scottmadden
MANAGEMENT CONSULTANTS

ENERGY INDUSTRY UPDATE

JUST CAN'T GET ENOUGH

Volume 23 - Issue 1

CONTENTS

EXECUTIVE SUMMARY
Just Can't Get Enough

This Energy Industry Update examines the state of the utility and energy industry broadly and those areas where we "just can't get enough" or would certainly like more—such as adequate energy resources to serve load during each hour of the year, or coordination of processes, approaches, and assumptions for planning, or enough financial returns in a rising cost environment. Utility and energy companies continue to pursue investment to "get enough" resources and growth in their business, in the face of macro headwinds and tailwinds.

Some Highlights of This ScottMadden Energy Industry Update	
Can't Get Enough Resources	▪ Recent grid stresses have spurred the electric industry to reconsider its approach to resource adequacy. Regulators, reliability coordinators, and system planners increasingly believe traditional measures of resource adequacy—availability at peak—are insufficient as more energy-limited resources come online. The industry is exploring alternative approaches, as some regions look at resource-pooling arrangements to lower resource adequacy costs. ▪ Winter Storm Elliott surprised many utilities during late December, with an unpredicted surge in power demand and non-performance by generating units in several regions. For a few days, grid reliability was pushed to the edge, and some utilities had to institute rotating outages. Months later, post-mortems of the event continue in the hope of learning lessons for the future.
Can't Get Enough Coordination	▪ As utility systems (electric generation, transmission, and distribution, as well as natural gas) become more complex and system elements involve more trade-offs and interrelationships, planning approaches, processes, and organizations must adapt to ensure goals are aligned across the utility and with regulatory policy. ▪ ScottMadden sponsored a Smart Electric Power Alliance fact-finding mission to Australia. Ambitions for rapid change in Australia's electric sector should send a clear message to U.S. utilities: the energy transition will be both top-down and bottom-up. Utilities must be active participants by offering balanced solutions that account for reliability and affordability.
Can't Get Enough Growth	▪ Utility investment continues apace, as opportunities presented by energy transition policy and enhanced by 2022's Inflation Reduction Act present themselves. We look at what utilities and industry observers have to say about their prospects, as these investment opportunities are weighed against macro and industry risks. ▪ Local gas distribution companies (LDCs) faced some hurdles in 2022 and into 2023, as higher gas commodity prices reduced bill headroom for needed capital spending. LDCs continue to focus on affordability as they modernize their systems and reduce leaks for both emissions and safety reasons. As some regulators are studying the future of natural gas, LDCs are studying long-term alternatives (renewable natural gas, hydrogen, non-pipes alternatives) to meet a lower-carbon regime.

Utility Themes: Headwinds and Tailwinds

Amid increasing costs and macro uncertainty, utilities plot their courses for investment.

Turmoil, Turbulence, and Treasure

- Since early 2022, a span of less than 18 months, the energy and utilities sectors have faced a remarkable set of macroeconomic and geopolitical events that could have durable effects on the North American utilities industry.
  - Russia's invasion of Ukraine has caused significant human devastation, as well as knock-on effects on global gas and oil markets and the nuclear fuel supply chain that have reverberated to North America.
  - The Federal Reserve is attempting to tamp inflation through monetary policy changes, removing liquidity from the market and steadily increasing the federal funds effective rate from .08% in early 2022 to 4.58% just 12 months later.
  - Following the 2021 authorization of roughly $1.2 trillion for U.S. infrastructure improvements under the Infrastructure Investment and Jobs Act (IIJA), Congress authorized an estimated additional $370 billion toward a broad array of new and existing technologies across energy generation, transmission, and distribution segments and for electrification of transportation and other end-use applications via the Inflation Reduction Act (IRA).

KEY TAKEAWAYS

Utilities continue to put significant capex into the business, with more firms employing "back-to-basics" rate-of-return strategies.

Sector headwinds—inflation, rising interest rates, high natural gas prices, and affordability concerns—have been balanced by continued opportunities for utility investment and support from 2022's Inflation Reduction Act.

It is unclear whether 2023 will match 2022's sector financial performance or whether macro risks will outweigh growth opportunities.

Turmoil, Turbulence, and Treasure (Cont.)

- Beneath this macro backdrop, energy and utility companies continue their efforts to reduce their greenhouse gas emissions footprints and, in many cases, pursue net-zero objectives.
- In their most recent annual commentaries, industry organizations American Gas Association and Edison Electric Institute highlighted opportunities for investment in their respective sectors. Key points raised by each are noted in Figure 1.1.

Figure 1.1: **Energy Industry Organization Highlights**

American Gas Association

- Unveiled **Net-Zero Emissions Opportunities for Gas Utilities**, detailing how natural gas, natural gas utilities, and delivery infrastructure will be essential to meeting GHG reduction goals, including net-zero emissions
- **Pipeline Safety Management System Portal** launched, providing a platform to access information to help promote risk reduction and improve safety
- Continued quality, quantity, and speed of reporting breaches, risks, and incidents through Downstream Natural Gas Information Sharing and Analysis Center, the industry's **alert system for both physical and cyber threats**
- Natural gas utility industry across North America invested $1.8 billion in **energy efficiency** in 2019 and budgeted more than $1.9 billion for 2020
- **IRA provisions** important to the natural gas utility industry include:
  - A new investment tax credit for **renewable natural gas**, a new clean **hydrogen** production tax credit, and an extension of credits for **carbon-capture** projects, all of which will aid utility decarbonization efforts
  - Tax credits for **energy efficiency-related investments** for homeowners, including natural gas heat pumps
  - A $4.3 billion **fuel-neutral home efficiency rebate** program. The HOMES programs provide rebates to homeowners for whole-house energy savings retrofits, and high-efficiency gas appliances for heating are included as eligible for the program
- **State programs** with innovative resource legislation promoting advanced emissions-reduction technologies and hydrogen-focused legislation and project proposals

Edison Electric Institute

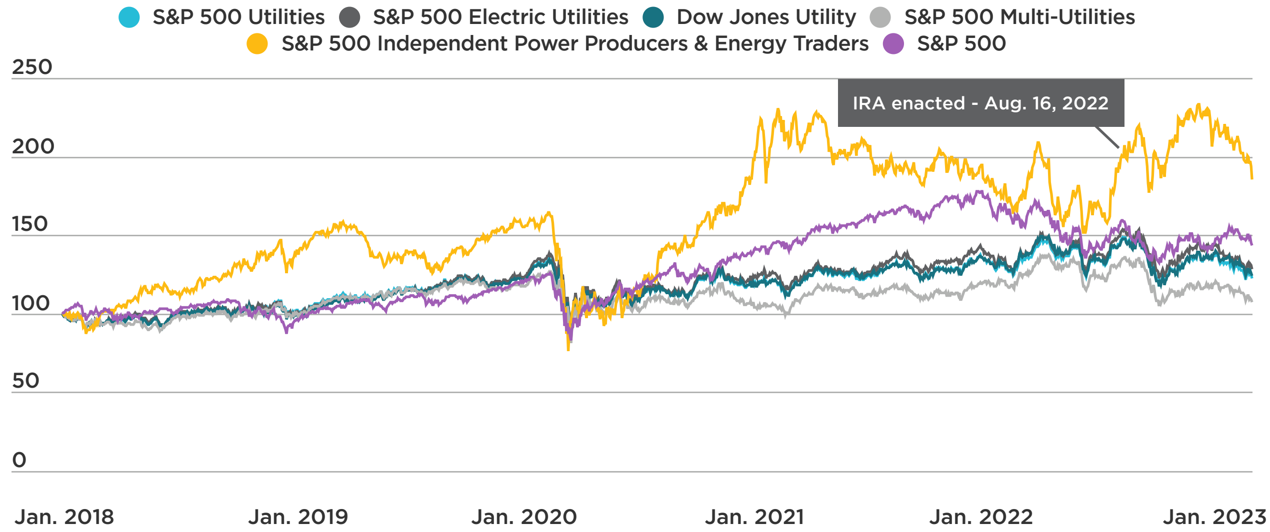
- **IIJA** provides significant R&D, demonstration, and deployment funding for new clean energy technologies
- **IRA** provides immediate customer benefits through individual and business tax credits and rebate programs
- Amount of **transmission infrastructure** in the United States will have to expand by two, if not three, times to support electrification and renewables integration
- **Rising cost environment and geopolitical tensions** create fuel supply risks, drive higher global energy prices, impact supply chains, and increase cyber and physical security threats
- Need a coordinated, consistent, and efficient **siting and permitting regulatory framework** with environmental and regulatory processes that are clear, transparent, and as efficient as possible
- **#Committed2Clean**: Electric companies to continue to lead energy storage growth, with 49 GW of battery storage through 2026, and propose new, more efficient natural gas generating units that are certified to use cleaner fuel blends, such as hydrogen and ammonia
- **Partnered to launch the Carbon-Free Technology Initiative** and created the **Institute for the Energy Transition**, each with the goal of identifying and advocating for specific policies that can help to ensure commercial availability of new, affordable, 24/7 carbon-free technologies by the early 2030s
- Projects there will be 26 million **EVs** on U.S. roadways in 2030, requiring approximately 140,000 EV fast-charging ports across the country—a 10-fold increase over today

Sources: AGA; EEI

Energy and Utility Financial and Stock Market Performance

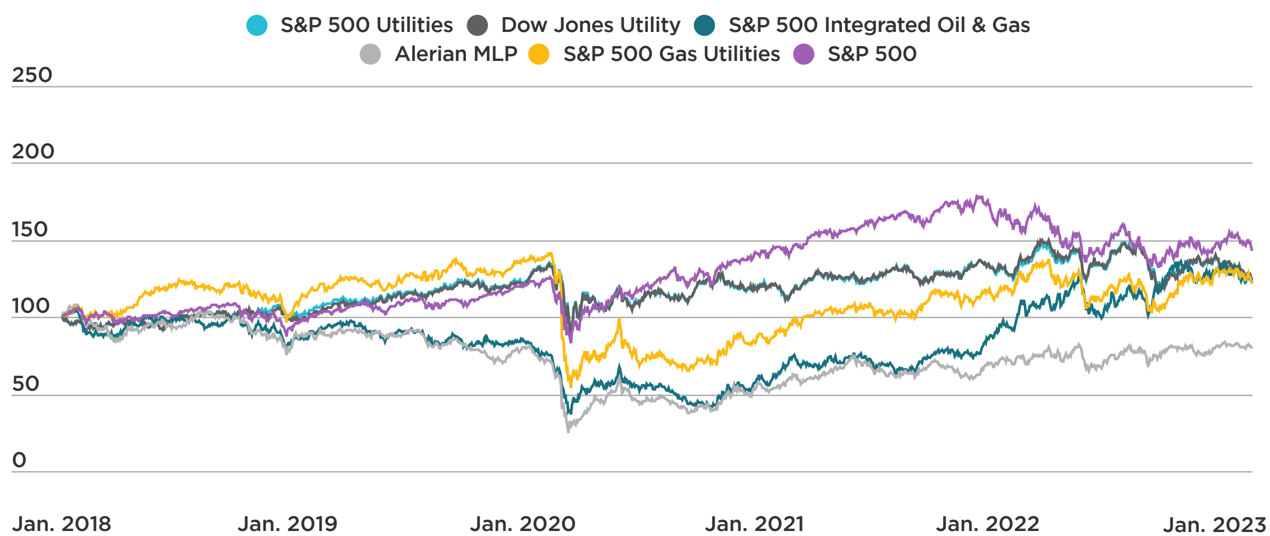
- Revenue growth across most industries is still positive, although it has ebbed in recent months. Concerns about a current or potential slowdown have weighed upon stock prices, which have tailed off from their highs in early 2022.
- Over the past 3 years—since the onset of COVID-19 in the United States in March 2020—both gas and electric utility stock indexes have generally trailed the broader S&P 500 index, as shown in Figures 1.2 and 1.3. The exception to this trend are independent power producers and renewables developers. Rising interest rates have contributed to stock declines through the second half of 2022.
- An exception to this general utility underperformance of the broader market has been the performance of independent power producers. Strong power market fundamentals have bolstered companies operating in markets such as PJM, and renewables, nuclear, and other lower-carbon emissions technology development is likely to accelerate as a result of the IRA.

Figure 1.2: **Selected Utilities Aggregate and Electric Sector Index Values (Jan. 2, 2018–Mar. 10, 2023) (Index: Jan. 2, 2018 = 100)**



Source: S&P Capital IQ Pro

Figure 1.3: **Selected Utilities Aggregate and Gas Sector Index Values (Jan. 2, 2018–Mar. 10, 2023) (Index: Jan. 2, 2018 = 100)**

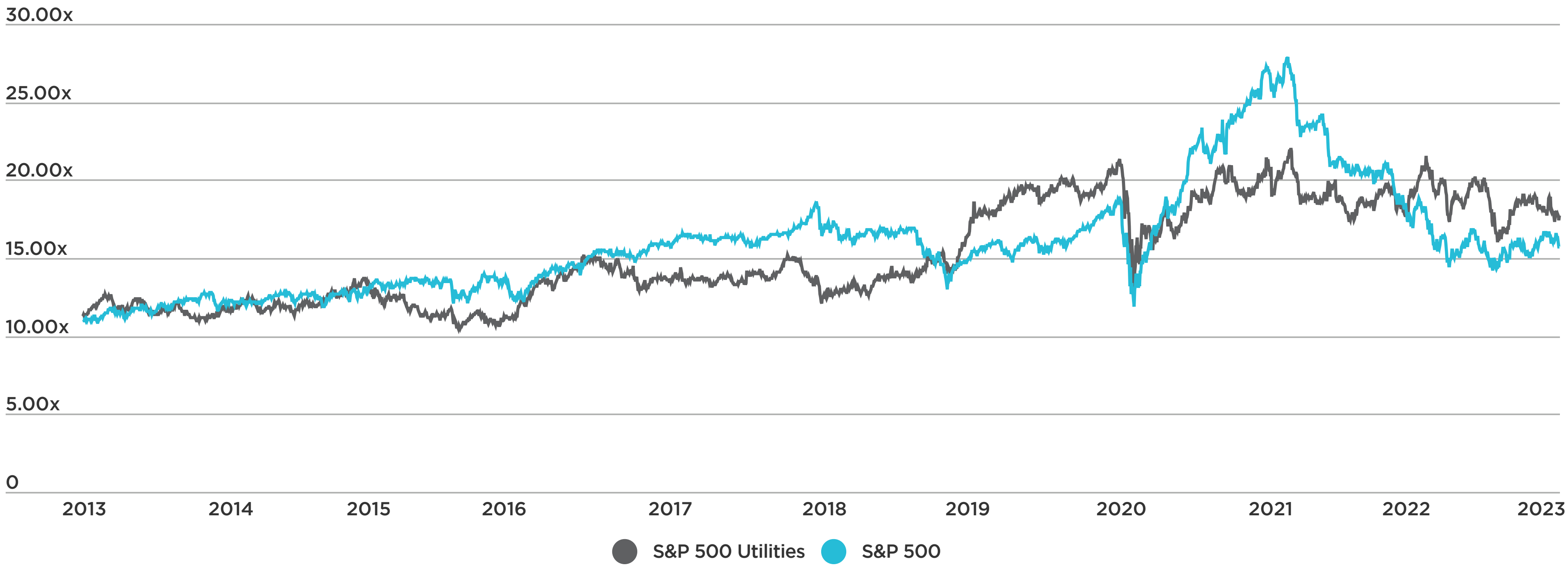


Source: S&P Capital IQ Pro

Energy and Utility Financial and Stock Market Performance (Cont.)

- Despite strong revenues, utilities have had negative EBITDA growth over the trailing four quarters (ended March 9), according to Standard & Poors. However, on a valuation basis, utilities have had a more attractive valuation over the past year, with utility market capitalization-to-earnings before taxes outpacing the same metric for the S&P 500 (see Figure 1.4). Some analysts attribute that to recession and geopolitical concerns and utilities' traditional role as a relative safe haven.

Figure 1.4: **Ratio of Market Capitalization to Earnings Before Taxes (Excluding Unusual Items) for Selected Indexes (Mar. 2013–Mar. 2023)**

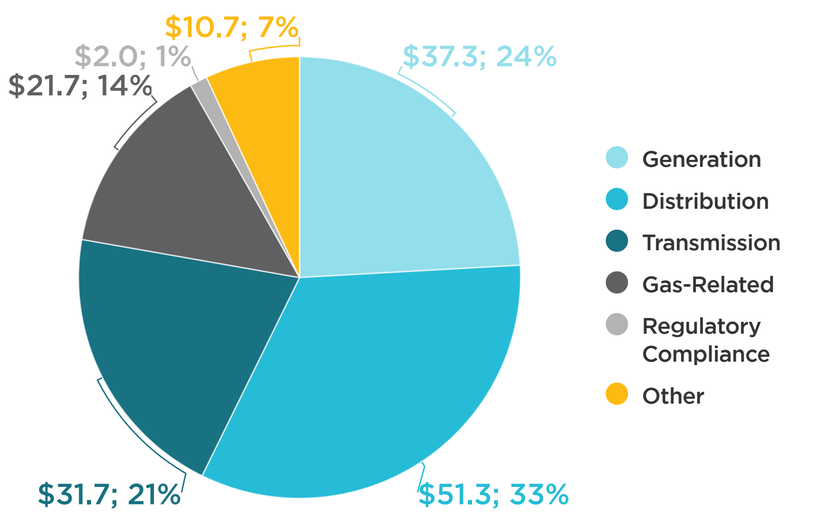


Source: S&P Capital IQ Pro

Significant Capital Investment Needs Over the Next Decade

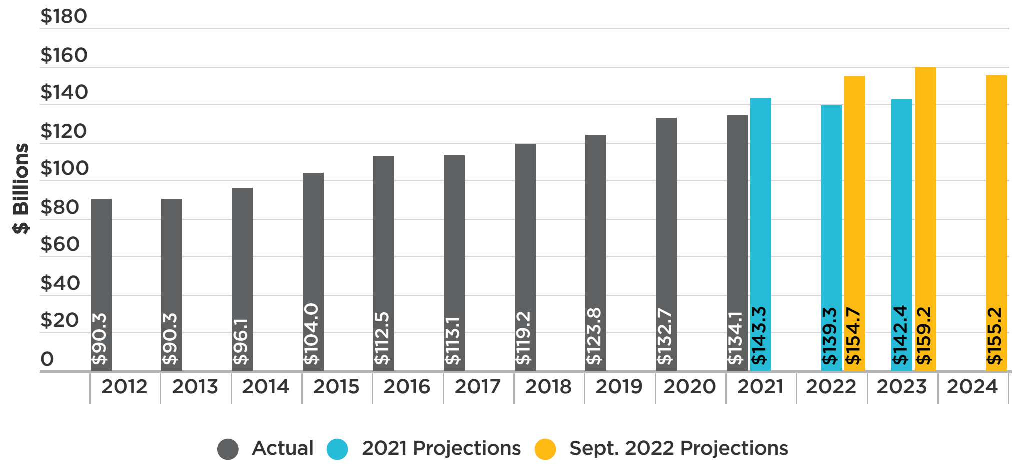
- Utilities have almost uniformly been emphasizing significant investment needs over the near to medium term. As many are pursuing a "back-to-basics" rate-of-return model, capex is expected to grow across all segments in both power and gas businesses—from production/generation to transmission to distribution (see Figures 1.5, 1.6, and 1.7). Energy transition and lower GHG emissions resource investment remain powerful drivers of capital investment. S&P Global Ratings estimated 2022 capex in its North America regulated utilities coverage universe was at an all-time high of $190 billion.
- The IRA can accelerate capital spending by utilities through funding opportunities and favorable tax incentives. However, electric utility capex was already increasing at an accelerated pace, even before the IRA. Constraining this growth are persistent issues of supply chain bottlenecks and swollen interconnection queues.

Figure 1.5: **Investor-Owned Electric Utilities Estimated Functional Capital Expenditures (2022) ($ Billions)**



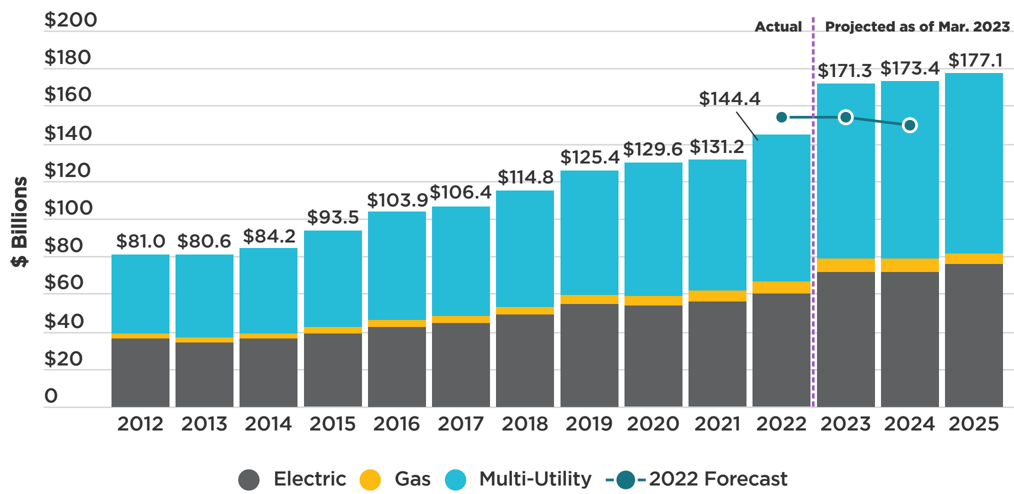
Source: Edison Electric Institute

Figure 1.6: **Actual and Projected Capital Expenditures for Investor-Owned Electric Utilities (2012–2024) ($ Billions)**



Source: Edison Electric Institute

Figure 1.7: **Actual and Projected Capital Expenditures for Selected Electric, Gas, and Combination Utilities (2012–2025P)**



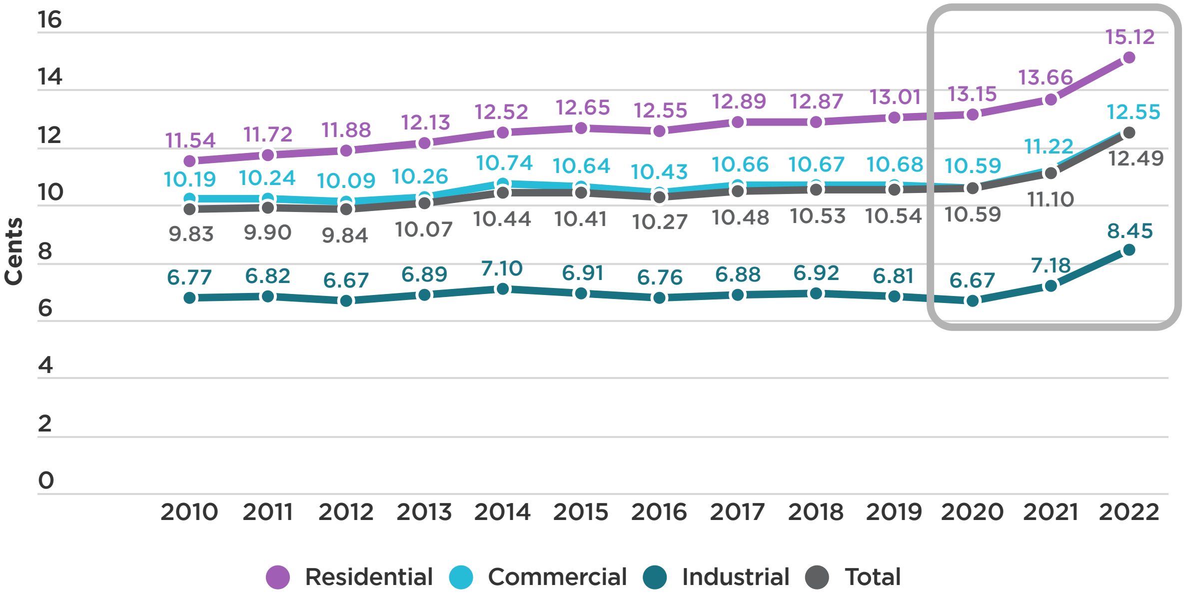
Notes: Values are for 46 investor-owned utility companies and holding companies from corporate investor presentations, annual reports, and other public sources. Based upon data available as of Mar. 14, 2023. 2022 figures are preliminary. P means projected.

Source: S&P Global Market Intelligence-Regulatory Research Associates

Rates and Ratings: Pressure on Utilities

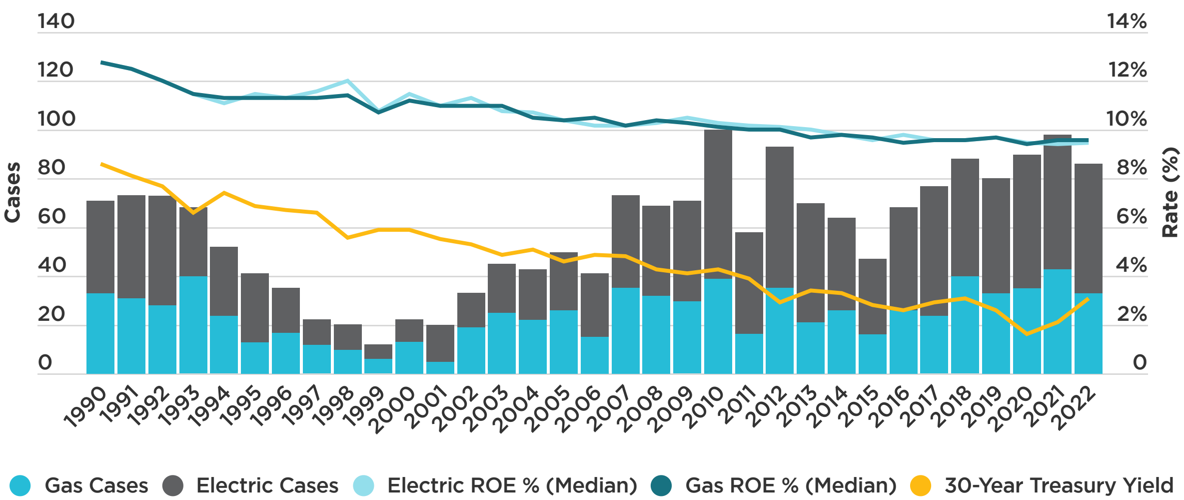
- The combination of higher commodity costs (especially natural gas), higher general inflation rates, and investment needs is making its way into customer costs. Revenue per kWh for electricity in the United States ticked up significantly in 2021 and 2022 across all customer classes (see Figure 1.8).
- Given rising costs, utility rate case activity continued apace in 2022 (see Figure 1.9). Regulatory Research Associates estimates that U.S. investor-owned utilities (IOUs) requested rate increases totaling a combined $16.78 billion in 2022, up about 13% from a record-setting 2021.
- And while each jurisdiction has its own approach and considerations for establishing return on equity (ROE) that is utility specific, median ROE nationwide has been slowly declining since 2020. It appears, however, to have bottomed out or reversed in the past year or two (see Figure 1.9), although the range of ROEs remains wide. This may bode well for improved return on capital for the sector.

Figure 1.8: **U.S. Revenue per Kilowatt-hour – Total and by Customer Class (2010–2022P) (Cents)**



Note: P indicates that 2022 prices are preliminary.
Source: Energy Information Administration

Figure 1.9: **Electric and Gas Rate Cases, Median Returns on Equity, and 30-Year Treasury Yields (1990–2022)**



Note: Axes represent cases (left-hand side) and rates (right-hand side).
Source: S&P Global Market Intelligence-Regulatory Research Associates

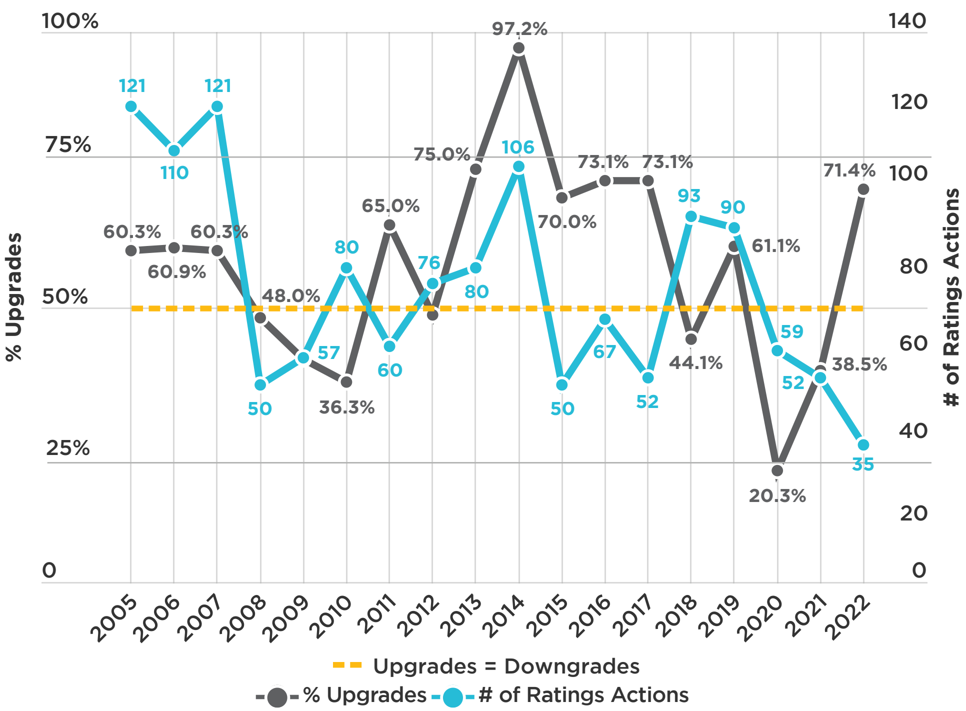
Rates and Ratings: Pressure on Utilities (Cont.)

- Rating agencies have expressed some concern over pressure on financial measures. As noted by S&P:

  "Over the past decade the industry's financial measures have weakened from a combination of rising capital spending, regulatory lag, and lower authorized return on equity (ROE). The industry's return on capital was about 6% a decade ago and today is closer to 4%. More recently, we have seen instances where not only the authorized ROE is lowered but also the equity ratio is lowered. These results have weakened the industry's financial measures, pressuring credit quality. Under our base case of moderating inflationary risks during 2023, we expect the industry's credit measures to generally remain flat."

- Interestingly, among IOUs, upgrades exceeded downgrades, reversing a trend from 2020-2021 (see Figure 1.10). However, there has been a significant move of electric IOUs from A- to BBB+ (see Figure 1.11).

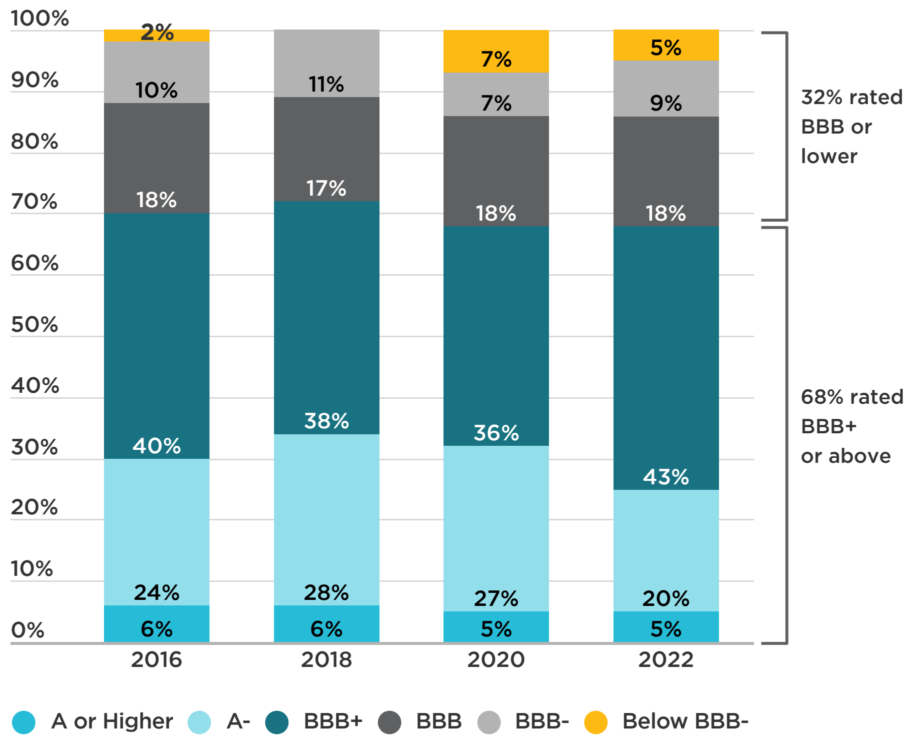
Figure 1.10: **U.S. Investor-Owned Electric Utilities (Parent and Subsidiaries) Ratings Actions and % Upgrades**



Notes: Axes represent % upgrades (left-hand side) and actions (right-hand side). Actions reflect those of Fitch Ratings, Moody's, and Standard & Poor's.

Source: Edison Electric Institute

Figure 1.11: **U.S. Investor-Owned Electric Utilities S&P Utility Credit Ratings Distribution (for Selected Years as of Dec. 31)**



Source: Edison Electric Institute

In Their Own Words: Banks, Ratings Agencies, and Energy Companies

- On nearby Figures 1.12A-B, we have reviewed and distilled comments by rating agencies and investment bank analysts on key issues faced by the energy and utilities sectors and their assessment of potential strengths and weaknesses of the sectors.

Figure 1.12A: **Utility Themes and Observations from Selected Investment and Credit Analyst Comments**

Business Focus	▪ We see a growing prioritization of steady, regular earnings growth and diminishing appetite for any non-linearity to EPS CAGRs, demonstrating a bias toward clean stories.... Meanwhile, minority interest sales and unregulated renewable sales continue to provide attractive optionality as buyer interest remains robust despite higher interest rates. ▪ While electric vehicles represented only about 6% of new U.S. car sales in 2022, we expect that by 2025 they will represent 15%-20%, leading to higher electricity sales.... [I]t is likely that by the next decade, electric vehicles will materially contribute to the industry's sales growth. ▪ Even with energy rallying, utilities continued to march toward fully regulated business models. Utilities are employing strategic actions to spin or sell non-regulated assets. Greater value in focusing on rate base growth: regulated utilities' strong electrification tailwinds; clear investor preference for regulated; renewables, transmission, reliability investments lifting capex; Treasury clarifications on IRA a further tailwind. ▪ Utilities may represent the best decarbonization investment as value creation flows down to the end asset owner.
Customer Bills	▪ Overall, bill pressure and contributing supply factors from elevated commodity prices loomed over discussions.... Growing concern over energy transition costs also stood out as a ratepayer risk.... Additionally, resource flexibility represented a newer emerging theme.... Overall, we observed little pushback to the system investment cases underpinning utility capex, even amid this...backdrop. ▪ As the customer bill continues to increase, the industry could experience increasing political interference.
Regulatory Environment	▪ The core outlook can be summarized succinctly: affordability, regulatory proceedings, interest rates, and credit profiles. Many of these are consistent with prior years and 2022, but the severity of the regulatory pushback still is in the early innings. ▪ Deferral recovery, approval of securitizations are key areas of regulatory challenges as bills move higher. Affordability pressures throughout COVID and into 2022 have prompted utility bill concessions, including fuel cost and COVID-era deferrals.
O&M Costs	▪ We expect labor costs will remain elevated in 2023 despite the potential recession and somewhat subdued wage pressures of late. Utilities will likely continue to experience acute labor supply constraints relative to the broader market, supporting wage stickiness. ▪ Given bill trends, managing controllable O&M is important, especially with elevated pass-through commodity expenses.

Sources: J.P. Morgan; S&P Global Ratings; Bank of America Securities; S&P Global Market Intelligence

Figure 1.12B: **Utility Themes and Observations from Selected Investment and Credit Analyst Comments (Cont.)**

Financial Management	▪ Because of the industry's high capital spending and consistent dividends, negative discretionary cashflow is regularly more than \$100B annually.... Rising interest rates, decreasing equity prices, and inflation could hamper consistent access the capital markets, potentially pressuring credit quality.
Physical Risks	▪ Weather-related physical risks appear to be continuing at a record pace. During the past several years, the United States has experienced record levels of damages from storms and hurricanes, driving costs up for utilities. ▪ We expect continued natural disasters, and reliability issues will encourage utility T&D hardening spend.... Yet, we do not expect T&D hardening will drive significant capex and rate base uplift in 2023. Many of the contemplated hardening plans do not start to meaningfully ramp up until 2025+.
Capital Expenditures	▪ Large projects could become more challenging. We expect the industry's 2023 capital spending to reach a record of more than \$200B but given the macro risks, large projects—including offshore wind—could become increasingly challenged. Supply chain delays and rising interest rates increase the probability that projects are not completed on time and on budget. While these risks affect all projects, larger and more complex projects are disproportionally affected, increasing the probability that some of these projects could be delayed or even canceled.
Mergers and Acquisitions	▪ M&A activity remains subdued amidst shift toward pure-play utility growth and ESG. Transactions trend toward portfolio optimizations and consolidation of regulated utility businesses. Grid investments preferred over M&A given increased regulatory scrutiny in recent years. ▪ U.S. utilities have been navigating the clean energy transition through small strategic transactions in contrast to the utility megadeals of decades past. ▪ Multiple companies have conducted internal strategic reviews and begun the process of divesting assets, or selling minority interests in projects, to raise cash and to facilitate capital reallocation.
ESG/Net-Zero	▪ Most of the industry is committed to a net-zero emissions date between 2030 and 2050. As customer bill pressure increases, the industry may be forced to slow the pace of the energy transition, delaying the timeframe to reach net-zero carbon emissions. ▪ Recently, we have seen a pull forward in net-zero timelines. Utilities strive to differentiate the time and scope of their "greenness." 2045 = "new 2050," as 52% of our IOUs cite 100% reduction by 2045. ▪ ESG is becoming a larger part of management team long-term strategies.... Utilities continue to focus on reducing their carbon emissions via changes to their existing fuel mix and new projects. ▪ We see structural decarbonization underpinning both robust growth opportunities and ESG tailwinds for the group over time, especially with IRA support.

Sources: J.P. Morgan; S&P Global Ratings; Bank of America Securities; S&P Global Market Intelligence

In Their Own Words: Banks, Ratings Agencies, and Energy Companies (Cont.)

- On nearby Figures 1.13A-B, we have taken comments by selected utility and energy companies on their recent performance, business drivers, and strategies. The companies do not reflect all within a sub-sector but were selected to provide representations of themes and priorities of their respective energy sub-sectors.

Figure 1.13A: **Utility Themes and Observations from Selected Utility Company Comments**

Combination Utilities	▪ Increased current [capital] plan through 2030 by $2.3B to support "customer-driven capital" (for strategic undergrounding; pole infrastructure; substation flood mitigation; "smart grid" technology).... Not reliant on "big bets": approximately 80% of the nearly $43B capital plan through 2030 expected to be recovered through regulatory interim mechanisms, and most projects can be completed in under 12 months. (CNP) ▪ Advancing our regulated decarbonization and resiliency strategy.... Top-to-bottom business review proceeding with pace and with purpose. Priorities: - Durable, high-quality, and predictable long-term earnings growth profile and consistent execution - Competitive and fair return on regulated utility investment - Reliable and efficient utility operations + continued focus on O&M cost control.... (D) ▪ Strategic business review – scale and portfolio diversity offers the best opportunity to drive long-term shareholder value. Conclusions: - Scale and portfolio diversity add value - Industry-leading recovery programs drive strong top-line growth - Identified opportunities to strengthen the balance sheet - Opportunity exists to improve cost profile, processes, and customer experience (NI) ▪ As the owner of one of North America's largest T&D networks, we envision positive tailwinds from the IRA and other recent federal legislation. (SRE) ▪ Robust capital program of $15.5B–$18B from 2023–2027 aligned with state clean energy goals at our best-in-class utility. Effective cost control to maintain customer affordability.... PSEG has extended cost-reduction efforts into 2023 to further mitigate the impacts of higher pension and interest costs. (PEG)
Delivery-Only Utilities	▪ The closing of the sale of the competitive energy businesses allows Con Edison to become a pure-play regulated business. Proceeds from the sale will strengthen the company's balance sheet and offset equity needs in 2023 and 2024.... 6.2% three-year rate base CAGR reflects infrastructure investment needed for the clean energy future. We envision $72B in investments for [operating companies Con Edison and Orange & Rockland Utilities] over the next 10 years. (ED) ▪ Strategic review of offshore wind assets advancing.... Commitment to a Science-Based Target*...Interconnection upgrades needed to deliver additional clean energy into our system. Current proposal would enable about 1 GW of solar if all six clusters are approved.... Under way in Four-Year [Grid Modernization] Plan (2022-2025): approximately $205M additional capital investment program through 2025. Includes grid technologies to improve reliability, system planning tools, communications infrastructure, and distributed energy resource management systems. (ES)

Notes: Company ticker symbols shown in parentheses. *Science-based targets represent the magnitude of emissions that companies need to reduce in response to warnings from the Intergovernmental Panel on Climate Change, indicating global temperature rise must not exceed 1.5 degrees Celsius above pre-industrial temperatures to avoid the worst impacts of climate change. Eversource stated that it will work closely with the Science-Based Targets Initiative within two years of its commitment to develop specific, measurable, short-term GHG reduction targets.

Sources: Company annual reports, Form 10-Ks, and investor presentations.

Figure 1.13B: **Utility Themes and Observations from Selected Utility Company Comments (Cont.)**

Independent Power Producers and Renewables Developers

- Competitive advantages: scale enables valuable supplier relationships; strong renewables platform and pipeline; strategic partnerships with global customers; and innovating to drive adoption of smart solutions. (AES)
- Growth advantages: best-in-class O&M and development expertise—supports organic growth; scale advantage; financing efficiency—broad banking group and strong industry relationships; access to a variety of low-cost capital; structural tax advantages—not expected to pay meaningful U.S. taxes for at least 15 years; "transformational impact of the IRA." (NEEP)
- We entered a number of new high-growth transition asset classes that are complementary to our core renewable assets, including carbon capture and storage, recycling, and renewable natural gas, through small, upfront investments with experienced partners, that are structured with downside protection, discretion over future investment, and significant potential upside returns on our capital. (BEP)
- Long-term, sustainable value creation through integrated [generation + retail] business model: successfully executed on a comprehensive multi-year hedging program.... Strategic growth of our clean energy portfolio, Vistra Zero, with a focus on diversified generation sources, markets, and revenue sources. (VST)

Gas Pipelines and Midstream

- Timing and pace of energy transition must balance energy reliability, sustainability, and affordability.... Gas Transmission & Midstream growth: meet growing utility customer demand; LNG export connections in Canada and United States; support electric generation growth.... Leveraging core infrastructure to advance lower-carbon opportunities. Value drivers: diversified low-risk pipeline/utility model; reliable cash flows and strong balance sheet; ~5% medium-term growth outlook; lower-carbon optionality throughout the business. (ENB)
- ~93% take-or-pay, hedged, and fee-based cash flows.... Expect annual growth capital spend of ~$1-$2B going forward, compared to ~$2-$3B historically.... Energy transitions take time: our assets and services will be needed for a very long time.... Multi-turn storage facilities provide customers with flexibility: key to supporting daily and seasonal variability from LDCs and power, LNG facilities, Mexico, and intermittent renewables; for power grids with a higher mix of renewables, we offer premium services that help support volatile demand swings. (KMI)
- Electrification and renewables buildout requires natural gas infrastructure expansion. Lower utilization of renewables requires flexible natural gas backup; dispatchable capacity needed as a backstop for low wind and solar days. Williams' contracted gas capacity continually needed to supply grid reliability on days of peak demand alongside ongoing renewable capacity buildouts in our pipeline markets.... Strategic organic and New Energy Ventures investments: invest in high-return growth opportunities to drive long-term value and seek renewable projects, leveraging existing footprint. 17.5% Return on Invested Capital 2019-2022.... Sourcing and certifying NextGen Gas and delivering a differentiated product to growing Gulf Coast and LNG markets. (WMB)

Integrated Electric Utilities

- ~90% of future investment is in wires and renewable generation. The ability to quickly redeploy T&D investment ensures we maintain capital spend while mitigating customer bill impact.... The strength of our balance sheet is a top priority.... O&M discipline over time amid rising costs and growing asset base helps keep customer rates affordable.... Electrification and higher penetration levels of distributed resources will drive additional distribution investment opportunities.... Resource plans are aligned with climate goals: current IRPs identify a significant need for new clean energy resources over the next 10 years. (AEP)
- Among the cleanest large-scale fleets in the United States; clear plans and commitments to continue decarbonizing our delivered energy; uniquely positioned to expand our positive impact by reducing industrial customers' Scope 1 and Scope 2 emissions. (ETR)
- NextEra Energy's two businesses are supported by a common platform:
  - Clean energy generation portfolio
  - Integrated supply chain, engineering, and construction
  - Best-in-class operations and innovation leader
  - Power delivery and transmission...
- Decarbonizing FPL is expected to have no incremental cost to customers and presents a nearly 160 GW solar, storage, and hydrogen opportunity. (NEE)
- Strong, projected state-regulated utility rate base growth. Grid and fleet modernization and resilience initiatives continue to drive the projected growth profile of our electric utilities. Investment in the safety and reliability of our pipeline infrastructure drives robust projected growth for the gas LDCs. (SO)

Note: Company ticker symbols shown in parentheses.

Sources: Company annual reports, Form 10-Ks, and investor presentations.

IMPLICATIONS

The investment community has recently wavered between positive and negative sentiment for utilities. Some analysts highlight risks from potential recession and increased regulatory and political scrutiny as rates are expected to increase. Positive surprises on economic outlook, project progress, and commodity prices could change the outlook.

Utilities would be well served to continue to watch their financial metrics, monitor the pace of investment, and engage regulators as investments in energy transition, grid modernization, resilience, and electrification/ decarbonization ramp up.

Sources:

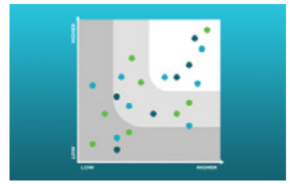
American Gas Association; Edison Electric Institute; American Petroleum Institute; Board of Governors of the Federal Reserve System (U.S.), Federal Funds Effective Rate [DFF], retrieved from FRED, Federal Reserve Bank of St. Louis, at https://fred.stlouisfed.org/series/DFF (Mar. 13, 2023); J.P. Morgan; S&P Global Ratings; Bank of America Securities; S&P Capital IQ Pro; EIA; ScottMadden analysis; company reports

RECENT INSIGHTS
Available at scottmadden.com

ScottMadden posts energy and utility industry-relevant content and publications on a regular basis.
The list below is a sample of recent insights prepared by our consultants.

ARTICLE

Five Keys to Successful IIJA and IRA Applications



ARTICLE

Materiality Assessments: Foundational to Comprehensive ESG and Corporate Strategies

CASE STUDY

Materiality Assessment for Electric Co-Op

INTERACTIVE INFOGRAPHIC

Recent Electric Vehicle Developments

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Australia’s Energy Transition: Ghost of the U.S. Future?

Australia’s grid operators learn to surf big waves of change.

Fact-Finding Mission Reveals Major Changes Underway, but Will the Lights Stay On?

- In November 2022, ScottMadden sponsored the Smart Electric Power Alliance's fact-finding mission to Australia to better understand the country's electricity markets and ongoing energy transition.
- Australia's energy transition is being driven by both top-down and bottom-up pressures:
  - In September 2022, Australia passed federal legislation requiring net greenhouse gas (GHG) emission reductions of 43% below 2005 levels by 2030 and net-zero by 2050.
  - Conversely, lucrative feed-in tariffs and high solar irradiance have driven significant adoption of rooftop solar, totaling 40% of dwellings in some states.
- With many similarities to the United States, including current grid developments and GHG reduction ambitions, the energy transition in Australia provides interesting insights into operational challenges and lessons for developing a long-term vision for the electric sector's future.

KEY TAKEAWAYS

Similar to the United States, the energy transition in Australia includes a variety of state and federal policy requirements, growing public demand for clean energy, increasing operational concerns, and a critical need for new capacity resources and transmission.

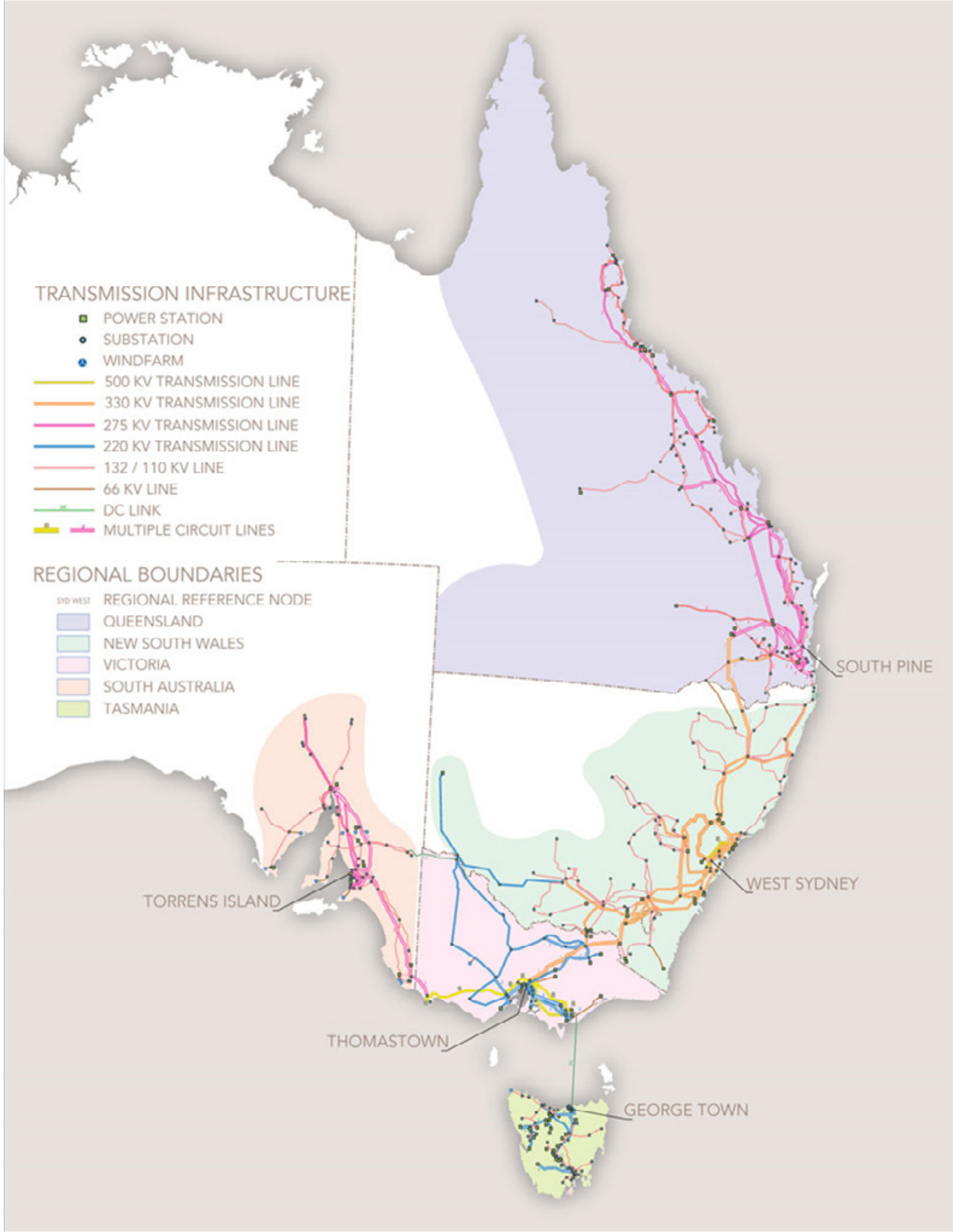
Despite the increasingly complex operating environment, utilities are expected to maintain reliability while meeting clean energy mandates and facilitating third-party deployment of distributed energy resources.

Australia demonstrates that the energy transition will require major new investments and new operating methods. In addition, the transition will require an honest discussion about the pace of change and trade-offs involved.

Australia's National Electricity Market (NEM): One of the World's Longest Interconnected Power Systems

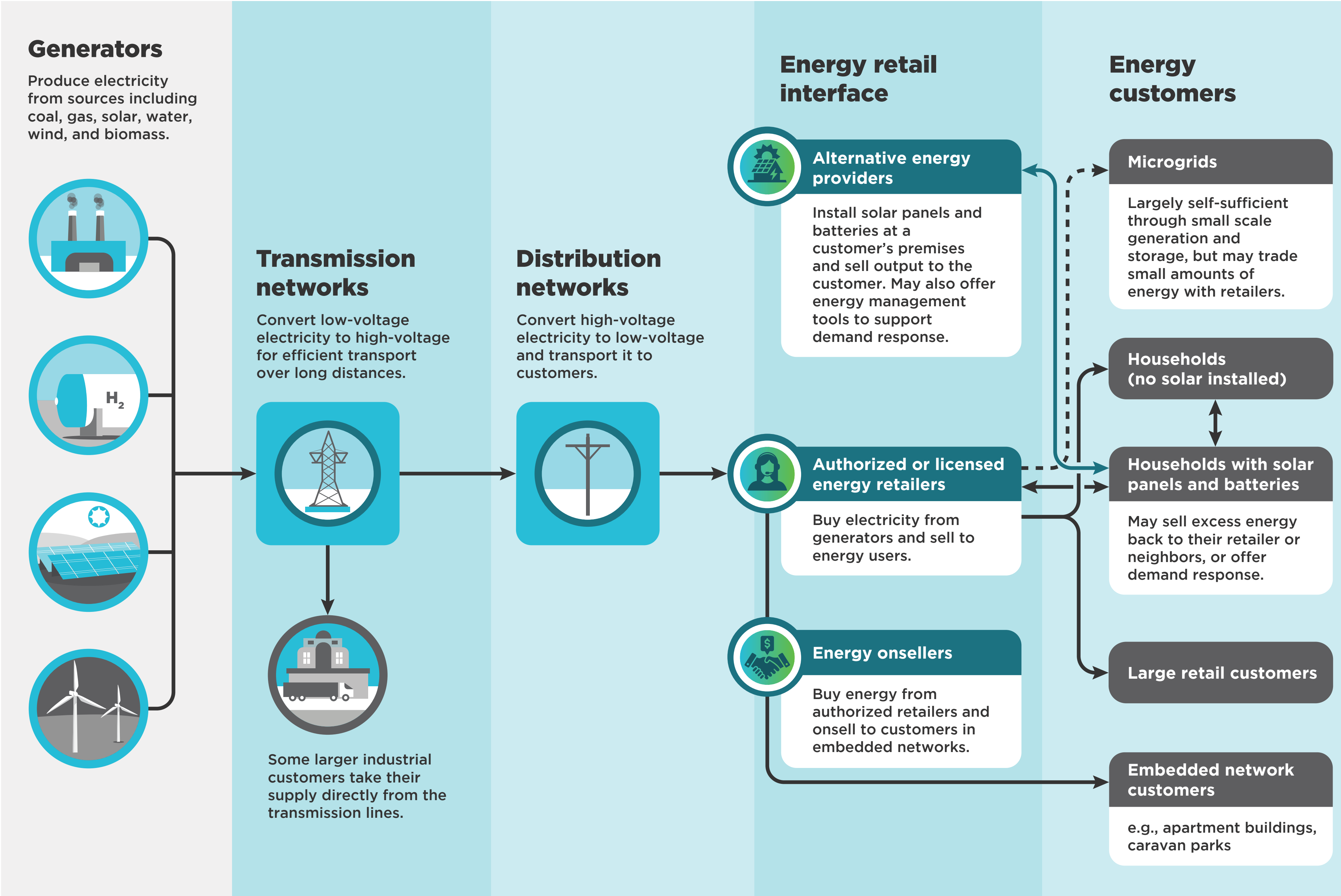
- Spanning Australia's eastern and southeastern coasts, the NEM provides electricity to 10.7 million customers (see Figure 2.1). In addition, the system:
    - Consists of five interconnected states that also act as price regions.
    - Stretches roughly 3,000 miles from Port Douglas in Queensland to Port Lincoln in South Australia and across the Bass Strait to Tasmania.
    - Incorporates roughly 25,000 miles of transmission lines and cables.
- The NEM consists of a wholesale spot market and transmission grid for electricity (see Figure 2.2 on next page).
    - Roughly 325 generating units produce electricity for sale into the NEM.
    - The Australian Energy Market Operator (AEMO) schedules the lowest-priced generation available to meet demand in five-minute dispatch intervals.
    - The transmission grid carries this electricity along high-voltage power lines to industrial energy users and local distribution networks.
    - Energy retailers complete the supply chain by purchasing electricity from the NEM and packaging it with transmission and distribution network services for sale to residential, commercial, and industrial energy users.
    - Electricity generated by rooftop solar is not traded through the NEM, but it does lower the demand that generators must meet.

Figure 2.1: **Australia's National Electricity Market (NEM)**



Source: Australian Energy Market Operator

Figure 2.2: **Overview of NEM Market Participants**

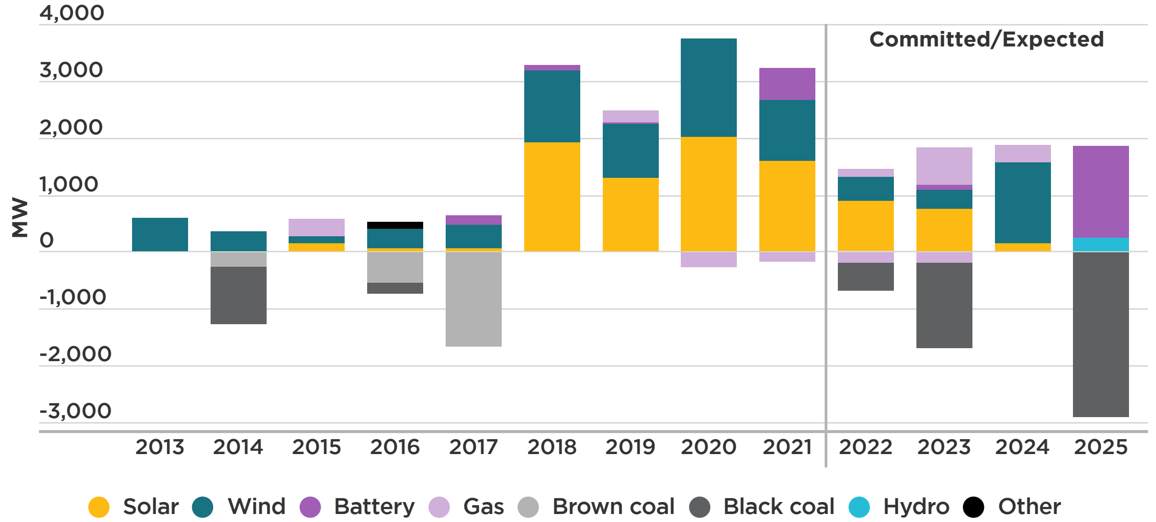


Source: Australian Energy Regulator

Australia's NEM (Cont.)

- The NEM generation portfolio, which totaled 70.5 GW as of January 2022, is undergoing a rapid transformation as coal capacity is replaced primarily with wind, solar, and storage capacity (see Figure 2.3).
- Australia is learning that coupling rapid energy transition with external shocks results in new challenges for the system.
  - In June 2022, sustained high prices triggered protective price caps, multiple market interventions, and unprecedented market suspension of the entire NEM (see Figure 2.4 for a view of regional power prices).
  - Contributing factors included:
    - **High fuel prices:** Elevated global coal and gas prices
    - **Increased demand:** Increased demand due to an early and very cold winter
    - **Coal plant issues:** Ongoing coal plant outages, significant coal supply challenges, and higher marginal coal prices
    - **Greater reliance on gas, hydro:** Reduced coal-fired generation, causing the market to rely on more expensive sources of generation, such as gas and hydro to meet demand. This high demand for gas-powered generation coinciding with gas supply limits and soaring gas spot prices.

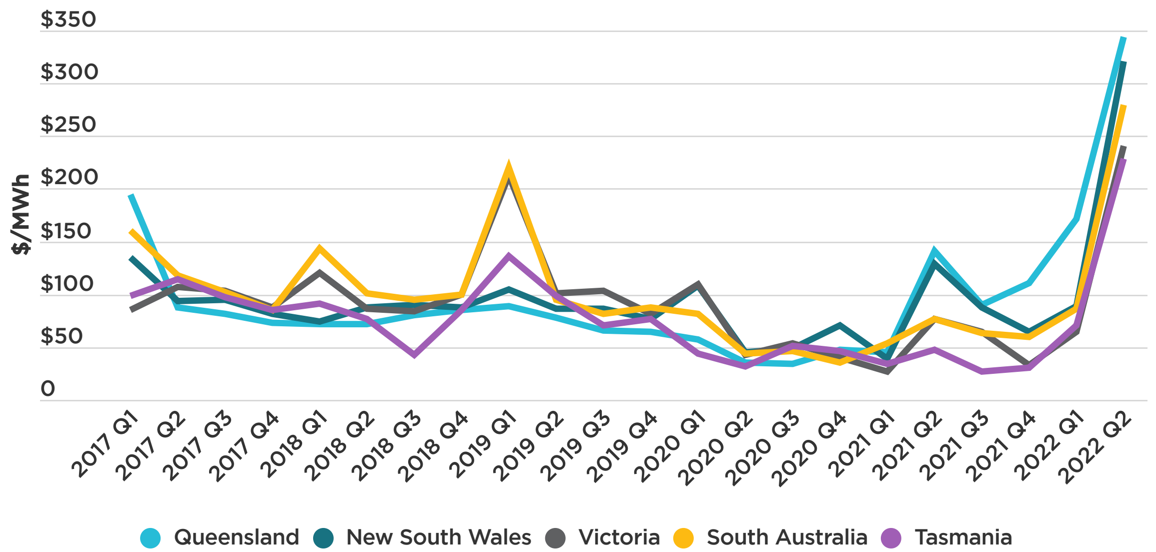
Figure 2.3: **New Generation Additions and Retirements by Fuel Type (2013–2025 Projected) (MW)**



Notes: Positive values are additions. Negative values are actual (before 2022) or expected (2022-2025) retirements.

Source: Australian Energy Regulator

Figure 2.4: **Australia NEM Wholesale Power Prices by State and Quarter (Jan. 2017–Jun. 2022) (in AU$)**



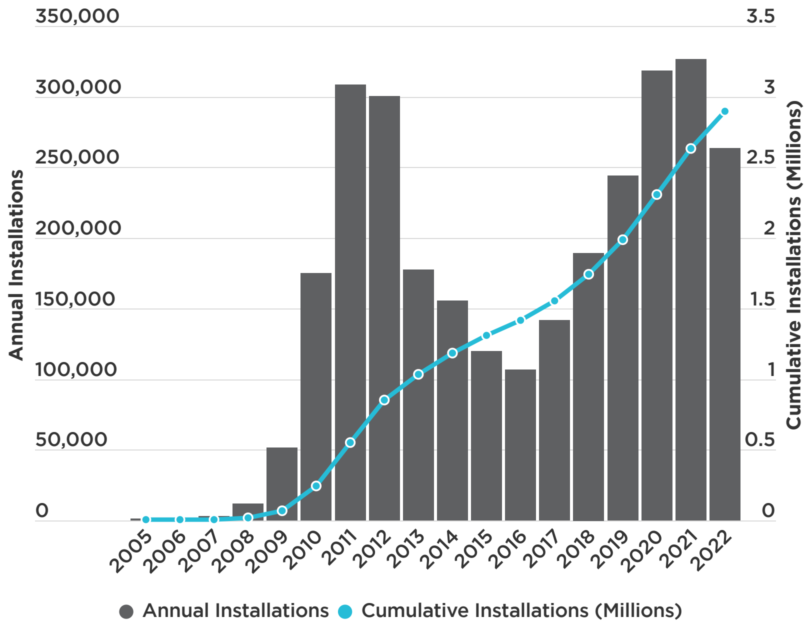
Notes: Prices are volume-weighted quarterly averages. As of March 16, 2023, AU$1.00 = ~US$0.67 (see https://www.xe.com/currencyconverter/).

Source: Australian Energy Regulator

Rooftop Solar Outshines Natural Gas but Creates Operational Challenges

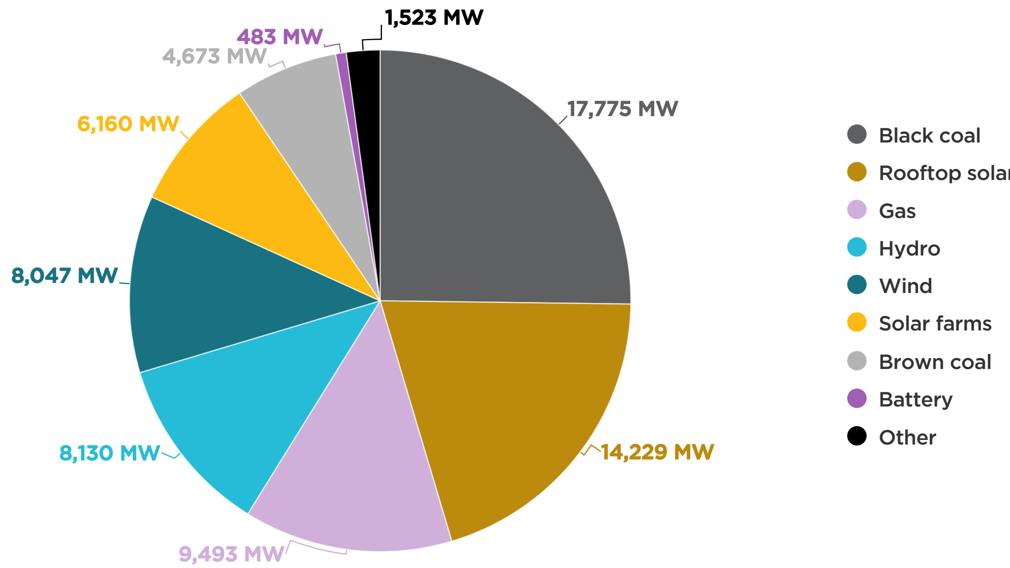
- With nearly 3 million installations (compared with approximately 9.6 million dwellings in NEM states), the adoption of rooftop solar (i.e., small-scale solar PV) in the NEM exceeds anything experienced in the United States (see Figure 2.5). For context,
  - Sustained growth is driven by a simple interconnection process, declining technology costs, and ongoing incentives from the federal government and some state governments.
  - In 2021, rooftop solar accounted for one-fifth of NEM's generating capacity, second only to black coal (see Figure 2.6).
  - In the same year, rooftop solar provided 8% of NEM's generation, which beat out the energy provided by natural gas (see Figure 2.7).

Figure 2.5: **Annual and Cumulative Small-Scale Solar PV Installations in Australia's NEM (2005–2022)**



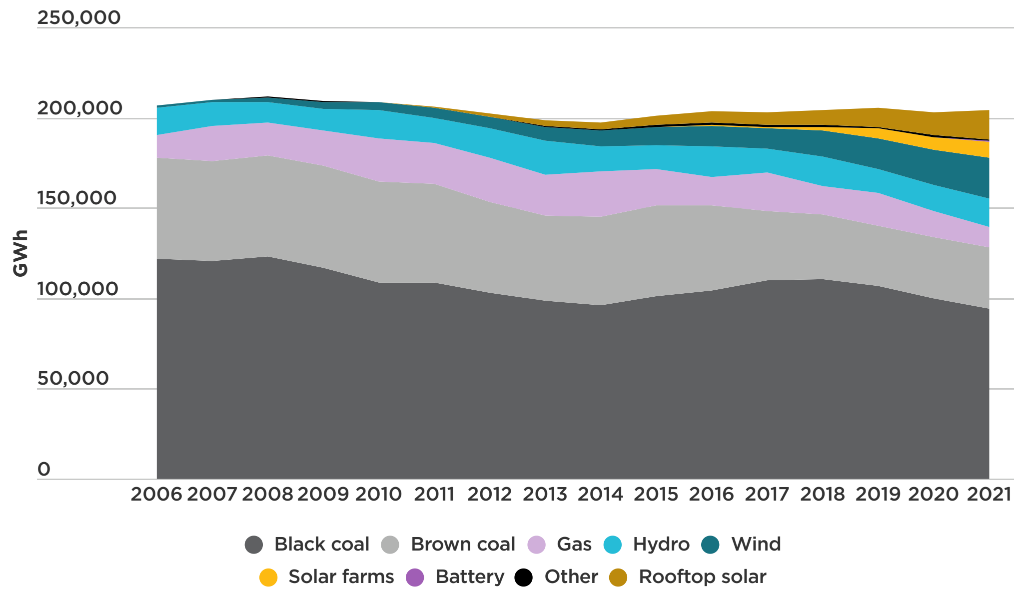
Source: Australia Clean Energy Regulator

Figure 2.6: **NEM Generation Capacity by Fuel Source (2021) (MW)**



Source: Australian Energy Regulator

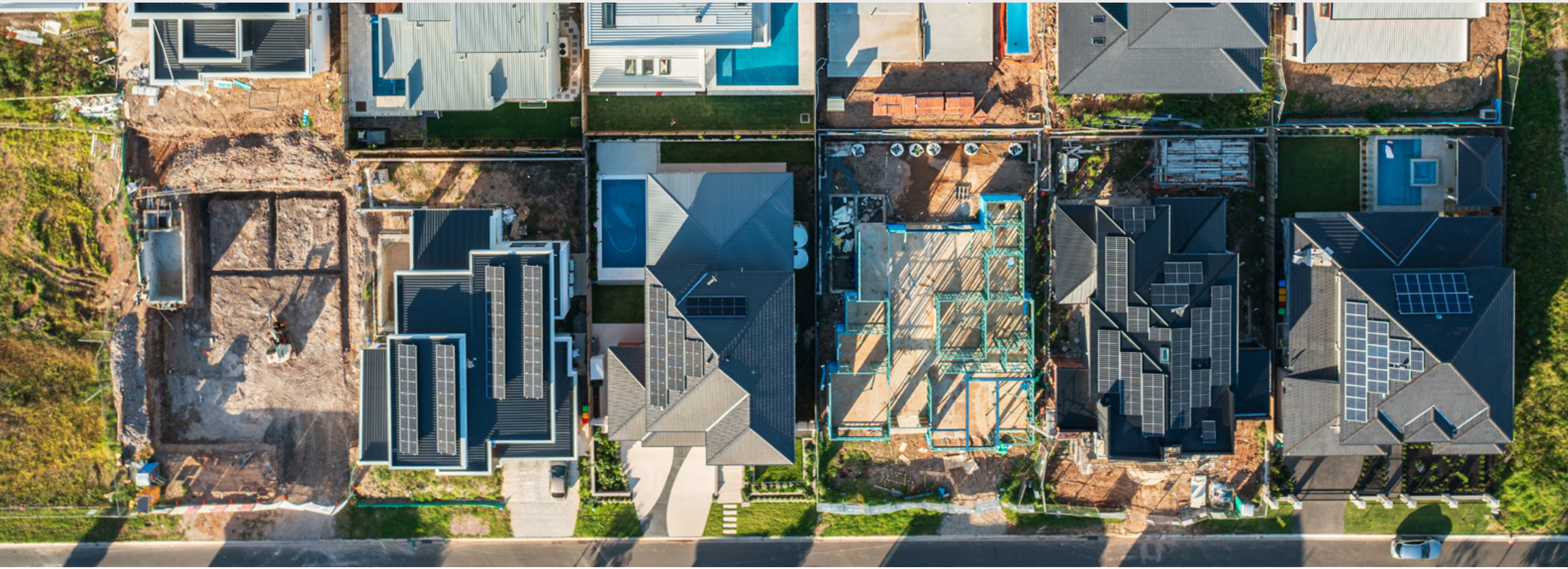
Figure 2.7: **NEM Generation Output by Fuel Source (2006-2021) (GWh)**



Source: Australian Energy Regulator

Rooftop Solar Outshines Natural Gas but Creates Operational Challenges (Cont.)

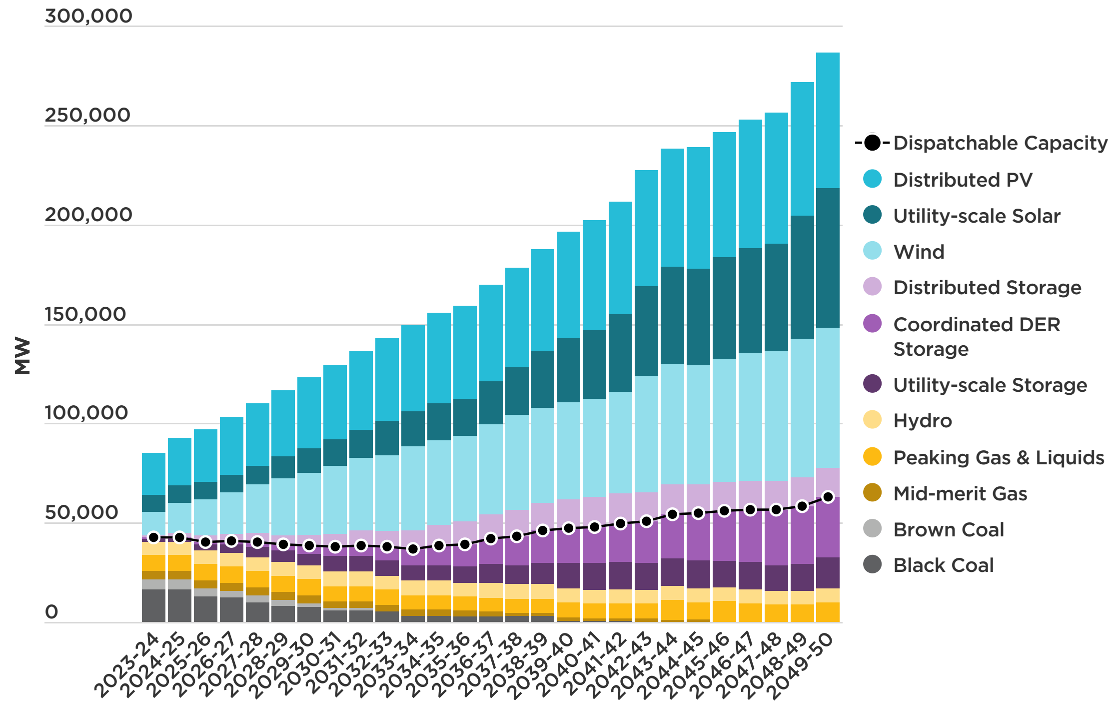
- Despite the higher penetration, many of the operational challenges seen in Australia are similar to experiences in the Unites States.
  - Excess electricity produced by rooftop solar in the NEM is typically sold by the consumer to their retailer for a flat feed-in tariff (FiT).
    - Victoria offers the lowest FiT at ~3.5 cents/kWh.
    - South Australia offers the highest FiT at ~5.6 cents/kWh.
  - Since the FiT is not linked to the actual value of the excess electricity, consumers are not incentivized to time exports for when additional energy is needed.
  - The result has been constraints requiring some networks to limit excess electricity exports from rooftop solar to the electric grid.
- Recent rule changes are designed to integrate consumer energy resources more efficiently onto the electric grid.
  - Network businesses may now charge consumers to export excess electricity during times of network congestion.
  - This new price signal is expected to encourage consumers to export electricity at times of need.



Grid Operator Blueprint for “Once-in-a-Century” Transformation

- As the electricity grid operator, the responsibilities of the AEMO include securing electricity systems, managing electricity markets, and leading the design of Australia’s future energy system.
- Released in June 2022, the Integrated System Plan (ISP) is a whole-of-system plan that provides a comprehensive roadmap for the efficient development of the NEM through 2050.
- In the analysis, the most likely future is called the “step change” scenario, which considers aging generation plants, technical innovation, economics, government policies, energy security, and consumer choice.
- Based on this scenario (see Figure 2.8), the energy transition will include:
  - An economy-wide electrification coupled with a transition to firmed renewables. More specifically, the ISP forecasts:
    - Nearly doubling electricity delivery by 2050
    - Sixty percent of coal capacity retiring by 2030
    - Nine times increase in utility-scale variable renewables by 2050
    - Nearly five times increase in distributed PV and substantial growth in distributed storage by 2050
  - Increasing firming capacity provided by dispatchable low-emission alternatives (e.g., dispatchable storage, hydro, gas-fired generation, and hydrogen)
  - Wholesale demand response and other flexible loads to help manage peak loads and troughs

Figure 2.8: **NEM “Step Change” Scenario Capacity Forecast to 2050 (MW)**



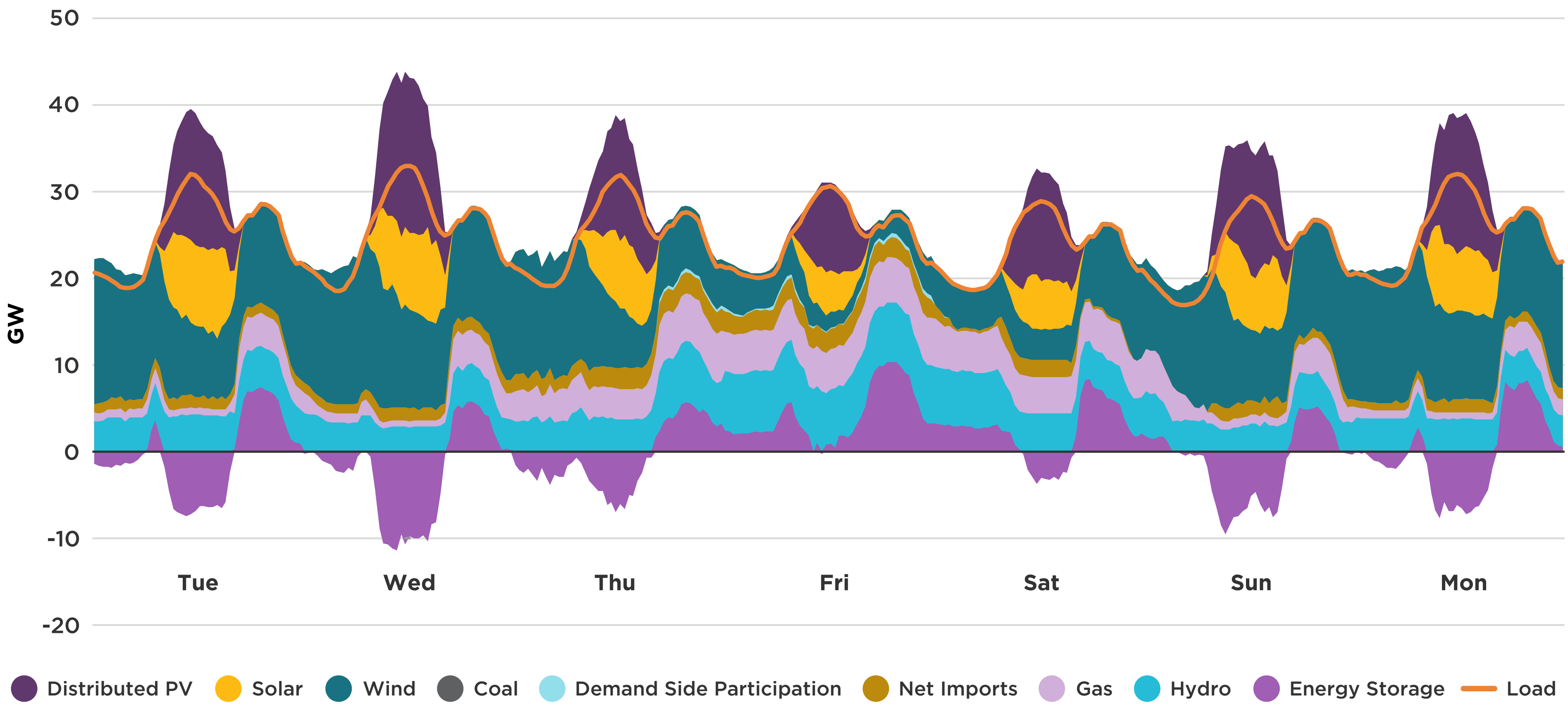
Source: Australian Energy Market Operator

  - Market and technical reforms to improve system services and allow for two-way electricity flow. Current work streams are focusing on:
    - Capacity mechanism
    - Essential system services (i.e., frequency, inertia, etc.)
    - Distributed energy resource integration
    - Transmission reform
    - Congestion management
  - Significant investment in the transmission network: $12.8 billion of actionable projects are modeled through 2026

Grid Operator Blueprint for "Once-in-a-Century" Transformation (Cont.)

- Geographical and technological diversity is expected to allow the future system to operate under increased uncertainty and a changing climate.
- A winter week forecasted in July 2040 (see Figure 2.9), shows generation sources interacting in New South Wales, Victoria, South Australia, and Tasmania.
- During low renewable periods, a combination of storage, hydro, and gas-fired generation plays a strong firming role, while transmission investments allow imports from other parts of the NEM.

Figure 2.9: **Hypothetical June 2040 Week NEM* Winter Dispatch Outcomes Under "Step Change" Capacity Forecast (GW)**



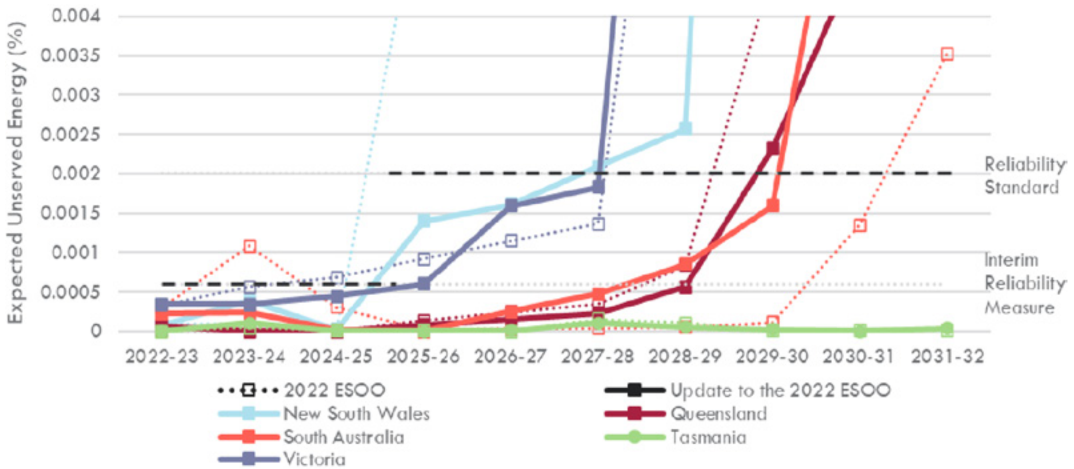
Note: *Excludes Queensland

Source: Australian Energy Market Operator

Looming Reliability Gaps Prompt Urgent Calls for Additional Investment

- The AEMO also publishes an annual Electricity Statement of Opportunities (ESOO), which provides a reliability outlook for the NEM over the coming decade.
  - The ESOO identifies the following factors that may impact reliability:
    - Unavailability of generation or transmission
    - Generation retirements
    - Delays in commissioning of new generation, storage, and transmission
    - Increasing demand (i.e., electrification)
  - Ultimately, the ESOO recognizes periods where electricity demand exceeds expected supply, thereby highlighting the need for capacity development.
- Published in August 2022, the most recent ESOO warned of near-term reliability gaps.
  - Reliability issues were forecast for South Australia during fiscal year 2024 and Victoria during fiscal year 2025.
  - However, an update published in February 2023 suggests a reprieve, as near-term reliability gaps are no longer forecast, considering the following actions:
    - Recent capacity developments that included new gas, wind, and battery storage
    - Delayed retirement of an existing 180 MW combined-cycle natural gas generator in South Australia
- Despite the near-term relief, forecasted reliability gaps remain a long-term concern.
  - All mainland regions are forecast to experience reliability gaps by fiscal year 2032 with present capacity commitments.
  - As a result, the AEMO continues to stress an urgent need to invest in generation, long-duration storage, and transmission to meet long-term reliability requirements.
- Even with major capacity investments, the AEMO notes reliability risks remain due to weather uncertainty and simultaneous generator or transmission outages.

Figure 2.10: **NEM Forecast (2022–2027) and Indicative Forecast (2027–2032) of Reliability by Region (in % of Expected Unserved Energy)**



Notes: ESOO is AEMO's annual Electricity Statement of Opportunities. Reliability in the ESOO is measured as the expected unserved energy (USE) as a percentage of energy demand. The forecasts are assessed against an Interim Reliability Measure of 0.0006% USE which is effective through June 30, 2025. After this date, forecasts are assessed against a reliability standard of 0.002% USE.

Source: AEMO

Australia's Energy Transition Provides Many Useful Insights for U.S. Utilities

The fact-finding trip raised the following key considerations for the U.S.'s energy transition:

Role of natural gas during an energy transition: With a strong reliance on coal, Australia has not built out natural gas generation capacity in the same manner as the United States. It remains unclear how much natural gas capacity and related gas infrastructure will be needed to ensure system reliability.

Public policy outpaces operational capabilities: Aggressive policy mandates and incentives are accelerating the adoption of utility-scale and distributed variable generation resources. The proliferation of variable resources concurrent with the retirement of baseload generation requires new operating paradigms to ensure reliability. As a result, grid operators are developing new approaches as new resources come online.

Pace and cost of the energy transition: Aggressive investment in lower or zero-carbon technologies can produce rapid reductions in greenhouse gas emissions but comes with a steep cost. Australia continues to monitor the investment needed to address emission reductions and ensure reliability.

Transmission provides critical linkages: Similar to the United States, Australia must build new transmission to connect renewable resources at the scale required to meet emission-reduction goals. Local opposition is a growing challenge both in Australia and the United States.

IMPLICATIONS

The energy transition in Australia includes rapidly growing distributed energy resources, significant and rapid retirements of baseload generation, and major investments in clean energy and grid technologies. Similarities with the United States include the need to meet varying state and federal policy requirements, growing public demand for clean energy, public policy demands resulting in operational concerns, and a critical need for new transmission.

The rapid change occurring in Australia should send a clear message to U.S. utilities: the energy transition will be both top-down and bottom-up. To avoid getting squeezed in the middle, utilities must be active participants by offering balanced solutions. In practice, this may require a cultural shift from "yes, but" to "yes, and" solutions that account for reliability and affordability.

Notes:

Australia's fiscal year ends on June 30. FiT prices are presented in USD. See Glossary for definitions of black and brown coal.

Sources:

Australian PV Institute, Mapping Australian Photovoltaic Systems (data through Dec. 31, 2022); Australia Energy Market Operator (AEMO), 2022 Integrated System Plan: A Report for the National Electricity Market (June 2022); AEMO, 2022 Electricity Statement of Opportunities: A Report for the National Electricity Market (Aug. 2022); AEMO, Update to 2022 Electricity Statement of Opportunities: A Report for the National Electricity Market (Feb. 2023); Australia Energy Regulator, State of the Energy Market 2022 (Sept. 2022); Clean Energy Regulator, Postcode Data for Small-Scale Installations (as of Mar. 3, 2023), at www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations; GEM Wiki; Energy Australia; ScottMadden analysis

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Winter Storm Elliott: The Reviews Continue

An early winter deep freeze tests the grid.

Reliability in Focus After Forced Outages and Rolling Blackouts

- In late December 2022, a powerful cold front (or polar vortex) developed in the United States and Canada. After strengthening over the Northern Plains, it descended and covered much of the eastern two-thirds of the United States from December 23 to December 25, bringing dangerous cold, high winds, and blizzard conditions to many areas.
- More than 100,000 MWs of coal- and gas-fired generation were unable to start or knocked offline, and as many as 1.6 million customers were without power at the peak of the extreme weather event.
  - PJM Interconnection (PJM) saw nearly 46,000 MW of forced outages, roughly 25% of the region's installed capacity.
  - The Midcontinent ISO's outages peaked at 50,000 MW.
  - Tennessee Valley Authority (TVA) and Duke Energy were forced to institute their first-ever rolling blackouts.
- On December 28, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation (NERC), and NERC's regional entities announced a joint inquiry into the operations of the wholesale power system during the event, since named Winter Storm Elliott. Recently, NERC indicated that it would release initial findings in late summer or early fall 2023.
- In the words of NERC CEO Jim Robb: "This storm underscores the increasing frequency of significant extreme weather events (the fifth major winter event in the last 11 years) and underscores the need for the electric sector to change its planning scenarios and preparations for extreme events."
- Since December, affected system operators have been conducting reviews to determine root causes and potential changes in planning, processes, and communication. While storms such as Elliott are unusual, they are not rare.
  - Notably, a second brief but powerful polar vortex lasting from February 3 to February 4 drove extremely low temperatures and bitter wind chills from New England through the Mid-Atlantic and upper Midwest.
  - At one point, Mount Washington in New Hampshire was purportedly colder than Mars with a temperature of -47° F, wind gusts of 127 miles per hour, and a wind chill below -100° F.
- As such, with growing electrification and a changing resource mix, grid operators will need to adapt their approaches to cold weather stresses on the grid.

KEY TAKEAWAYS

While much attention has been paid to summer reliability, the grid remains vulnerable to extreme cold snaps. Winter Storm Elliott illustrated this, as unexpected weekend holiday demand coupled with poor weather-related generator performance pushed some regional grids to the edge.

Emergency measures, particularly through demand reduction, helped avoid more significant and extended disruption.

The utility industry has known for more than a decade that gas and power were interdependent, but progress has been halting; the industry must look more closely at where continued improvement in planning and processes is needed.

Looking ahead, increased electrification will amplify this challenge.

The Bills Come Due

- PJM has estimated that nonperformance penalties could total up to $2 billion, as it lost about 23% of generating capacity during the Elliott event.
- Some assessments are significant and financially consequential:
  - NRG, for example, estimated an $80 million impact on earnings, in part from performance penalties as some of its large units had long startup times.
  - Lincoln Power, a Carlyle Group subsidiary that operates more than 900 MWs in PJM, declared Chapter 11 bankruptcy after being levied $39 million in penalties by PJM, which also requested $7 million in collateral against those obligations.
- Some generators are challenging the penalties, seeking recalculations and refunds.
  - One group asserts that PJM's load underestimation (discussed later) led to inadequate day-ahead market commitments and that its declaration of a maximum generation event came too late for units that required emergency dispatch to procure natural gas.
  - Generators also assert that PJM should not have called upon their units because transmission constraints prevented their deliverability into PJM's eastern footprint and that it should have stopped all non-firm exports before instituting emergency procedures.
- FERC, meanwhile, approved on April 3 a PJM plan to invoice the nonperformance penalties (and delay related overperformance bonuses) over nine months to reduce generator financial stress and potential defaults. One can expect more litigation over these issues.

Early Observations Indicate Myriad Challenges

- While Winter Storm Elliott caused significant struggles, utility actions appear to have averted a worst-case scenario.
  - Duke Energy officials noted in a North Carolina Utilities Commission hearing that had they not instituted rolling outages, grid instability could have knocked out the Eastern Interconnection.
  - Additionally, despite their own generation struggles, exports from MISO and PJM provided valuable assistance to neighboring regions, including those of TVA and Southern Company.
  - Imports from Canada also played a major role in keeping the lights on. During the height of the storm, MISO imported a combined 2.9 GW from Ontario and Manitoba.
- As mentioned above, generally reliable fossil resources were a major source of generation outages during the storm. In addition to generation, fuel supply systems also faced complications. At the peak of outages in PJM, more than 10,000 MW of fossil generation were forced offline due to fuel supply problems. Similarly, other regions cited low pressure in gas pipelines as a reason for decreased performance of certain gas generators.
- Conversely, wind generation outperformed expectations during the storm; however, a lack of transmission capacity led to significant curtailments, wasting valuable power. At some points during the storm, the Southwest Power Pool had more than 3 GW of wind power curtailments due to the lack of transmission capacity.
- A major source of unpreparedness arose due to incorrect load forecasts. Forecasted load was understated by around 10% for Duke Energy Carolinas and was 8,000 MW short in PJM. Due to forecast inaccuracy, utilities were not nearly as prepared as they were expected to be. This compounded the fact that natural gas generators were unable to provide adequate reserve generation or, in some cases, procure fuel over the holiday weekend.

Figure 3.1A: **Survey of Winter Storm Elliott Impacts**

GRID OPERATOR	ISO New England (ISO-NE)	New York ISO (NYISO)	PJM Interconnection (PJM)	Midcontinent ISO (MISO)
OPERATIONAL CHALLENGES	▪ ISO-NE experienced 2.2 GW of outages at the peak hour of the storm, 32.5% of which were outages of dual fuel generators, and the majority of the outages were cited as mechanical issues. ▪ The ISO states that the public was not in danger of emergency or outages on the bulk power system, yet outages led to more than 500,000 customers losing power throughout the region, mostly caused by storm-related damage to distribution systems.	▪ The storm had minimal impacts on NYISO compared to other regions. The ISO credits dual fuel capabilities as a major reason they were able to maintain reliability despite the conditions. ▪ The storm caused minimal interruptions to generation and some freezing to pipelines as well as a brief interruption of service for Con Edison.	▪ PJM's models under-forecast load by 10% during the peak of the storm. ▪ At the peak of the storm, PJM was missing approximately 57 GW of the available generation fleet due to outages and fuel-related issues. Notably, 63% of outages were natural gas. ▪ An emergency order went into effect at the height of the storm, requiring all units to operate at their maximum output.	▪ MISO reported 23 GW of unplanned generation outages, of which 10 GW were due to fuel issues, and 8 GW due to mechanical issues. Gas generation was heavily affected by the fuel outages. ▪ MISO received significant imports from Canada and PJM during the storm but was not at load risk, so they were able to export power to neighboring regions, including sales of emergency energy to TVA.
ADDITIONAL CHALLENGES	▪ As a result of the storm and its effects to customers, 11 senators wrote a letter to the ISO requesting an explanation for the outages and demanding steps be taken to prevent future occurrences. ▪ In response to the senators, the ISO notes the limited fuel infrastructure and changes in the LNG market have caused issues in maintaining adequate fuel reserves.	▪ The rate of change of the temperature was as noteworthy as the absolute temperature. The region cited that temperatures fell from 50° F to 15° F with wind chills as low as 10° F within the span of eight hours.	▪ PJM has estimated $1 to $2 billion in penalties for generators that failed to perform as required during the weather event. ▪ The performance penalties have resulted in bankruptcy filings and pushback from FERC. ▪ PJM's winter assessment planned an outage contingency of 16.5 GW, a fraction of the outages that occurred during the storm.	▪ The 23 GW of outages during Winter Storm Elliott is slightly less than the 24 GW of outages MISO experienced during Winter Storm Uri, leading to questions about preparedness and lessons learned. ▪ Unlike during Uri, wind generation performed significantly above average during Elliott, averaging close to 20 GW of output through the storm.

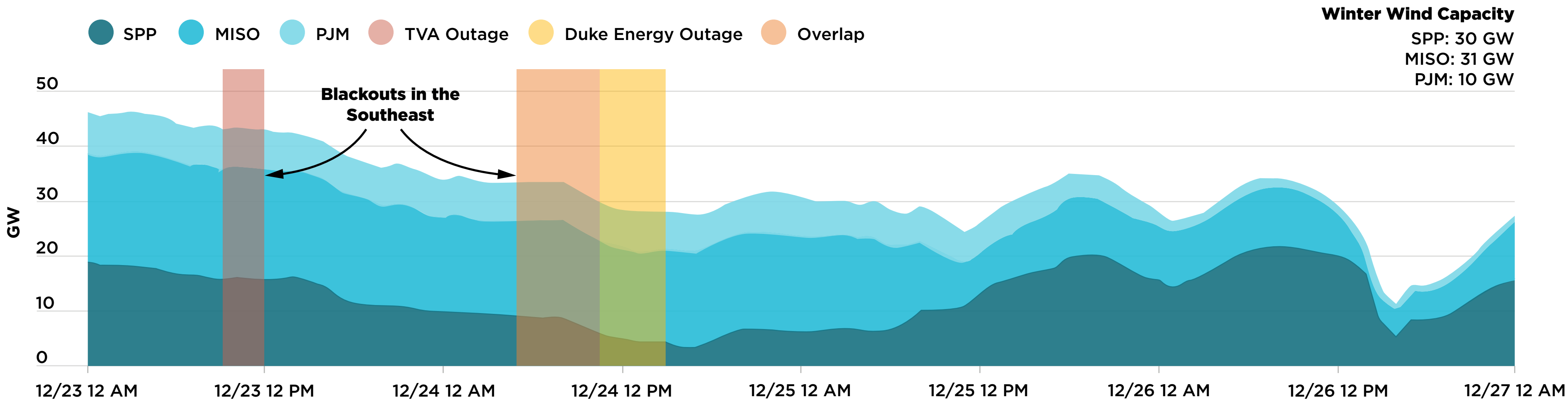
Note: See also ScottMadden Infographic, "Winter Storm Elliott: Grid on the Edge," at **www.scottmadden.com/insight/winter-storm-elliott-grid-on-the-edge/**.

Figure 3.1B: **Survey of Winter Storm Elliott Impacts (Cont.)**

GRID OPERATOR	**Electric Reliability Council of Texas (ERCOT)**	**Duke Energy Carolinas/ Duke Energy Progress**	**Tennessee Valley Authority (TVA)**	**Louisville Gas & Electric Co. (LG&E) and Kentucky Utilities Co. (KU)**
OPERATIONAL CHALLENGES	▪ ERCOT's peak demand during Elliott surpassed its previous demand record and exceeded forecasts by 13 GW, yet the region was able to avoid outages seen during Winter Storm Uri. ▪ The prolonged low temperatures impacted portions of the gas fuel supply system, limiting the ability to deliver fuel to some gas-fired generators.	▪ The storm caused steep demand increases in both the Carolinas and Progress territories, each increased by 4 GW between 3 pm and 10 pm. ▪ Duke had 3.7 GW of coal and gas resources offline during the storm mostly due to unplanned outages. ▪ Complications due to Winter Storm Elliott led to the first-ever rolling outages in Duke Energy's Carolinas and Progress territories.	▪ TVA lost 6.7 GW of coal, gas and independent power producer generation during the storm. ▪ For the first time in its 90-year history, TVA was forced to implement emergency procedures directing local power companies to reduce power demand, which resulted in localized interruptions.	▪ LG&E noted that significant pressure drops on the interstate Texas Gas Pipeline forced two of their major gas-fired plants to cut generation by almost 50% during the storm. ▪ The utilities were forced to enact rolling blackouts for three hours, impacting less than 5% of the customer base.
ADDITIONAL CHALLENGES	▪ The region's operating reserves remained above critical levels throughout the storm, so an emergency alert was never issued. ▪ ERCOT's weatherization & inspection team examined 255 resources, only four of which experienced weather-related outages during the storm.	▪ Overall, approximately 500,000 customers, 15% of their customer base, were affected. ▪ Duke Energy testified to the North Carolina Utilities Commission that its equipment is weatherized.	▪ TVA set a new winter peak record of more than 33 GW during the storm. ▪ In order to replace missing capacity, TVA was forced to make significant amounts of power purchases. TVA estimates that the financial impact of the storm totaled about $170 million.	▪ Peak demand during the storm was roughly 16% higher than the utilities forecasted.

Note: See also ScottMadden Infographic, "Winter Storm Elliott: Grid on the Edge," at **www.scottmadden.com/insight/winter-storm-elliott-grid-on-the-edge/**.

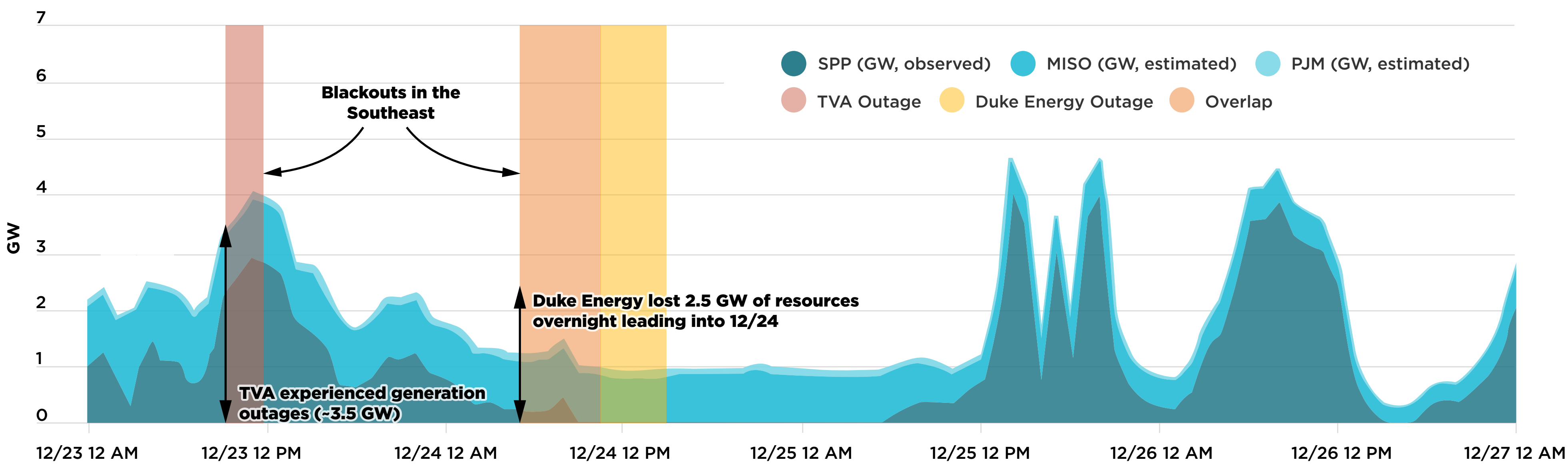
Figure 3.2: **Wind Power During Winter Storm Elliott (GW)**



Notes: All times are in Central Standard Time. TVA's periods of rolling blackouts are in red, while Duke Energy's outage period is in yellow (orange indicates overlap).

Source: Rocky Mountain Institute

Figure 3.3: **Wind Curtailments by ISO during Winter Storm Elliott (GW)**



Notes: All times are in Central Standard Time. SPP reports the amount of wind curtailed in its footprint, while MISO and PJM do not explicitly do so. To estimate the amount of wind curtailed in MISO and PJM, the 2021 annual average curtailment rate from LBNL's "Land-Based Wind Market Report: 2022 Edition" was applied to the reported hourly wind generation profile in the two regions. TVA's periods of rolling blackouts are in red, while Duke Energy's outage period is in yellow (orange indicates overlap).

Source: Rocky Mountain Institute

FERC Actions on 2021's Winter Storm Uri Arrive After Elliott

- On February 16, 2023, FERC approved the implementation of two new extreme cold weather reliability standards derived from the findings of a joint inquiry of FERC and NERC into 2021's Winter Storm Uri. The standards will implement:
  - Generator freeze protection measures
  - Enhanced cold weather preparedness plans
  - Identification of freeze-sensitive equipment in generators
  - Annual training for generator maintenance and operations personnel
  - Procedures to improve the coordination of load reduction measures during a grid emergency
- Along with the approval of the measures, FERC directed NERC to modify the standards in any way it thinks will address concerns related to applicability, ambiguity, a lack of objective measures and deadlines, and prolonged, indefinite compliance periods. FERC also directed NERC to collect data in order to monitor and assess the implementation of the new requirements.

IMPLICATIONS

While Winter Storm Elliott caused significant outages in some regions, utilities were able to mitigate most of the damages, avoiding a catastrophe similar to Winter Storm Uri in 2021. That being said, there are still significant lessons to be learned from this event.

Fossil generation proved to be less reliable than expected and demand forecasts in some regions proved to be entirely inadequate. Additionally, increased transmission capacity could have negated some of the problems by reducing curtailments and increasing import capacity.

In the short term, utilities will have to respond to regulators' inquiries into system shortcomings. Planning and resource adequacy may need to be adapted to prepare for future extreme weather events.

The post-mortem analyses by both grid operators and FERC and NERC should be monitored and lessons learned as these issues can and will impact all systems.

Sources:

ISO-NE; NYISO; MISO; PJM; SPP; S&P Global Market Intelligence; Megawatt Daily; Utility Dive; Mt. Washington Observatory data; EIA; FERC; TVA, After Action Report: Winter Storm Elliott (May 2023); North Carolina Utilities Comm'n; National Weather Service; ScottMadden Infographic, "Winter Storm Elliott: Grid on the Edge," at www.scottmadden.com/insight/winter-storm-elliott-grid-on-the-edge/; industry news; ScottMadden research

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INTERACTIVE INFOGRAPHIC

Winter Storm Elliott: Grid on the Edge

ARTICLE

Grid Reliability Is Changing Before Our Eyes

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Gas Utility Developments: Where To From Here?

Evolving regulatory and market conditions create an uncertain outlook for natural gas local distribution companies (LDCs).

Major Industry Trends Keeps LDCs Focused on Customer Affordability

- Throughout the 2010s, consistently low natural gas commodity prices, due in part to the shale boom boosting production, offset growing costs for pipeline integrity improvement programs. However, over the past several years, a more cautious approach to production increases and geopolitics factors have affected global gas markets, causing increased price volatility and the possible end of sustained low prices.
- Gas prices have moderated after their highs in 2022 (see Figure 4.1), and many analysts predict prices will continue to trend toward pre-pandemic levels. However, gas prices over the longer term remain uncertain due to fundamental supply and demand factors:
  - Anticipated reliance on natural gas through the energy transition, but eventual flattening of demand (over an undefined period) as more renewable resources come online
  - Higher production in the United States, with more disciplined production capex
  - Increasing U.S. liquefied natural gas (LNG) export capacity will attempt to support strong global LNG demand in the near term as Europe seeks alternative gas sources to offset Russian piped gas
  - Impacts of methane regulation on cost of gas
  - Generalized impacts of inflation (wages and materials) and higher interest rates on commodity costs
- While low gas prices have kept customer bills low despite increasing costs for LDC capex, recent higher gas costs have increased customer bills, highlighting the need for LDCs to continue to manage costs aggressively.

Figure 4.1: **Weekly Henry Hub Natural Gas Spot Price (Week of Jan. 1, 2010–Mar. 17, 2023) ($/MMBtu)**

Sources: AGA; EGI

KEY TAKEAWAYS

There is significant uncertainty in the gas LDC sector, as the years' long trend of low commodity prices has been upended by recent global market disruptions. Rising costs have forced utilities to continue to emphasize cost efficiency to ensure affordability despite increased gas commodity price volatility.

Spurred by methane reduction objectives and safety needs, gas utilities continue to invest in system modernization. However, debates over the role of natural gas continue, spurring concern about a static or declining customer base and potential stranded costs.

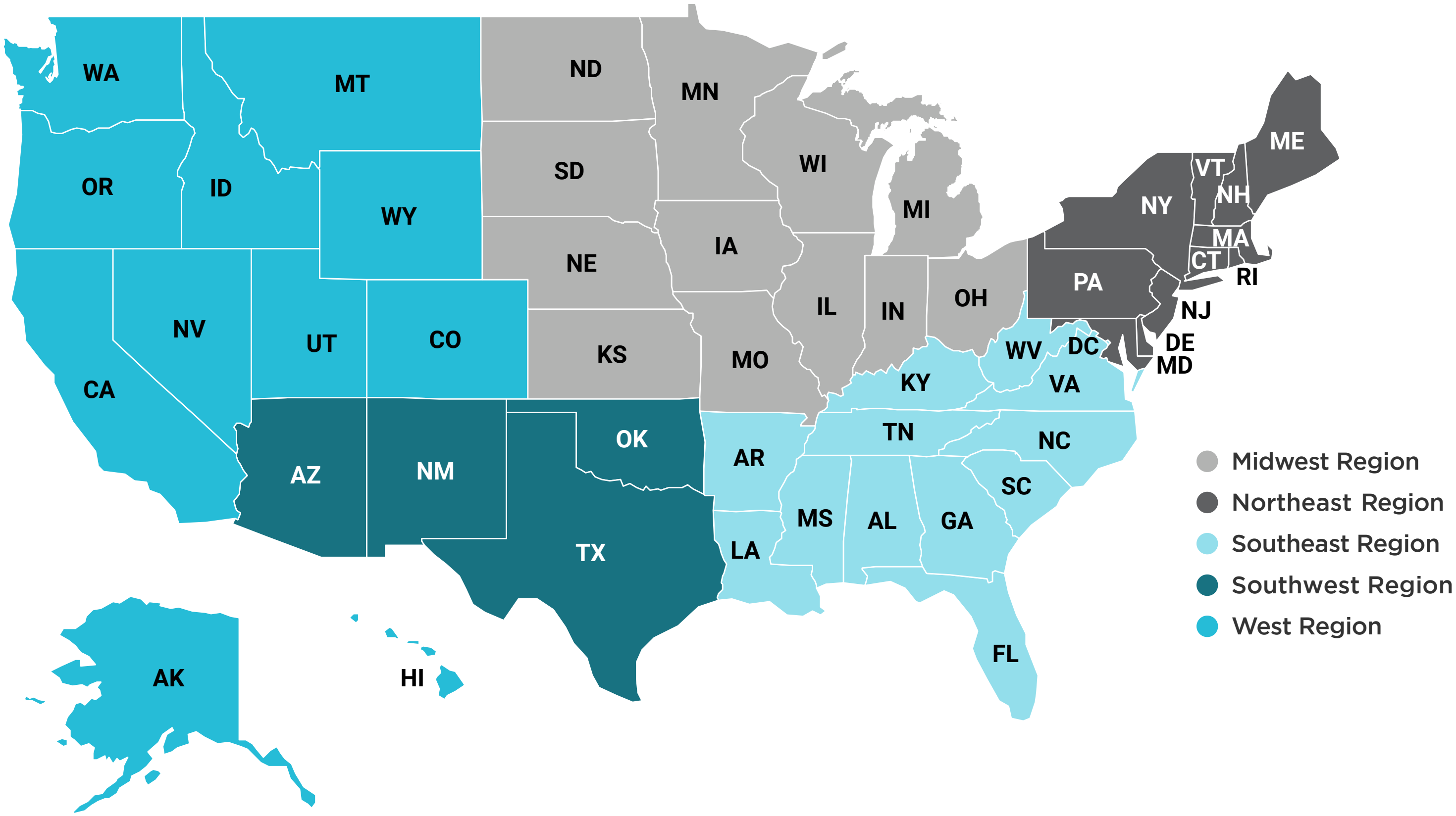
To support a lower carbon regime, renewable natural gas, non-pipeline alternatives, and hydrogen offer ways to reduce emissions while maintaining the use of existing infrastructure.

Figure 4.2: **Selected U.S. Natural Gas Distribution Utility Statistics by Region (2021)**

West
Avg. no. of customers per mile of main: 54.7
Avg. % of gas lost/unaccounted for: 0.645%
Avg. purchased gas cost per decatherm: $2.87

Midwest
Avg. no. of customers per mile of main: 47.5
Avg. % of gas lost/unaccounted for: 0.509%
Avg. purchased gas cost per decatherm: $3.10

Northeast
Avg. no. of customers per mile of main: 76.4
Avg. % of gas lost/unaccounted for: 1.148%
Avg. purchased gas cost per decatherm: $3.46



Southwest
Avg. no. of customers per mile of main: 46.3
Avg. % of gas lost/unaccounted for: 1.27%
Avg. purchased gas per decatherm: $2.10

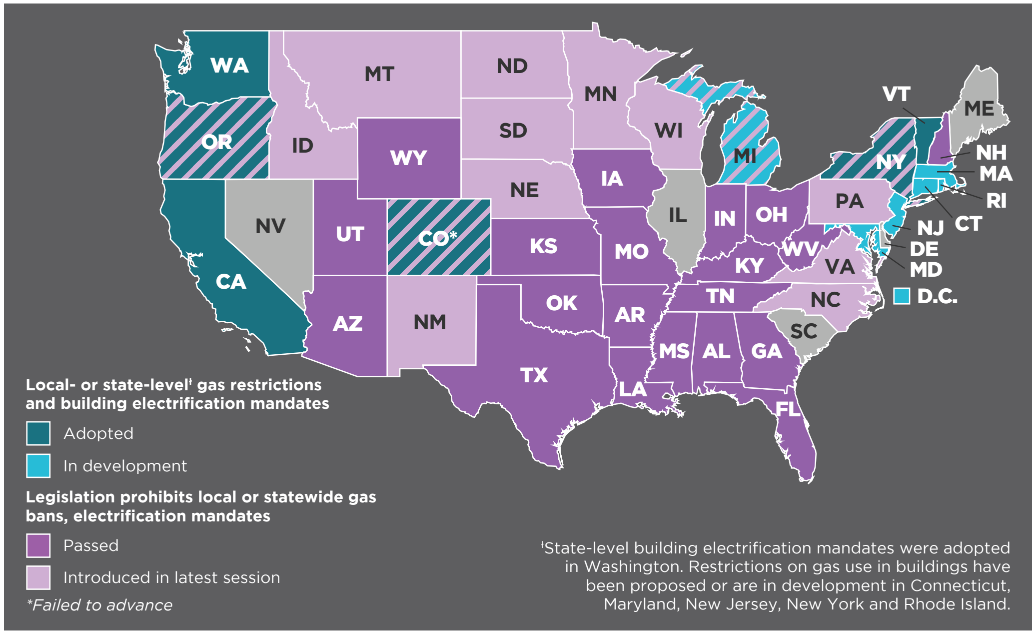
Southeast
Avg. no. of customers per mile of main: 42.8
Avg. % of gas lost/unaccounted for: 1.184%
Avg. purchased gas cost per decatherm: $2.48

Source: ScottMadden LDC Database

Continued State Divergence on Natural Gas Bans

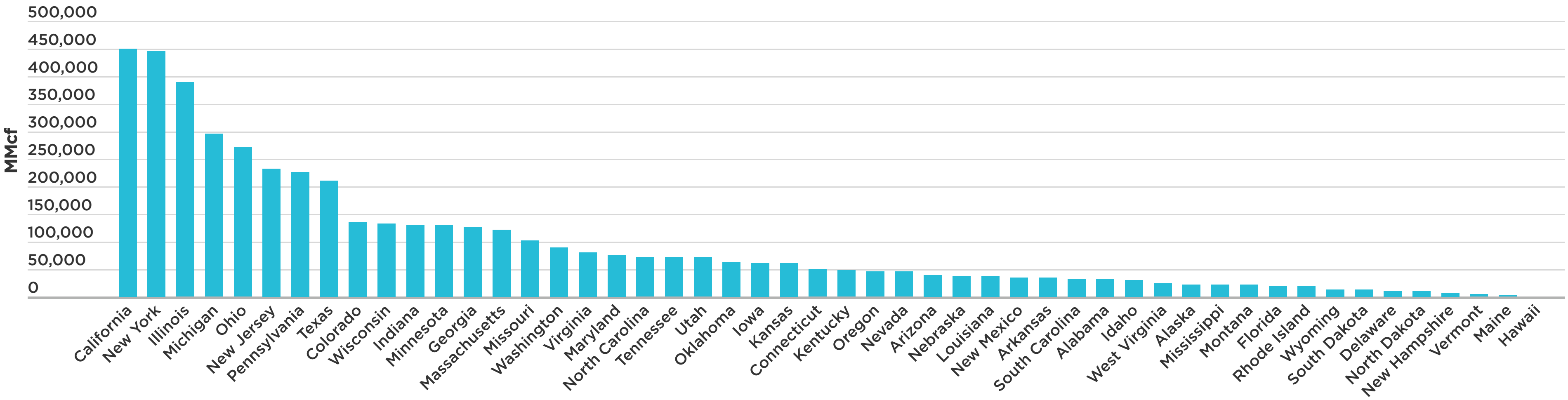
- A dichotomy exists in states' attitudes toward the future use of natural gas. As of mid-February 2023, there were six states in which either the whole state or certain localities had enacted restrictions on gas hookups for new buildings along with electrification mandates (see Figure 4.3). Four more states and the District of Columbia are developing similar restrictions. Currently, Washington is the only state with a statewide all-electric construction mandate.
- In contrast, as of mid-February 2023, 20 states had enacted legislation prohibiting gas bans. More states have introduced similar legislation to prohibit bans; however, in many of those cases, the legislation failed to advance.
- Notably, the two largest states in terms of residential natural gas volume—New York and California—are among states in which some localities have enacted bans on gas hookups for new construction (see Figure 4.4). New York is currently considering banning new gas hookups statewide, with a measure that is on track to be added to the state's coming budget.

Figure 4.3: **State Legislation on Gas Bans**



Source: S&P Capital IQ Pro **Note:** As of Feb 17, 2023.

Figure 4.4: **Residential Natural Gas Consumption by State (2021) (MMcf)**



Source: EIA

Beyond Debates on Gas Bans: States and Utilities Explore the Future of Gas

- While debates over permitting natural gas as an energy source in new construction persist, state policymakers, regulators, utilities, and other stakeholders in various jurisdictions are examining the future role of natural gas, including infrastructure investment programs and decarbonization efforts.
- One conundrum for the utility industry is that regulation in some states pushes for utility investment in electrification, while expecting utilities to maintain natural gas infrastructure for both reliability and safety.
  - The push for electrification affects the number of gas customers and, depending upon its extent, could shrink the overall customer base. Despite this, gas companies are expected to maintain their current infrastructure, which in the case of a reduced customer base, spreads costs over fewer customers.
  - Further, for combination utilities, managing gas infrastructure and an increasing push to electrify their customer bases could create additional cost-to-serve challenges.
- Some states and utilities have either planned for or conducted expansive studies into the future of gas in their respective energy mixes. For example, in response to an executive order from the governor, the New Jersey Board of Public Utilities initiated a proceeding in March 2023 to determine how the gas industry can best meet the state's goal of 50% emissions reduction from 2006 levels by 2030. The proceeding will consider what role natural gas should play in emissions reduction, as well as how the industry can manage changes to its business and customer base.
- Some jurisdictions have approached decarbonization issues through various discrete policies and initiatives. A few examples are shown in Figure 4.5 on the next page.

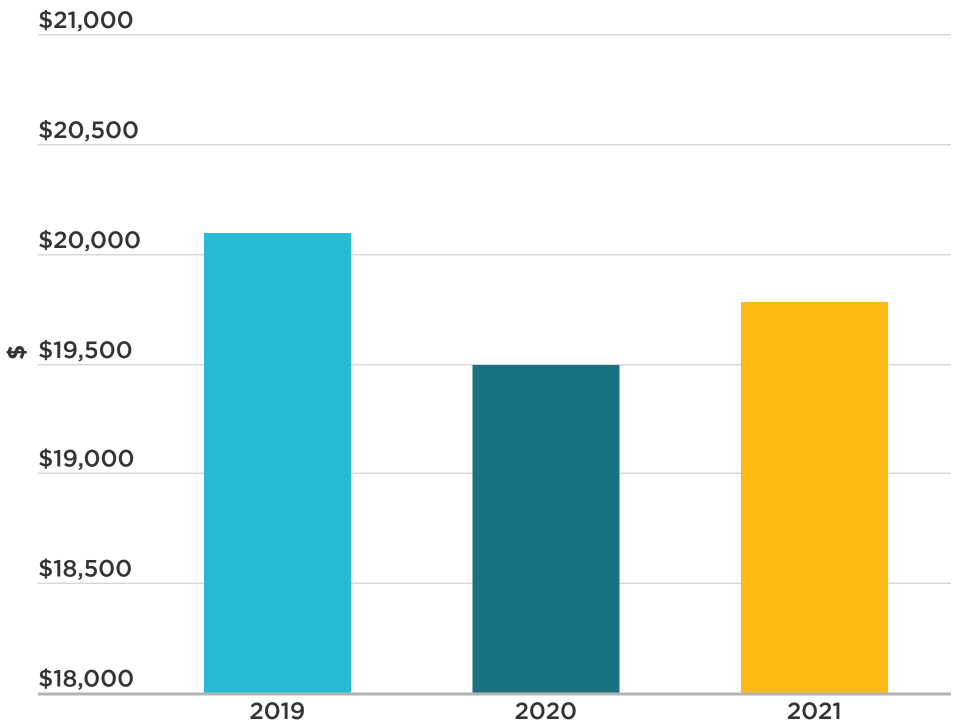
Figure 4.5: **Selected Regulatory and Utility Actions on Decarbonization in the Gas LDC Sector**

	Selected Regulatory and Utility Actions on Decarbonization in the Gas LDC Sector
Changing line extension policies	▪ Several states and local jurisdictions have restricted gas line extensions, and regulators in states, such as California, Colorado, and Washington, have modified gas line extension allowances making the build-out of gas infrastructure less financially viable. ▪ Opponents of changing line extension policies have promoted the affordability and reliability of natural gas, as well as the need to preserve customer choice and protect the obligation to serve.
Terminating gas efficiency programs	▪ California's utility regulators voted to phase out funding for natural gas energy efficiency incentives in residential and commercial new construction. The order complements regulatory efforts to support building decarbonization and electrification. ▪ A cost-effectiveness framework for efficiency measures and working groups to evaluate viable electric alternatives for gas measures was established to alleviate concerns regarding the customers' bill impact of the phase out.
Hybrid-heating programs	▪ Hybrid-heating systems use smart control technologies to alternate the operation of an electric heat pump with a gas-fired boiler or furnace. The heat pump generally provides heating during moderate winter temperatures, while the gas-fired system operates during the coldest periods. ▪ Hybrid-heating shifts electric load to gas during winter peak periods, mitigating the need for distribution capacity upgrades and additional electric peak generation capacity. Additionally, hybrid-heating systems enable decarbonization through reduced gas consumption and switching to lower marginal emitting resources during peak periods. ▪ In North America, hybrid heating has been implemented most notably via a partnership between Hydro-Quebec and Energir in Quebec.
Requirement to conduct non-pipes analysis	▪ Several states, such as Colorado and New York, have requirements to assess non-pipes alternatives (NPAs) before making significant investments in gas infrastructure. NPAs can include demand-side solutions such as energy efficiency and electrification measures as well as supply-side solutions such as trucked compressed natural gas or liquefied natural gas (LNG). ▪ Benefits of NPAs include potential cost reductions, lower carbon emissions, cost savings for ratepayers, reduction in regulatory risks related to pipeline investments, and reduction in stranded asset risks.
Hydrogen and networked geothermal pilots	▪ Gas utilities are actively exploring and developing alternative energy sources, such as hydrogen and networked geothermal, as part of their efforts to decarbonize their operations. Numerous gas utilities, including Duke Energy, Xcel Energy, and Northwest Natural Gas, have made plans to blend low-carbon hydrogen into their distribution systems. ▪ Additionally, networked geothermal systems offer LDCs the potential to reduce GHG emissions, avoid gas infrastructure investments, and leverage their existing workforce in operating the systems. Several utilities, including Eversource Energy, National Grid, and Orange & Rockland Utilities, have networked geothermal projects that are underway.

Focusing on Operating Efficiency

- As mentioned above, the uptick in natural gas prices in 2022 and its potential effect on gas bill headroom to cover other expenses has led gas utilities to focus on ways to keep rates affordable. One area of interest is keeping O&M expenses flat or reducing them through operational efficiencies, leveraging process and technology improvements.
- It is notable that from 2019 to 2021, O&M costs declined across the LDC industry (see Figures 4.6A-B). The year 2020 was expected to be an exception, with significantly lower O&M due to COVID-19; however, O&M spend did not return to pre-pandemic levels in 2021, reflecting continued efforts at maintaining an efficient cost structure.

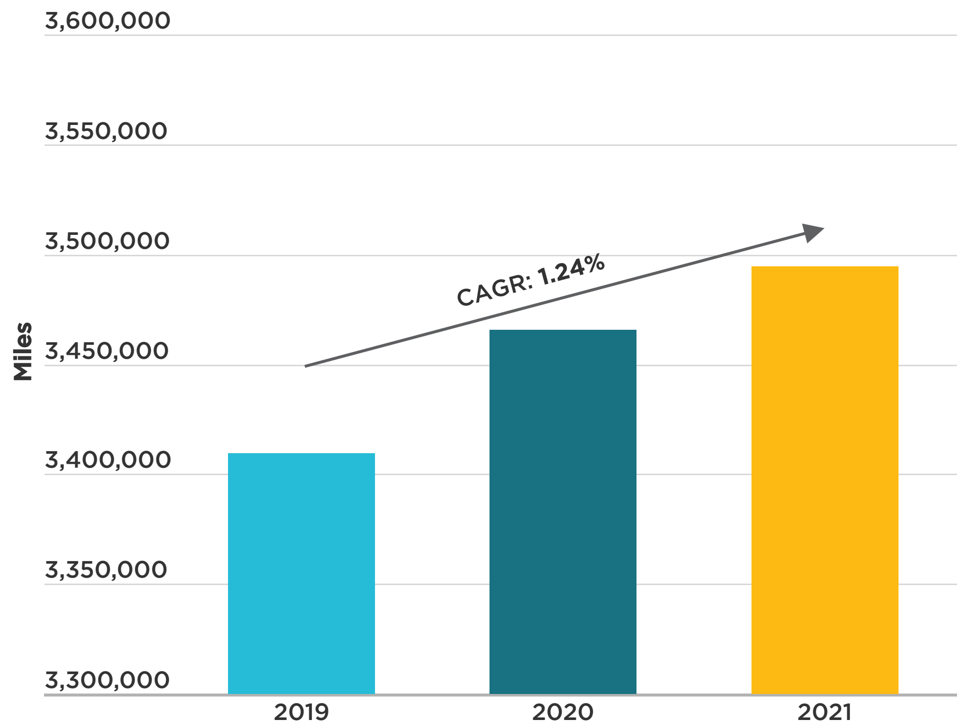
Figure 4.6A: **Total U.S. Investor-Owned Natural Gas Distribution Company Operation & Maintenance Expense* Per Mile of Distribution Main ($)**



Note: *Less production costs.

Source: ScottMadden LDC Database

Figure 4.6B: **Total Miles of Mains for U.S. Investor-Owned Natural Gas Local Distribution Utilities**



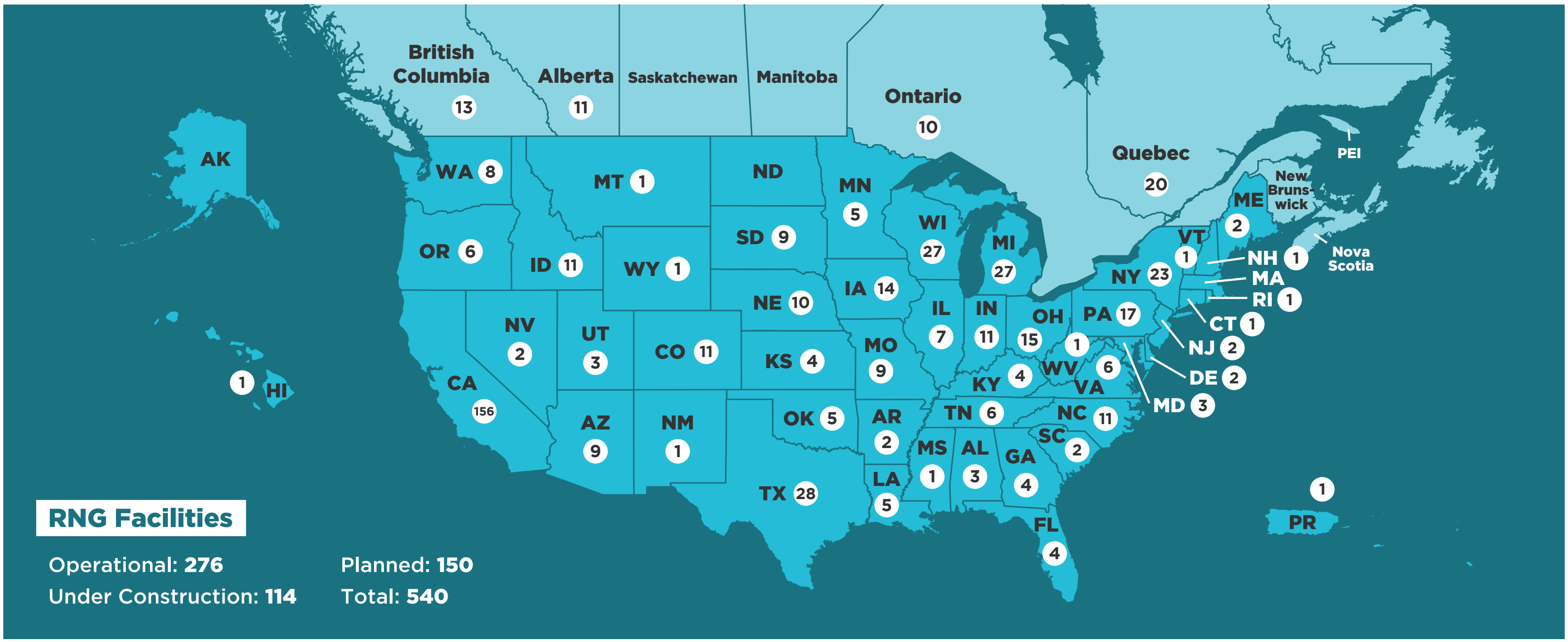
A Few Strategic Transactions: Are More Coming?

- Accompanying the uncertainty surrounding the long-term role of gas utilities and selected local opposition to growth of gas use, some utility and financial players are making strategic bets on LDC properties.
- Recently, J.P. Morgan purchased South Jersey Industries (SJI) in a deal finalized February 1, 2023. SJI is a holding company whose subsidiaries operate gas distribution systems that served more than 384,000 customers at the end of 2021. In statements made by both parties, the transaction is noted as bringing together SJI's environmental goals with J.P. Morgan's resources and expertise.
- Similarly, Summit Utilities (also owned by J.P. Morgan) purchased CenterPoint's gas assets in a deal that was finalized in January 2021. Through this deal, Summit acquired distribution assets, which included 17,000 miles of gas mains that serve approximately 525,000 customers. After the completion of the deal, CenterPoint's CEO stated: "Completing the sale of these natural gas distribution businesses will help us achieve a number of our strategic goals, including efficiently funding our long-term capital investment plans...and allowing us to focus our efforts on executing our plan across fewer jurisdictions."
- Southwest Gas Holdings divested its Mountain West subsidiary in a deal finalized in February 2023. Mountain West's assets were comprised of roughly 2,000 miles of interstate gas transmission pipelines, totaling about 8 Bcf/d of transmission capacity. Southwest Gas stated the sale was "a significant step toward returning Southwest Gas to its core regulated utility business," continuing that its planned spin-off of Centuri will help further that goal.
- Some owners of gas utilities continue to evaluate whether to keep those businesses in their portfolios. Expect to see continued realignment as gas players decide their long-term strategies.

Carbon Reduction, Safety, and Reliability Drives Spending

- As natural gas works out its role in the energy transition, one of the transition's major goals—carbon reduction—has grown into a driver of capital expenditures for LDCs. In 2020, leaks from natural gas and petroleum systems made up 32% of methane emissions in the United States. For both emissions reduction and safety, LDCs continue to focus on pipeline replacement and modernization programs, with the following recent trends for reporting U.S. gas utilities:
  - From 2019 to 2021, main leaks repaired declined 10.4%, service leaks repaired declined 3.6%, and hazardous main leaks repaired declined 11.3%.
  - The number of known system leaks scheduled for repair has increased 6.8% from 2019 to 2021. Presumably, this increase in scheduled repairs is intended to remedy this backlog.
  - Finally, the total number of main miles has increased only slightly (2.5% over the same period), indicating that the majority of capital being deployed is for replacements.

Figure 4.7: **Proposed and Operational Renewable Natural Gas (RNG) Projects in North America (as of Nov. 21, 2022)**



Source: The Coalition for Renewable Natural Gas

Carbon Reduction, Safety, and Reliability Drives Spending (Cont.)

- In order to incentivize the reduction of methane emissions from gas systems, recent legislation has created programs to appropriate funds to speed up emissions reductions and to levy fees on companies that do not keep their emissions in check.
  - The Inflation Reduction Act (IRA) appropriated $1.55 billion for the Methane Emissions Reduction Program, which will fund grants and technical assistance to accelerate emissions reduction from petroleum and natural gas systems.
  - The IRA also established a methane emissions fee in Sec. 60113. The program imposes a maximum annual methane waste rate of 25,000 metric tons of CO_2-equivalent per facility and imposes penalty charges starting at $900/metric ton of methane in 2024 and increasing to $1,500/metric ton by 2026 for excess emissions.
- Options like RNG, NPAs, and in the future, hydrogen, have been receiving increasing attention.
  - RNG specifically has received major interest from many LDCs, with some having operational projects (see Figure 4.7 on previous page).
  - NPAs are a tool LDCs are using to minimize spending and reduce emissions. NPAs exist both on the demand side and supply side and consist of activities or investments that delay, reduce, or avoid the need to build or upgrade traditional gas infrastructure (see Figure 4.8).
  - Hydrogen, discussed in detail on the next page, offers a carbon free fuel which can make use of the extensive gas infrastructure that will continue to exist regardless of the role of gas in the future of the energy industry.

Figure 4.8: **Examples of Non-Pipes Solutions**

Demand-Side Solutions	Supply-Side Solutions
Targeted Demand Response	Targeted Demand Response
Targeted Energy Efficiency	On-system Renewable Natural Gas
Heat Pumps	On-system LNG Peaking Storage
Thermal Storage	Compressed and LNG Trucking (Virtual Pipelines)
Other Electrification and Fuel Switching	LNG Liquefaction Port Terminals
Behavior Change	

Source: ICF International

Looking to the Future: Hydrogen

- Many energy transition observers and advocates expect hydrogen to be a fuel of the future, with the potential to replace natural gas and make use of the extensive gas infrastructure that currently exists. It is currently in the early development stages. However, there is significant investment on the horizon, both from utilities and legislators.
- Utilities have for years been investigating and investing in pilot projects working on the production of blue and green hydrogen, which have differing levels of emissions, fuel blending, hydrogen hubs, and hydrogen microgrids (see Figure 4.8).
- Hydrogen has also received interest from policymakers. The Infrastructure Investment and Jobs Act includes $8 billion for Regional Clean Hydrogen Hubs, $1 billion for a Clean Hydrogen Electrolysis Program, and $500 million for Clean Hydrogen Manufacturing and Recycling Initiatives. Additionally, the IRA created production tax credits of up to $3/kg for clean hydrogen plants.
- The Regional Clean Hydrogen Hubs (H2Hubs) program is designed to create networks of hydrogen producers, consumers, and local connective infrastructure to accelerate the use of hydrogen. The DOE envisions selecting 6 to 10 H2Hubs for a combined total of $6–$7 billion in federal funding. Overseen by the DOE's Office of Clean Energy Demonstrations, the program received 79 concept papers through late 2022 requesting a total of $60 billion in federal funding, with 33 papers encouraged and 46 discouraged. Full applications were due on April 7, 2023. At this time, it is unclear who was awarded funding and whether any winner's partners included gas utilities.

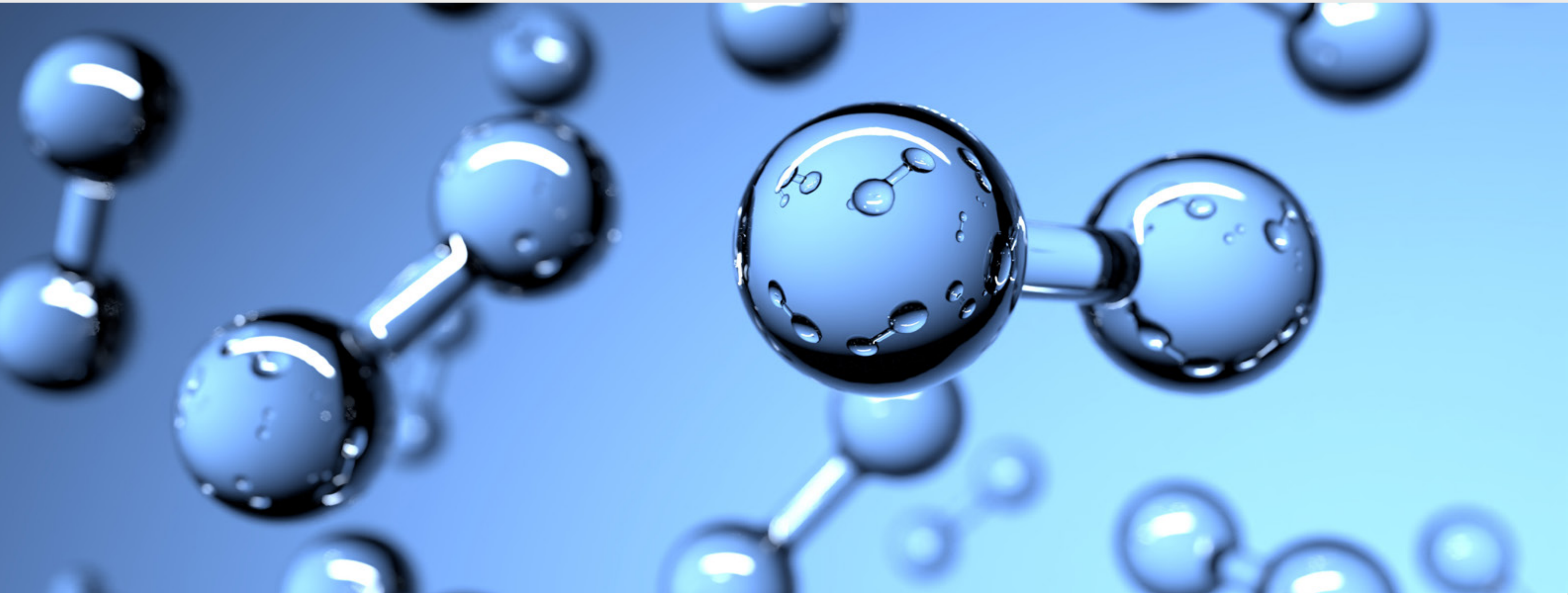


Figure 4.9: **Selected Gas Utility Hydrogen Projects**

Utility	Selected Gas Utility Hydrogen Projects	
Enbridge	Begun operation of hydrogen blending pilot for 3,600 customers, with another blending project serving 43,000 customers expected in 2025	Launched a power-to-gas facility in 2018, capable of producing green hydrogen with excess renewable power
Northwest Natural Gas	Hydrogen Blend Testing: Testing of 5% underway, with a 20% blend goal by 2024 (if learnings allow) at Northwest Natural's state-of-the-art training facility	Turquoise Hydrogen Pilot Project: Partnering with Modern Electron to turn methane into clean hydrogen and solid carbon
Southwest Gas	Filed for approval of a hydrogen-blending demonstration project with California PUC on September 8, 2022	
South Jersey Gas	Currently performing a Green Hydrogen Pilot program	
New Jersey Resources	First utility on the East Coast to blend green hydrogen into its fuel stream	
Southern California Gas	Filed hydrogen-blending application with California PUC	Successfully tested its H2 Innovation Experience microgrid

Hydrogen Blending | Pilot Programs | Power-to-Gas

Sources: ScottMadden research; company investor presentations

IMPLICATIONS

Gas utilities face multiple challenges and opportunities. The direction of gas commodity prices is uncertain after a long period of plentiful and cheap natural gas. Capital programs (and related costs) are needed to upgrade and replace infrastructure for leak reduction, to reduce methane emissions, and for safety and reliability. Depending upon the utility's jurisdiction, there are mixed and evolving policy postures regarding the role of end-use gas in the energy transition.

To navigate this environment, gas LDCs will have to consider various management priorities, including:

- **Evaluation of gas utility implications of changes in regulatory policies and customer demands**
- **Capital cost management and oversight**
- **Constructive relationships with stakeholders, particularly with respect to investments that enhance efficiency and decarbonization, such as NPAs, RNG, and (over the longer term) hydrogen**
- **Communication of the value of gas as an end-use energy resource, particularly for heating and hard to decarbonize applications**
- **Long-term strategies that consider scale economies, balance sheet strength, steady returns, and other factors that inform transaction decisions**
- **O&M cost management and commodity risk management approaches that keep customers' bills stable and affordable**

Sources:

RBC Capital Markets, "U.S. Power & Utilities: 2023 Best Ideas Portfolio" (Jan. 17, 2023); AGA, AGA Playbook 2023 (Jan. 2023); J.P. Morgan, "High Grade and High Yield Power & Utilities" (Nov. 2022); S&P Capital IQ, "States that outlaw gas bans account for 31% of US residential/commercial gas use" (June 9, 2022); Advanced Energy Economy, "Non-Pipeline Alternatives (NPAs)" (Oct. 2022); RBC Capital Markets, "2023 Global Energy Outlook" (Dec. 7, 2022); EIA, "Introduction to the EIA and the U.S. Natural Gas Market" (Jan. 18, 2023); EPA, "Overview of Greenhouse Gases," at www.epa.gov/ghgemissions/overview-greenhouse-gases (last updated May 16, 2022); DOE, Office of Clean Energy Demonstrations, "Regional Clean Hydrogen Hubs," at www.energy.gov/oced/regional-clean-hydrogen-hubs (accessed Mar 30. 2023); DOE Press Release, "DOE Establishes Bipartisan Infrastructure Law's $9.5 Billion Clean Hydrogen Initiatives" (Feb. 15, 2022); White House Office of Domestic Climate Policy, "U.S. Methane Emissions Reduction Plan" (Nov. 2021); EPA; Holland & Knight; company investor presentations and announcements; ScottMadden U.S. Gas LDC Peer Analytics tool; industry news; ScottMadden research and analysis

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Gas Local Distribution Company Peer Analytics

CASE STUDY

Identifying Best Practices and Efficiencies for LDCs

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Integrated System Planning: The Next Evolution

An evolving energy ecosystem drives utilities toward comprehensive planning approaches.

Utility Evolution Drives Planning Process Integration

- Historically, utilities planned for customers' energy needs assuming additions of centralized generation, then planned the transmission and distribution networks to support energy delivery. This method has become insufficient in the current, rapidly changing utility environment.
- The energy transition continues to bring about an evolution of utility systems, accommodating new goals, such as greenhouse gas emissions reductions, distributed energy resources (DERs) and two-way flows, and increasing renewable resources. These and other factors are driving change within each of the electric generation, transmission, and distribution planning processes, as shown in Figure 5.1.

Figure 5.1: **Drivers of Change for Utility Segments**

Segment	Drivers of Change
Generation	• Increasing intermittent generation sources • Availability of gas for electricity production • Increasing demand from electrification • Shifting and more complex load profiles • Increased ramping requirements • Changes in resource adequacy standards • Need for probabilistic forecasting techniques
Transmission	• Management of shoulder months (as opposed to strictly peak load) • Intermittency (high and low load periods) • Availability of gas-fired generation • Potential for common mode failures • Interconnection of renewable resources • Impacts of extreme weather events • Incorporation of demand-side resources • Need for probabilistic forecasting techniques
Distribution	• DER deployment trends and net loads • Electrification impacts on load volume and patterns • Increasing granularity driven by hosting capacity considerations • Incorporation of end-user data • Need for probabilistic forecasting techniques • Increasing stakeholder involvement

Changes to electric forecasting and planning processes require utilities to manage increasing levels of complexity at shorter intervals.

Source: ScottMadden analysis **Note:** Some drivers may be common across multiple segments.

KEY TAKEAWAYS

Utility systems are growing more complex and interconnected, necessitating planning that accounts for these changes. As planning processes evolve, they must ensure goals are aligned within different segments of the utility, as well as with the policy that is driving the change.

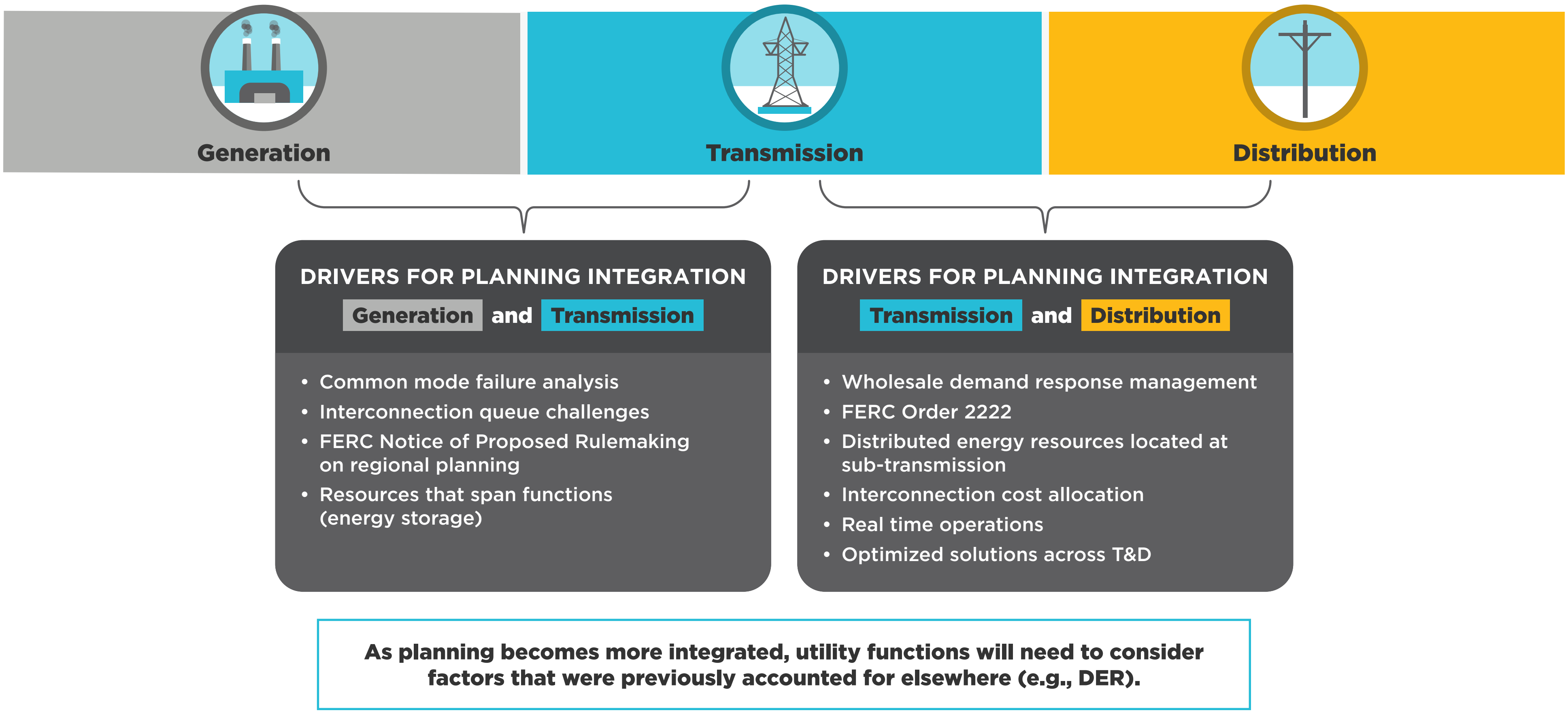
All types of electric utilities are exploring comprehensive planning approaches and are at various stages of the exploration process. Some utilities have been driven by policy or regulatory requirements, while others have enacted changes of their own volition, in many cases doing so with the expectation that it will help them reach aggressive net-zero targets.

Gas utilities are also facing a turning point, as uncertain market conditions and changes in regulatory approaches on the future role of natural gas are driving early conversations on updating long-standing planning practices.

Utility Evolution Drives Planning Process Integration (Cont.)

- These changes have not only led to increased complexity within the utility segments, but they have also increased interdependency with their counterparts. A few examples are illustrated in Figure 5.2.
- As utility evolution continues, planning processes will need to adapt to keep up with changes in the industry. In particular, utilities must optimize system investments across generation, transmission, and distribution to support the achievement of corporate and policy objectives. Many see modifications to planning processes and assumptions, designed to address these change drivers, as required to support the continuation of reliability and affordability objectives, while adapting to achieve national, state, and local policy goals.

Figure 5.2: **Change Drivers Impacting Utility Planning Processes**



Source: ScottMadden analysis

What Is Integrated System Planning?

- There is growing discussion within utilities and industry groups regarding the alignment and integration of disparate utility planning processes: electric generation/resource, transmission, distribution, and potentially gas. There is, however, much variation between these groups regarding the definition and scope of this integration.
  - Integrated system planning is still relatively nascent, and as such, it is being considered independently by utilities and regulators. Given this independent development, various utilities have developed different monikers for processes which include parts of the planning environment (see Figure 5.3).
  - Further, in some cases, this integration is being discussed within the context of other established planning processes (e.g., as modifications to the integrated resource planning or distribution system planning processes).

Figure 5.3: **Myriad Names for and Approaches to Utility Planning Integration**

Source: ScottMadden research

What Is Integrated System Planning? (Cont.)

- In 2018, in response to changes in the electricity sector, NARUC and the National Association of State Energy Officials (NASEO) created a task force to look at the need for planning integration, calling it Comprehensive Electricity Planning (CEP).
  - The task force gave the following definition for CEP: "a comprehensive electricity planning process refers to the alignment or integration of distinct planning processes that, historically, have not significantly informed one another (i.e., resource, distribution, and transmission planning processes)."
  - The task force noted that CEP may look different for various utilities based on key operational characteristics, such as whether the utility:
    - Owns generation assets
    - Operates in an organized wholesale market
    - Focuses on aligning distribution, resource, and transmission planning (or one or two of those segments)
- The task force released its findings in early 2021 outlining the following objectives for CEP:
  - Improve grid reliability and resilience
  - Optimize use of distributed and existing energy resources
  - Avoid unnecessary costs to customers
  - Support state policy priorities
  - Increase the transparency of grid-related investment decisions
- The task force notes the overarching goals of CEP above; however, the process will look different depending on the utility. For example, wires-only utilities will not be able to integrate planning for generation assets they don't own. The task force designed roadmaps as starting points for state-specific efforts to improve planning processes, differentiated by market structure, utility generation ownership, and planning processes to be aligned (distribution, resource, and/or transmission).

Who Is Integrating What Planning?

- Several utilities have begun to discuss or signal interest in different forms of integrated planning and are in various stages of implementing related processes.
- It is noteworthy that the push to better align or integrate planning processes is not unique to specific utility types, those operating in specific regions, or market structure or business model (e.g., vertically integrated vs. wires-only utilities, investor-owned utilities vs. public or municipal utilities, and utilities operating inside or outside of organized markets).
- Among the various utilities engaged in integrating their planning functions, common drivers include the desire to:
  - Better manage increasing penetrations of DERs and associated complexities
  - Achieve aggressive net-zero/carbon emission reduction targets
  - Optimize investments at the system level (for effectiveness and lowest cost)
  - Fairly and accurately account for the full value of non-wires alternatives
  - Share data required to transition from deterministic to probabilistic forecasting
  - Better support system scenario planning
- In some cases, utilities are pursuing planning integration on their own, while others are pursuing it due to regulatory guidance; however, in both cases, the drivers above appear to be relatively consistent.

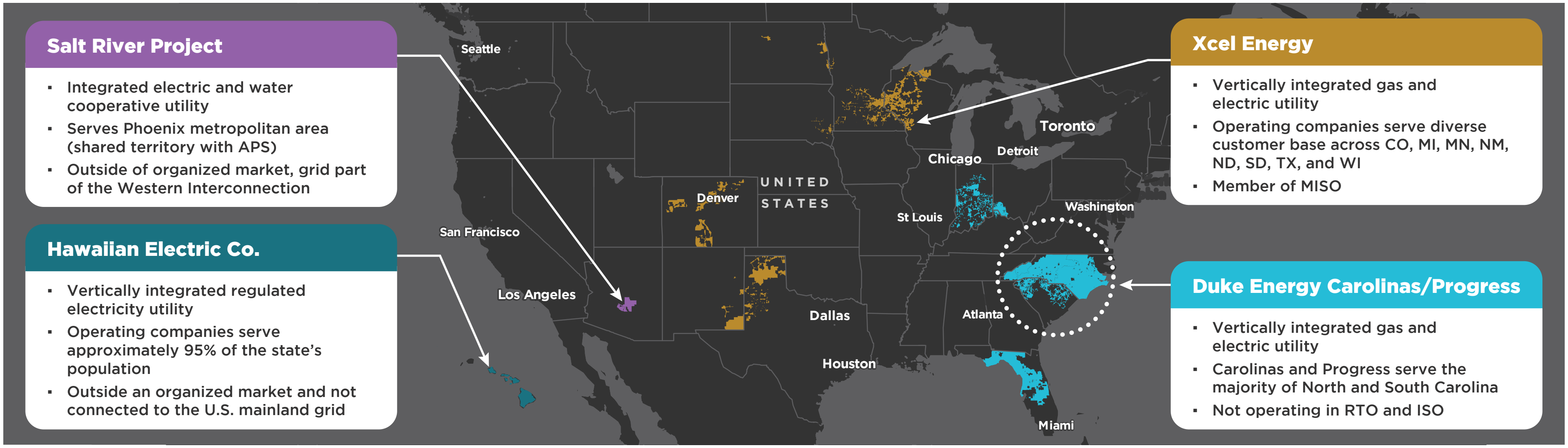
A Closer Look at a Few Utilities Advancing Planning Integration

- Utilities across the country are in various stages of developing integrated planning processes across multiple segments of the utility system. A few that are further ahead in their development are highlighted in Figure 5.4.

- Xcel's subsidiary Northern States Power proposed its Integrated Distribution Plan (IDP) in 2019. It was accepted by the Minnesota PUC in 2022. The IDP presaged more comprehensive integrated planning. Xcel noted that it is "taking steps to align and integrate our distribution, transmission, and resource planning processes. We support a shift toward more integrated system planning… We are currently evaluating our existing planning processes and tools to determine how to better align and integrate the distribution, transmission, and resource planning processes in the future."
  - There is emphasis in the IDP on the impact of the growth of intermittent resources like wind and solar that has led to a reversal of the typical planning timeline, putting transmission planning first, compared with the historical approach which would put generation planning first.
  - With greater integration, not only is Xcel updating its processes and tools, but it is also adjusting its organization. Xcel recently announced that it has assembled all of its planning activities—generation, transmission, distribution, and natural gas service—into a single, company-wide planning department.
  - Additionally, an emphasis is placed on maximizing the benefits of DER integration. In its IDP, Xcel notes: "We support a shift toward more integrated system planning, where utilities assess opportunities to reduce peak demand using DER and to supply customers' energy needs from a mix of centralized and distributed generation resources."

- Xcel's Alice Jackson, senior vice president of system strategy and chief planning officer, noted: "Historically…generation planning would come first. Transmission would come after. You locate generation, and then the extension to bring it to the city."

Figure 5.4: **Selected Utilities That Are Implementing Variations of Comprehensive Electric Planning**

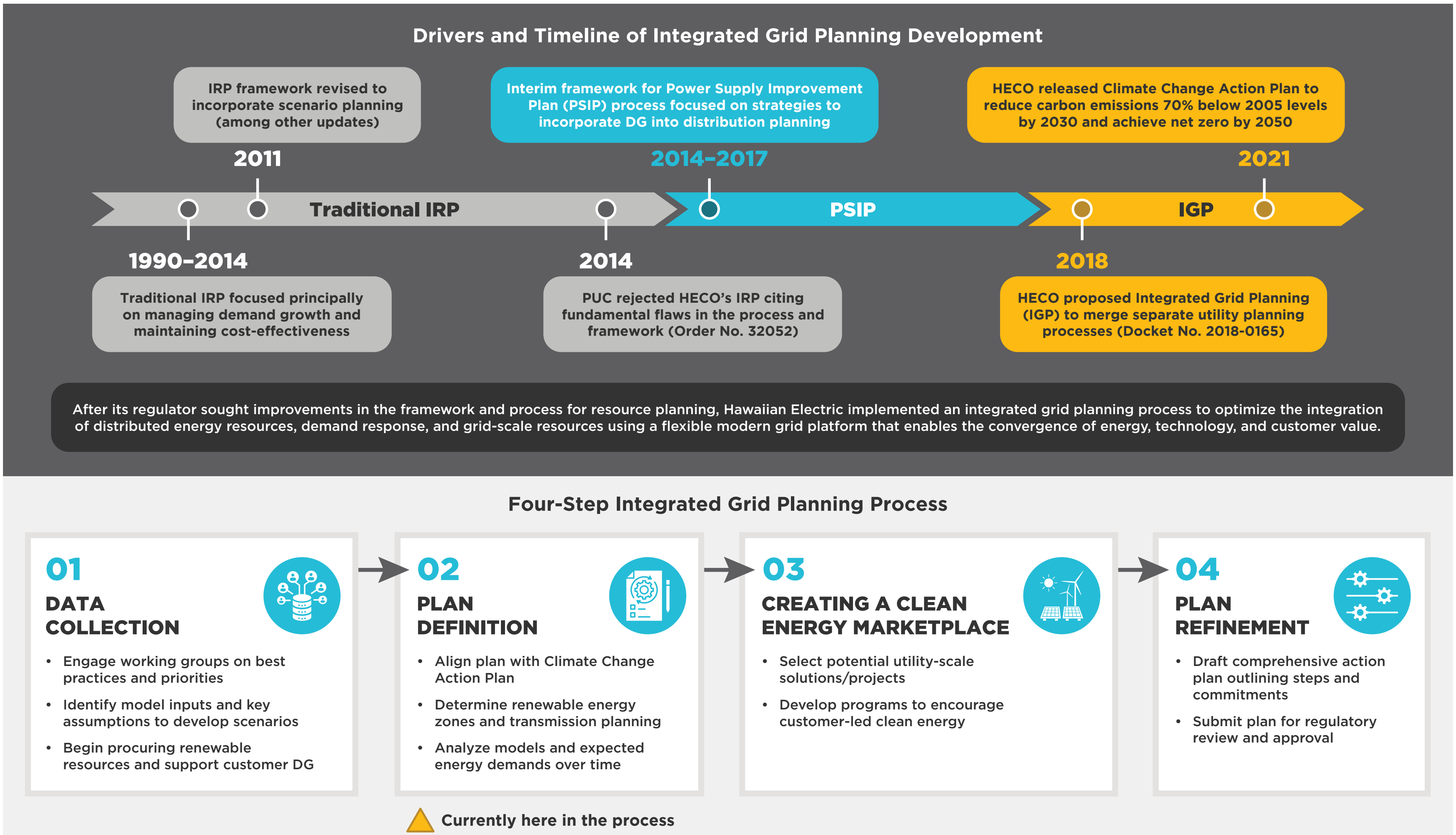


Source: S&P Capital IQ Pro

A Closer Look at a Few Utilities Advancing Planning Integration (Cont.)

- Other utilities that have revisited planning processes, driven particularly by increasing current or expected DER penetration are Hawaiian Electric Company (HECO), Salt River Project (SRP), and Duke Energy's North and South Carolina operating companies, Duke Energy Carolinas and Duke Energy Progress (DEC/DEP). Brief summaries for each of the drivers of planning changes and key elements are shown in Figures 5.5 through 5.8.

Figure 5.5: **Hawaiian Electric Integrated Grid Planning**



Source: Hawaiian Electric Company

Figure 5.6: **Salt River Project Integrated System Planning**

Drivers of Planning Process Change

- Salt River Project (SRP) announced climate goals to reduce CO_2 emitted per MWh 65% from 2005 levels (90% by 2050).
  - Announced retirements for five coal-generating units
- In 2017–18, SRP issued its last integrated resource plan.
  - "The objective of SRP's resource portfolio has always been to deliver reliable, affordable and sustainable power to our customers."
- In 2022, SRP kicked off its integrated system planning (ISP) process.
  - "[T]raditional planning methods are increasingly insufficient to optimally develop a safe, reliable, affordable and environmentally responsible power system."
  - "An Integrated System Plan is the blueprint for the power system of the future that includes all major power system pieces of meeting future customer demand: power generation, transmission, distribution and customer programs."

Integrated System Plan Advisory Study Schedule

Prepare	Analyze	Synthesize
Q4 2021 – Q2 2022	**Q2 2022 – Q4 2022**	**Q4 2022 – Q2 2023**
Six advisory group meetings to develop model inputs and two large stakeholder review sessions	Process reflection, topical meeting including one advisory group meeting	Review analysis with three advisory group meetings and two large stakeholder meetings

Integrated System Planning Key Elements

FOUR SCENARIOS
Distinct and plausible future states of the world

TEN SENSITIVITIES
Varying single assumptions in a scenario

THREE STRATEGIC APPROACHES
Outlining decisions SRP could make

DIVERSE SET OF METRICS
Compared across a diverse set of metrics (i.e., model outputs)

System modeling creates 42 possible system plans.

Source: Salt River Project

Figure 5.7: **Duke Energy Carolinas/Progress System and Operations Planning**

Drivers of Planning Process Change

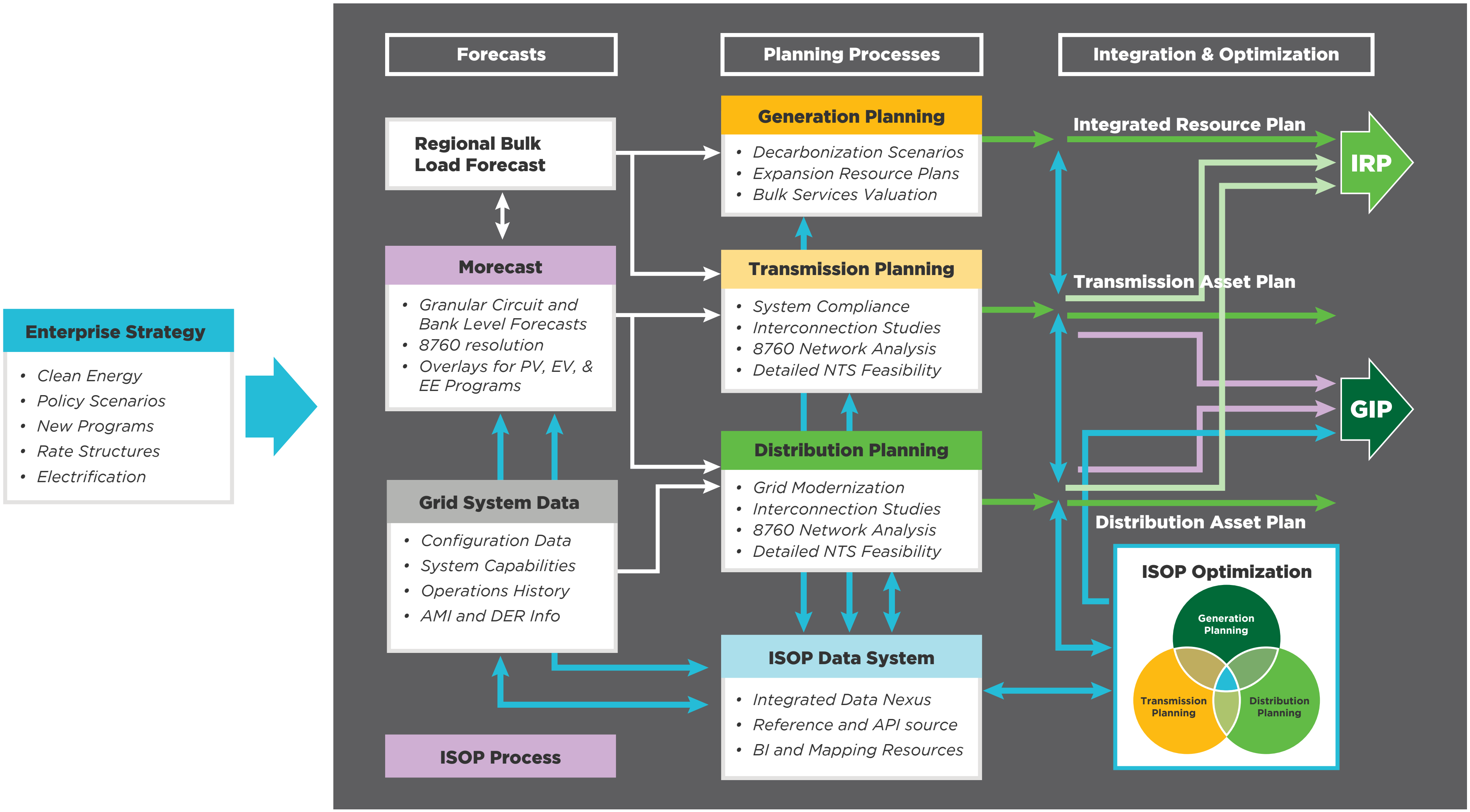
- DERs are growing rapidly.
- Over longer term (5–15 years), declining technology costs are likely to make non-traditional resources/solutions increasingly competitive.
- Delivering carbon reductions at the lowest total cost requires improved planning tools to better evaluate non-traditional solutions.
- An overarching motivation to invest in integrated system and operations planning (ISOP) is that customers will benefit:
  - Ensures operational feasibility while enabling additional renewable/DER adoption
  - Lowers total costs while enabling carbon reductions

Integrated System and Operations Planning Key Elements

- Enhanced forecasting: 10-year window considering multiple planning scenarios
- Advanced distribution planning (ADP) power flow models
- Evaluation of non-traditional solutions (NTS)
- Generation-transmission-distribution coordination
- Feed-in to integrated resource plan

Source: Duke Energy

Figure 5.8: **Duke's Integrated System and Operations Planning (ISOP) Process**



Notes: AMI means advanced metering infrastructure
EE means energy efficiency
GIP means Grid Improvement Plan
NTS means non-traditional solutions
PV means solar photovoltaic systems
EV means electric vehicle

Source: Duke Energy

Coordination of Growing Interest: Gas vs. Electricity Planning

- The NARUC/NASEO task force notably dubbed the concept of integrated planning as Comprehensive Electricity Planning; however, gas will not be left on the sideline as utilities evolve.
- There is a large focus on clean energy and decarbonization as a part of the energy transition, yet gas is expected to remain a key component within the energy sector for many years to come. That said, the gas industry has experienced significant disruptions and increasing attention from policymakers in recent years, highlighting the need for planning to adapt to keep up with changing market and political environments.
- There are early conversations about changes to gas forecasting and planning processes. Key topics in these conversations include:
  - Moving from deterministic forecasting and planning models based on historical data to probabilistic models that incorporate anticipated impacts from energy efficiency programs (e.g., electrification) and extreme weather events.
  - Increasing the granularity of gas forecasts to support the evaluation of non-pipes alternatives and align more closely with the granularity of electric system forecasts (i.e., developing gas forecasts for more specific locations on the gas network and, in some cases, planning for design hours vs. design days).
  - Planning perspectives apply divergent assumptions for electric and gas. In each case, planners are preparing to meet demand under worst-case scenarios. For heat pumps, this may result in gas assuming low heat pump adoption while electric assumes high adoption.
- Differing from the objectives of CEP, which adapts and combines existing planning structures to help manage increasing levels of complexity, changes in planning on the gas side will require analyses not typically performed in the gas forecasting and planning processes today.

IMPLICATIONS

An evolving utility environment requires planning that can accommodate evolving objectives. Policy and technological advancements have led to significant changes in the electricity industry, and comprehensive planning can help capture potential value brought about by these trends. By broadening the scope of planning to incorporate once independent processes, utilities can streamline and optimize their efforts, as well as align goals between systems seeking common objectives (e.g., net-zero and greenhouse gas emissions reductions).

Notes:

ScottMadden engages with utility companies looking at enhanced integration across planning functions and activities. ScottMadden recently engaged in a benchmarking comparison with selected utilities, gauging plans and levels of activity with respect to comprehensive planning integration, including organizational, process, tools and infrastructure, and other integration activities.

Sources:

NARUC, "Comprehensive Electricity Planning Roadmaps" (Feb. 2021); NARUC, "Task Force on Comprehensive Electricity Planning" (2021); Energy Exemplar, "Integrated System Planning: A holistic modeling approach for energy" (May 23, 2022), at www.energyexemplar.com/blog/integrated-system-planning; Regulatory Assistance Project, Modernizing Gas Utility Planning: New Approaches for New Challenges (Sept. 2022); Smart Electric Power Alliance, "Integrated Distribution Planning (IDP) – What is it? and How do we Achieve It?" (Nov. 5, 2020), at sepapower.org/knowledge/integrated-distribution-planning-idp-what-is-it-and-how-do-we-achieve-it/; NREL, Distribution Capacity Expansion Planning: Current Practice, Opportunities, and Decision Support (Nov. 2022); Sandia National Laboratories, "Multi-objective Decision Planning (MOD-Plan) for Equity, Resilience, and Decarbonization" (2021), at https://energy.sandia.gov/programs/electric-grid/mod-plan/; Salt River Project, Integrated System Plan (Nov. 2021); T&D World, "Integrated Grid Planning is Critical for Clean Energy" (Dec. 16, 2021); Xcel Energy, Integrated Distribution Plan (2020-2029), Docket No. E002/M-19-666 (Nov. 1, 2019); HECO, Integrated Grid Planning (2021); Xcel Energy, Integrated Distribution Planning at Northern States Power Company – Minnesota (May 13, 2022); Duke Energy, Integrated Systems and Operations Planning Reference Information Portal, at https://www.duke-energy.com/our-company/isop; Utility Dive, "Xcel, other utilities launch dedicated planning teams to streamline energy transition, boost innovation" (Jan. 25, 2023), at https://www.utilitydive.com/news/xcel-srp-planning-teams-integrated-planning/639674/.

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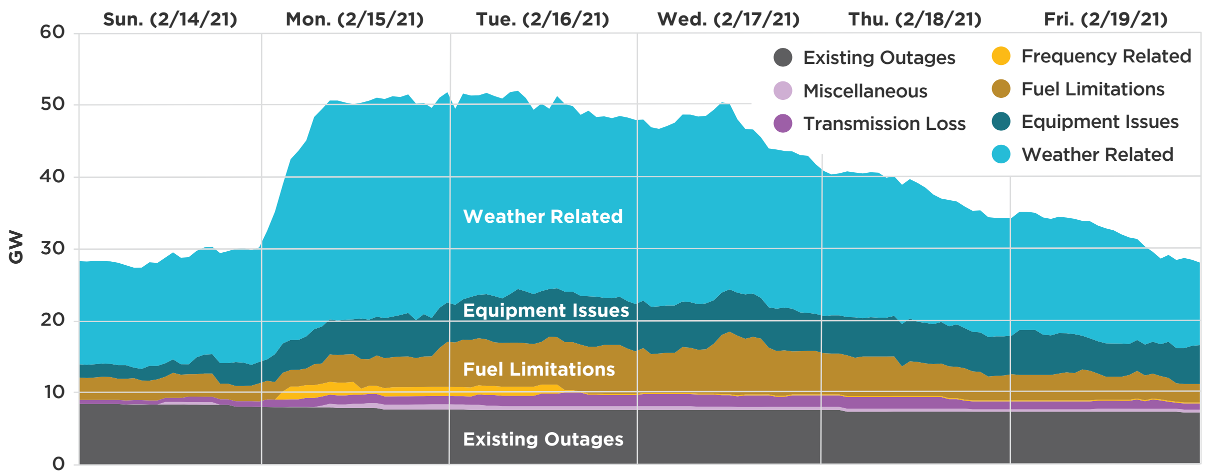
Resource Adequacy: Ready for an Update?

Recent grid emergencies highlight the electric industry's reconsideration of its approach to resource adequacy.

Extreme Events and Changing Resource Mix Challenging the Bulk Power Grid

- The past several years have seen weather events challenge the grid operators' ability to balance supply and demand on the bulk power grid.
  - In February 2021, an extended cold snap in the south-central United States (dubbed Winter Storm Uri) dipped south into Texas, combining high load for heating with widespread generator outages. Those outages were largely due to fuel availability issues for dispatchable gas-fired generators and cold weather impacts, including ice accumulation and low temperature limits for solar and wind units and frozen sensing lines, water lines, and valves on thermal units (see Figure 6.1 below).
  - California, in late summer during the past three years, has endured long-duration wide-area heat events that have led to emergency actions and, in some cases, controlled rolling outages.
  - Most recently, late December's Winter Storm Elliott caused unanticipated load surges accompanied by generator breakdowns, reliance on oil-fired units in some regions, and controlled rolling outages in the Tennessee Valley region and the Carolinas.*
- In addition, as NERC notes: "Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources as the energy transition continues."
- As the electric industry and regulators further consider these reliability events and the changing nature of grid resources, they are reconsidering traditional reliability planning approaches to determine what improvements and modifications may be needed.

Figure 6.1: **Winter Storm Uri ERCOT Net Generator Outages and Derates by Cause (GW)**



Source: ERCOT

KEY TAKEAWAYS

The nature of bulk power resources has changed over the past decade, and significant amounts of proposed solar and wind resources are in interconnection queues.

Recent summer and winter weather events have tested power supply availability—both for renewable and gas-fired generation—on several systems.

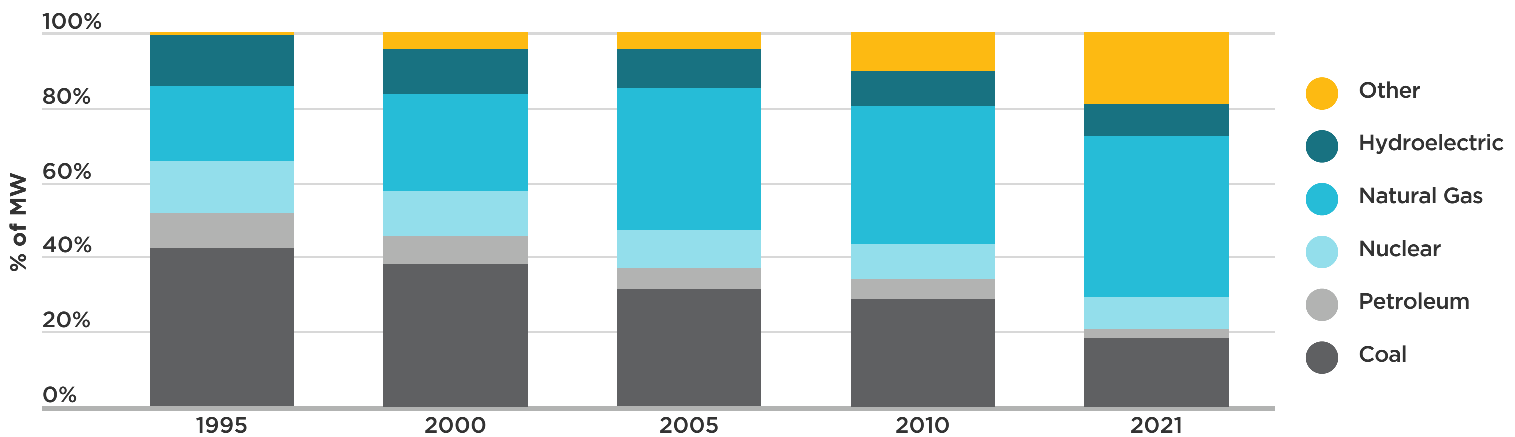
Traditional measures of resource adequacy—availability at peak—are deficient as more energy-limited resources come online and hours of energy insufficiency during non-peak hours and shoulder months increase.

Resource adequacy analysis is adapting to account for different supply composition, potential effects of climate change, the needs for energy adequacy through multi-hour and multi-day events, and load flexibility.

Resource Adequacy: The Historical View

- Resource adequacy is the ability of the electricity system to supply aggregate electric power and energy to always meet the requirements of consumers, taking into account scheduled and unscheduled outages of system components.
- It is a long-term planning metric, focused on a 10-year horizon over which programs can be instituted (e.g., demand response) and resources can be activated (e.g., new generating resources).
  - Adequacy has historically been measured as the ability to meet peak demand with a margin of excess resources (as a percentage of MW demand or "planning reserve margin") in the event of a loss of a system element (typically a large generating unit).
  - The standard level of expected reliability—measured in terms of loss-of-load expectation—is defined as one day in 10 years (or 2.4 loss of load hours per year). The origin of this standard is unclear, although some trace it back to seminal academic work in the late 1940s. While few have questioned the metric until recently, some have questioned whether it imposes too high a cost for customers.
  - These standards vary by region; some have higher or lower targeted reserve margins as dictated by the prevailing regulatory authority or the market operator. FERC has targeted 15% reserve margins in predominantly thermal systems. NERC sub-regional margins vary from 10.42% to 20%.
  - Resource adequacy planning is typically co-optimized with least or lowest reasonable cost resource planning.
- This approach was developed in an environment of large, dispatchable, thermal generating stations with large stocks of on-site fuel—oil, coal, and nuclear.
  - However, those traditional units are rapidly retiring. In their place, amounts of variable and natural gas-fired resources are increasing in all U.S. bulk power systems.
  - Reliability remains of prime importance, so the changes from a system of mostly dispatchable resources to those with limited or no dispatchability, or with potential fuel deliverability risk, create variability and uncertainty, affecting operations and planning.

Figure 6.2: **U.S. Net Summer Capacity by Energy Source (% of MW)**



Notes: Hydroelectric includes pumped storage. Other includes non-hydro renewable resources such as wind and solar.

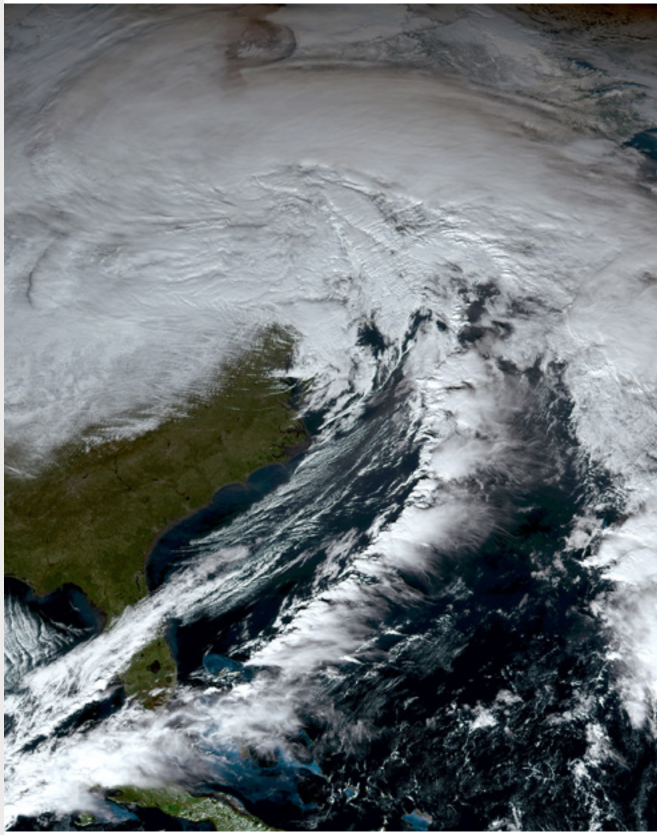
Source: EIA

Resource Change

U.S. renewable, hydro, and natural gas generating capacity has gone from about 1/3 of total capacity in 1995 to more than 2/3 as of 2021.

Gaps in the Status Quo

- **Weather's increasing impacts on supply:** Weather is now a key driver of generation capability.
  - With increased variable resources, including resources relied upon for meeting peak load, weather or environmental conditions (wind droughts, overcast skies) can directly affect resource output.
  - Extreme weather is of particular concern, as common mode failures from extended droughts can, for example, affect hydropower supply and force derates of thermal generation.
  - Similarly, as current storage solutions are duration limited, natural gas-fired generation has been used to provide flexible, quick response capacity. However, in extreme cold events, gas deliverability for power generation can be compromised.
- **Changing demand levels and patterns:** As end-use applications electrify (e.g., buildings, vehicles), the electric industry expects significant growth in both consumption and peak demand. These changes can shift demand more dramatically than may currently be modeled.
  - Heating load can peak in early morning hours in winter when relatively few resources are running. Late afternoon demand peaks can occur from post-workday residential demand or electric vehicle charging. Further, with increased electrification, system peaks can shift from summer to winter as heating load increases.
  - Demand has traditionally been viewed as static. However, increasing distributed energy resources can provide some demand flexibility, although lack of visibility may keep system planners and operators cautious in their treatment of these resources.
- **Energy insufficiency (versus peak sufficiency):** Resource adequacy has focused on meeting peak demand, but recent supply/demand imbalance risks have occurred during multi-hour or multi-day events, when piped or stored fuel access or battery recharging is difficult to achieve. There is an increasing need to analyze all hours of the year probabilistically to identify more frequent periods of potential risk, including shoulder seasons when units are often on maintenance outage.
- **Seasonality:** Unlike weather, these effects are more predictable. For example, solar irradiance in the Northern Hemisphere is greater during summer than during winter. As such, while peak load solar resources may be adequate on a hot summer afternoon, those resources may not be able to perform at similar levels on winter mornings.
- **Complexity:** With so many new or different variables and stochastic characteristics in supply and demand drivers, both planning and operating the grid are becoming more complex and require more sophisticated approaches to scenario planning for resource adequacy.



Note: The December 2022 North American winter storm (Winter Storm Elliott) intensifying over Canada on December 23, 2022.

Resource Pooling and Capacity Transfers: An Approach to Adequacy

- For each increment of reliability, additional cost is required for resource procurement and maintenance. This is particularly acute for high-renewable systems that have elevated redundancy requirements. Thus, while systems could procure all resource adequacy needs within their footprint, some are employing resource pooling arrangements.
- In the western United States, the Western Power Pool is developing the Western Resource Adequacy Program (WRAP), the first regional reliability planning and compliance program in the history of the West. It will deliver a region-wide approach for assessing and addressing resource adequacy, providing coordination and visibility across participants, and "encouraging the use of western regional resource diversity compared to the status quo." FERC approved WRAP in February 2023.
- Per its FERC application, WRAP's 26 entities represent winter and summer peak load of approximately 65 GW and 72 GW, respectively, across 10 states and one Canadian province (see Figure 6.3). As of January 2023, 20 utilities from the Northwest, parts of the Desert Southwest, Canada, and northern California have committed to the program.
- WRAP is a voluntary program that uses the West's bilateral market structure (i.e., it does not establish an ISO/RTO or a centralized capacity market) to conduct regional resource adequacy planning. It is comprised of two components:
  - ***Forward-Showing:*** WRAP sets a regional reliability metric and a consistent approach for counting resources. Seven months in advance participants must demonstrate they've brought their fair share of regional capacity for the upcoming season—winter or summer. If they are short of needed resources, participants may secure more before the applicable season.
  - ***Operational:*** This component allows participants to pool and share resources during tight grid-operating conditions. It measures the forward-showing forecast against a much nearer-term forecast, a week or day ahead of when energy needs to flow to keep the lights on. Depending on load and output from variable resources, for example, participants could have a deficit or surplus compared to forward-showing positions or portfolios. Those with a surplus will share resources with those who have a deficit in the hours of greatest need.
- This resource pooling and transfer approach relies upon deliverability of the resources to the system in need.
  - Adequate transmission capacity between regions is critical. WRAP includes an analysis of transmission capabilities and availability, and each participant has a forward-showing requirement for transmission service.
  - Moreover, the external resources must be available. This can be problematic where wide-area events affect nearby regions and, during emergency conditions, may require system operators to limit exports.

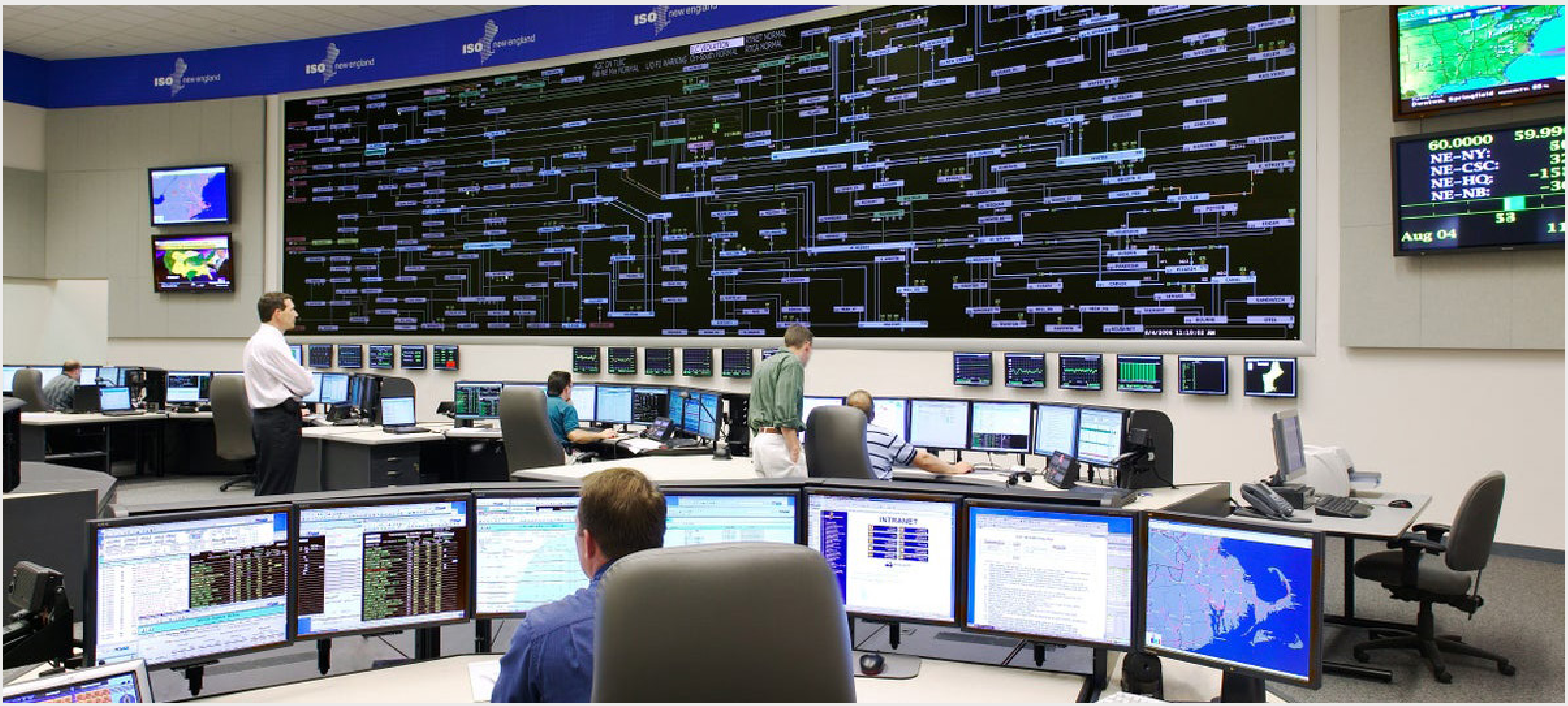
Figure 6.3: **Western Resource Adequacy Program Footprint**

Note: As of March 1, 2023.

Source: Western Power Pool

Rethinking Resource Adequacy

- As mentioned earlier, changes in characteristics of supply and demand have introduced more variability in resource adequacy. Probabilities of reliability events due to mechanical failure (forced outage) were assumed to be independent or largely uncorrelated with other variables such as weather.
- Variable renewables are, by nature, subject to weather variability, such as wind availability, solar irradiance, and ice accumulation on wind turbine blades.
- As gas turbine units are increasingly the key dispatchable resources, their performance is increasingly correlated with weather, which influences fuel supply, derates due to high ambient temperatures, and frozen equipment.
- Climate trends require reconsideration of reliance on solely historical data for probabilistic analysis.
- New hybrid technologies (solar + storage) and long-duration storage have novel operating characteristics that do not fit neatly into traditional resource adequacy analyses.
- The Energy Systems Integration Group has proposed some principles for modernizing the approach to resource adequacy analysis. Those principles and related considerations are shown in Figure 6.4 (see next page).



Source: Photo courtesy of ISO New England.

Figure 6.4: **Six Principles (and Objectives) of Modernized Approaches to Resource Adequacy**

<table>
<tr><th></th><th>Principle</th><th>Considerations</th></tr>
<tr><td rowspan="2">Understanding Capacity Shortfalls</td><td>1. Quantifying size, frequency, duration, and timing of capacity shortfalls is critical to finding the right resource solutions.</td><td>▪ Conventional resource adequacy (RA) metrics, such as loss of load expectation (LOLE) and expected unserved energy, do not characterize magnitude or duration of specific outage events.
▪ Expected value analysis approaches do not distinguish frequent, smaller events from rare but very large events. RA metrics may be the same for very different events, which may require different mitigation actions.
▪ Analysis should go beyond expected values (average) events but potential individual tail events: size (MW peak and MWh), frequency, duration, and inter-hour variability.</td></tr>
<tr><td>2. Chronological operations must be modeled across many weather years.</td><td>▪ As systems increasingly rely upon energy-limited variable renewable resources, this also increases reliance upon weather and power forecasting and integrated storage scheduling.
▪ RA analysis thus requires attention to hourly, seasonal, and inter-annual resource variability.
▪ Chronological stochastic analysis is increasingly important, simulating hourly dispatch of the system's resources for an entire year of operation across many different weather patterns, load profiles, and random outage draws.
▪ Climate change must be accounted for; for example, Europe's grid operator, ENTSO-E, is working on a database that will reflect the potential impact of climate change on weather variables.</td></tr>
<tr><td rowspan="3">Understanding Capacity and Resource Types</td><td>3. There is no such thing as perfect capacity.</td><td>▪ Conventional system planning treats a natural gas combustion turbine as peaking firm capacity—nearly perfect for system reliability. But weather-related outages can occur impacting fuel availability and operations, separate from EFORd.
▪ Equivalent load-carrying capability—used to assess capacity accreditation for RA—should be expanded to include other renewable resources.
▪ RA analysis should recognize all resources have limitations based upon weather dependence, potential for outages, flexibility constraints, and common points of failure.</td></tr>
<tr><td>4. Load participation fundamentally changes the RA construct.</td><td>▪ Traditional RA analysis treats load as static and uncontrollable.
▪ Load flexibility, with the appropriate mechanisms for increased load participation, should be considered as a supply-side resource.</td></tr>
<tr><td>5. Neighboring grids and transmission should be modeled as capacity resources.</td><td>▪ Traditional RA assessment focuses on self-reliance. But resource sharing can be a significant, low-cost alternative to procuring new resources, because of load and weather diversity.
▪ Transmission is key, and transmission assets should be evaluated as a capacity resource if they allow flow into a capacity- and transmission-constrained region.
▪ RA analysis should also provide detailed, probabilistic assessments of neighboring systems to better evaluate availability of imports.</td></tr>
<tr><td>Inclusion of Economic Considerations</td><td>6. Reliability criteria should be transparent and economic.</td><td>▪ Reliability has a cost, and the relationship between reliability and cost is non-linear (i.e., an incremental reduction in LOLE can cost significantly more than the last increment).
▪ RA analysis should be "designed to increase cost transparency so that regulators, policymakers, and consumers understand the relative costs of different levels of and approaches to reliability and can make informed investment decisions."</td></tr>
</table>

Notes: RA means resource adequacy. EFORd means equivalent forced outage rate demand, which is the probability that an electric power generating unit will not be available due to a forced outage or forced derating when there is a demand on the unit to generate.

Source: Energy Systems Integration Group

IMPLICATIONS

Traditional measures of adequacy—meeting peak with a margin of spare resource availability—worked well in the past when power supply was provided primarily by large, dispatchable, thermal units, many of which had ample on-site fuel.

Conditions today are different and continue to change: rapidly growing and more variable demand with electrification of "everything," two-way grid resources (distributed energy and possibly electric vehicles), less dispatchability, more long-duration extreme weather events affecting both supply and demand, among other things.

Resource planners are adjusting through resource-sharing arrangements and reconsidering how asset availability metrics, such as equivalent load-carrying capability, are applied.

With increasingly complex interactions of variables, utilities must re-examine tools and models, planning criteria, assumptions, and resource-planning processes to accommodate these evolving supply, demand, and environmental dynamics.

Notes:

*We review regulatory actions and utility investigations stemming from events during Winter Storm Elliott elsewhere in this Energy Industry Update.

Sources:

NERC, Long-Term Reliability Assessment (Dec. 2022); ENTSO-E, European Resource Adequacy Assessment (Dec. 2022); NERC, 2022 State of Reliability (July 2022); National Regulatory Research Institute, Resource Adequacy Modeling for a High Renewable Future (June 2022); NERC, 2022-23 Winter Reliability Assessment (Nov. 2022); NERC, 2021 ERO Reliability Risk Priorities Report (Aug. 2021); NARUC, Resource Adequacy Primer for State Regulators (July 2021); ERCOT, Update to April 6, 2021 Preliminary Report on Causes of Generator Outages and Derates During the February 2021 Extreme Cold Weather Event (Apr. 27, 2021); FERC, NERC, and Regional Entity Staff Report, The February 2021 Cold Weather Outages in Texas and the South Central United States (Nov. 2021); Electric Systems Integration Group, Redefining Resource Adequacy for Modern Power Systems (2021); Western Power Pool; NERC; NRRI; industry news; ScottMadden analysis.

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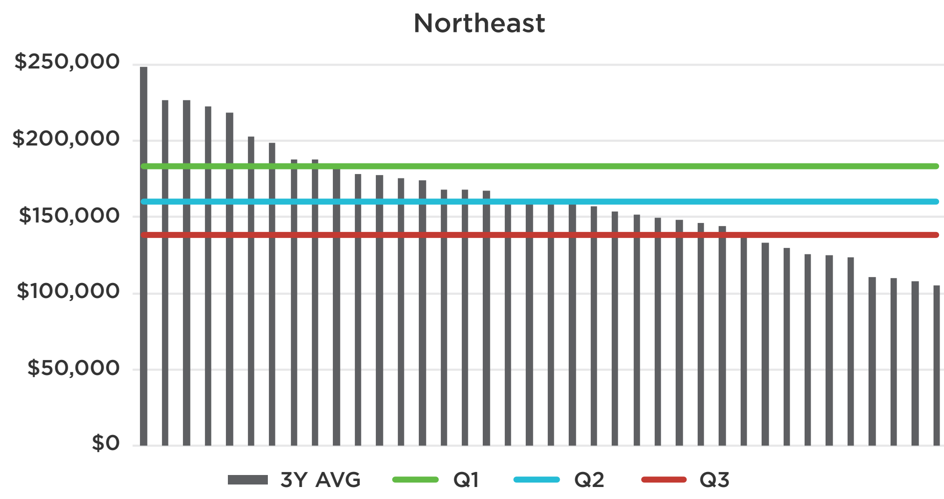
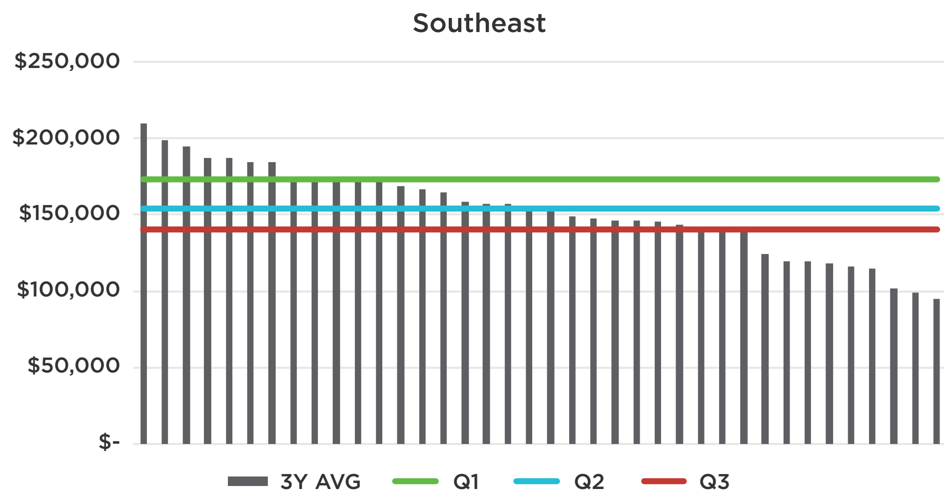
THE ENERGY INDUSTRY
IN CHARTS

- **As mentioned elsewhere in this Spring 2023 Energy Industry Update, the business and regulatory environment for gas local distribution companies (LDCs) is changing.**
- **However, gas LDCs continue to focus on infrastructure improvements, leak reduction, and profitability.**
- **In this section, we use our proprietary Gas LDC Peer Analytics product to show some high-level regional comparisons on a few metrics that reflect those focus areas.**
- **Utility names have been redacted for simplicity of illustration. In analyses for clients using the Peer Analytics tool, ScottMadden typically shows more detail about panels reviewed.**

As shown at right, excluding one outlier in the Northeast, gas LDCs in the Northeast at median are $10,000 greater per $ million of gas plant in service than those in the Southeast.

Figures 7.1A-B: **Gross Margin per $M Gas Plant In-Service (3-Year Average 2019-21)**



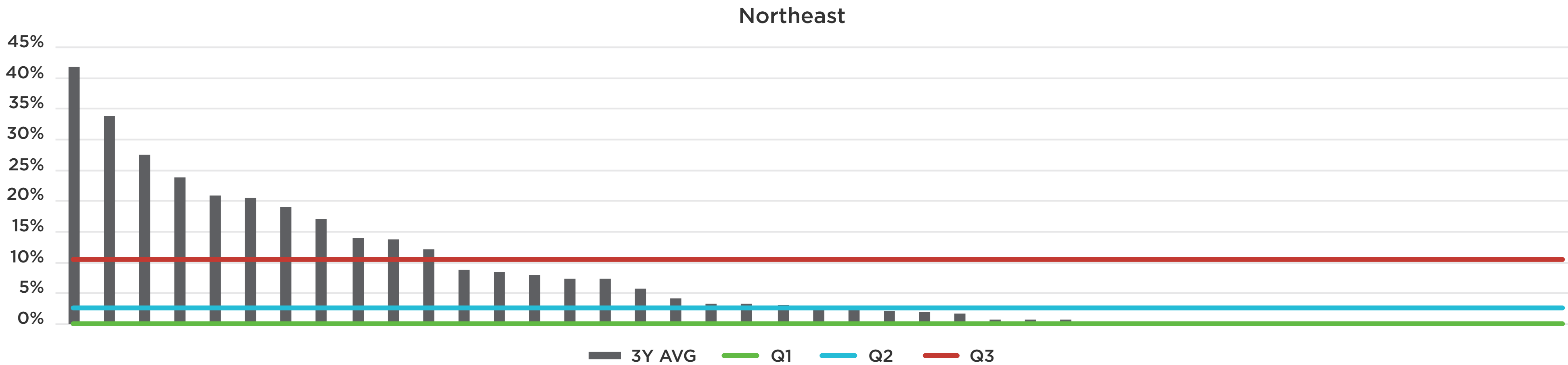


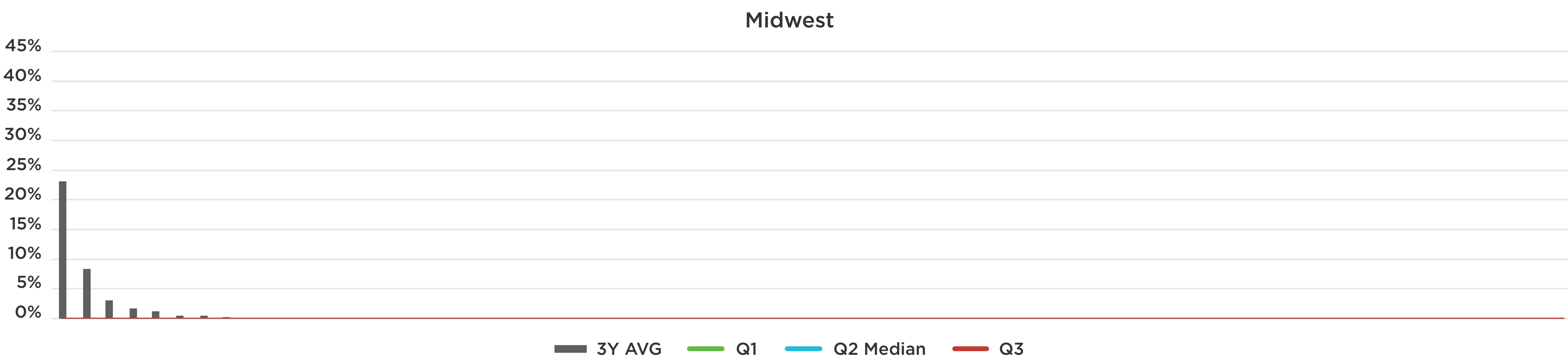
Notes: Northeast includes CT, MA, ME, NH, RI, and VT. Southeast includes AL, AR, FL, GA, MS, NC, SC, TN, VA, and WV.

Sources: Federal, state filings; S&P Capital IQ; ScottMadden LDC Peer Analytics product

- **The percentage of cast iron mains varies sharply across different regions in the United States.**
  - **85% of gas LDCs (56 of 66) in the Midwest have replaced all cast iron mains on their systems vs. only 32% in the Northeast.**
  - **Those gas LDCs with cast iron mains still in service in both regions are replacing them at 1%-2% per year.**

Figures 7.2A-B: **Percentage of Cast Iron Mains In-Service (3-Year Average 2019-21)**





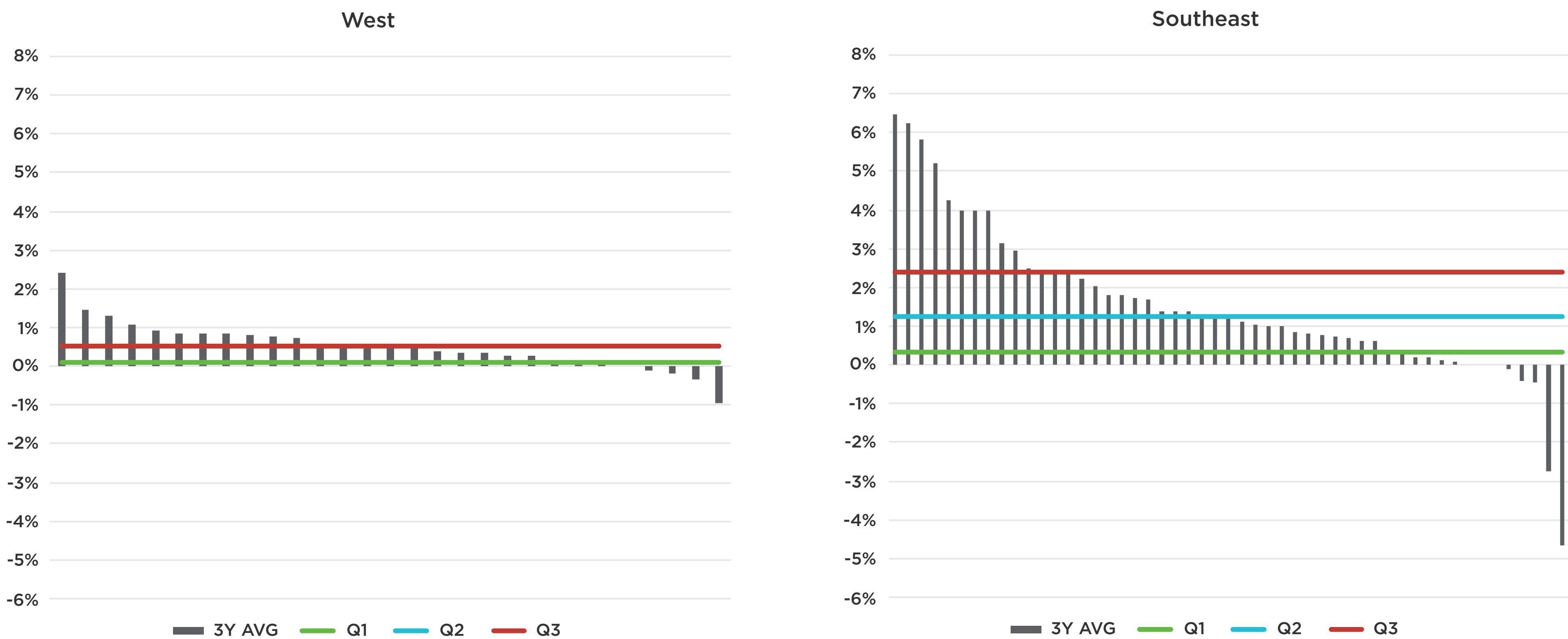
Notes: Northeast includes CT, MA, ME, NH, RI, and VT. Midwest includes IA, IL, IN, KS, KY, MI, MN, MO, NE, OH, SD, and WI.

Sources: Federal, state filings; S&P Capital IQ; ScottMadden LDC Peer Analytics product

- **The percentage of lost or unaccounted for gas varies across different regions in the United States.**
  - **In the West, the median value is 0.7%, and most utilities experienced an increase over the past three years.**
  - **In the Southeast, the median value is 1.0%, and roughly the same number of gas LDCs experienced a decrease as experienced an increase over the past three years.**
  - **The values range from -1.0% to 2.9% in the West, and the values range from -5.4% to 6.2% in 2021.**

To learn more about the ScottMadden LDC Peer Analytics product, go to this website or use the QR code below:

Figures 7.3A-B: **Percentage Lost or Unaccounted for Gas (3-Year Average 2019-21)**



Notes: West includes AK, AZ, CA, ID, MT, NV, OR, WA, and WY. Southeast includes AL, AR, FL, GA, MS, NC, SC, TN, VA, and WV.
Negative values may reflect measurement inaccuracies.

Sources: Federal, state filings; S&P Capital IQ; ScottMadden LDC Peer Analytics product

GLOSSARY

AEMO
Australian Energy Market Operator

Ass'n
Association

B
billion

Black coal
sub-bituminous, bituminous and anthracite coal

Brown coal
lignite

capex
capital expenditures

CAGR
compound annual growth rate

CEP
comprehensive electricity planning

Comm'n
Commission

DER
distributed energy resources

DOE
U.S. Department of Energy

EBITDA
earnings before interest, taxes, depreciation, and amortization

EEI
Edison Electric Institute

EIA
U.S. Energy Information Administration

EPS
earnings per share

ERCOT
Electric Reliability Council of Texas

EV
electric vehicle

FERC
Federal Energy Regulatory Commission

FiT
feed-in tariff

GHG
greenhouse gas

GW
gigawatt

GWh
gigawatt-hour

IDP
integrated distribution plan

IIJA
Infrastructure Investment and Jobs Act

IOU
investor-owned utility

IRA
Inflation Reduction Act of 2022

ISO
independent system operator

ISOP
integrated system and operations plan

kWh
kilowatt-hour

LDC
local gas distribution company

LNG
liquefied natural gas

M&A
mergers and acquisitions

MISO
Midcontinent Independent System Operator

MMcf
million cubic feet

MMBtu
million British thermal units

MW
megawatt

MWh
megawatt-hour

NARUC
National Association of Regulatory Utility Commissioners

NASEO
National Association of State Energy Officials

NEM
Australia's National Energy Market

NERC
North American Electric Reliability Corporation

NPA
non-pipes alternatives

O&M
operating and maintenance expense

PJM
PJM Interconnection LLC

PUC
public utility commission

PV
photovoltaic

ROE
return on equity

RTO
regional transmission organization

SPP
Southwest Power Pool

T&D
transmission and distribution

TVA
Tennessee Valley Authority

ENERGY PRACTICE
ScottMadden Knows Energy

About ScottMadden

We know energy from the ground up. Since 1983, we have served as energy consultants for hundreds of utilities, large and small, including all of the top 20. We focus on Transmission & Distribution, the Grid Edge, Generation, Energy Markets, Rates & Regulation, Enterprise Sustainability, and Corporate Services. Our broad, deep utility expertise is not theoretical—it is experience based. We have helped our clients develop and implement strategies, improve critical operations, reorganize departments and entire companies, and implement myriad initiatives.

Stay Connected

ScottMadden will host a free webcast on **Thursday, June 15, from 1 to 2 pm ET** to explore topics related to resource adequacy, integrated planning, Australia's energy transition, and more.

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