses power burn and keeps more gas in storage, softening prices relative to pre-season expectations.

Cold outbreaks also create volatility by increasing demand and disrupting production in adjacent regions across the Southwest. Arctic blasts and winter storms have at times cut Permian and other Lower 48 production by several Bcf/d, with events like Winter Storm Uri and subsequent cold snaps knocking 5–10+ Bcf/d offline at times as un winterized wells, gathering systems, and plants froze. When those storms extend into West Texas and the Four Corners region, the Southwest can see both reduced inflows and elevated heating and power demand, impacting basis prices at regional hubs and driving short duration intraday price spikes.

Hydrology and renewables further modulate weather driven volatility in the Southwest. Strong hydro years and high solar output in the broader Western Interconnect can displace some gas fired generation during mild periods, capping prices, whereas drought conditions or cloudy, low wind situations create increased reliance on gas just as temperatures deviate from normal. As renewable penetration grows, the system becomes more sensitive to extreme temperature days when wind or solar underperform, making weather shocks translate more directly into swings in Southwest gas burn, storage trajectories, and spot price volatility.

These weather factors were evaluated in the analysis completed based on Platt's *Gas Daily* Daily (GDD) price history that was used to complete the modelling and calculate volatility. Additionally, we evaluated the price history to identify the frequency, duration and cost impact of short duration basis market disruptions. Extreme weather events will continue to occur and may increase in frequency and intensity; however, we do not believe they create a material long term risk and can be mitigated cost effectively.

Inflation analysis

During one of the PNM facilitated stakeholder conference calls, Third Act asked if inflation impacts would be addressed during the study. This is an entirely valid inquiry given the recent volatility in the monthly Producer Price Index (PPI) and Consumer Price Index (CPI) values as reported by the BLS history. The question was initially addressed during the Siemens presentation outlining the analytical approach that would be used to complete the gas volatility study. The initial response based on anecdotal price history was that gas prices and inflation are not correlated. Siemens also confirmed that inflation would be evaluated using a rigorous analytical approach and the results of that analysis would be included as part of the volatility analysis report.

To assess whether Henry Hub natural gas prices move with the general CPI price level, Siemens performed an Ordinary Least Squares (OLS) regression analysis using monthly Henry Hub spot prices and headline CPI data from January 1997 onward. OLS regression is a statistical method used to model the relationship between a continuous dependent variable and one or more independent variables. It determines the "line of best fit" (red line) by minimizing the sum of the squared differences (residuals) between the actual observed values and those predicted by the linear equation. In basic terms, the OLS regression looks for a mathematical relationship between an independent value (inflation) and a dependent value (natural gas prices). This mathematical relationship is reflected by the red line in the sample graph below. If the data point plots (blue dots) are tightly grouped around the redline, it indicates a strong correlation.

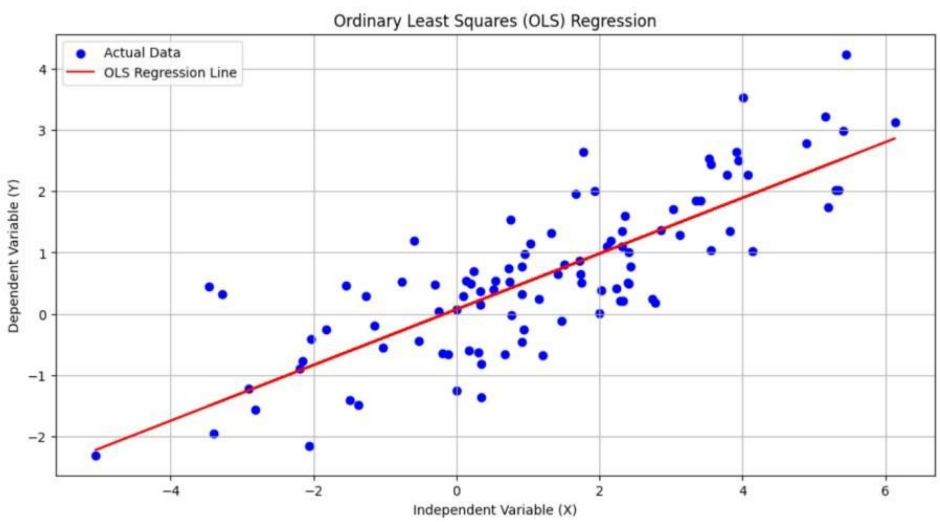

Figure 4 OLS Output Example

To conduct the analysis both variables (CPI and natural gas prices) were transformed into natural logs. The first regression tested whether log gas prices showed a long-term time trend. The time-trend model produced a small but statistically significant relevant output, suggesting a slight downward trend over the sample period. However, the model had a very low R^2, indicating although we do see a slight relationship between time and price; time explains only a small portion of the variation in gas prices.

The second step in the analysis was testing whether log gas prices moved in tandem with CPI. That analysis with log CPI produced a statistically significant but negative coefficient that can be interpreted as elasticity; a 1% increase in CPI was associated with an estimated 0.28% decrease in Henry Hub prices over the sample. However, the model fit (distance between blue data dots and the red line) was even weaker, indicating that CPI explains very little of the movement in gas prices. Overall, the results suggest that Henry Hub prices do not behave like a stable inflation-linked commodity and are likely driven more by market-specific factors such as weather, storage levels, supply-demand conditions, and energy market shocks.

Infrastructure analysis

Several gas pipeline projects are proposed or advancing in New Mexico, ranging from large interstate expansions out of the Permian Basin to short laterals for specific loads within New Mexico. While the laterals will have a limited impact on price volatility other than creating additional load, the interstate projects will increase capacity to bring Permian gas into the PNM service territory helping to reduce price volatility. Given that pipelines are subject to multiple regulatory agencies at the Federal and State level, construction is always subject to delay.

The following is a list of major projects planned for the New Mexico market

- Energy Transfer is developing the Desert Southwest pipeline, an addition to and expansion of the Transwestern pipeline system. The new system will consist of approximately 516 miles of 42-inch pipe plus nine compressor stations across Texas, New Mexico, and Arizona. Design capacity around 1.5 Bcf/d to move Permian gas to growing Southwest demand (utilities, data centers, high-tech load), with in-service targeted for Q4 2029. Positioned as a $5.3 billion project leveraging the existing Transwestern system. The proposed pipeline pathway will pass through the southern portions of PNM's service territory in the Cliff Silver City region with delivery locations planned for Doña Ana County and Luna counties. The project sold all 1.5 Bcf/d of the initial capacity under 25-year contracts with investment-grade counterparties. Since the initial open season, Energy Transfer has received considerable interest above planned capacity and is considering expansion options.

- Western States and Tribal Nations (WSTN) have developed a proposed Southwest Pathway concept to bring Rockies gas down into New Mexico to serve growing regional demand as well as move gas to LNG facilities in Mexico creating greater access to Asian markets with requiring transit of the Panama Canal reducing shipping times by 50%. Unlike the Desert Southwest pipeline, this project is conceptual at this point and likely will be several years in development prior to construction; however, it shifts the supply source from the Permian basin to the Rocky Mountains potentially offsetting some degree of basis risk.

  New Mexico is part of a multistate roadmap (with Wyoming, Utah, tribal partners) proposing routes to move Rockies gas to western U.S. markets and Asian export paths. Options include building new pipe paralleling Transwestern and Public

Service of New Mexico ROWs, potentially tying into expansions like Desert Southwest and other proposed lines toward Phoenix and El Paso.

Energy Transfer has proposed developing a 17-mile gas pipeline (Green Chile) in southern New Mexico to serve "Project Jupiter," a controversial data center load near Las Cruces. Filed with FERC in Feb 2026; the project is currently in the approvals queue having been denied an easement by NM Land Commission forcing a re-route of the pipeline. Sierra Club Rio Grande and other environmental groups filed a formal protest at FERC demanding a full environmental review of both the pipeline and the powerplant. The original start date of April 16th has slipped and there is no new in-service date until the FERC issues are resolved. While laterals are generally not major contributors to price volatility, this project is designed for up to ~400,000 Dth/d, mostly across BLM and private land, but is facing opposition from some state legislators and environmental groups concerned about air quality and permitting speed. Put in perspective, 400,000 Dth/d is enough natural gas to fuel four (4) 500 mw combined cycle plants dispatching as base load units. At issue is the speed at which permitting is proceeding as a precedent for additional mid volume interconnects for additional data center generation load.

These New Mexico-linked projects sit alongside a broader wave of Permian takeaway additions (e.g., other pipelines into Texas and to Mexico), which the EIA notes could add significant capacity between 2025–2029. The net effect is more optionality to move Permian gas westward and into regional power and data-center loads, with associated siting and environmental risk around projects like Green Chile. Our conclusion is that new pipeline builds will increase operation flexibility to bring gas into the PNM service territory and decrease spot gas price volatility

LNG Exports

U.S. LNG exports have grown rapidly over the past decade, turning the country into one of the world's largest LNG suppliers. Growth has been driven by abundant shale gas (especially from the Permian, Haynesville, and Marcellus), relatively low domestic prices, and heavy investment in Gulf Coast liquefaction capacity. Export volumes are concentrated at a handful of large terminals, with most cargoes destined for Europe and Asia under a mix of long-term contracts and spot sales. Policy decisions, permitting timelines, and global demand cycles now play a major role in shaping forward U.S. gas balances.

The expansion of U.S. LNG exports has significant implications for domestic gas prices and regional basis. As more liquefaction capacity comes online, Gulf Coast and associated upstream hubs (Henry Hub, Houston Ship Channel, Waha, Haynesville-linked points) become increasingly tied to global LNG netbacks. In tight global markets, strong LNG demand can pull U.S. prices higher; in oversupplied conditions, U.S. liquefaction plants may run at lower utilization, easing pressure on domestic prices. This linkage also raises the importance of pipeline infrastructure connecting producing basins to export terminals.

LNG exports also carry geopolitical and energy-security implications. For allies in Europe and parts of Asia, U.S. cargoes provide diversification away from more politically exposed pipeline supplies and single-supplier LNG dependence. At the same time, U.S. export policy, environmental scrutiny over new projects, and community impacts along the Gulf Coast have become more prominent in permitting debates. Over the medium term, the balance between adding new LNG trains and meeting domestic decarbonization and affordability goals will shape both the scale and pattern of U.S. LNG exports.

Exports averaged on the order of 14–15 Bcf/d in 2025 and are projected to climb further as new Gulf Coast capacity ramps through 2026–2027. Government and industry estimates put operating U.S. LNG export capacity near 18 Bcf/d in mid-2026, with another roughly 15 Bcf/d under construction, implying a potential doubling of effective capacity over the next several years as projects like Plaquemines, Golden Pass, Port Arthur, and Corpus Christi Stage 3 move toward full service. Forward analyses suggest that incremental LNG feedgas demand in 2026 alone could add roughly 6–8 Bcf/d of call on U.S. gas versus today as this next wave comes online and ramps up. With 2027 export volume estimated to be 18.1 Bcf/d.

For U.S. gas markets, this LNG growth wave tightens the link between Henry Hub and global LNG netbacks and puts a premium on Gulf Coast and feedgas-adjacent basis. As new trains ramp, feedgas demand can rise by mid-single-digit Bcf/d chunks, absorbing surplus production from basins like the Permian and Haynesville and potentially flattening or lifting domestic price curves, especially in winter or during global disruptions such as outages in competing export regions. At the same time, pipeline delays or bottlenecks into liquefaction sites remain a risk factor, with EIA flagging that most new liquefaction capacity is Gulf-centric and contingent on synchronized midstream build-out.

Key upcoming LNG projects after 2026 are dominated by U.S. Gulf Coast expansions plus a handful of floating and modular concepts that could add a sizeable new wave of liquefaction capacity late in the decade. Many are already approved by FERC but not yet built, while others (like certain Plaquemines and Port Arthur phases) are in various stages between pre-FID and early construction. Together, these projects could add well over 10 Bcf/d of additional U.S. capacity post-2026 if they all proceed, with timing and volume governed by global demand, contract coverage, and financing conditions.

Beyond individual terminals, the post-2026 period is characterized by a broader “second wave” of LNG capacity globally, including Qatar’s additional North Field East/West trains, projects in Canada, Africa, and Russia, and Asia-Pacific expansions. Analyses of this wave highlight that while 2026–2027 are pivotal startup years for currently-under-construction U.S. plants, much of the incremental capacity that truly reshapes balances will arrive closer to 2028–2032 as these new U.S. phases and competing global projects ramp. This timing matters for U.S. gas markets because it affects when the next “step change” in LNG feedgas demand hits basins like Permian and Haynesville after the mid-decade build-out.

From a risk and strategy angle, these post-2026 projects set the stage for a possible second tightening in U.S. balances late in the decade, following the initial 2026–2027 ramp. If most of the listed U.S. expansions reach final investment decision (FID) and execute on time, U.S. LNG capacity by early-2030s could be more than double mid-2020s levels, deepening the linkage between Henry Hub and global LNG netbacks and keeping Gulf Coast basis structurally supported, but also increasing sensitivity to global overbuild and cyclical LNG price swings. This may put upward pressure on prices in the PNM service territory but should not impact price volatility in a meaningful way.

Data center/ load growth; impact on gas price volatility

The New Mexico Consumer Protection Alliance inquired about the impact of data center load growth and the resulting impact on natural gas price volatility. This is a valid concern as data center development in New Mexico has accelerated over the past few years, transforming the state from a secondary market into an emerging hub for hyperscale and AI-focused infrastructure. Meta’s multibillion-dollar campus in Los Lunas, now expanding with dedicated AI and machine-learning buildings, exemplifies this trend and has helped anchor a broader ecosystem of facilities around Albuquerque and central New Mexico. New projects such as large campuses planned by New Era Energy, Zenith Volts, and others could, if built, make New Mexico one of the most significant data center geographies in North America by total capacity.

This growth is driven by several structural advantages and policy signals. New Mexico offers abundant, relatively affordable land, access to high-capacity transmission corridors, and proximity to major renewable energy developments such as the SunZia Wind project, which is adding thousands of megawatts of new capacity in the region. The state’s Energy Transition Act aligns well with hyperscale operators’ decarbonization commitments and supports long-term renewable procurement strategies for data center loads.

Longer-run, the impact on PNM’s supply mix and rate trajectory depends heavily on how projects are structured. If big campuses act as “anchor customers” that sign long-term renewable PPAs, pay green premiums, and co-fund transmission and storage, they can help de-risk new carbon-free build-out and spread fixed grid costs over more kilowatt-hours, moderating or even offsetting bill impacts for other customers. Policy debates now underway in New Mexico regarding regulating data-center microgrids, setting fair cost-allocation rules, and shaping PNM’s 2026 IRP will be critical in determining the impact of data-center growth. Given the data center developers preference for renewably sourced power, regulatory constraints on grid interconnections and prudent resource planning; data center load growth may drive an increased demand for gas fired generation but due to the 24/7 baseload nature of data center load, that demand will likely be served under long term gas purchase agreements backed with transportation capacity that will not create a significant demand for incremental spot priced gas thereby negating the daily gas price volatility risk.

Fundamental analysis conclusions

PNM plans to meet future electric demand by transitioning to a carbon-free portfolio built around large additions of renewable energy, storage, and flexible thermal resources that can ultimately burn clean fuels like hydrogen. Under the 2023 Integrated Resource Plan and subsequent planning updates, coal exits entirely by 2032, nuclear from Palo Verde remains a key carbon-free baseload component, and new solar, wind, and battery storage provide most incremental energy and capacity. To maintain reliability as renewable penetration rises, PNM's "All Technologies" planning scenario includes new combustion turbine-type units that start on natural gas but are designed to convert to hydrogen as PNM progresses to a carbon free portfolio.

While this increase in thermal generation is significant, fundamental analysis indicates that short term basis disruptions will continue to occur however the market will be able to supply this generation with minimal long term volatility impact.

Quantitative Analysis

Translating volatility into IRP scenarios and metrics

For an integrated resource plan, the statistical volatility model is a means to an end: it supplies a distribution of future gas prices used to stress test resource portfolios, not an end in itself. A common approach is to use forward curves as a baseline expectation and then layer on stochastic shocks calibrated from a Monte Carlo simulation model to generate multiple fuel price paths that preserve observed volatility and mean reversion. These paths can then be fed into gas supply forecasts to evaluate how the proposed portfolio will perform in terms of expected cost, cost variance, and downside risk (e.g., high price percentile metrics).

Volatility characteristics and modeling framework

Natural gas prices exhibit volatility clustering, heavy tails, and strong seasonality, with winter and extreme weather events driving many of the largest moves. Empirical studies and EIA analysis show that annualized volatility for Henry Hub can range from roughly 20–30 percent in benign periods to 70–80 percent or more during stress episodes, and that gas volatility is typically higher and more erratic than oil volatility. Volatility also varies by tenor: front month futures display higher conditional variance than longer dated contracts, which is relevant when IRPs use different horizons for near term dispatch versus long term planning.

Quantitative analytical framework

For the quantitative analysis of the natural gas exposure, a model was created which simulates gas markets and quantifies the possible gas exposure of PNM to the unpredictable nature of Henry Hub and the basis markets. The methodology consists of a stochastic simulation for gas prices with Monte Carlo integration to create confidence intervals of gas prices starting with the prompt month through the end of 2045.

To estimate the impact of natural gas spot price volatility Siemens used a 6-step approach as outlined below:

1. Analyze historical spot pricing data to calculate volatility including short duration market disruptions that create pricing anomalies
2. Apply this volatility to the forward curve via Monte Carlo simulation
3. Generate thousands of potential price paths
4. Organize these paths into standard deviation bands around the forward curve
5. Apply these paths to forecasted monthly gas consumption (from IRP dispatch) to quantify cost exposure
6. Estimate the variance between expected and unfavorable outcomes to assess risk potentially passed on to ratepayers

To create the price paths, Siemens used 3.5 years of historical market prices for both Henry Hub as well as the local basis markets. The three-and-a-half-year period was selected to provide a reasonable amount of history to be statistically valid without capturing history that predates infrastructure and structural market changes that impact price.

Prices were simulated considering historical volatility, correlation between hubs and mean reverting prices. The prices listed in the table below were used as the starting point for simulations. These prices represent the range of expected prices over the future starting with a low price in the 5th percentile indicating all but 5% of prices will be above that price increasing to the 95th percentile which indicates a price point at which 95% of prices will be at or below that level. These prices are used to bound the simulations. Using a blend of the potential range of prices Siemens conducted a market simulation to estimate the future cost of natural gas and its impact on PNM's annual gas expense based on the expected volume requirement provided by PNM.

Percentile	Platts Waha	Platts Houston Ship Channel	El Paso Permian	El Paso San Juan	Platts Henry Hub
95%	$ 2.21	$ 3.34	$ 2.28	$ 4.04	$ 3.82
75%	$ 2.13	$ 3.31	$ 2.19	$ 3.90	$ 3.77
50%	$ 2.06	$ 3.28	$ 2.12	$ 3.81	$ 3.74
25%	$ 2.01	$ 3.25	$ 2.07	$ 3.71	$ 3.71
5%	$ 1.93	$ 3.21	$ 1.99	$ 3.52	$ 3.66

Table 1 Basis market simulation constraints

The following table utilizes the price distributions shown above to quantify the potential impact of forward-looking price over the planning horizon. The expected cost is based on the P50 scenario while the unfavorable case is based on the P95 price scenario. The P50 case is the expected case or 50% probability of occurrence event. P95 is the high market case, or the unfavorable event. The difference between the two cases is the "at risk" number; the difference between expected and unfavorable case, assuming no hedging.

Year	Volume (millions)	Unit Cost P50 ($)	Total Cost P50 ($ millions)	Unit Cost P95 ($)	Total Cost P95 ($ millions)	At risk spread ($ millions)
2026	26.5	2.93	77.6	3.43	91.0	13.3
2027	31.8	3.85	122.1	4.74	150.6	28.5
2028	30.6	3.87	118.4	4.86	148.4	30.0
2029	32.9	3.77	124.0	4.71	154.9	30.9
2030	37.7	3.83	144.6	4.67	175.9	31.4
2031	45.2	3.78	170.7	4.62	209.0	38.3
2032	32.8	3.87	127.2	4.70	154.4	27.1
2033	32.8	3.79	124.2	4.74	155.4	31.2
2034	33.4	3.91	130.7	4.69	156.7	26.0
2035	34.0	3.87	131.4	4.99	169.3	37.9
2036	33.8	3.82	129.3	5.02	170.0	40.7
2037	33.7	3.85	129.8	5.13	172.7	42.9
2038	34.0	3.83	130.3	4.91	166.9	36.7
2039	34.0	3.76	127.9	4.70	160.1	32.2
2040	34.5	4.03	139.0	4.94	170.3	31.3
2041	33.1	3.87	128.1	4.77	157.9	29.8
2042	34.2	3.73	127.6	5.07	173.3	45.7
2043	33.2	3.84	127.5	4.70	156.1	28.7
2044	27.9	3.82	106.6	4.78	133.5	26.8
2045	2.6	3.64	9.5	4.37	11.4	1.9

Table 2 Annual gas cost variances

Short term basis analysis

As mentioned in the fundamental analysis section, short-term disruptions will continue to occur due to four primary factors:

- Pipeline constraints or outages that prevent gas from moving from a surplus region to a demand center (capacity limits, maintenance, explosions, force majeure).
- Extreme weather that simultaneously spikes local demand and disrupts production or transportation (polar vortex, hurricanes, deep freeze-offs).
- Low regional storage levels or loss of storage flexibility, which tighten local balances and amplify price response to any shock.
- Sudden shifts in regional supply–demand from structural changes or global/geopolitical events that change flows and competition for gas supply.

As reflected in the graph below, El Paso San Juan experiences some short duration basis events that could cause significant increases in natural gas expense if not appropriately mitigated.

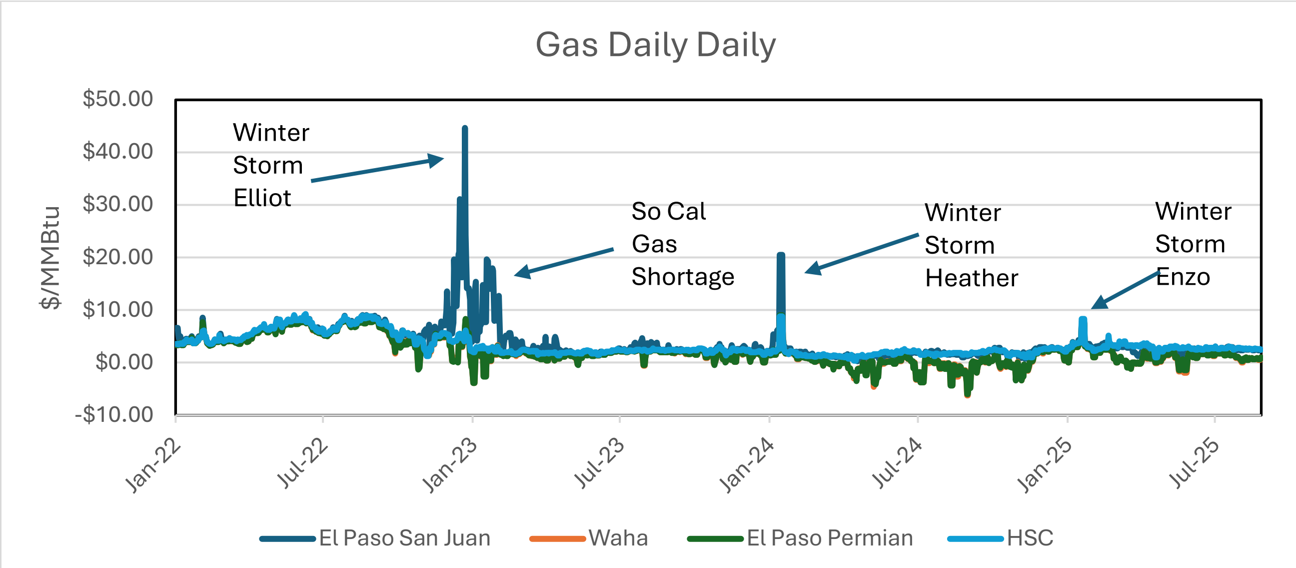

Figure 5 Natural gas spot price history

To quantify the potential impact of these basis market anomalies Siemens considered three and a half years of spot price history and identified 6 events, totaling 47 days, ranging from 1 day in duration to 20 days in December of 2022. The events selected were based on days when gas basis differentials were two standard deviations above the mean. Siemens assumed that the average daily volume during an event increased by 20% over forecast and then applied the historical basis differential that occurred during the event to the increased volume to quantify the financial impact.

Over the 3 ½ year analysis time frame, the cost implication was slightly under $10.4 mm with the majority concentrated in the December and January period in 2022/2023. Assuming the pattern were to repeat, on an average annual load of 30 Bcf the potential impact would be $0.30 to $0.33/MMBtu, assuming no basis hedging is in place. The vast majority of that risk occurs in the near term current and prompt month markets where the PNM risk management program allows for up to an 85% hedge ratio. An 85% hedge ratio would reduce the $10.5 mm exposure to $1.6 mm or approximately 2%-4% of the expected p50 annual gas cost. When evaluating basis risk in the Western US markets it is critical to remember that basis can swing in both directions and there may be situations where due to pipeline constraints PNM could experience negative basis and be paid to take gas.

Risk Mitigation

Natural gas price volatility does create risk for PNM ratepayers. Markets in the Southwest, particularly the Permian and San Juan basins can be volatile as discussed earlier in this report. Using risk management tools readily available in the physical and financial energy markets can reduce those risks to an acceptable level. PNM has a functional commodity price risk management program in place that was approved for hedging through 2028 by the New Mexico Public Regulation Commission under Docket No. 24-00238-UT. The plan, as approved, authorizes PNM to hedge forward energy requirements using physical and financial instruments. It is important to note that volatility in the basis markets can be both favorable and unfavorable therefore PNM limits the volumes for gas hedging to a reasonable level except during the current and prompt month when PNM is most exposed to unfavorable price swings. The guidelines apply to the amount of energy required to meet jurisdictional loads projected for the forward planning period, subject to the condition that PNM will hedge no more than 30% of projected annual gas supply required to fuel the gas fired generation fleet, with the exception of the prompt month, where up to 85% of the projected month's energy requirement may be hedged. The plan further allows the current year energy requirement to be hedged to 70%, 1st calendar year out to be hedged to 60%, and the 2nd calendar year to be hedged to 40%. These longer-term energy hedges reduce volumetric exposure on gas fired generation. When coupled with the near-term natural gas hedges will substantially reduce PNM's exposure to both short- and long-term natural gas prices spikes.

In addition to the risk reduction achieved through fuel hedging, PNM's targeted timeline for compliance with the ETA will, by default, reduce exposure to fuel price swings by structurally shifting the supply mix away from fuel-dependent generation toward renewables and other carbon free resources. As PNM moves toward meeting the ETA's renewable and carbon free standards, the goal is to develop a carbon free portfolio as soon as possible. Accordingly, as PNM adjusts its resource base to accomplish these objectives, its marginal energy needs will increasingly come from wind, solar, and other resources with no commodity fuel cost, rather than increasing reliance on gas-fired units whose dispatch costs are directly tied to natural gas prices. This transition means a growing share of PNM's cost of service is driven by fixed-capital and contracted capacity costs instead of pass-through fuel costs, dampening the impact of short-term gas price spikes on retail rates. In practical terms, each incremental megawatt-hour served from long-lived renewable assets under ETA compliance displaces prospective gas-fired generation, narrowing PNM's "open" natural gas requirement and thereby reducing the volume of gas that must be procured at floating market prices, which in turn lowers the utility's cash-flow and revenue requirement sensitivity to natural gas price shocks over time.

Conclusions

The quantitative and fundamental analyses presented in this study indicate that fuel cost variability associated with natural gas price volatility, while non-trivial, is bounded and can be prudently managed within the context of PNM's long-term resource planning framework. Long-horizon simulations calibrated to observed market behavior suggest that annual average gas cost outcomes are expected to remain within an approximate range of $0.14 to $1.09 per MMBtu around the forward curve, even after explicitly incorporating stochastic shocks and basis dynamics into the modeling construct. This per unit variance equated to a $26-to-$46 million-dollar annual variance as reflected in

Figure 6 spread across 5000+ GWh of generation. Coupled with basis risk in the $10.8 million dollar range, this is not an insignificant amount of exposure. It is important to remember; these risk numbers do not include the impact of the risk reduction of the hedging program discussed previously. When viewed against total portfolio fuel costs and the broader IRP time frame, this level of variance is material for planning and risk-allocation purposes but does not rise to the level of a structural threat to overall rate stability, provided that it is explicitly recognized and addressed through ongoing risk management practices.

At the same time, the historical basis assessment confirms that short-duration, high-magnitude disruptions—such as the six identified events totaling 47 days over the observed period—can create concentrated cost impacts if left unmanaged; in PNM's case, the back-cast estimate of roughly $0.30 to $0.33 per MMBtu on an annual load of 30 Bcf illustrates the potential rate effect of unhedged exposure to such episodes. However, these disruptions are episodic rather than chronic and occur within a broader market context characterized by robust domestic supply growth, ongoing interstate pipeline expansions, and increasing routing optionality into the desert Southwest. When combined with the established commodity risk-management program, structured procurement, and storage and capacity rights, these market fundamentals support the conclusion that both long-dated volatility and short-term basis risk can be reduced to levels consistent with a reasonable balance of affordability, reliability, and prudence for retail customers.

Accordingly, the conclusions developed in this analysis support a finding that PNM's treatment of gas price risk within its Integrated Resource Plan is reasonable and consistent with sound utility practice, in that it relies on empirically grounded stochastic methods, incorporates both qualitative and quantitative assessments of key drivers, and translates resulting cost distributions into actionable planning metrics. The Company's strategy—anchored in portfolio diversification, flexible thermal resources capable of transitioning to lower-carbon fuels, and the selective use of financial and physical hedging instruments—provides a credible path to maintaining cost variability within tolerable bounds over the 20-year horizon while continuing to meet statutory decarbonization and reliability objectives. On this basis, it is reasonable to conclude that fuel price risk to ratepayers is bounded and mitigated to align with Commission's expectations for prudent risk management. No additional modifications to the Company's gas price volatility assumptions or risk management practices are warranted at this time.