THE SCOTTMADDEN ENERGY INDUSTRY UPDATE

HOW SOON IS NOW?

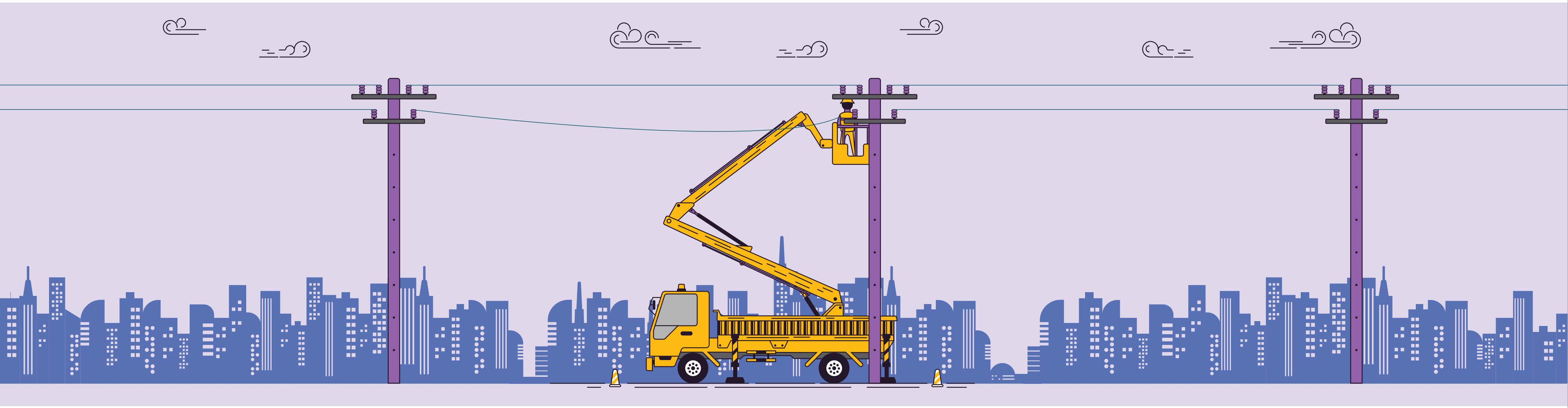
Volume 19 - Issue 1

TABLE OF CONTENTS

EXECUTIVE SUMMARY
HOW SOON IS NOW?

The cacophony of voices advocating for change in the energy industry is growing—whether that is transitioning away from coal, increasing renewables, deploying distributed energy resources, or decreasing reliance on natural gas. Clean technologies are advancing (e.g., battery storage, renewables, distributed energy resources, small modular reactors), and all may have a role to play, but how soon? In the meantime, the industry continues to focus on resiliency and what that means for the grid, pipelines, and generation mix. This issue of the ScottMadden Energy Industry Update focuses on "how soon is now?" How quickly can we make the changes many are advocating without compromising reliability, resiliency, affordability, and the financial viability of the industry's key players?

Some Highlights of This ScottMadden Energy Industry Update	
How Soon to Clean, Scalable Energy?	▪ Many U.S. nuclear power plants face economic threats to their continued operation, while the United States risks failing to meet ambitious decarbonization goals, including carbon emissions targets set by the Paris Agreement. ▪ Small modular reactors (SMRs) have gained renewed interest as a potential, scalable non-emitting resource, as countries with well-established nuclear industries, particularly Canada, seek to build upon the existing supply chain and know-how to develop an SMR industry.
How Soon to a Future Grid?	▪ There is much talk about smart cities and many entities interested in playing a role. The key question: what are the potential roles for energy utilities? ▪ Power transmission and distribution utilities are, by choice or mandate, looking at alternatives to traditional wires solutions—including efficiency, demand response, energy storage, and other distributed energy resources—to meet system needs and defer expensive upgrades. ▪ In the United Kingdom, electric industry regulators are assessing how a new approach to performance-based ratemaking has fared in promoting policy objectives, including customer service, innovation, reliability, affordability, and a transition to a low-carbon energy system.
How Soon to Resilient Infrastructure?	▪ Demand for natural gas for end use, power generation, and export as liquefied natural gas is on the rise, as the United States has become a net gas exporter. And while production has kept pace with increased demand, it remains to be seen whether midstream infrastructure can as well. ▪ Major storms, wildfires, and extreme cold snaps over the past few years have driven home the need to shore up energy infrastructure, but stakeholders are debating roles, costs, and actions to be prioritized.



RESILIENCE AND RELIABILITY
MATTERS OF KIND AND DEGREE

The industry focuses on preparing for changing system characteristics and more frequent "extreme" contingencies.

Resilience on the Docket

- Both government and industry leaders are increasingly focused on power system resilience. This topic can be viewed through two lenses:
  - Increasingly challenging weather events, such as Hurricane Maria, which ravaged Puerto Rico, and California's wildfires. These events require a different kind of planning.
  - A changing generation mix, which leads to discussion of implications of plant retirements, reliance on natural gas, and electric/gas convergence. DOE set in motion regulatory action with its proposed rulemaking focused on fuel-secure power generation (see timeline on next page).

Scenes of Utility Damage from Recent Major Storms
Hurricane Maria and Winter Storms Quinn-Riley

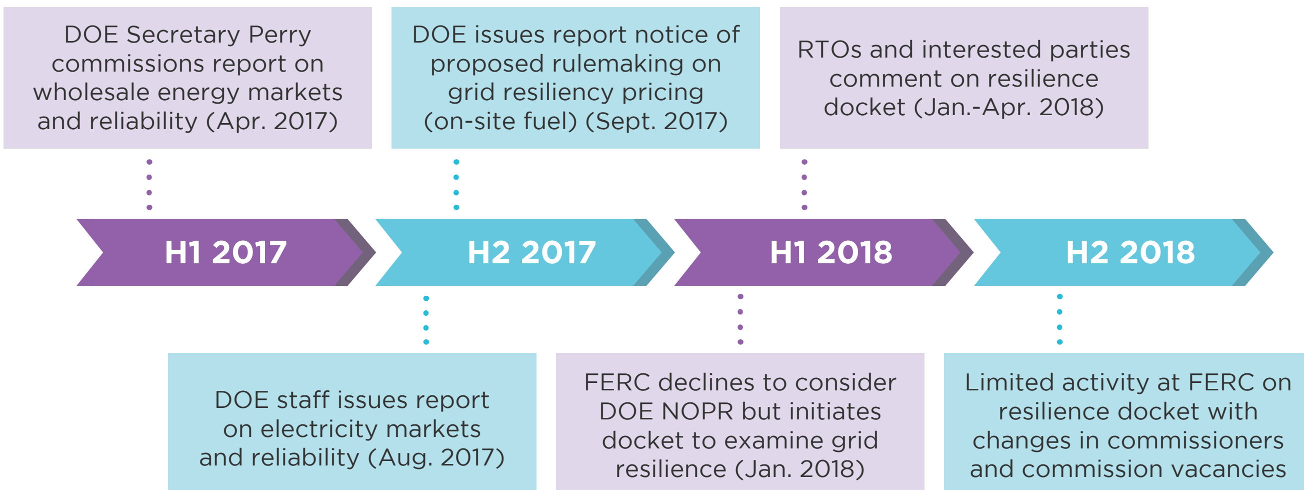
Source: REUTERS / ALVIN BAEZ - stock.adobe.com

Source: Con Edison

Some Definitional Issues

- Debate over what the appropriate scope of responsibilities and extent of preventative and remedial actions are has begun with differentiation between resilience and reliability.
- Time horizon, predictability, and severity of potential impacts are a few areas of distinction. Some working definitions have been discussed by stakeholders, including the two noted below.
- Why does it matter? While reliability has always been a focus of FERC and NERC, resilience—particularly involving long-duration events—has implications outside of the industry involving first responders, governmental agencies, and others, in addition to utilities.

Recent Policy Activity on Resilience and Reliability



Sources: FERC; DOE; ScottMadden analysis

Separate but Related: Resilience and Reliability

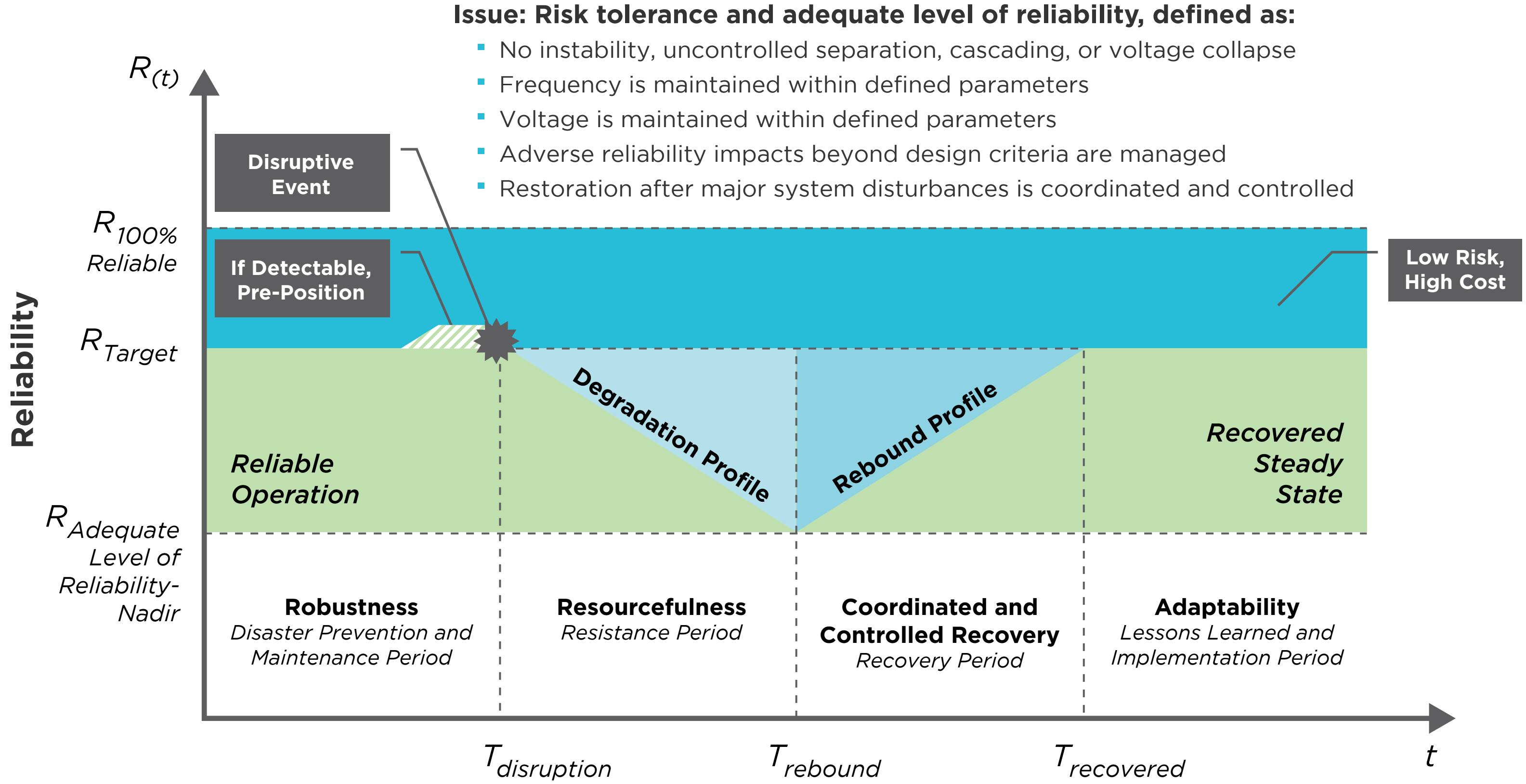
Resilience (extreme and long-lived events): The ability [of the electric system] to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event. (FERC Grid Resilience Order, Jan. 8, 2018)

Reliability (every day): The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components (adequacy) and the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components (operating reliability). (NERC, 2018 Long-Term Reliability Assessment, Dec. 20, 2018)

KEY TAKEAWAYS

- **Resilience continues to be a utility industry priority, and—given boundaries and overlaps—federal and state governments, utilities, and grid operators seek to find the right balance of authority and jurisdiction as different approaches to ensure resilience are formulated.**
- **Treating it not as a matter of if but when, utilities are focused on operational readiness and are planning for more frequent, extreme events (N-2-plus planning) and developing responses to a long-duration outage event.**
- **As the fuel mix shifts rapidly to variable and gas-fired resources, fuel security remains a reliability and resilience concern in some regions.**
- **Still to be debated is what is a reasonable outlay to achieve a required level of resilience, and who bears that cost.**

NERC Resilience Framework (Based upon National Infrastructure Advisory Council Framework)



Source: NERC

NERC Resilience Framework: Outcome-Based Capabilities

- **Robustness –** the ability to absorb shocks and continue operating
- **Resourcefulness –** the ability to detect and manage a crisis as it unfolds
- **Rapid Recovery –** the ability to get services back as quickly as possible in a coordinated and controlled manner, taking into consideration the extent of the damage
- **Adaptability –** the ability to incorporate lessons learned from past events to improve resilience

Source: NERC, Reliability Issues Steering Committee Report on Resilience (Nov. 7, 2018)

Generator Retirements: An Issue of Reliability or Resilience or Both?

- Much of the debate about the DOE's proposed resilience rulemaking centered on whether on-site fuel requirements unfairly tipped the scale toward coal-fired and nuclear power plants, violating traditional notions of fuel agnosticism in competitive markets.
- However, in 2018, several reports examined whether increasing baseload generator retirements would have an adverse effect on system reliability and, in the event of unusual and severe weather events, resilience.
- NERC conducted a stress test of its assessment areas, assuming retirement forecasts were understated. It found:
  - In a stress-test scenario, four regions—Texas, the Southwest, the Rocky Mountains, and parts of the Southeast—would fall well short of needed reserves, absent addition of Tier 2 (requested but not approved for planning) gas units.
  - Although NERC did not analyze natural gas infrastructure, natural gas generation is expected to provide adequate levels of voltage support and frequency response.
  - Large-scale retirements in a short time frame would require transmission network upgrades.
- PJM explored a similar question, testing resilience during a 14-day cold snap under various scenarios of generator retirements, pipeline disruptions, gas availability, and forced outages. It found:
  - With announced retirements, its system remains reliable under extreme winter load scenarios.
  - However, with accelerated retirements and extreme winter load, its system is at risk for voltage reduction and localized manual load shed, in addition to demand response deployment and reserve shortage.
  - With extended extreme cold weather, the key variables become non-firm gas availability, pipeline configuration, on-site fuel inventory, and oil deliverability.

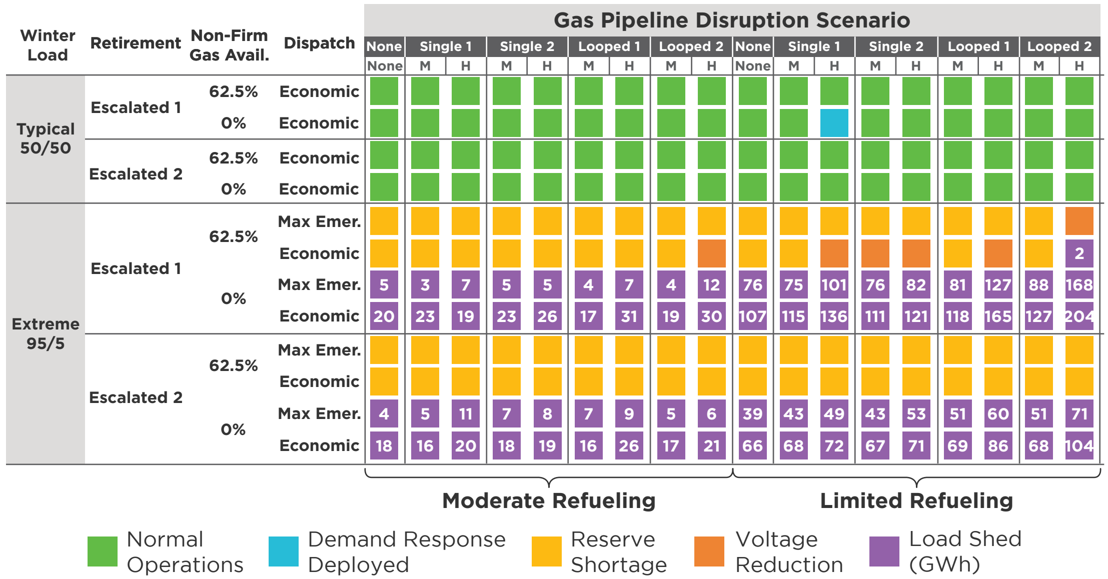
Some Analyses of Reliability and Resilience Impacts of Accelerated Generator Retirements

NERC Generation Retirement Scenario	PJM Fuel Security Analyses
Scenario(s)	**Scenario(s)**
• "Stress-test" retirement scenario – 91 GWs retired (63 GWs coal; 29 GWs nuclear) – Compare 27 GWs "confirmed" planned to date • Assumes 37 GWs of gas resources to replace retired units, including Tier 2 resources • Also looks at various regional analyses (PSEG-PJM; ISO-NE; ERCOT)	• Retirement scenarios – Up to 45 GWs retired (some replaced) – 28 GWs without replacement • 14 days of high winter demand (1 in 20 event) • Forced outage rate up to 12% • Fuel oil inventory at 85%, with 10 to 40 oil trucks per day per plant, depending upon size • 0 to 10 GWs non-firm gas capacity available • 5 days of pipeline disruptions (scenarios considered both looped and single pipeline configurations)
Findings	**Findings**
• Resource adequacy is sufficient in 6 of 10 areas • On a regional scale, significant replacement reserves are needed, requiring expedited queues • Gas is expected to be the predominant replacement resource, but NERC did not assess gas infrastructure and increases may be needed • Large number of retirements may result in extensive transmission network upgrade requirements	• Overall, current gen portfolio is reliable and fuel-diverse, but… • Some risks are associated with accelerated retirements • Oil refueling is a key factor in determining reliability in an emergency scenario • Pipeline disruptions trigger more emergency procedures
Source: NERC	**Source:** PJM

Note: Gas pipeline disruption scenarios characterized by type (single-feed and looped) and by severity (medium "M" or high "H")

Source: PJM

PJM "Trouble Spots": Escalated Retirements and Typical and Extreme Winter Load (with GWh of Load Shed)

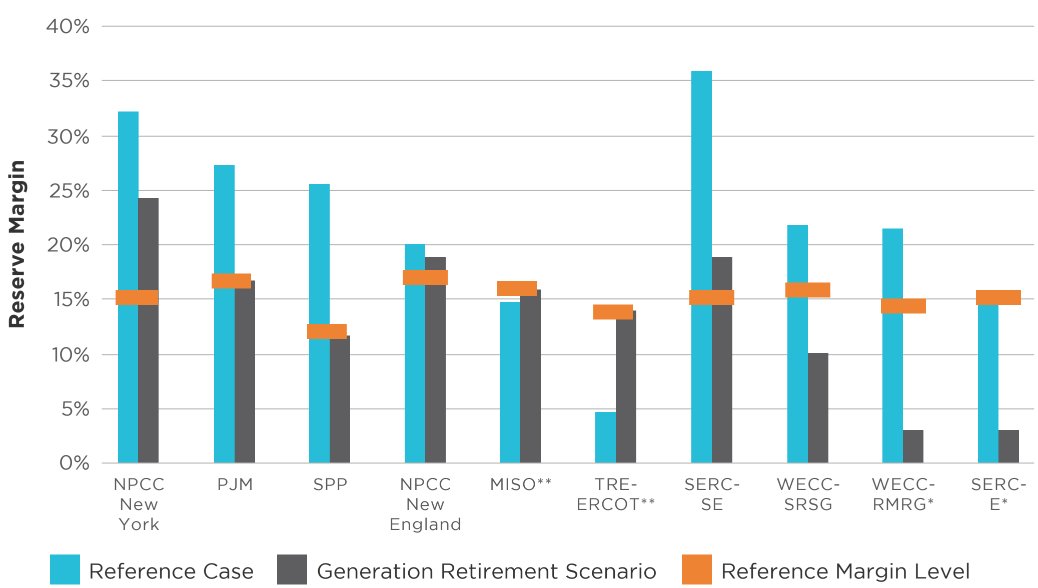


Notes: *Actual Planning Reserve Margin is near or below 0%

**Chart depicts the projected 2022 Planning Reserve Margin Reference Case below Reference Margin Level based on 2017 LTRA data and confirmed retirements. Generation Retirement Scenario Planning Reserve Margins assume new generation is installed to make up for confirmed and accelerated retirements.

Source: NERC

NERC Regions to Watch: Planning Reserve Margins for the 2022 Reference Case and Stress-Test Scenario



Bottom Line for Infrastructure:

As pace and amount of baseload retirements increase, significant amounts of backfill capacity (mostly gas-fired) and related gas infrastructure, as well as transmission upgrades, will likely be needed in the next three to five years.

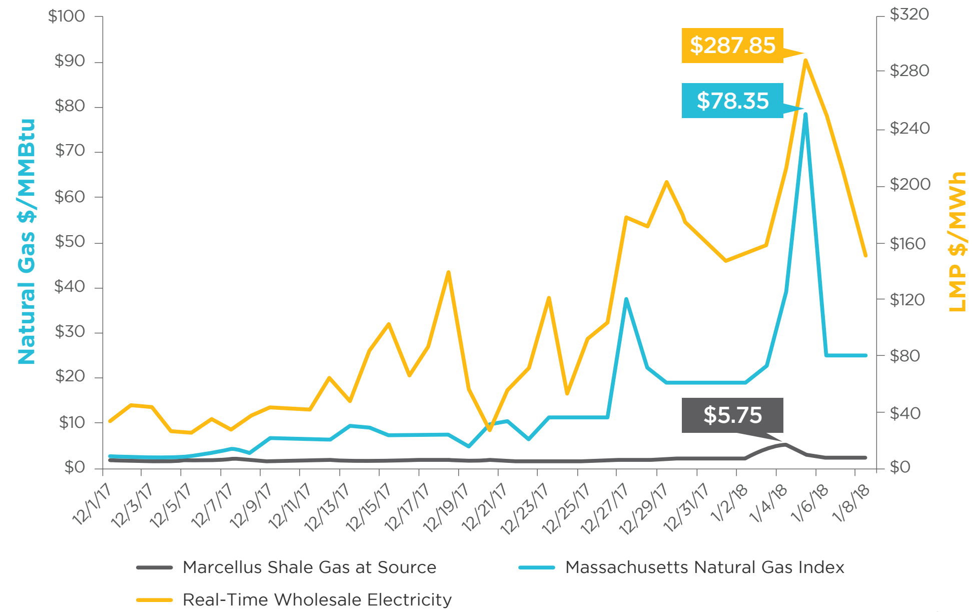
Gas-Power Interdependence Remains an Issue, Especially as Gas-Fired Generation Continues to Displace Retiring Oil, Gas, and Nuclear Units

- For as long as shale gas has been dramatically altering the natural gas commodity cost curve, reliance on natural gas as a primary generation fuel has been an issue in certain regions.
- The extreme cold (polar vortex) events of winters 2014-15 and 2015-16 motivated regulators, grid operators, and reliability organizations to study infrastructure adequacy and operational considerations of gas and power interdependence.
- Some efforts have been made to coordinate gas and power scheduling (and to accommodate power generation needs for gas during high gas demand days). And various regions are testing different approaches, such as pay for performance, expanded availability requirements for load-modifying resources, and market rules to enhance fuel security.

New England Serves as a Harbinger of Challenges to Come

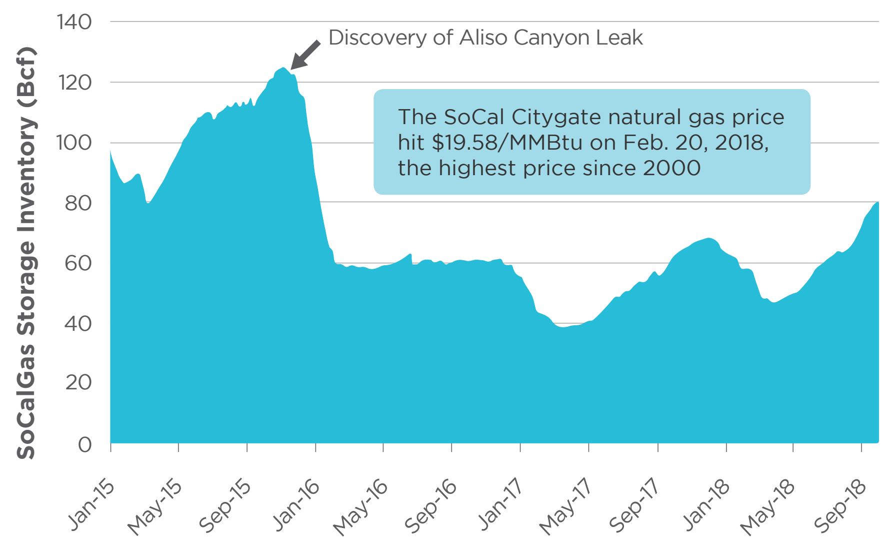
- New England's dependence on natural gas continues to increase, with 51% of its 2019 on-peak fuel mix comprised of natural gas.
- New England has limited gas storage capability and constrained pipeline capacity that operates at or near maximum during extreme or extended cold weather.
- Historically, gas delivery limitations—driven by mismatches between generator compensation and costs of firm gas transportation—have manifested themselves in power prices, but grid operator ISO-NE has expressed reliability and resilience concerns. ISO-NE has used pay-for-performance incentives and oil inventory compensation schemes to ensure winter reliability.
- In an effort to preserve system flexibility, however, ISO-NE has also begun contracting with fuel-secure resources that would have otherwise retired. For example, ISO-NE contracted with Exelon's gas-fired Mystic plant, including contractual support of the Everett LNG import terminal that provides Mystic's primary fuel supply.
- These market "fixes" have not been without controversy. Critics assert these solutions are temporary, suppress capacity prices, and distort markets.

New England Story: Frigid Cold Drives Gas Demand and Price Spikes, Leading to Power Price Spikes with Oil-Fired Generation "In the Money"



Source: ISO-New England

Even California Has Issues: Diminished Gas Storage at Aliso Canyon Affects Flexible Generation as California Ramps up Renewables



Sources: FERC; EIA

Preparing for the Worst

- As debate continues on climate action and related adaptation and resilience efforts, utilities and agencies are increasingly interested in fortifying the grid against extreme events (see figure at right).
- The National Infrastructure Advisory Council issued a report in December 2018 addressing the risks and readiness associated with a severe, widespread, and long-lasting catastrophic power outage. Among its recommendations specifically impacting utilities are the following:
  - Develop design criteria and/or standards for critical infrastructure hardening
  - Implement cost recovery and return-on-equity incentives for investments in hardening the bulk power system
  - Consider regulatory compliance waivers and liability protections during events
  - As backup resources and mutual aid agreements are exhausted, conduct regional catastrophic power outage exercises that identify second- and third-order cascading failures over time and examine cross-sector supply chain and cyber risk that could delay re-energizing the grid
  - Ensure critical gas transmission pipeline infrastructure has appropriate standards, design, and practices to continue services and maintain rapid availability to support black-start generation

Selected Grid Hardening and Resilience Preparations	
Hurricane and storm hardening 	▪ In the wake of 2005's Hurricane Wilma, which caused more than 3 million customers to lose power, Florida Power & Light has hardened its system, spending $3 billion since 2006 on pole inspection and replacement, vegetation clearing, and targeted undergrounding. Average time required to restore power after 2017's Hurricane Irma was 2.1 days compared to 5.4 days after Hurricane Wilma. Additional work on feeders and undergrounding is under way.
Storm response adaptation 	▪ Back-to-back winter nor'easters Quinn and Riley battered the Northeast in March 2018. The storms caused New York-area outages second only to Superstorm Sandy, despite a storm-hardening investment of $1 billion. Key challenges, which all utilities will have to consider for future planning given increases in storm intensity, were as follows: - Storm strength far exceeded weather forecasts, especially wind gusts. - Storm breadth interfered with ability to secure mutual assistance crews. - Quick succession of storms meant a second caused additional damage before repairs to damage from the first were completed. - Significant grid damage was caused by trees not in the utility right-of-way.
Disaster recovery and infrastructure rebuild 	▪ Puerto Rico's grid, flattened by Hurricane Maria in September 2017, continues recovery efforts. Increased renewable and perhaps nuclear power (small modular reactors) have been discussed. The Puerto Rico Electric Power Authority has proposed a 20-year integrated resource plan that would, among other things, divide the island's grid into eight mini-grids, as well as add floating LNG plants to provide fuel for gas-fired power plants.
Wildfire protection 	▪ In 2017 and 2018, California wildfires scorched thousands of acres across the state and cost dozens of lives. Given the state's inverse condemnation law (imposing financial liability regardless of whether good maintenance and operations practices are used), potential liability from 2018 wildfires forced Pacific Gas & Electric into bankruptcy. At the behest of California lawmakers and regulators, California's investor-owned utilities proposed $4 billion in investments to prevent future catastrophic wildfires. Among the proposals: covered conductors, tree removal, increased inspections, selective undergrounding, new weather stations, composite poles, and proactive de-energization plans.

Sources: Industry news; Florida PSC; Consolidated Edison Company of New York

IMPLICATIONS

Utilities must proactively develop risk management, grid hardening, and disaster recovery and resilience plans in anticipation of extreme weather events. Close coordination with regulators and other stakeholders is needed to ensure public acceptance and timely and adequate cost recovery.

Sources: Industry news; *Palm Beach Post*; *The Wall Street Journal*; Florida PSC; Consolidated Edison Company of New York; ISO-New England; PJM Interconnection, Fuel Security Analysis: A PJM Resilience Initiative (Dec. 17, 2018); NERC, Generation Retirement Scenario: Special Reliability Assessment (Dec. 18, 2018); NERC, Reliability Issues Steering Committee Report on Resilience (Nov. 7, 2018); NERC Compliance and Certification Committee Agenda Package (Dec. 5, 2018); FERC, 2018 Reliability Technical Conference, AD18-11-000 (July 31, 2018); WIRES; J. Schneider & J. Trotta, "What We Talk About When We Talk About Resilience," Energy Law Journal, Vol. 39, pp. 353-400; The President's National Infrastructure Advisory Council, Surviving a Catastrophic Power Outage: How to Strengthen the Capabilities of a Nation (Dec. 2018); Bipartisan Policy Center, Power System Resilience Primer (Feb. 2018); NERC, 2018 Long-Term Reliability Assessment (Dec. 2018); ScottMadden analysis

For more ScottMadden energy insights, visit our Insights Library: scottmadden.com/insights

UNITED KINGDOM FACT-FINDING MISSION
TEA, CRUMPETS, AND RIIO

SEPA and ScottMadden explored decarbonization and performance-based ratemaking.

Looking across the Pond for Lessons Learned

- With the United Kingdom serving as a poster child for utility business model reform, it is important to understand RIIO (see next page), the highly touted performance-based regulatory mechanism for the country's decarbonization efforts that also served as one of the models New York examined when developing its Reforming the Energy Vision (REV) policy framework.
- In October 2018, utility executives from the United States traveled to the United Kingdom to gain a first-hand understanding of how these efforts are unfolding.
- The Smart Electric Power Alliance (SEPA) and ScottMadden observed a clear commitment to and path toward decarbonization, yet implementation of the RIIO model has not been without challenges.

U.K. Electricity Market and the Path toward RIIO

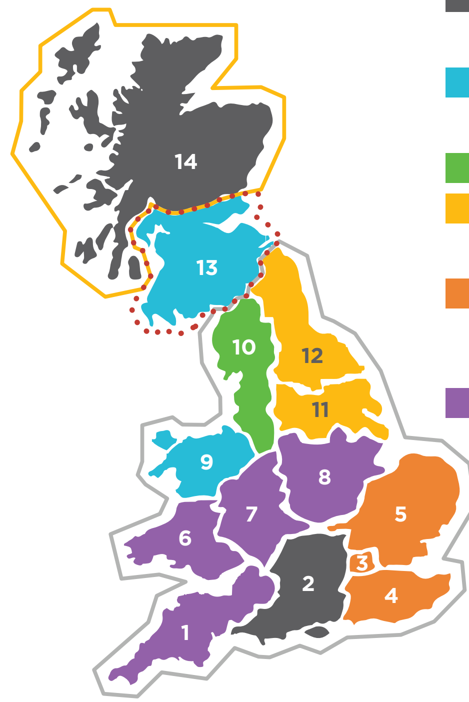
- The U.K. electricity sector consists of 173 generation firms, three transmission network operators (TNOs), 14 distribution network operators (DNOs), and 73 energy suppliers (see map on next page).
- The U.K. electric sector was privatized in 1990, with gradual implementation of retail electric choice taking place throughout that decade. By May 1999, all retail customers could choose their supplier.
- Generation has historically been dependent on coal and, more recently, natural gas (see graph on next page).
- Consequently, the U.K.'s interest in performance-based ratemaking stems from a desire to address climate change.

KEY TAKEAWAYS

- **A commitment to decarbonization drove the adoption of performance-based ratemaking and RIIO in the United Kingdom.**
- **Though it remains early, utilities have met most performance targets despite emerging questions about reliability and provider-of-last-resort standards in an age of distributed generation and non-wires alternatives.**
- **Ofgem has proposed a framework for RIIO-2 that would save customers money but dramatically lower the revenue potential for electric utilities.**
- **The U.K. RIIO experience, as well as major energy sector initiatives in the United States, illustrates that major transitions in the energy sector require a clear focal point.**

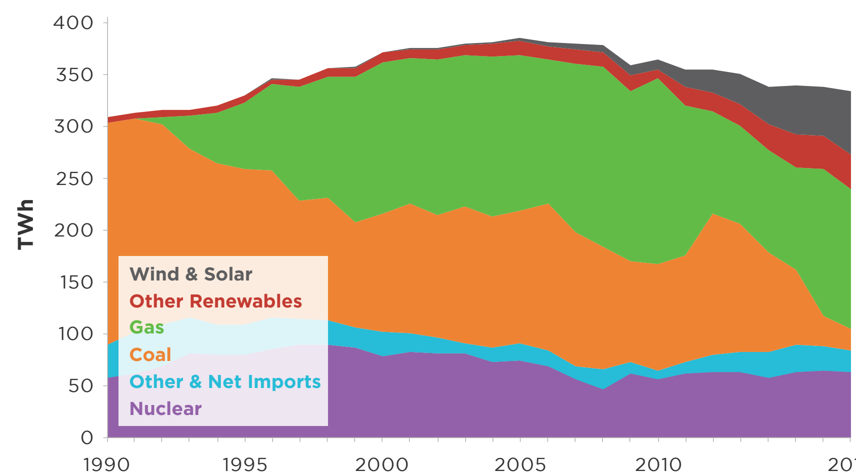
- In 2008, the United Kingdom passed legislation requiring the government to reduce greenhouse gases (GHGs) by 2050 to at least 80% below 1990 levels.
- In the same year, the Office of Gas and Electricity Markets (Ofgem)—the U.K.'s energy regulator—began a multi-year assessment of the existing regulatory construct and concluded the following:
  - The existing system would not sufficiently encourage or reward transmission and distribution operators for taking a leading role in decarbonization.
  - Further, to build a network capable of addressing climate change, the utilities would need to take risks, innovate, and focus on customers.
- Ofgem proposed a new model to "drive smarter and more sustainable networks to deliver a secure, low-carbon energy sector and long-term value for money for consumers."
- The performance-based regulatory model adopted by Ofgem sets Revenue using Incentives to deliver Innovation and Outputs—and thus the name "RIIO" was born.
- Put more simply, RIIO is a comprehensive approach to reward TNOs and DNOs for innovating and delivering on desired outcomes.

U.K. Transmission and Distribution Network Operators



Source: Ofgem

U.K. Electricity Supplied by Fuel Type (1990–2017)

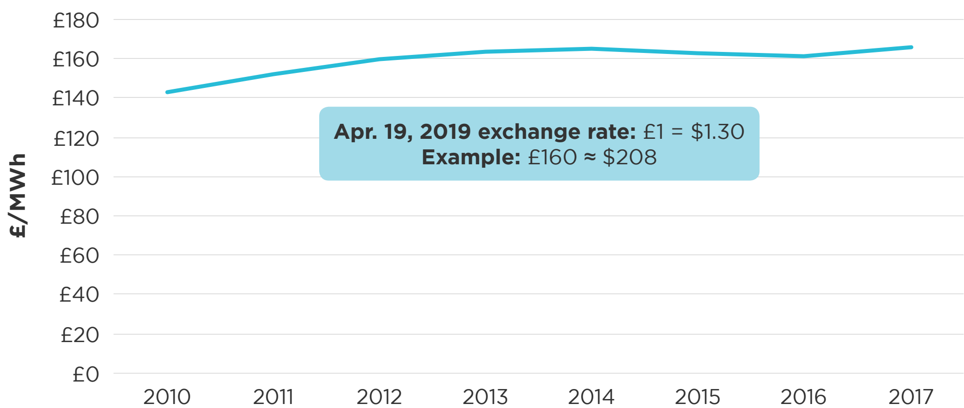


Source: U.K. Dept. of Business, Energy & Industrial Strategy

Act One: RIIO-1 Launches Performance-Based Rates in United Kingdom

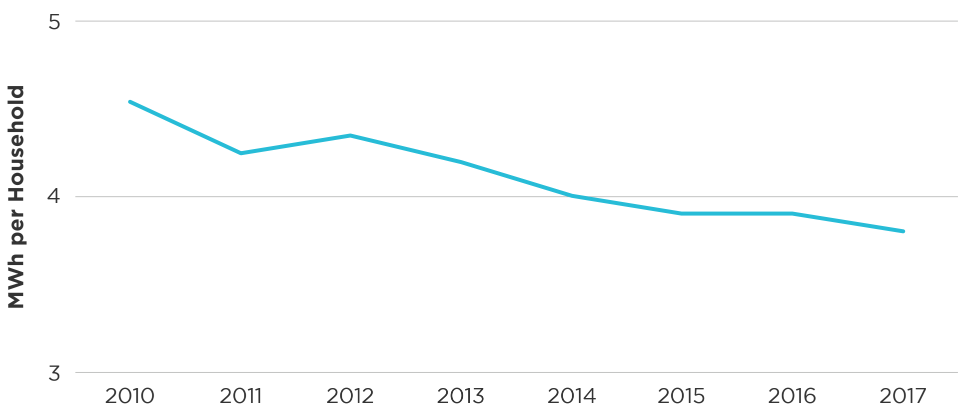
- Once the United Kingdom committed to the RIIO framework, the TNOs and DNOs submitted business plans to Ofgem.
- After review and stakeholder consultation, Ofgem set (1) the revenue that companies are allowed to earn through base revenues and incentive awards or penalties and (2) the outputs they must deliver (e.g., network reliability, customer service, etc.).
- After years of preparation, RIIO-1 was implemented for TNOs in April 2013 and DNOs in April 2015.
- Some notable features of the regulatory model include:
  - **Multi-Year Rate Plan:** To encourage long-term investments, RIIO-1 consists of an eight-year rate period.
  - **Totex:** A portion of capital expenditures (capex) and operating expenditures (opex) can be placed in a regulatory asset allowing a rate of return.
  - **Performance Incentives:** Ofgem sets specific targets for utilities that may impact financial performance up to +/- 250 basis points on return on regulatory equity.
    - There are six target categories: reliability and availability, environment, connections, customer service, social obligation, and safety.
    - Utility benchmarks and scorecards are published.
    - Efficient utility operations are incentivized as a portion of cost savings (and cost overruns) are shared with (or borne by) the utility.
  - **Innovation Fund:** Ofgem created a source of funds to sponsor innovative pilots testing new technologies and operating and commercial arrangements.
- Though it remains too early for a full evaluation, generally RIIO-1 is performing as expected:
  - TNOs and DNOs have successfully met most of their performance targets.
  - Customers have seen the average retail electricity price stabilize and average household consumption decline.
  - Carbon emissions from the electric sector continue to decline (see next page).
- Despite the progress, challenges similar to those facing U.S. electric utilities were apparent. As distributed energy resources and third-party non-wires alternatives are integrated into the grid, the same questions are emerging regarding responsibility for reliability and the obligation to serve.

U.K. Average Retail Electricity Price (£/MWh)



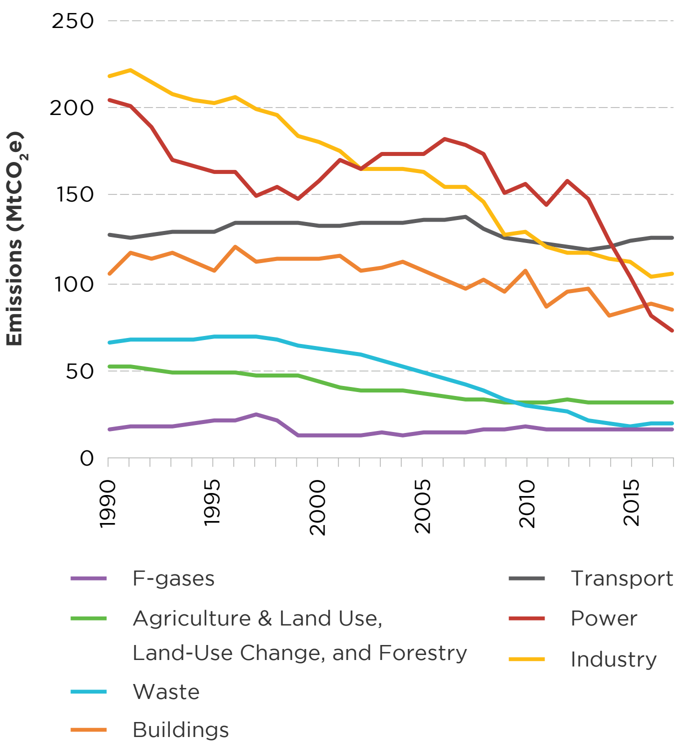
Source: Ofgem

U.K. Average Annual Household Electricity Consumption (MWh per Household)



Source: Ofgem

U.K. Greenhouse Gas Emissions by Sector (1990–2017)



Source: U.K. Committee on Climate Change

Act Two: Ofgem Lays out Framework and Plans for RIIO-2 in 2021

- As the United Kingdom prepares for the second multi-year rate period, some critics have argued network operators are being overcompensated in RIIO-1. For example, the consumer advocate group Citizen Advice has argued that assumptions in RIIO-1 have resulted in £7.5 billion ($9.75 billion) in unjustified profits for network operators.
- Against this backdrop, Ofgem released a proposed framework for RIIO-2 in December 2018. The RIIO-2 framework, which would begin in 2021, includes the following notable changes:
  - Lower baseline returns on equity for power transmission networks to 4% to 5%, down by almost half from 7% to 8% in RIIO-1 (for comparison, the yield on a 30-year U.K. government bond recently stood around 1.71%)
  - Shorten the multi-year rate period to five, down from RIIO-1's eight
  - Reduce the cost of debt at which network operators may borrow to better reflect falling interest rates
  - Change the inflation index from a retail price index to a consumer price index, including housing
- Ofgem estimates customers would save a total of £6.5 billion ($8.45 billion), with individual electric bills declining by an average of £30 ($39) a year.
- S&P Global Ratings signaled several network companies would be at risk of downgrades if they failed to reduce debt leverage under the proposed framework.
- Meanwhile, network companies are concerned that a change in returns could impede new capital from flowing to the sector. They contend that the proposed changes would thus shift focus from innovation and efficiency to risk aversion and penalty avoidance.
- Stakeholder consultations are underway, and Ofgem is expected to finalize the RIIO-2 framework in the summer of 2019.

Key Finding from Fact-Finding Mission: Major Transitions Require a Focal Point

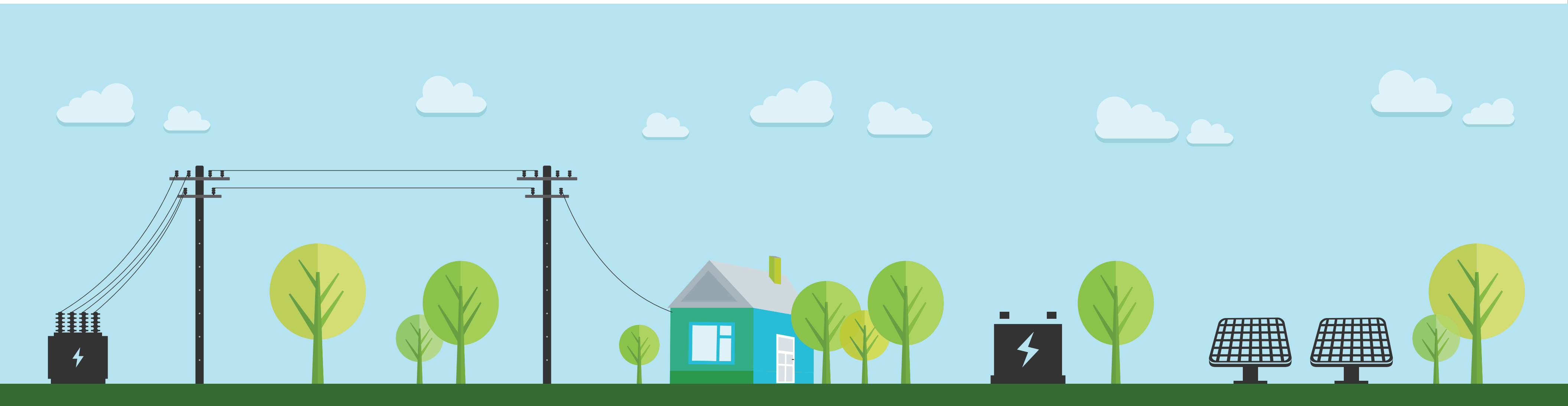
- A key finding for participants was that major transitions in the energy industry require an agreed-upon, common focal point to drive innovation and change.
- For the United Kingdom, an interest in deep decarbonization, which includes the legislation requiring GHG reductions, was the primary motivation to pursue the performance-based rates and develop the original RIIO framework.
- In the United States, examples like Illinois' grid modernization efforts indicate the focal point does not always have to be climate change and decarbonization.
- Absent a focal point, stakeholders are left merely with standalone initiatives, while prudently allocating resources becomes challenging with no metrics for comparison and evaluation.

IMPLICATIONS

RIIO-1 remains a positive example of how a performance-based rate can encourage transmission and network operators to meet performance metrics. However, it remains unclear if the significant changes to the framework proposed in RIIO-2, focused on saving customers money, will shift the operational mindset of utilities to a more defensive position.

Notes: Portions of this section are adapted from "Decarbonization and RIIO in the U.K.: Look Across the Pond" published in the February 2019 edition of *Public Utilities Fortnightly*. Currency conversions assume £1 GBP equals $1.30 USD.

Sources: J. Hamm & C. Lyons, "Decarbonization and RIIO in the U.K.: Look Across the Pond," *Public Utilities Fortnightly* (Feb. 2019); AEE Institute; America's Power Plan; Committee on Climate Change, Reducing U.K. Emissions: 2018 Progress Report to Parliament (June 2018); Digest of U.K. Energy Statistics 2018, Ch. 5: Electricity; U.K. Department for Business Energy Industrial Strategy; U.K. Office of Gas and Electricity Markets; Rocky Mountain Institute; S&P Global; Bloomberg; ScottMadden; SEPA



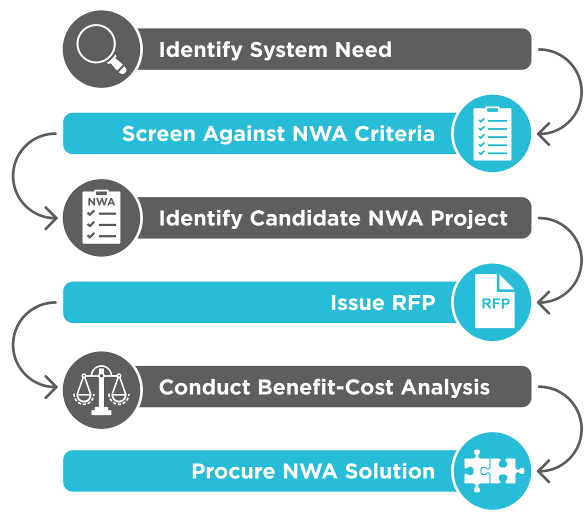
NON-WIRES ALTERNATIVES
NON-TRADITIONAL SOLUTIONS TO GRID CONSTRAINTS

NWAs are being introduced across the country as a potential alternative to building utility infrastructure.

Defining NWAs

- Over the past few years, NWAs have emerged as an alternative to traditional investments in the electric transmission and distribution (T&D) system. Regulators and utilities are increasingly interested in NWAs as an alternative to meeting the needs of the electric grid.
- NWAs may provide benefits to utilities and customers, including deferral of infrastructure investments, reduction in carbon emissions, and decreased energy and capacity costs.
- NWAs leverage energy efficiency, demand response, distributed generation, and other DERs to address grid capacity needs, facility upgrades, or select contingencies. Many see them as a way to integrate clean, non-carbon-emitting resources into the grid.
- These solutions may be more cost effective than traditional infrastructure projects and can be utility owned or implemented by a third party.
- NWA technologies can be deployed individually or as a portfolio to address a system need.

Simplified NWA Assessment Process



NWAs Have Emerged as a Component of New York's REV Initiative

- In July 2018, New York's electric utilities filed updated Distributed System Implementation Plans (DSIP) in which they detailed progress made regarding NWA procurement. As of that month, utilities had identified 57 potential NWAs and issued 22 solicitations for NWAs.

Progress of Select NWAs in NY (as of July 2018)

	O&R	NYSEG & RG&E	National Grid	Con Edison	Central Hudson
Opportunities Identified	7	15	22	8	5
Solicitations	3	4	7	4	4
In Development	1[c]			1[a]	1
Implemented				1[b]	3

Notes: **a)** Glendale – Deferral of a traditional solution included in BQDM
b) BQDM – Preceded REV/DSIP NWA solicitations
c) Pomona – Reflects 4/13/2019 developer selection announcement

Sources: Con Edison DSIP and NWA solicitations

Example of Deferred Investments Sought from NWAs

- Substation upgrade
- Network feeder upgrade
- Primary feeder upgrade
- Transformer replacement
- New 138-kV sub-transmission feeder

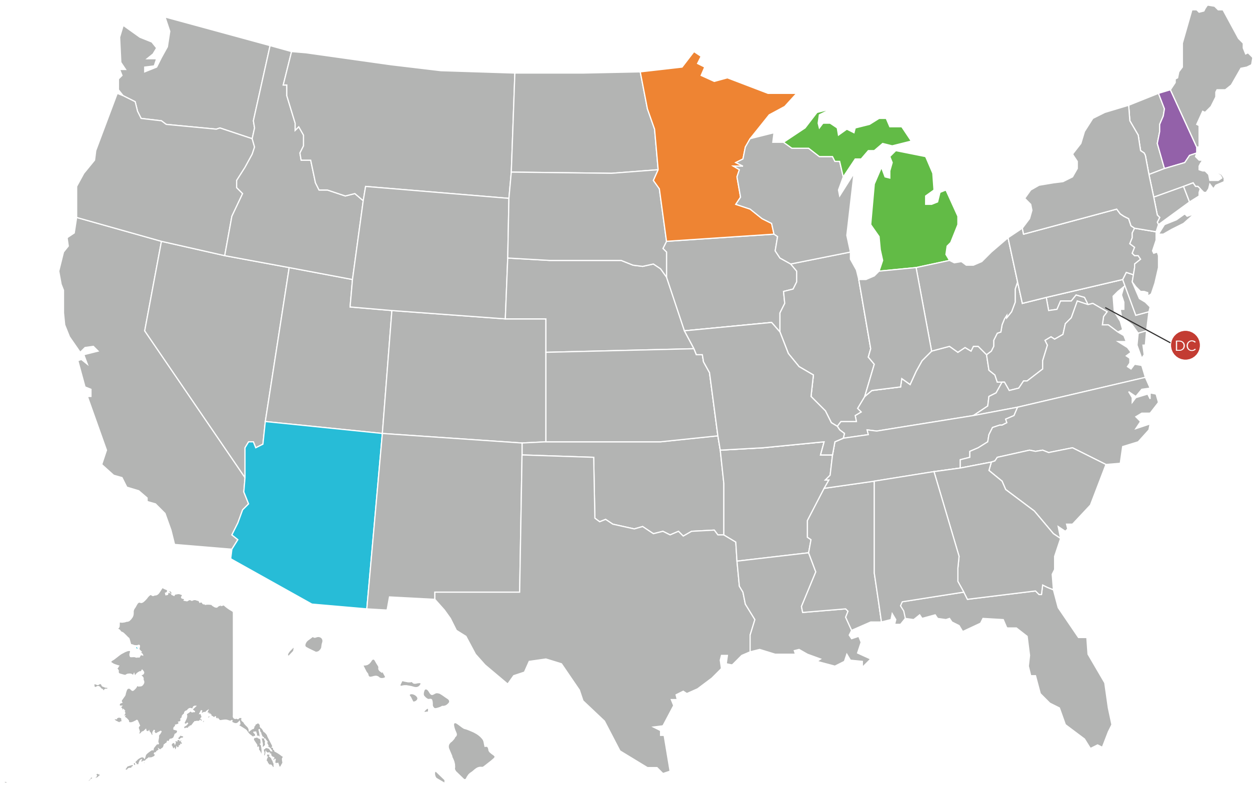
Sources: Con Edison DSIP and NWA solicitations

A number of stakeholders have been participants in the NWA proposal and development process.

KEY TAKEAWAYS

- **Utilities are increasingly assessing and implementing NWAs as a solution to system constraints.**
- **In addition to New York, other states have begun requiring utilities to include NWAs in distribution system plans.**
- **Depending on the retail structure of the state, a utility may either implement NWAs with DERs it owns and operates, or it may contract with a third party to operate and maintain them.**
- **The processes to successfully develop and execute an NWA program can span many functional areas within a utility and require coordination and management.**

Examples of States beyond New York That Are Exploring NWAs



Arizona's Arizona Public Service installed an energy storage facility (2MW/8MWh) instead of upgrading 20 miles of rural T&D lines.

D.C. Council members introduced the Distributed Energy Resources Authority Act of 2018, which calls for a new independent body that, among other activities, would be responsible for the planning and evaluation of NWAs.

Michigan Public Service Commission approved DTE Energy's NWA pilot, which will install a battery storage facility at an existing solar project to improve renewable integration and inform DTE's understanding of battery storage performance.

Minnesota's Northern States Power (Xcel Energy) filed its first integrated distribution plan, which discussed the viability of NWA projects and included an example analysis for a proposed feeder project.

New Hampshire Public Service Commission required Liberty Utilities to include the planning process and evaluation method for NWAs in its latest least-cost integrated resource plan.

Sources: Industry news; ScottMadden research

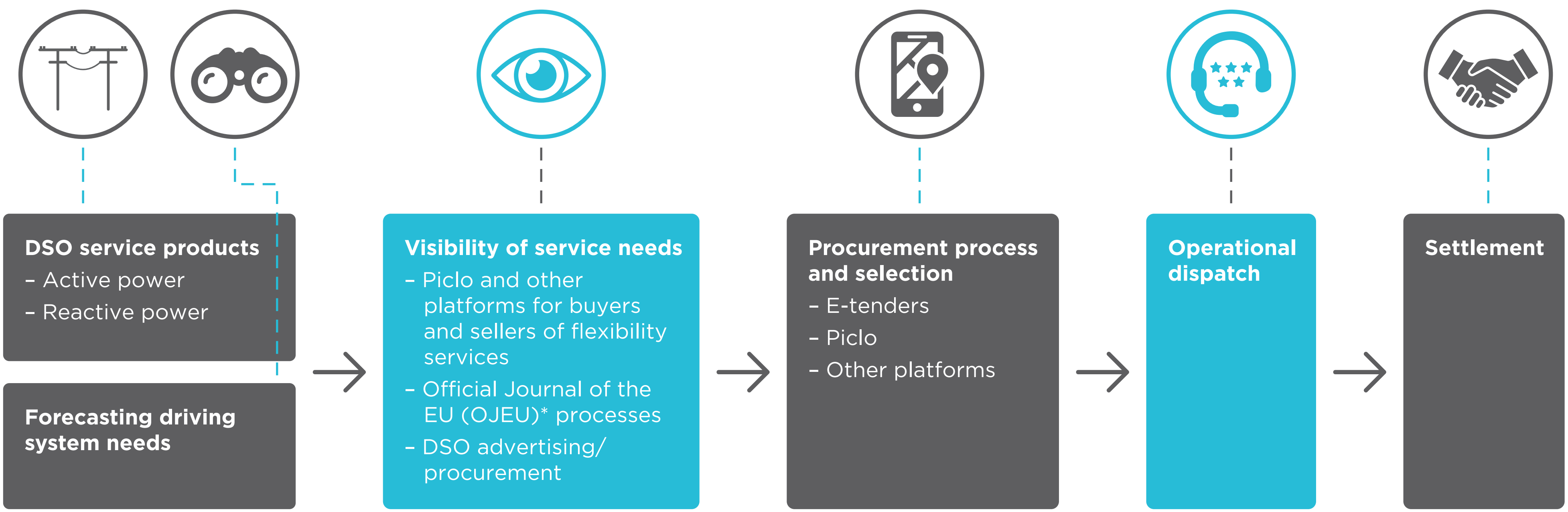
Own or Contract NWAs: The Nature of Incumbent Utility Matters

- As the industry considers NWAs to address system needs, the structure of the utility is an important consideration.
- In the case of fully integrated utilities that own both wires and generation assets, integrating NWAs may simply mean expanding the distribution planning process to consider new resources by which to address system needs. The operations and maintenance of the new resources are integrated into existing (or newly developed) processes and procedures; the utility owns and controls the asset.
- For wires-only utilities, a different issue emerges. Depending upon state regulation, the utility might not own the resources deployed as part of the NWA. From an operations and maintenance perspective, the utility may contract with the provider of the DERs based on grid requirements, which may require relying on a third party to manage the assets on its behalf.

U.K. RIIO Requires Distribution Operators to Open System and Procure NWAs

- The U.K. electricity market's RIIO mechanism (explored earlier in this Update), requires distribution network operators to transition to distribution system operators and operate a distribution system which actively manages demand, local generation, and other DERs.
- As part of the "Smart Systems and Flexibility Plan" of RIIO, DNOs have had to open up their networks to alternative "flexible" solutions that provide revenue opportunities for non-traditional network solutions, such as storage, demand response, and energy efficiency. Some examples:
  - In 2018, U.K. Power Systems announced plans to procure 100 MWs of flexibility from DERs, across 25 "flexibility first" zones, to test the market for flexible resources.
  - Western Power Distribution is designing "flexible power," a product which would incentivize customers to shift or alter electricity usage at certain times.
- DNOs are working with Ofgem, the government regulator for gas and electricity markets, to develop price formation frameworks to ensure that financial incentives encourage the greater use of flexible services and do not favor traditional investments where flexible solutions are more efficient. For all new projects of significant value, DNOs are required to leverage the newly created market to compare traditional investments to flexible solutions.
- While RIIO drives flexible solutions, DNOs need to continue to plan for the same levels of reliability. As these NWAs or flexible solutions proliferate, DNOs may need to implement a performance obligation for third parties' operating system assets.

End-to-End Process for U.K. Distribution System Operator Services



Source: Energy Networks Ass'n (U.K.)

Some Important Issues to Be Addressed in Implementing NWAs

Integration of NWAs into Utility Organization

Impacts of Integration of NWAs on Planning Process

- Planning and forecasting processes will have to expand to incorporate these resources; both new resources and expanded planning horizons may be needed.
- NWA suitability criteria are key to defining potential NWA projects early in the planning process—considerations include the type and scale of the grid need and the lead time before the solution must be operational.
- Third-party developers have a keen interest in these projects; developing a mechanism by which to share system data is critical.
- Capital planning time frames may need to be extended to allow for backstop traditional solutions if NWA resources are not available or deployed in time.

Importance of Coordination across Internal Departments

- Various departments may be involved in developing, procuring, and operating NWAs (regulatory, operations, planning, supply chain, etc.).
- Clear governance and well-established processes are key to deploying these projects.

O&M Differences for NWAs

- Third parties may be contracted to manage NWA assets. As such, performance standards and contracting terms are critical for ensuring NWA availability.
- Reliability risk is typically borne by the utility: How might this change with third parties operating critical assets to maintain grid reliability?

Considerations in Cost-Benefit Analysis

Cost-Benefit Framework

- A cost-benefit framework establishes the valuation methodology by which the costs and benefits that NWAs present are compared to traditional wires solutions.
- Understanding the costs and benefits is essential to determining the applicability of NWAs as possible solutions to system needs.
- Many view NWAs as a means to further integrate clean energy into the grid; if there are policy or other objectives driving NWA development, they should be reflected in the framework.
- Environmental considerations, as well as deferred wires investments, can drive NWA projects. To the extent that environmental or carbon attributes are monetized as part of the cost-benefit analysis, parties should understand the potential cost to customers.

Incentives and Cost Recovery

- Per New York regulators, “markets and positive financial incentives—rather than direct regulatory mandates with negative consequences—should be the primary drivers” of implementation.
- The typical NWA is split between O&M and capital; recovery of costs will be different from traditional projects.
- Incentives for utilities to implement NWAs should align with overarching regulatory and utility objectives.
- There should be a process to recover the traditional solution if the NWA is unsuccessful.

Benefits Realization

- Consideration should be given to the manner in which benefits are realized by the utility: Will benefits associated with reductions in capacity obligations be recognized by the organization funding the NWA? How will customers realize NWA benefits that don’t have immediate bill impacts?
- Benefits harvesting should be built into the utility’s NWA process to ensure benefits promised in cost-benefit analyses are captured by the utility.

Procurement of NWAs

Third-Party Procurement

- The procurement and contracting processes need to ensure that the project is implemented on time and that the resources are available when needed by the grid.
- The different operating characteristics of third-party solutions make comparing contract options challenging—procurement evaluation processes need to consistently evaluate solutions while retaining flexibility to compare dissimilar solutions.

Asset Mix

- The portfolio of assets procured must meet the need identified in the planning process.
- Low-cost assets, such as EE and DR programs, may be combined with high-cost assets, such as storage, to achieve needed load reduction in a cost-effective manner.
- Asset mix may be driven by load shape, peak duration, customer types, etc. Not all DERs will be suitable in every situation.

IMPLICATIONS

Over the past several years, the United States has seen a rise in the number of NWA projects being proposed and implemented. Industry observers expect that NWAs will continue to be part of utility programs, providing important lessons in the coming years. Stay tuned.

Note: *The OJEU is the gazette of record for the European Union. About 2,500 new notices are advertised each week, including invitations to tender, prior information notices, qualification systems, and contract award notices.

Sources: New York electric utilities' distribution system implementation plans (filed Jul. 2018); SEPA, Non-Wires Alternatives: Case Studies from Leading U.S. Projects (Nov.2018); ScottMadden, "A First-of-Its-Kind Move: D.C. Council Proposes a Revolutionary Approach to Distribution Planning" (May 2018); Michigan Public Service Comm'n, Notice of Proposal for Decision, Case U-20162 (Mar. 15, 2019) (regarding DTE Energy); ScottMadden, "Xcel Energy Prepares for the Future with Its Integrated Distribution Plan Filing in Minnesota" (Dec. 2018); Liberty Utilities (Granite State Electric), Least-Cost Integrated Resource Plan — Appendix (Jan. 15, 2016); Energy Networks Association (U.K.), Open Networks Project: 2018 Review (Feb. 2019); industry news; Con Edison NWA RFP website; ScottMadden analysis

For more ScottMadden energy insights, visit our Insights Library: scottmadden.com/insights

SMART CITIES
HOW UTILITIES CAN SHAPE THE CITY OF THE FUTURE

How can electric utilities be a natural ally and effective partner?

Smart Cities Share Common Objectives, Yet Differ When Ranking Priorities

- Smart city initiatives take many shapes and forms, ranging from information kiosks to street light management to gunshot detection and response.
- Despite the breadth of activities, most smart city efforts are driven by just five common objectives (shown at right).
- Communities pursuing smart city initiatives have different priorities and fiscal constraints, resulting in different rankings of these objectives.
- Key considerations for prioritization may include population density (e.g., urban vs. rural), campus environments (e.g., colleges and universities), operational requirements (e.g., military installations), and budgetary constraints (e.g., efficiency improvements).

Common Smart City Objectives	
Economic Development	Attract and retain a diverse economic base and talented workforce
Security	Ensure the safety and protection of critical assets, which include IT/OT
Quality of Life	Enhance services and amenities offered to residents and visitors
Cost Savings	Leverage technology to improve the efficiency of service delivery
Sustainability	Improve environmental performance and outcomes

KEY TAKEAWAYS

- **While priorities may differ, all smart city initiatives share a common set of objectives.**
- **Because of the existing infrastructure and customer relationships, utilities are natural allies in smart city efforts.**
- **Utility smart city participation can range from providing traditional energy services to building new non-energy business models.**
- **Utilities can take several concrete steps to be an effective and engaged smart city partner.**

Electric Utilities Will Be Critical Stakeholders—and Natural Allies—During Smart City Planning and Deployment

- The electric utility has an existing relationship with every citizen and business within the community considering smart city solutions and is positioned as a trusted essential service provider.
- The electric utility may already offer a variety of services that align with smart city planning (e.g., outdoor street lighting, energy efficiency services, EV make-ready infrastructure, etc.).
- Fundamental to this relationship and service are the utility's existing physical assets (poles, conduit, outdoor lights, etc.) across the geographic footprint of the future smart city.
- The challenge for a utility is that its assets are built for a specific purpose within a particular regulatory and financial construct.
- The design and operation of existing assets, as well as their having been funded by ratepayers, may limit a utility's ability to leverage the assets for smart city purposes.

Electric Utilities' Support of Smart City Solutions May Scale from Providing Energy Services to Launching New Business Models

- Smart cities require four building blocks: infrastructure, connectivity, sensors, and data analytics. The most dynamic smart city solutions will leverage all four.
- Electric utilities—and other smart city solutions providers—could offer services within the scope of each one.
- This creates three lanes for potential smart city participation for an electric utility:
  - Lane 1 – Energy Services Provider: The electric utility is a primary stakeholder offering energy-related smart city solutions
  - Lane 2 – Non-Energy Solution Enabler: The electric utility partners with other vendors, who bring specialized expertise, to deliver non-energy-related smart city solutions
  - Lane 3 – Non-Energy Solution Provider: The electric utility builds expertise and capabilities in new areas in order to serve as a vendor providing non-energy-related smart city solutions
- Providing energy services is one obvious service that aligns with the core business of an electric utility.
- Engaging in non-energy solutions (as an enabler and/or solution provider) requires an evaluation of the opportunities, likely outcomes, and impacts on the overall utility business.

Electric Utility Potential Roles and Example Smart City Services

Smart City Building Blocks		Potential Smart City Roles for Utilities (Lanes): Lane 1: Energy Services Provider	Lane 2: Non-Energy Solution Enabler	Lane 3: Non-Energy Solution Provider
		The electric utility is a primary stakeholder, offering energy-related smart city solutions. Keys to success include targeted offerings and robust customer engagement.	The electric utility partners with other vendors, who bring specialized expertise, to deliver non-energy-related smart city solutions. Keys to success include opportunity identification and partnership development.	The electric utility builds expertise in new areas in order to serve as a vendor providing non-energy-related smart city solutions. Keys to success include a high-risk tolerance and ability to advance alternative business models.
Infrastructure	Basic physical structures and facilities (e.g., electric poles, pipes, roads, etc.)	Install traditional street lighting that illuminates from dusk to dawn	Allow telecommunication companies to run fiber networks through utility conduit	Launch bike or scooter sharing program
Connectivity	Communication system that allows data collection and ability to control smart city assets	Leverage communication networks for demand response signals	Allow third parties to transfer data over the RF mesh network used for AMI meters	Leverage fiber or 5G networks and offer consumers TV and phone service
Sensors	Hardware that collects the data needed for more advanced smart city offerings	Use methane sensors to detect gas leaks	Allow third parties to install gunshot-detection sensors on utility poles or street lights	Use cameras to monitor activity in public spaces
Data Analytics	Analysis of data resulting in enhanced services or improved outcomes	Operate advanced street lighting (e.g., turns on during storms or dims when not needed)	Coordinate fleet vehicle charging behavior for large commercial clients	Provide parking and traffic management services

INCREASING OPPORTUNITIES AND VALUE

INCREASING UTILITY ENGAGEMENT IN SMART CITY DEPLOYMENT

A Clear Path for Electric Utilities to Support Communities Pursuing Smart Cities

- Electric utilities can be valuable strategic partners to communities preparing to embark on a smart city journey:
  - **Support Community Planning Efforts**
    - Planning efforts should initially focus on prioritizing alignment on common objectives rather than specific smart city solutions.
  - **Examine Current Utility Offerings**
    - The low-hanging fruit to meeting community objectives may lie in minor modifications to existing utility offerings (e.g., expanding or re-targeting energy efficiency programs).
  - **Engage Stakeholders to Identify Potential Utility Contributions**
    - As the community conducts stakeholder engagement, the electric utility may explore partnerships to enable non-energy services.
  - **Ensure Organizational Commitment**
    - Smart city planning and deployment will touch multiple internal groups (e.g., economic development, regulatory affairs, etc.).
    - It will be critical to identify a primary point of contact for the community as they undertake smart city activities.
  - **Create Cross-Functional Feedback Loops**
    - Supporting these efforts allows a utility to deepen its smart city understanding.
    - To fully leverage the knowledge, utilities should develop an internal cross-functional feedback loop.
    - Any shifts in the community approach can then be incorporated into the utility's support and relevant business plans.

Alabama Power Pilots Smart Neighborhoods

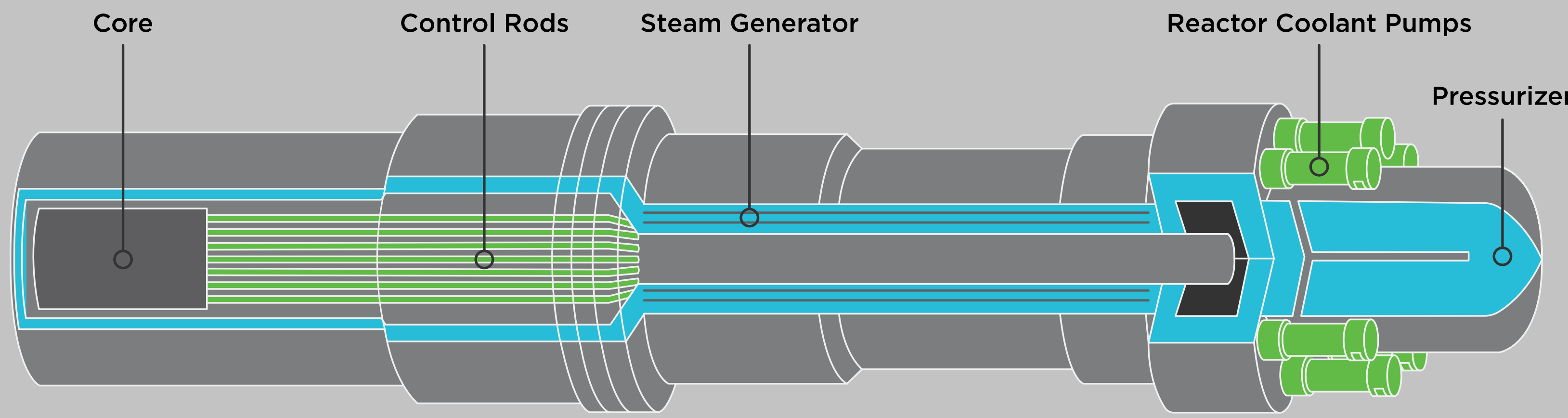
- To understand what technologies will be commonplace in 2040, Alabama Power recently partnered on a smart neighborhood called Reynolds Landing.
- The project includes 62 single-family homes with:
  - High-efficiency construction – Each home scores 40 to 50 on the Home Energy System Rating System (HERS) (lower is better in HERS; benchmark home scores 100; net-zero energy home scores 0)
  - Building-to-grid communications – Internet-connected water heaters and HVAC systems allow grid interactions
  - Community microgrid – A 1-MW microgrid consists of solar PV, battery storage, and a natural gas generator
- Project partners include Signature Homes, Electric Power Research Institute, and Oak Ridge National Laboratory.
- Homeowners agree to provide researchers circuit-level end-use data for the first two years and participate in monthly meetings to provide feedback.
- Alabama Power's sister company, Georgia Power, is piloting a similar program using rooftop solar and behind-the-meter battery storage instead of a community microgrid.

Source: *T&D World*

IMPLICATIONS

Electric utilities are poised to be a strategic partner and natural ally for communities exploring smart city solutions. An electric utility can provide energy services, enable non-energy services, and/or become a non-energy service provider. In any of these roles the utility can take deliberate actions to ensure they are an effective smart city partner.

Sources: Greentech Media; *T&D World*; ScottMadden analysis



SMALL MODULAR NUCLEAR REACTORS
GROWING INTEREST, BUT HOW VIABLE?

The search for low-carbon energy renews interest in small nuclear reactors.

Recent SMR Activity in the United States

- 2018 was an active year for SMR development in the United States, or at least a year of rising interest in SMR projects.
- NuScale Power submitted a design certification application in 2017 for its 50 MWe SMR (now boosted to 60 MWe), and the U.S. NRC completed its Phase I safety evaluation report in April 2018. Final safety approval is targeted for September 2020.
- Further, the U.S. Department of Energy awarded $40 million toward a first-of-a-kind SMR plant at Idaho National Laboratory, with Utah Associated Municipal Power Systems (UAMPS) as owner and energy off-taker to serve its 46 members.
  - The project, dubbed the Carbon-Free Power Project, would be comprised of 12 60-MW modules (totaling 720 MWs), sited near Idaho Falls, Idaho, and is scheduled for commercial operation by 2026 or 2027.
  - The project is currently undergoing feasibility analysis to determine whether to proceed with a construction and operating license application. UAMPS members are expected to vote on the project sometime in 2019.

Note: Graphic above adapted from DOE's Office of Nuclear Energy

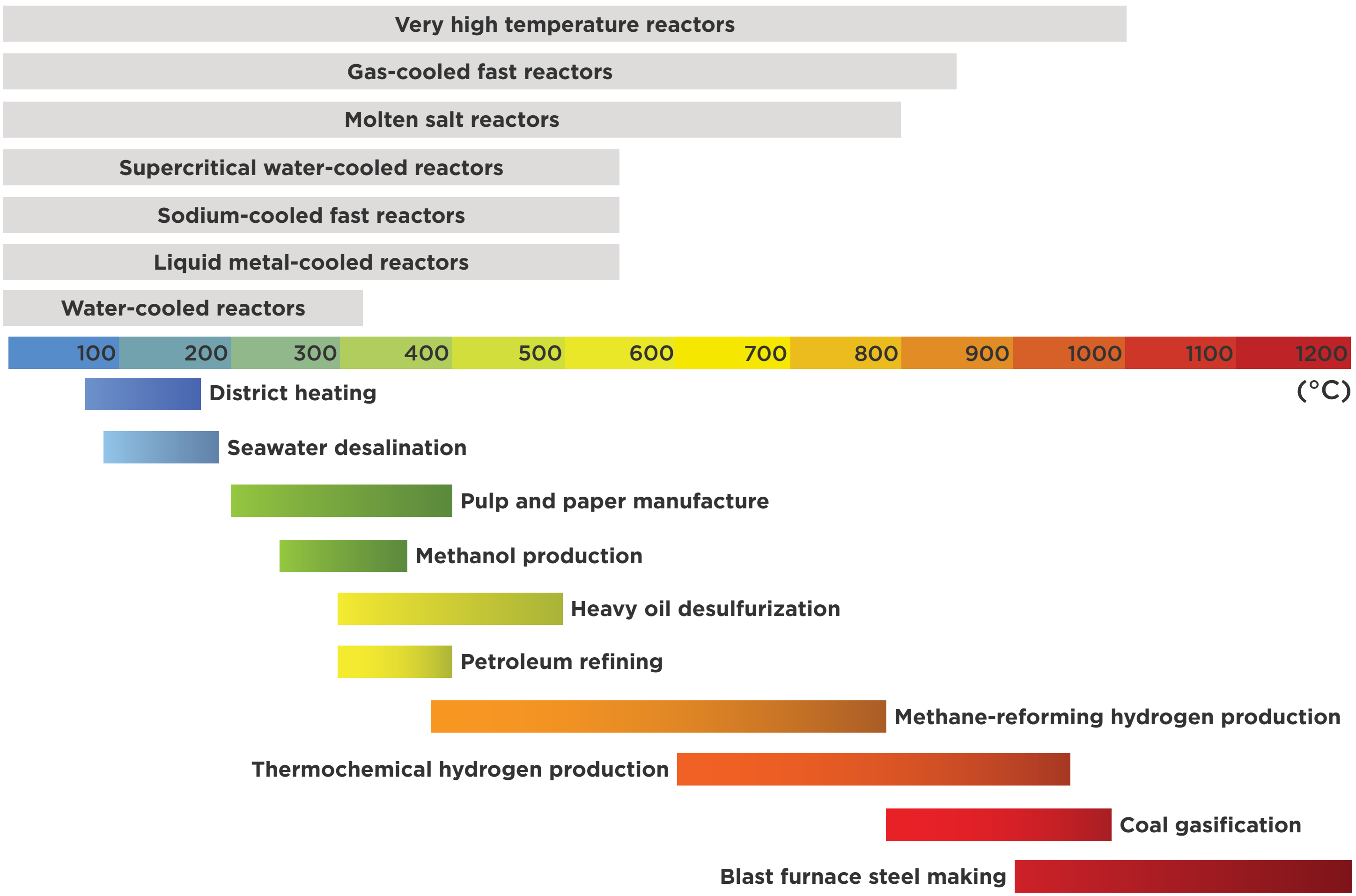
What Is a Small Modular Reactor?	
Defined	▪ Nuclear reactors of generally 300 MWe or less, designed and built using modular technology in pursuit of economies of series production and short construction times ▪ Very small modular reactors (or vSMRs) are typically less than 25 MWe
Key Features	▪ Small power, compact architecture, and at least for nuclear steam supply system and associated safety systems, usually employ passive concept - Less reliance on active safety systems, additional pumps, and AC power for accident mitigation - Smaller emergency planning zones ▪ Modular fabrication (in-factory), which can facilitate implementation of higher quality standards and efficiency ▪ Smaller radioactive inventory in a reactor ▪ Longer fuel cycles vs. large units ▪ Need not be grid-connected for certain applications ▪ Potential for sub-grade (underground or underwater) location of the reactor unit, providing more protection from natural (e.g., seismic or tsunami) or man-made (e.g., aircraft impact) hazards ▪ Multiple units can share the same site ▪ Lower requirement for access to cooling water, therefore suitable for remote regions (not necessarily near large bodies of water) and for specific applications, such as mining or desalination ▪ Ability to remove reactor module or in-situ decommissioning at the end of the lifetime
Main Technologies	▪ Nuclear plants using the land-based, light-water cooled reactors are the most mature technology, similar to most large nuclear plants ▪ Other technologies vary based upon coolant (sodium, liquid metal, etc.) and neutron spectrum

Sources: IAEA; World Nuclear Ass’n

KEY TAKEAWAYS

- **Global development of small modular nuclear reactors continues, with about 50 designs and concepts at various stages of development.**
- **A handful of designs have claimed the early lead in development.**
- **To compete with low or no marginal-cost resources, SMR developers will have to look toward learning curve effects to drive down installed cost, with concomitant lowered levelized energy costs.**
- **Some U.S. and Canadian firms are actively pursuing development of selected SMR technologies.**

Summary of SMR Designs for Potential Non-Electric Applications



Source: IAEA

In addition to non-electric applications, SMRs' flexible operations and load-following capabilities have been touted for the potential to supplement variable energy resources, such as wind and solar power.

Canada Develops an SMR Roadmap

- A group of Canadian provincial governments, territorial governments, and power utilities issued an SMR roadmap in November 2018. After making the case for SMRs as an energy resource, including their carbon-free characteristics, the group recommended federal and provincial financial and policy support for developing SMRs, with a view to, among other things:
  - Anchor domestic and global R&D and establish Canada as an SMR innovation hub, as well as an exporter to a global market
  - Preserve and enhance Canada's nuclear supply chain
  - Influence international regulatory and policy guidance for SMRs
  - Maintain the nuclear workforce and grow the pipeline of innovators
- Canadian generators have been supporting SMR development and are making early moves.
  - In early November 2018, Ontario Power Generation (OPG) signed a memorandum of understanding with NuScale to support its vendor design review with Canada's Nuclear Safety Commission
  - Also in November, NuScale inked another MOU with Bruce Power
- Canadian Nuclear Laboratories, a nuclear science and technology organization, has solicited proposals for development of a demonstration SMR at its Chalk River site by 2026. Two vendors have advanced to a due diligence stage, while a third group (Global First Power, OPG, and Ultra Safe Nuclear Corporation, proposing a 5-MWe high-temperature gas reactor) has advanced to non-exclusive contract negotiations.

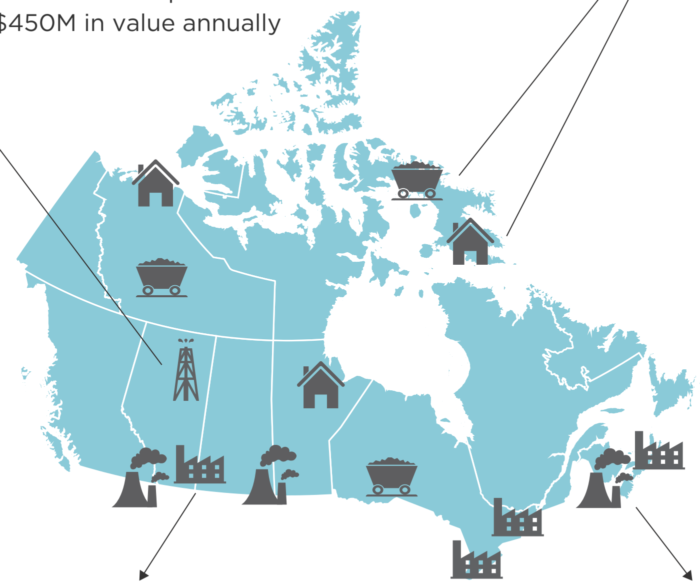
The Canadian SMR Roadmap Identified a Number of Promising Domestic Applications and Related Market Potential for Small Modular Reactors

Oil Sands

- Steam for SAGD* and electricity for upgrading at 96 facilities
- 210 MWe average size for both heat and power demands
- 5% replacement by SMRs between 2030 and 2040 could provide $350M-$450M in value annually

Remote Communities and Mines

- 79 remote communities in Canada with energy needs > 1 MWe
- SMRs replacing costly diesel and heating oil could reduce energy costs to the territorial government
- The high cost of energy from diesel is a barrier. SMRs could facilitate and enable new mining developments.
- 24 current and potential off-grid mines



High-Temperature Steam for Heavy Industry

- 85 heavy industry locations (e.g., chemicals, petroleum refining)
- 25 to 50 MWe average size
- 5% replacement by SMRs between 2030 and 2040 could provide $46M in value annually

Replacing Conventional Coal-Fired Power

- 29 units in Canada at 17 facilities
- 343 MWe average size
- 10% replacement by SMRs between 2030 and 2040 could provide $469M in value annually

Note: *SAGD means steam-assisted gravity drainage, an enhanced oil recovery technology.

Source: Canadian SMR Roadmap

Lowering SMR Costs Remains a Priority

- Lower overall capital costs make SMRs a less significant overall financial commitment versus larger units ($2 to $3 billion vs. $12 to $15 billion). However, SMR developers continue to work to bring per-kilowatt installed costs down to make the units more competitive with dispatchable resources, such as gas combined cycle units.
- In North America, SMR development partnerships with public power entities have advanced as considerations other than profit potential (carbon reduction, economic development, market fit for niche applications) and a lower cost of capital (one that does not include a required equity return) have driven their interest in participation.
- Commercialization remains on the distant horizon, though. Most viable SMR technologies are not expected to be built until the late 2020s or early 2030s. Light-water SMRs are the farthest along in engineering completion, technology readiness, licensing, and utility partnering. A high price on GHG emissions could accelerate investment and development.

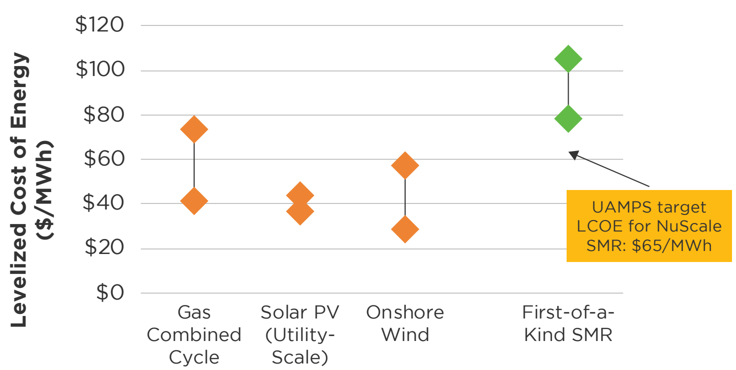
Priority Recommendations of the Canadian SMR Roadmap

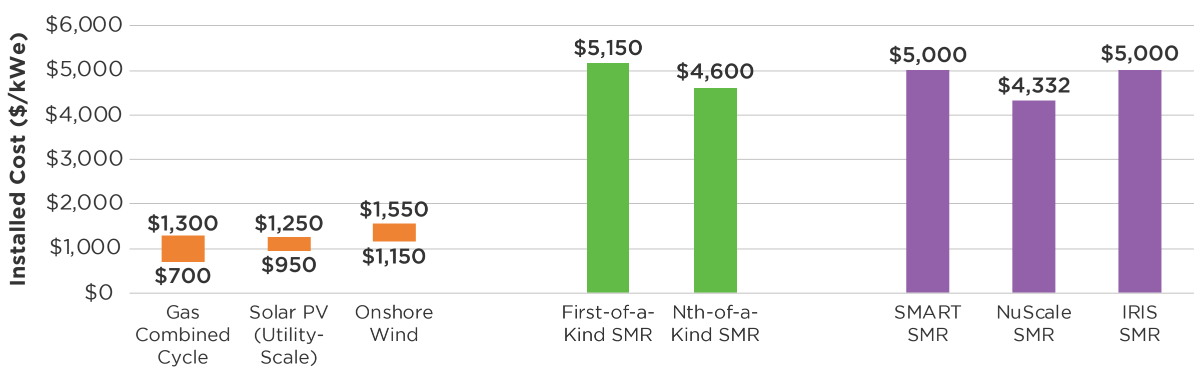
Pillar 1	Pillar 2	Pillar 3	Pillar 4
Demonstration and Deployment	**Policy, Legislation, and Regulation**	**Capacity, Engagement, and Public Confidence**	**International Partnerships and Markets**
▪ Funding for SMR demonstration projects (cost-share) ▪ Risk-sharing measures for first commercial SMRs	▪ Federal impact assessment to accommodate SMRs ▪ Nuclear liability reform ▪ Regulatory efficiency and nuclear security ▪ Waste management	▪ Indigenous engagement	▪ International enabling frameworks

Recommended next steps: Take early action on priority recommendations (above), finalize an SMR action plan, and form a Nuclear Energy Advisory Council to review progress and discuss strategic priorities.

Source: Canadian SMR Roadmap

Ranges of Installed (Overnight) and Levelized Costs of Selected Utility-Scale Energy Resources ($/kWe and $/MWh)

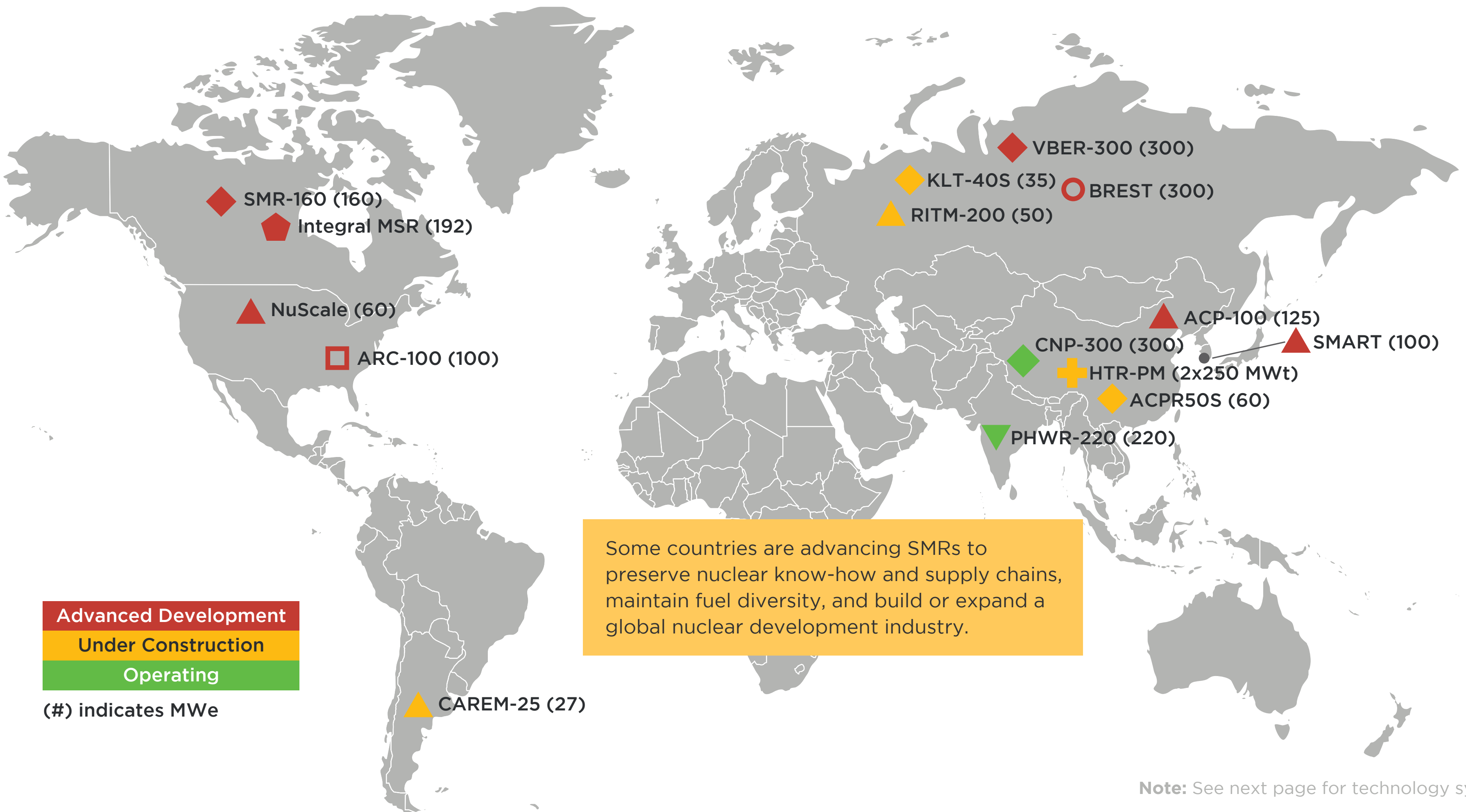




Notes: Range of SMR LCOEs is for municipal (low) and investor-owned utility (high), largely due to cost of capital. kWe means kilowatt electric.

Sources: EIA; SMR Start; Lazard; American Public Power Ass'n

Selected SMRs and vSMRs by Development Stage, Technology, and Country



Some countries are advancing SMRs to preserve nuclear know-how and supply chains, maintain fuel diversity, and build or expand a global nuclear development industry.

Note: See next page for technology symbols.

Sources: World Nuclear Ass'n; IAEA

Some Key Issues for SMRs

- Certainty in the regulatory environment (especially in the United Kingdom, the United States, and Canada) is needed to provide stable "rules of the road" to foster investment.
- Licensing approaches require adaptation to reflect the different risk of SMRs vs. large-scale nuclear units.
- First-of-a-kind construction costs must be driven down to achieve long-term economic viability.
- Siting and permitting SMRs will mean working through local concerns and formulating new standards.

Selected SMR Technologies' Features and Characteristics

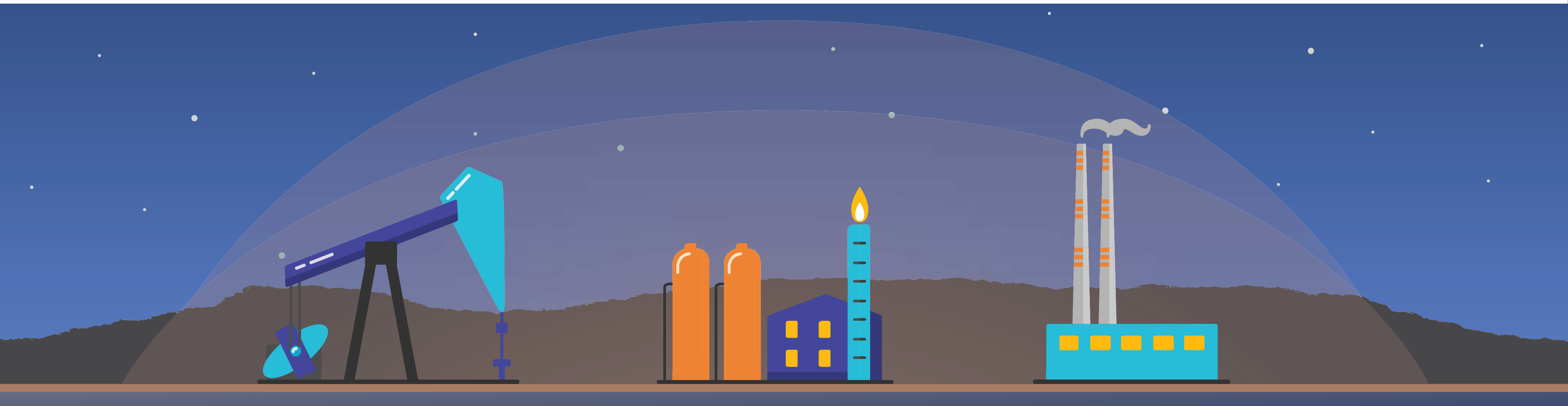
Technology		Features and Characteristics
Integral PWR	Integral pressurized-water reactor	▪ Similar characteristics to PWR (below) ▪ Unlike standard PWRs, steam generator/supply system is inside reactor vessel, increasing plant efficiency
HTR	High-temperature gas-cooled reactors	▪ Graphite as neutron moderator ▪ Fission reaction slows as temperature increases, making them inherently safe ▪ Helium-cooled, although CO_2 or nitrogen may be a coolant ▪ New high-temperature reactors (up to 1,000°C) may be able to deliver high-temperature gas for industrial applications or steam for a secondary circuit
PWR	Pressurized-water reactor	▪ Typically, light water reactors: moderated and cooled by ordinary water ▪ Reactor core heats water (which does not boil), then exchanges heat with a lower-pressure water system, which turns to steam and drives a turbine ▪ Fuel enriched to less than 5% U-235 ▪ No more than a six-year refueling interval
PHWR	Pressurized heavy-water reactor	▪ Similar characteristics to PWR ▪ Typically uses unenriched natural uranium as fuel ▪ Heavy water (D_2O) as coolant and moderator
Sodium FNR	Sodium fast-neutron reactor	▪ Smaller and simpler than light water types ▪ Better fuel performance and longer refueling interval (up to 20 years) ▪ Designed to use the full energy potential of uranium (vs. 1% in conventional reactors) ▪ Liquid sodium as coolant (drawbacks: flammable and reacts violently with water)
MSR	Molten-salt reactor	▪ Molten fluoride salts at low pressure as primary coolant ▪ Variety of potential fuels (such as thorium or spent fuel) ▪ Shorter fuel life (4 to 7 years) ▪ Graphite as neutron moderator ▪ Able to operate at higher temperatures (500°C to 1,400°C)
Lead FNR	Lead fast-neutron reactor	▪ Similar characteristics to FNR (above) ▪ Liquid lead as coolant; corrosive but doesn't react with air or water, alleviating some concerns about leakages

Sources: World Nuclear Ass'n; IAEA

IMPLICATIONS

While there are about 50 SMR designs in various stages of development, some are further along and drawing increasing interest from utilities, governments, and even clean energy groups. Utilities will have to think about whether they should actively participate in or promote research and development or take a "wait-and-see" position, pending emergence of viable and cost-effective technologies.

Sources: U.S. Nuclear Regulatory Commission; International Atomic Energy Agency (IAEA), Advances in Small Modular Reactor Technology Developments (Sept. 2018); IAEA Advanced Reactors Information System (accessed Feb. 2019); World Nuclear Association; U.S. Energy Information Agency; SMR Start, The Economics of Small Modular Reactors (Sept. 14, 2017); NuScale; Lazard; American Public Power Association; U.S. Dept. of Energy, Office of Nuclear Energy; EPRI Emerging Technologies Brief, "Progress toward U.S. Commercialization of Small Modular Light Water Reactors" (Aug. 2018); Idaho Nat'l Labs; Utah Associated Municipal Power Systems; Canadian Small Modular Reactor Roadmap Steering Committee, A Call to Action: A Canadian Roadmap for Small Modular Reactors (Nov. 2018); Nuclear Innovation Alliance, Enabling Nuclear Innovation: Leading on SMRs (Oct. 2017); Clean Air Task Force, Advanced Nuclear Energy: Need, Characteristics, Projected Costs, and Opportunities (Apr. 2018); ScottMadden analysis



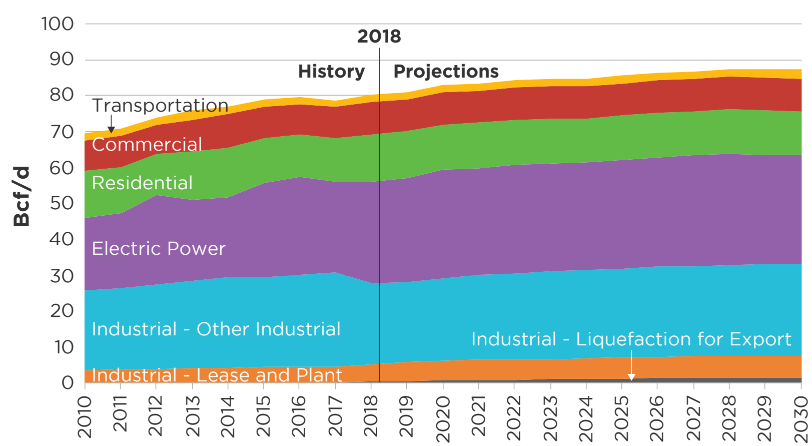
GAS TRANSFORMATION
SUPPLY AND DEMAND IN HIGH GEAR

With increasing power generation demand for gas, and prospects for LNG exports, is the gas market ready?

U.S. Gas Prices, Production, Consumption, and Exports All Increased in 2018

- Whether considered a transition fuel or a permanent part of our energy mix, use of natural gas in the United States, and North America more broadly, continues to increase.
- While upstream producers have discussed being disciplined in application of capital, scale economies continue to drive increased production despite relatively low market prices for dry natural gas. In some regions, associated gas production from oil production also accounts for some of the continued increase.
- Consumption continues to grow, driven by three primary demand drivers: power generation, industrial uses (including petrochemicals), and LNG exports.
- Residential and commercial consumption growth is relatively flat and projected to continue to be flat in EIA's most recent forecast due to efficiency and population shifts (migration to warmer regions).

U.S. Natural Gas Consumption by Sector (EIA Reference Case) (in Bcf/d)



Source: EIA, Annual Energy Outlook 2019 (Jan. 24, 2019)

KEY TAKEAWAYS

- **Abundant supply and low prices continue to characterize the North American natural gas market.**
- **In response, new demand—in nature, quantity, location, and seasonality—continues to change the dynamics of markets. Power generation, LNG exports, and industrial consumption continue to drive year-over-year growth.**
- **However, there are regional mismatches and midstream constraints that continue to bedevil in some regions.**
- **Market players are using a variety of approaches to manage price and deliverability risks.**

Natural Gas Exports Continue Growing as a Demand Driver

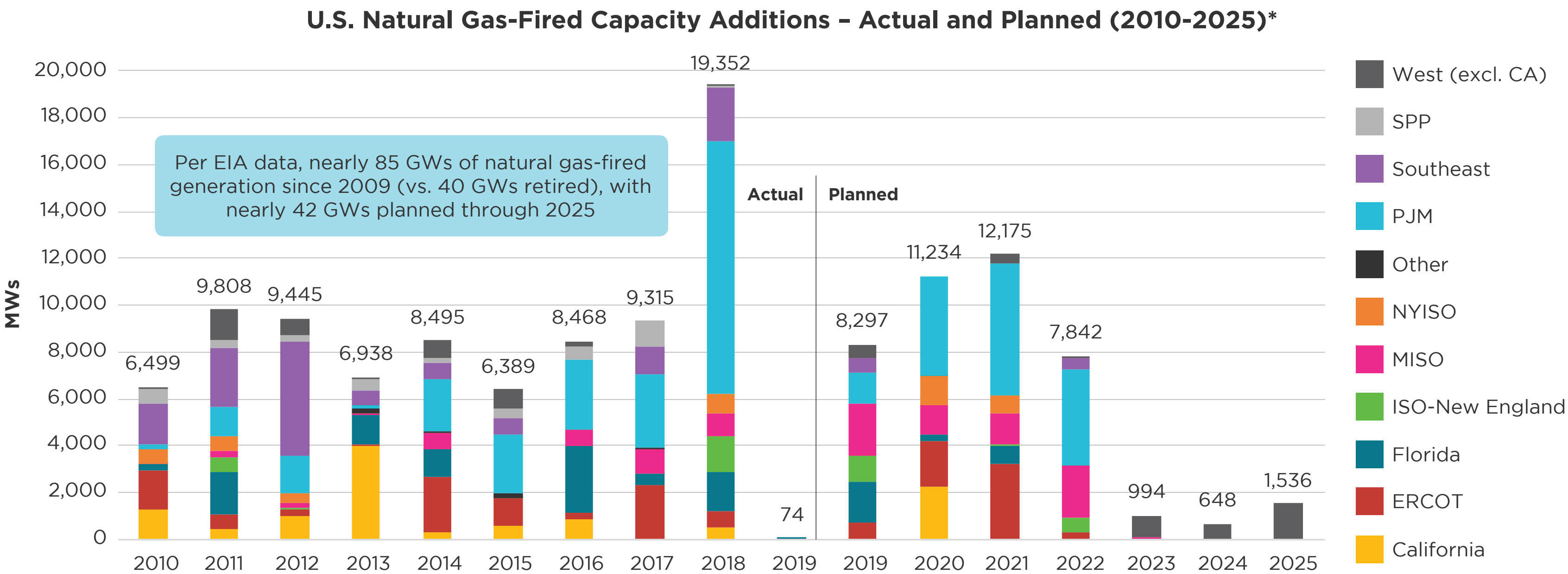
- U.S. LNG exports are anticipated to grow, and, in fact, in a recent oil and gas industry survey, respondents see U.S. LNG exports as the biggest impact on gas markets in 2019. Longer term, LNG exports from the United States are expected to grow from their current level of nearly 3 Bcf/d to 14 Bcf/d by 2030.
- More North American LNG export capacity is expected in the near term, as the 2.1 Bcf/d Golden Pass (ExxonMobil, Qatar sponsors) and 3.5 Bcf/d LNG Canada (major players, including Shell) facilities have received favorable final investment decisions.
- Mexican demand for gas (and related imports from north of the border) was expected to increase, but some uncertainty has arisen about whether and how much gas Mexico's new government will take from the United States. The Obrador government, which took power in late 2018, is reconsidering reforms that might impact its appetite for U.S. gas, although pipeline capacity into Mexico is abundant.
- One little-noticed trend is the growth in U.S. exports to Canada. The completion of Rover and NEXUS pipelines and a reduction in off-shore Nova Scotia production, among other things, have contributed to this growth. The U.S. exported (gross) 842 Bcf to Canada in 2018, compared with 559 Bcf in 2008, a compound annual growth rate of more than 4%.

Meanwhile, Gas for Power Generation Continues Remarkable Growth

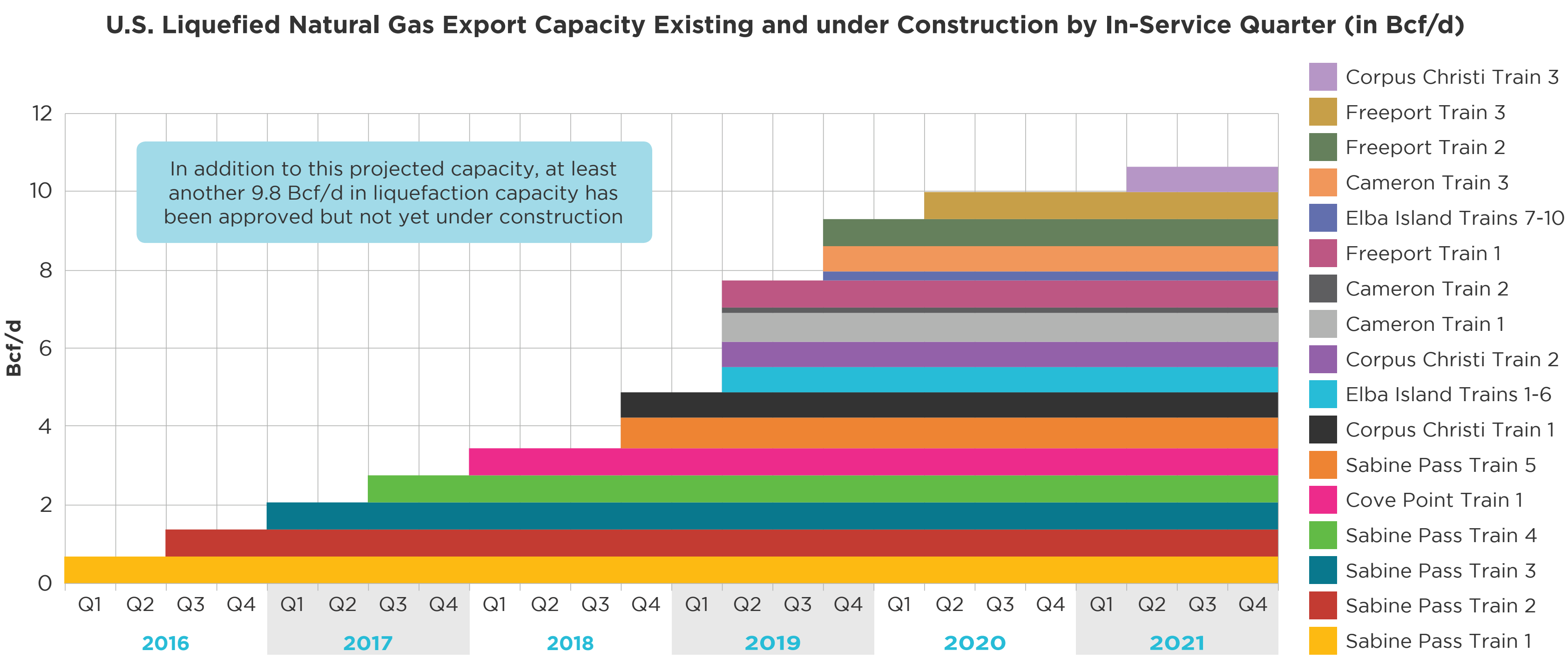
- 2018 was a banner year for power sector consumption of natural gas, accounting for 35% of U.S. natural gas consumption (29.1 Bcf/d). Weather was a key contributor—with warmer average temperatures (air conditioning demand) and prolonged cold snaps driving demand.
- Gas-fired generation continues to be added. More than 60% (or about 19.3 GWs) of new utility-scale capacity added in the United States was gas fired, with 90% of that being combined-cycle generators.
- Canada and the United States projected continued reliance on gas as a key element of the on-peak fuel mix, with gas rising to 46% of on-peak fuel by 2028, as another 41 GWs (to perhaps 96 GWs) of gas-fired capacity added by that year. Looking beyond the averages, however, some regions are, and will be, significantly more dependent upon gas-fired capacity: areas of the West and New England (>50%), Texas (>60%), and Florida (75%+). PJM and the Southeast, too, are adding significant amounts of gas-fired capacity.

Note: *Preliminary data

Sources: EIA Form 860M, Preliminary Monthly Electric Generator Inventory (Jan. 2019); ScottMadden analysis



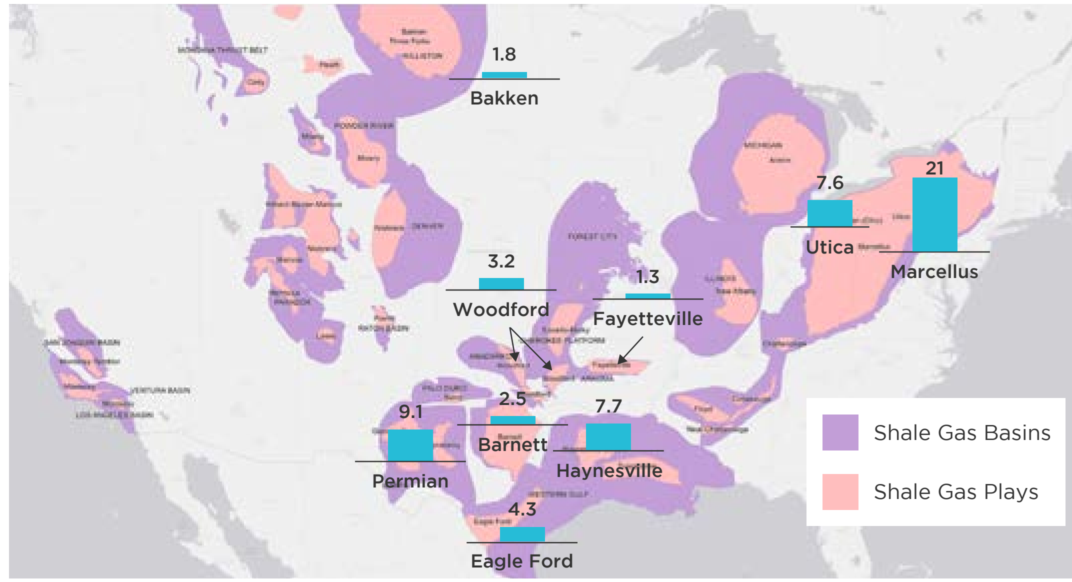
Sources: EIA, U.S. liquefaction capacity data (Mar. 25, 2019); ScottMadden analysis



Will There Be Enough Supply to Meet Demand?

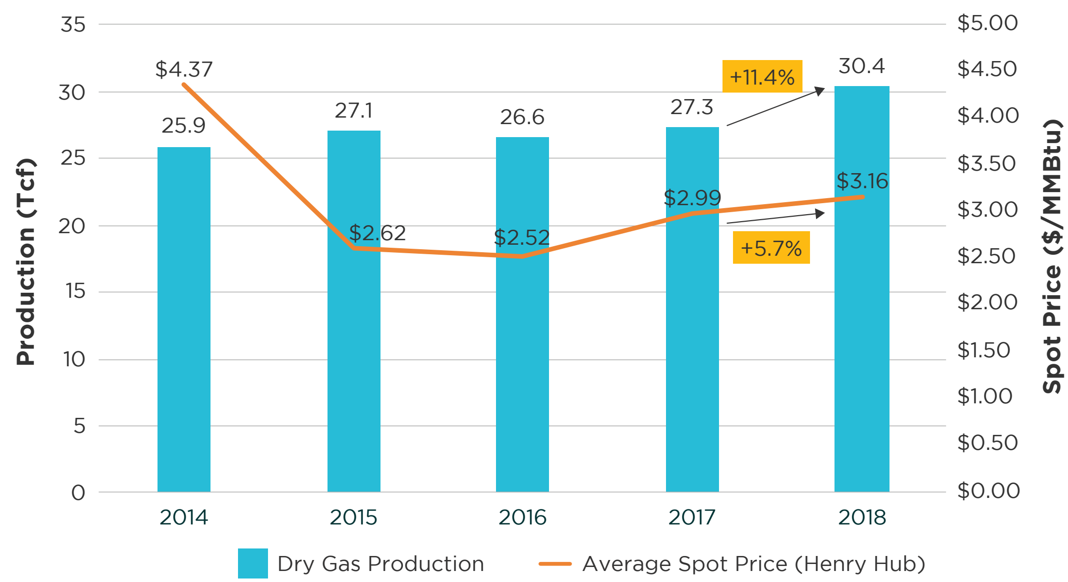
- While gas demand continues to increase, North American supply remains ample and production, concentrated in shale plays, continues apace.
- In the United States, 2018 dry gas production of 30.4 Tcf outstripped domestic end-use consumption by about 0.5 Tcf. Balancing demand, imported Canadian gas has reliably stayed within 2.5 Tcf and 3.0 Tcf over the past several years, and the United States has emerged as a net gas exporter.
- Low natural gas prices have been widely expected to dampen production, but that has not nor is it projected to occur in the intermediate term. Economies of learning and scale in shale oil and gas development have begun to accrue as some key shale plays—Marcellus, Utica, and increasingly Permian—remain prolific.
- One observer notes that current North American resource estimates show that there is about 25 years of gas production at a cost of below $3 per MMBtu.

Selected U.S. Shale Gas Basins and Plays and Dry Gas Production (as of Feb. 2019) (in Bcf/d)



Sources: S&P Global Market Intelligence; EIA; ScottMadden analysis

U.S. Dry Gas Production (Tcf) vs. Henry Hub Annual Average Spot Prices ($/MMBtu)



Sources: Potential Gas Committee; EIA

Location, Location, Location: Infrastructure Is Key

- While supply is abundant, market-driven interest in changing gas flow direction and new and different (in kind and scale) demand are driving new pipeline and storage development. Increasingly, flows are moving from the Marcellus/Utica region east and south. The Texas Gulf Coast and the southcentral United States are growing destinations for gas as LNG and pipeline exports increase. More than 5 Bcf/d in pipeline reversals (shifting from northbound to southbound) were completed in 2018 and early 2019.
- However, with the increases in power sector consumption, gas demand for power and heating is more correlated on cold days, stressing available non-firm pipeline capacity in some regions.
  - For example, New England has grown reliant on gas-fired capacity, with gas providing 40% of energy for the region. But during peak winter gas demand days, pipeline capacity into the region is constrained, increasingly having implications for electric system operations.
  - Similarly, the Southwest and California have only a few pipelines and limited storage availability near load, particularly after a leak in southern California's Aliso Canyon gas storage facility reduced its available capacity. This, too, affects gas for both end-use customers and for gas-fired power generation, which is increasingly called upon to balance the system as penetration of renewables grows.
- And while many pipeline projects (new pipelines and expansions) are proposed and even under construction, debates at FERC over review criteria (GHGs) and local environmental opposition threaten completion, or at least timely completion. This impacts both takeaway capacity from shale plays and pipeline expansion into currently bottlenecked regions.

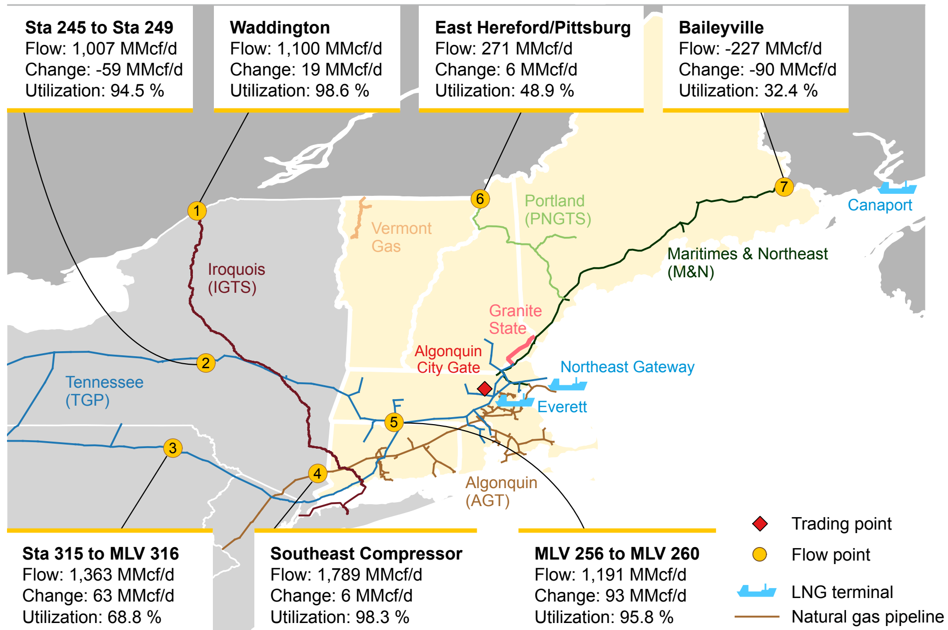
Approaches to Coping with Changing Supply-Demand Alignment and Market Dynamics

- In light of abundant but regionally concentrated gas supply, new and different (in kind and in amount) sources of demand, and still-evolving infrastructure to move it, the energy industry is adapting.
- For LNG, Cheniere pioneered a tolling contracting model where buyers acquire gas at spot market prices (with commodity price risk) and pay a fee (toll) under a take-or-pay arrangement to liquefy the buyer's gas.
- Given the growing role of gas for electric system reliability, system operators (e.g., California ISO) are beginning to model pipeline constraints and their impacts on fuel assurance for gas-fired plants. And ISO-New England, for example, has proposed new market elements, including a multi-day-ahead market and seasonal forward market, that would encourage and compensate more robust fuel supply arrangements.
- Non-pipes solutions (e.g., gas energy efficiency and demand response) are also playing a growing role in some regions to address peak gas demand.
- Dealing with peak gas demand is front and center. A new and perhaps trending development is the avoidance of connecting new demand sources when pipeline constraints impinge on deliverability (e.g., Con Edison's moratorium on new gas connections). Further, in areas such as the Desert Southwest where gas storage capacity is limited, electric approaches in the form of solar plus electric storage can reduce reliance on peaking gas transport capacity.

Two Regions Feel the Gas Infrastructure Pinch

Despite having the Marcellus shale play on its doorstep and being increasingly reliant on gas-fired generation (40% of energy), New England has constrained pipeline capacity from supply centers to the west.

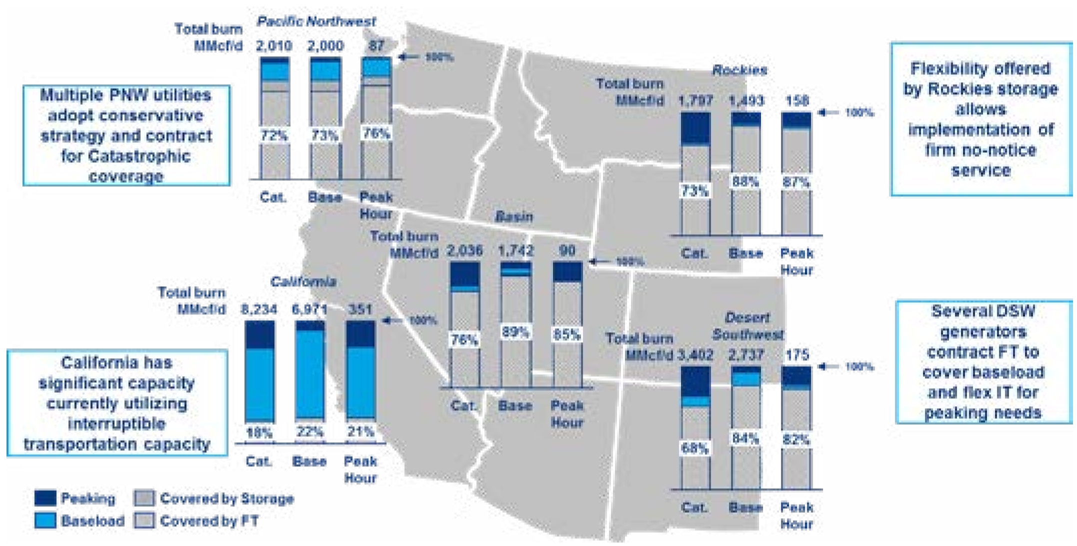
New England Gas Infrastructure on a Cold Winter Day (Feb. 1, 2019)



Source: EIA

WECC examined gas-power interdependence and found that as gas market dynamics tighten in the West and particularly in low hydro conditions, power system operational difficulties could increase, especially in southern California and the Desert Southwest where gas storage is limited.

Gas Contracting Analysis for Power Generation by U.S. Western Region



Cat.: Catastrophic (24-hour max burn)

Base: 7-hour peaking plant utilization

Peak Hour: Max burn for 1 hour

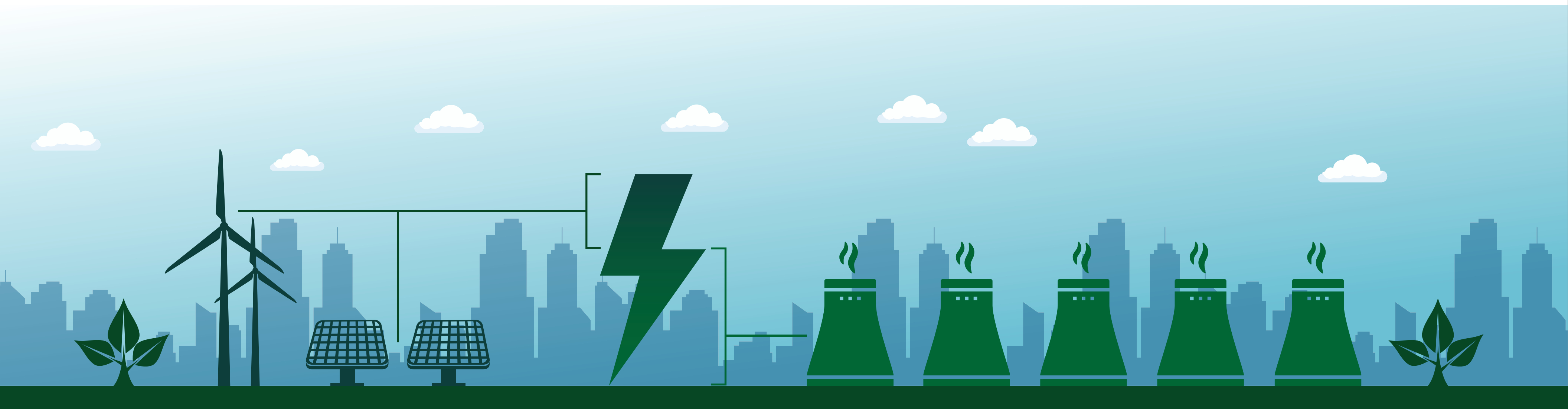
Notes: FT is firm transmission; IT is interruptible transmission

Sources: WECC; Wood Mackenzie

IMPLICATIONS

Amidst changing gas market dynamics, satisfying gas demand on peak days is becoming a more urgent issue, although these issues are largely regional, for now. Time will tell whether these constraints can be relieved, but in the meantime, industry players are taking physical and contractual approaches to manage their risks.

Sources: EIA; S&P Global Market Intelligence; Energy Intelligence, Energy Intelligence 2019 Outlook (Jan. 2019); FERC; LNG Canada; NERC, 2018 Long-Term Reliability Assessment (Dec. 2018); Equinor, Energy Perspectives 2018 (June 2018); Western Electric Coordinating Council & Wood Mackenzie, Western Interconnection Gas-Electric Interface Report (June 2018); ISO-New England; *Forbes*; Utility Dive; industry news



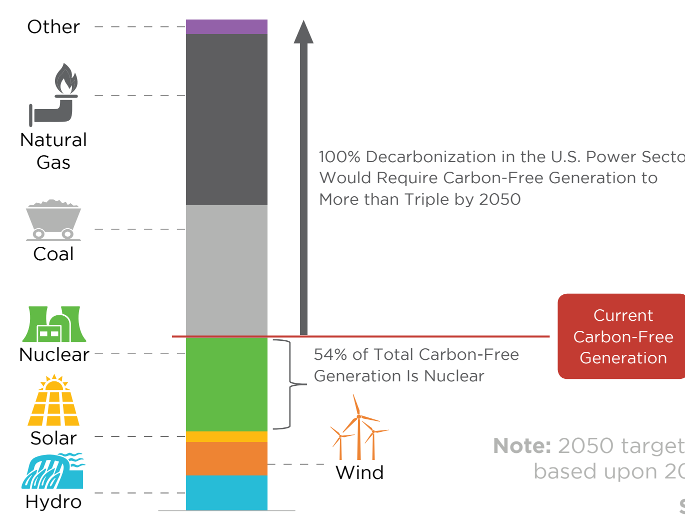
ONE STEP FORWARD, TWO STEPS BACK
THE UNNOTICED LOSS OF CARBON-FREE GENERATION

Progress in greenhouse gas emissions reduction is at significant risk due to the loss of nuclear power plants.

To Dramatically Decarbonize, More than Renewable Energy Is Needed

- The United States has begun acting to combat climate change by focusing on lowering the greenhouse gas (GHG) emissions from the electric generation sector. One key strategy has been to invest in the growth of renewables, principally solar and wind.
- Were the United States to meet Paris Agreement goals of 80% decarbonization of the entire economy by 2050, most agree that the electric generation sector would need to achieve 100% decarbonization. Carbon-free generation currently provided by wind, solar, hydro, and nuclear would need to more than triple.
- To make this progress in the electric generation sector does not require a choice between nuclear and renewables, as both technologies contribute to carbon-free generation (see chart).
- Despite significant renewable capacity growth in the past decade, the risk of early nuclear plant retirements jeopardizes the possibility of meaningful gains in carbon-free generation.

2018 U.S. Electricity Net Generation Fuel Mix (GWhs)



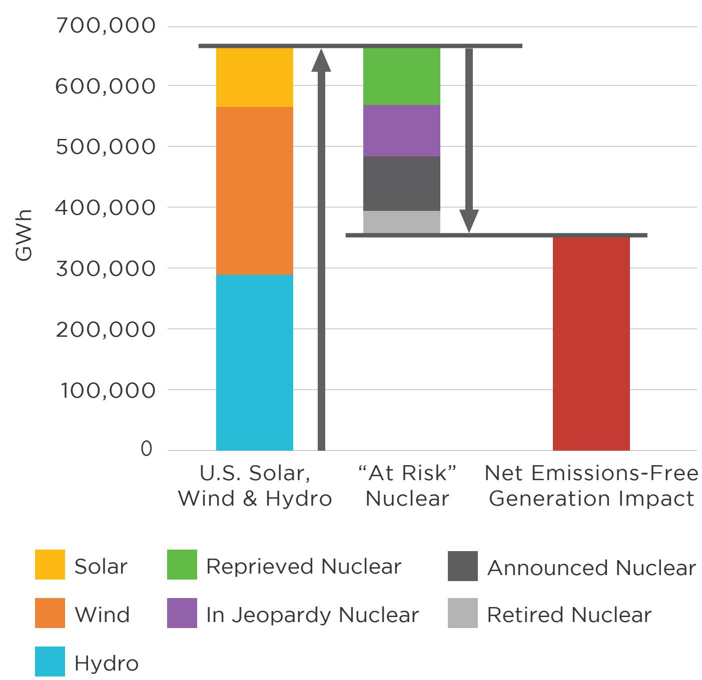
Note: 2050 target illustration based upon 2018 fuel mix

Source: EIA

Current Clean Energy Challenge: Nuclear Plant Retirements

- Though not widely known, the United States is facing early (before a unit's operating license expiry) retirement of nuclear power plants, putting a significant source of non-emitting generation at risk. This threat has been caused by a combination of zero and low marginal cost generation (fueled by cheap natural gas) and a lack of market compensation for nuclear's emissions-free characteristics.
- In a previous white paper, ScottMadden evaluated the potential for loss of carbon-free generation because of early nuclear retirements.
- We defined nuclear assets as currently "at risk" of closure based on four categories of plants:
  - **Retired** – Any nuclear plant that has ceased operations since 2008. Physical issues drove the retirement of some plants on the list, but they might have continued to operate under different economic circumstances, including markets valuing carbon-free generation.
  - **Announced** – Any nuclear plant whose owner has announced plans to cease operations early.
  - **In Jeopardy** – Any nuclear plant whose owner has indicated the plant may close if market conditions do not improve.
  - **Reprieved** – Any nuclear plant that has received state support to remain open. These were on the verge of closure, and absent follow-through on these programs, the plants will likely close.
- Each nuclear plant operating in 2008 (a date that coincides with the rapid growth in renewables) was reviewed and, if applicable, placed in one of the "at risk" categories.
- For each "at risk" category, we calculated total capacity and annual generation:
  - "At risk" nuclear plants have a combined estimated output of 311,555 GWh.
  - In 2018, solar, wind, and hydro produced a total combined 666,000 GWh of carbon-free energy.
- Thus, if all these "at risk" nuclear plants are lost, the potential GHG emissions-free output lost is the equivalent of 47% of the total carbon-free energy produced by all solar, wind, and hydro assets currently in the United States. The United States will have very little to show for its investment in and efforts to grow renewable energy if these "at risk" plants close.

Potential Changes in U.S. Carbon Emissions-Free Generation (as of 2018) (in GWhs) with Loss of "At Risk" Nuclear Generation



Sources: EIA; NREL; ScottMadden analysis

KEY TAKEAWAYS

- **Climate progress made by the addition of new carbon-free electric generation from solar and wind is in danger of being largely "given back" due to the potential loss of existing carbon-free nuclear generation.**
- **More than 74,000 MWs of nuclear capacity faces early retirement, a significant potential reduction in carbon-free power production.**
- **Licenses of 35 nuclear reactors will expire in the next 15 years (2020–2035), jeopardizing the nation's ability to achieve a deep, realistic, near-term decarbonization.**
- **Despite having added significant renewable resources, Germany's early retirement of nuclear plants has limited progress in reducing total carbon emissions in its electricity sector. The United States may be headed down a similar path.**

Future Clean Energy Challenge: A Thought Experiment

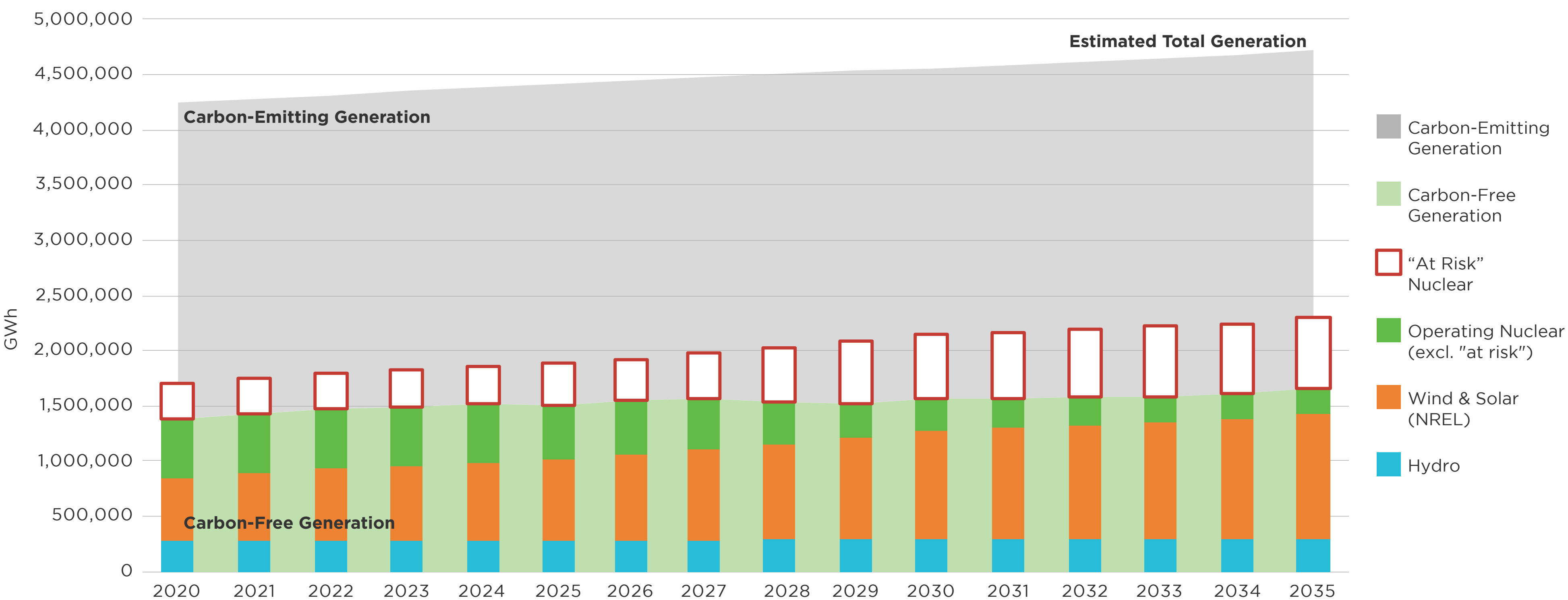
- While the initial analysis may be bleak, ScottMadden posed the following question: "Can we look forward to emissions improvements given plans for adding new carbon-free generation?"
- We developed a new analysis projecting carbon-free electricity over the next 15 years based on growth in renewables and potential future nuclear plant retirements. We chose 15 years as a pivotal period if deep, near-term decarbonization is to be achieved.
- For renewables, we estimated growth in generation from wind (on- and off-shore), solar (utility and distributed), and hydro based upon forecasts from the U.S. Department of Energy's National Renewable Energy Laboratory. Those forecasts are generally optimistic views of renewable resource market penetration.
- For nuclear, we re-assessed "at risk" nuclear plants using the same four categories, projecting early retirements based on current license expiration dates and the following assumptions:
  - Nuclear plants may operate only for the duration of their current 20-year license.
  - Given the current economic and political climate, we assumed no relicensing of nuclear plants in the next 15 years.
  - Plants whose operators have already announced a closing year were placed in the "retired" category in that year.
  - Plants with a reactor whose license expires in the next 15 years were:
    - Placed in the "retired" category the year of their license expiration regardless of their current category (even "reprieved" plants)
    - Placed "in jeopardy" five years prior to license expiration*
  - Vogtle Units 3 and 4 (totaling 2,234 MWs), owned in part by Georgia Power Company and currently under construction, are assumed to become operational in 2021 and 2022, respectively.

Note: *Five years prior to a nuclear reactor's license expiry, nuclear plant owners must decide whether to relicense. While these plants are not shut down immediately, closure is determined at this point, putting them "in jeopardy."

Clouds on the Fifteen-Year Horizon

- After conducting this thought experiment, we find that the medium-term projection does not show much, if any, improvement from the current clean energy challenge discussed earlier. Even using relatively rosy projections of renewables growth, total carbon-free generation barely grows 20% by 2035—a far cry from the more than doubling of such generation needed should the United States want to meet Paris goals.
- Early retirements of all “at risk” nuclear plants would represent a giveback of 649,019 GWh in 2035.
  - Licenses of 35 nuclear reactors are set to expire in the next 15 years (2020-2035).
  - This loss of nuclear generation represents more than 460 million short tons of CO_2.† For perspective, this is equivalent to the total emissions of roughly 100 million cars, or one-third of all cars on the road today.
- To achieve deep, quick decarbonization, we will need all existing non-CO_2-emitting generation, plus a lot more.
- Next-generation SMRs are one of the few new technologies to offer potential for a meaningful near-term contribution to clean energy targets.

Estimated U.S. Carbon Emissions-Free Power Generation (2020–2035) (in GWhs)



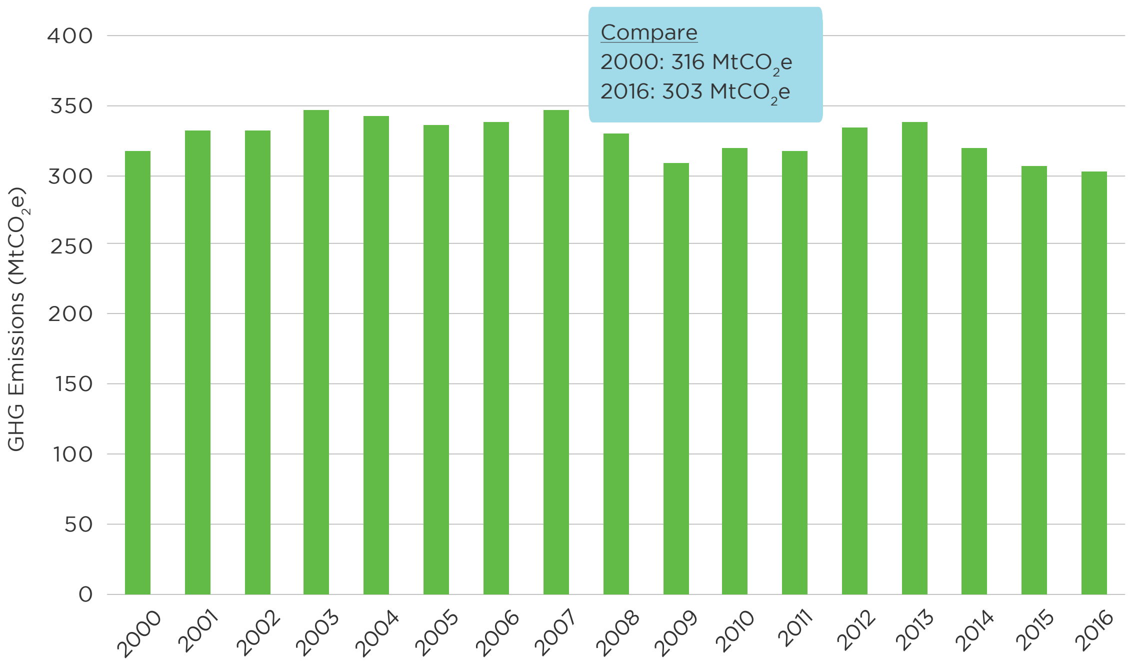
Note: †Our analysis uses the average regional CO_2 intensity from The Brattle Group’s 2016 white paper, “Nuclear Retirement Effects on CO_2 Emissions: Preserving a Critical Clean Resource.” In reality, CO_2 emissions from electricity in the United States vary by region and could range from 337 million short tons to 545 million short tons.

Sources: NEI; EIA; NREL; ScottMadden analysis

Similar Stories Abroad

- Our projected U.S. clean energy future is just that, a projection. But other nations further along on the decarbonization path can provide a window into the future.
- Many have pointed to Germany as a bellwether in deployment of renewables.
- In 2000, nearly two decades ago, Germany's Renewable Energy Act established feed-in tariffs and priority grid access for renewables. The action represents a key milestone in the Energiewende—the transition to a low-carbon economy based on renewable resources.
- Since then, the country has spent more than $222 billion on renewable subsidies. Renewable energy as a percentage of gross electricity generation has increased from 6.2% in 2000 to 37.8% in 2018.
- At the same time, however, Germany has embarked on a strategy of shuttering its nuclear plants. Roughly 40% of the country's nuclear capacity was shut down in 2011, following the Fukushima nuclear accident.
- The net results?
  - Despite the addition of significant renewable resources, there is limited progress in reducing total carbon emissions in the electricity sector. GHG emissions from the electricity sector have only decreased roughly 4% from 2000 to 2016.
  - And the cost? In 2017, Germany had the highest power prices in Europe, with households paying more than 30 Eurocents per kWh, compared to an average of less than 20 Eurocents per kWh for the rest of Europe.
- It should be noted that Germany still has seven operating nuclear power plants, although all are expected to shutter by 2022. What the impacts are on German GHG emissions and prices when the last of its fleet retires will bear watching.

German Electricity Sector Greenhouse Gas Emissions (2000–2016)
(in Millions of Metric Tons of CO_2-Equivalents)



Source: United Nations Framework Convention on Climate Change

IMPLICATIONS

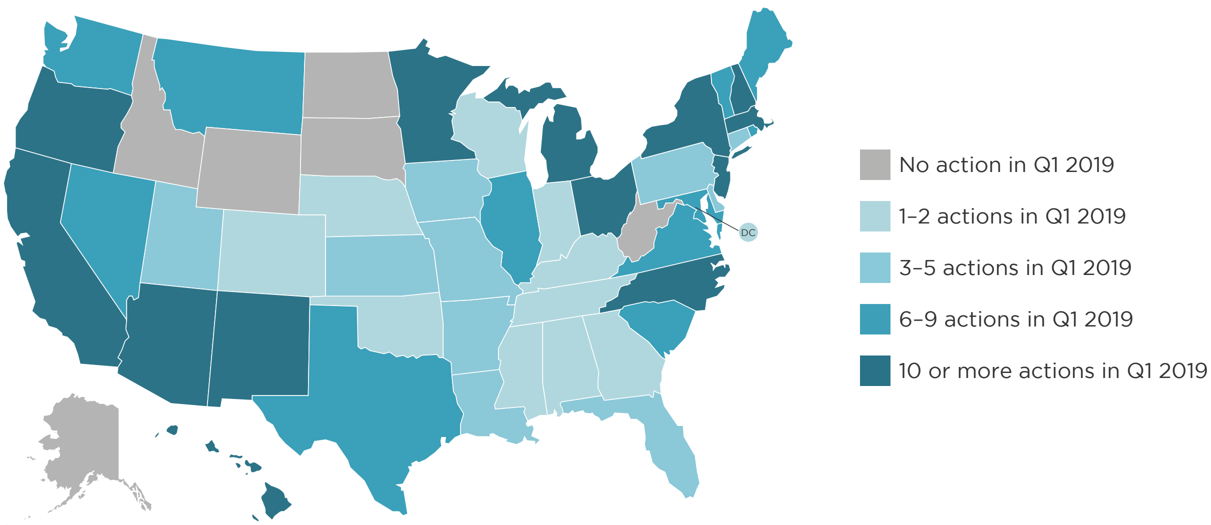
Solar and wind have contributed greatly to emissions-free electricity generation, an important step toward reducing carbon emissions. However, the progress engendered by solar and wind carbon-free generation is in danger of being annulled due to early retirements of nuclear plants. Contrary to some assertions, lost nuclear is not fully replaced by renewables. Unfortunately, the void left by "at risk" nuclear is in fact filled with carbon-emitting resources. Thus, retaining "at risk" nuclear could have "avoided" more than 430 million short tons of carbon on top of the contribution of renewables. Bottom line: If the goal is to grow overall clean energy in a significant way, we will need more renewables and nuclear.

Sources: The Brattle Group, "Nuclear Retirement Effects on CO_2 Emissions: Preserving a Critical Clean Resource" (Dec. 2016); Nuclear Energy Institute, U.S. Nuclear Plant License Information, available at www.nei.org/resources/statistics/us-nuclear-plant-license-information (accessed Mar. 2019); ScottMadden, "One Step Forward, Two Steps Back… The Worsening Risk of Losing Carbon-Free Generation in the United States" (Apr. 2018); ScottMadden, "While You Were Sleeping: The Unnoticed Loss of Carbon-Free Generation in the United States" (Apr. 2019); U.S. Environmental Protection Agency, Greenhouse Gas Emissions from a Typical Passenger Vehicle, available at www.epa.gov/greenvehicles/greenhouse-gas-emissions-typical-passenger-vehicle; EIA; NREL, 2018 Annual Technology Baseline and Standard Scenarios, available at www.nrel.gov/analysis/data-tech-baseline.html; The White House, United States Mid-Century Strategy for Deep Decarbonization (Nov. 2016); European Commission, Energy Prices and Costs in Europe (Jan. 9, 2019); United Nations Framework Convention on Climate Change, Greenhouse Gas Inventory Data; Southern Company Plant Vogtle Units 3 & 4 Fact Sheet; Bloomberg New Energy Finance, 2019 Sustainable Energy in America Factbook (Feb. 2019); industry news; ScottMadden analysis.

For more ScottMadden energy insights, visit our Insights Library: scottmadden.com/insights

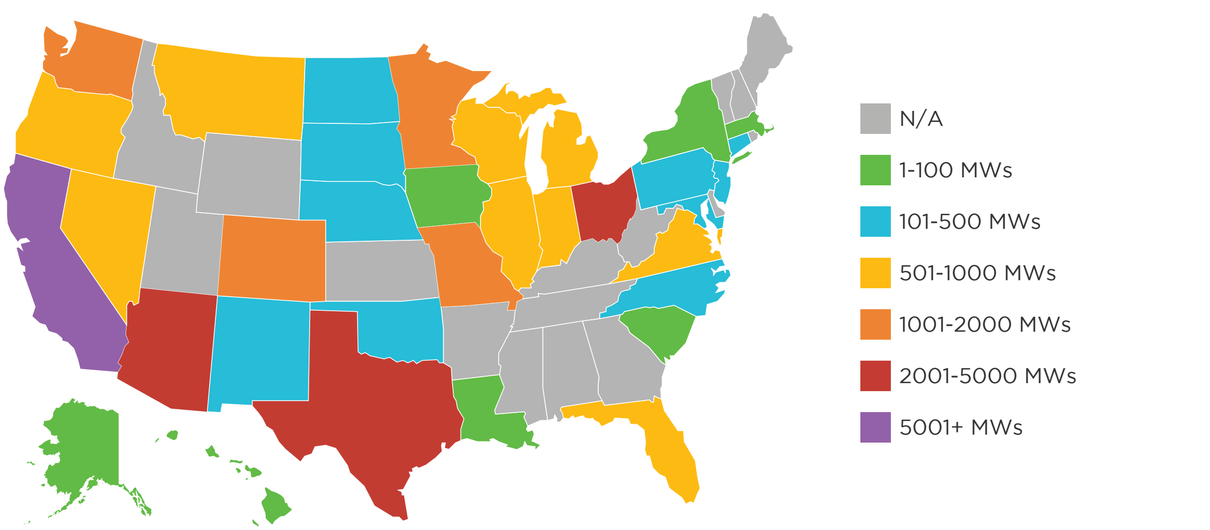
THE ENERGY INDUSTRY IN CHARTS

Q1 2019 State and Utility Action on Grid Modernization



Source: North Carolina Clean Energy Technology Center, The 50 States of Grid Modernization: Q1 2019 Quarterly Report (May 2019)

Planned Fossil Generation Retirements by MWs by State (2019-2025)

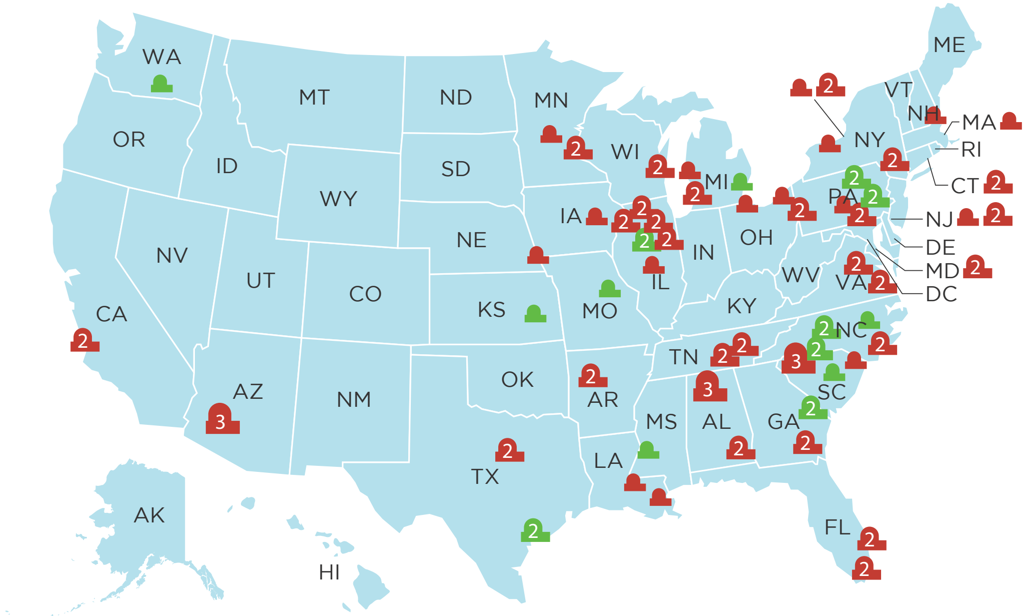


Sources: EIA; ScottMadden analysis

U.S. Operating* and Potentially "At Risk" Commercial Nuclear Plants

Potentially "At Risk" Plants:**

- Announced retirement
- Owner has indicated possible early closure
- Plants "reprieved" via state support
- Plants whose license expires in the next 20 years



Operating; not currently "At Risk"

Operating and "At Risk"

= 1 unit

= 2 units

= 3 units

Notes: *As of Sept. 2018; **see pp. 47-52 of this Energy Industry Update

Sources: NEI; EIA; U.S. NRC; industry news; ScottMadden analysis

U.S. Renewable Portfolio Standards and Goals and Carbon-Free Energy Policies

Renewable portfolio goal

Renewable portfolio standard (<50%)

50%-90% RPS

RPS plus 100% carbon-free plan

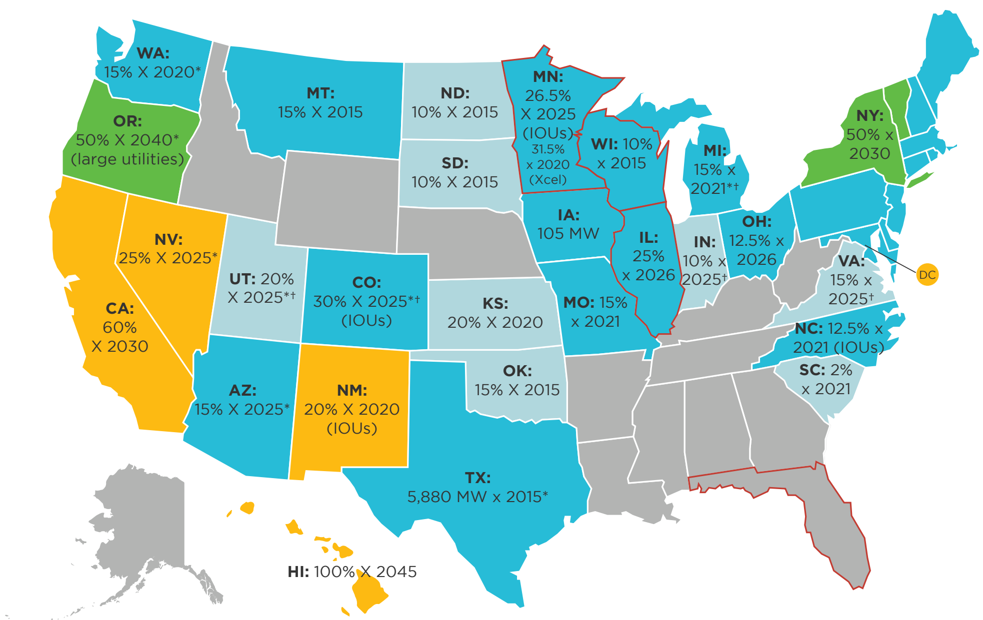
Considering increasing RPS target

∗ Extra credit for solar or customer-sited renewables

† Includes non-renewable alternative resources

Note: Targets shown are for renewables.

Sources: North Carolina Clean Energy Technology Center, Database of State Incentives for Renewables & Efficiency, accessed May 8, 2019; ScottMadden research



ME: 40% x 2017

NH: 25.2% x 2025

VT: 75% x 2032

MA: 35% x 2030 + 1% each year thereafter (new resources) 6.7% x 2020 (exisiting resources)

RI: 38.5% x 2035

CT: 40% x 2030

NJ: 50% x 2030

PA: 18% x 2021†

DE: 25% x 2026*

MD: 25% x 2020

DC: 50% x 2032

GLOSSARY

AMI
advanced metering infrastructure

Bcf
billion cubic feet

Bcf/d
billion cubic feet per day

BQDM
Brooklyn Queens Demand Management Demand Response Program

DER
distributed energy resource

DOE
U.S. Department of Energy

DR
demand response

EE
energy efficiency

EIA
U.S. Energy Information Administration

ERCOT
Electric Reliability Council of Texas

EV
electric vehicle

FERC
Federal Energy Regulatory Commission

GBP
British pound

GWs
gigawatt

GWh
gigawatt-hour

HVAC
heating, ventilation, and air conditioning

IAEA
International Atomic Energy Agency

ISO
independent system operator

ISO-NE
ISO New England

IT/OT
information technology/operational technology

kV
kilovolt

kWh
kilowatt-hour

LMP
locational marginal price

LNG
liquefied natural gas

MISO
Midcontinent ISO

MMBtu
million British thermal units

$MtCO_2e$
million metric tons CO_2-equivalent

MW
megawatt

MWe
megawatt electric

MWh
megawatt-hour

MWt
megawatt thermal

N-2-plus planning
transmission contingency planning based upon loss of the two or more bulk transmission elements simultaneously

NWAs
non-wires alternatives

NEI
Nuclear Energy Institute

NERC
North American Electric Reliability Corporation

NOPR
notice of proposed rulemaking

NPCC
Northeast Power Coordinating Council

NREL
National Renewable Energy Laboratory

PJM
PJM Interconnection

PV
photovoltaic

R&D
research and development

RF
radio frequency

RIIO
(Revenue = Incentives + Innovation + Outputs) is the U.K.'s performance-based framework for setting price controls for electric and gas transmission and distribution networks

RTO
regional transmission organization

SERC
SERC Reliability Corp.

SMR
small modular nuclear reactor

SPP
Southwest Power Pool

Tcf
trillion cubic feet

Totex
Total expenditure under the U.K.'s RIIO performance-based ratemaking framework, eliminating the distinction between capital expenditures (capex) and operational expenditures (opex)

TRE
Texas Reliability Entity

TWh
terawatt-hour

USD
U.S. dollar

WECC
Western Electricity Coordinating Council

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.

Energy Markets	▪ Decarbonization and RIIO in the United Kingdom ▪ Does Europe Have a Handle on Its Energy Future?
Generation	▪ One Step Forward, Two Steps Back…The Worsening Risk of Losing Carbon-Free Generation in the United States ▪ Driving Innovation and Sustainable Cost Reductions for the Nuclear Generation Sector ▪ New Jersey among Many States Combatting Early Nuclear Retirement
Grid Edge	▪ Charging Up: A Review of Electric Vehicle Workplace Charging ▪ Illinois Remains at the Forefront of Grid Modernization Advancements: DERs, Renewables, and Beyond ▪ What's Next for Duke Energy's North Carolina Grid Modernization Plan?
Rates and Regulation	▪ Planning beyond Rate Cases: Michigan Orders Utilities to File Five-Year Distribution Investment and Maintenance Plans ▪ What the State [Puerto Rico] Giveth [Monopoly Power to Its Electric Utility PREPA] the State Is Proposing to Taketh Away…
Strategy and Services	▪ Powering On: Four Factors to Energize a Corporate Renewable Energy Program ▪ 2018 Atlantic Hurricane Season Recap and 2019 Implications for Utilities ▪ Handling the Most Pressing Concern for the Utility Industry: The Growing Threat of Cyber Attacks
Transmission and Distribution	▪ Nevada Proposes New Distributed Resources Plan ▪ Xcel Energy Prepares for the Future with Its Integrated Distribution Plan Filing in Minnesota

To view these and other insights, please visit our **Insights Library**.

Subscribe to get the latest highlights and noteworthy developments in energy. See **scottmadden.com** for more.

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 for energy clients. Our broad, deep utility expertise is not theoretical—it is experience based. We have helped our clients develop and implement their strategies, improve critical operations, reorganize departments and entire companies, and implement myriad initiatives.

Contact Us

Brad Kitchens
President & CEO
sbkitchens@scottmadden.com
919-781-4191

Cristin Lyons
Partner
Energy Practice Leader
cmlyons@scottmadden.com
919-781-4191

Bob Hevert
Partner
Rates, Regulation, & Planning Practice Leader
bhevert@scottmadden.com
508-202-7918

Greg Litra
Partner
Director of Research
glitra@scottmadden.com
919-781-4191