

GENERATION GENERATION TO

AN ENERGY EVOLUTION



The ScottMadden
ENERGY INDUSTRY UPDATE

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VIEW FROM THE EXECUTIVE SUITE

EXECUTIVE SUMMARY

Generation to Generation: An Energy Evolution

Change is in the air. Many of our industry challenges are being converted into opportunities by our clients. We are seeing changes in how we generate electricity and manage the grid and in how we generate innovation and new ideas. We are also on the cusp of generational change, and a new generation of industry leaders is emerging. For these reasons, we themed this issue “Generation to Generation: An Energy Evolution.”

Many questions remain in addressing this evolution. Which technologies will co-exist? How? Which generation technologies should remain valued and valuable? What’s on the horizon? Will new technologies fill the gap for power technology “generations” that recede but still provide the energy, performance attributes, and social goods that people want? What is the proper role of markets, federal government, state government, and others with an interest in getting this generational shift right?

We put this *ScottMadden Energy Industry Update* together for industry leaders who are keeping the lights on today and figuring out how tomorrow will work. We loved preparing it for you. We hope you enjoy it.

Some Highlights of this ScottMadden Energy Industry Update	
Getting the Signals Right	<ul style="list-style-type: none">• The central station generation mix is changing, as solar, wind, and gas-fired generation continue to be added, with significantly more expected. And distributed energy resources, while still a small proportion of overall generation, are growing very rapidly• The fate of nuclear power is a big unknown, as some units have retired, more retirements have been announced, and construction of new nuclear units in the United States has hit a rough patch. But wholesale price formation is under review, recognition and compensation for their carbon-free emission characteristics are being discussed and implemented by some states, and small modular reactors are garnering interest• Seeking to advance the renewables shift, communities in some jurisdictions (especially California) are aggregating load and buying their own power. The projections for growth of this are extremely high, but “stranded” costs are an unresolved issue• FERC continues to seek an optimal balance between power generation characteristics in bid-based power markets, while seeking to preserve reliability and reasonable rates. At the same time, the Department of Energy has laid down a marker and an aggressive timeframe for market reform aimed at preserving baseload generation
Evolution Not Revolution	<ul style="list-style-type: none">• New supply and demand options slowly begin to share the spotlight. Energy efficiency, for example, has significant potential, enhanced by improved interactive, Internet-of-things technology, but program designers must still deal with behavioral responses to get the most savings possible• An old storage technology—pumped hydroelectric storage—is gaining attention as new concepts get tested, improved turbines provide more flexible operating options, and utility-scale renewables emerge as a potential energy resource for pumping• The solar industry is raising awareness of increasing amounts of “flexible” solar power, which could provide grid services beyond energy and, when teamed with energy storage, could someday provide a trifecta of characteristics: good grid citizenship, energy when needed (not just when the sun shines), and cost competitiveness with gas-fired generation
Preparing the Grid for a Multi-Generation Resource Mix	<ul style="list-style-type: none">• As generations of resources begin to co-exist on the grid—both “old” and “young”—utilities continue to invest. But they are adapting grid architecture to provide a more flexible backbone to enable two-way power flows and more variable supply and demand• One example of a grid that is changing to accommodate distributed resources is that of Illinois, which has implemented grid modernization efforts as well as changing incentive mechanisms to encourage distributed energy resource development

ENERGY SUPPLY, DEMAND, AND MARKETS

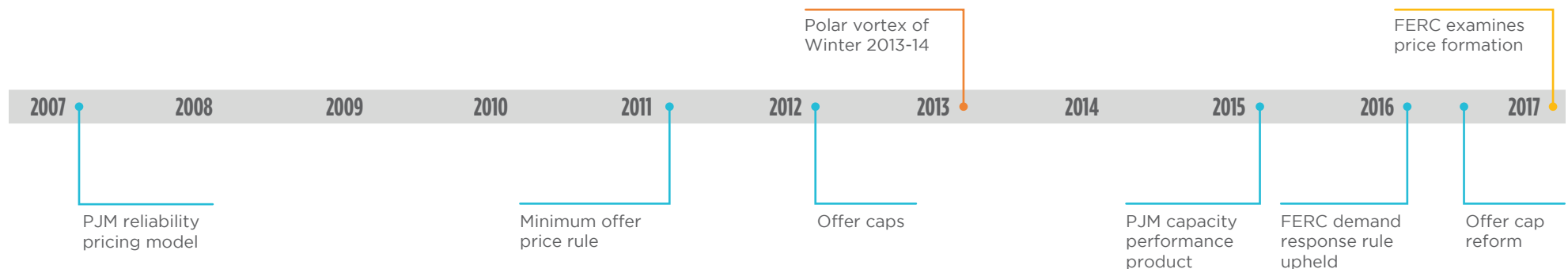
COMPETITION AT THE CROSSROADS: RECONCILING STATE POLICIES AND WHOLESALE POWER MARKETS

Trying to make the theory work: FERC seeks a price formation construct in competitive electric markets that provides the “right” price signals.

The Macroeconomics

- Unlike power transmission and distribution, power generation is not a natural monopoly, meaning a competitive market could, in theory, produce efficient allocation of resources and lower energy costs
 - › But it was thought that prices would only go down and we would never run out
 - › In most competitive markets, prices can spike, and there are stockouts
 - › So, to prevent that, electricity markets were tweaked with administrative overlays multiple times, e.g., price caps and floors in lieu of scarcity prices
 - › But some claim that as a result of these tweaks, current centralized, administered markets lack some of the market mechanisms that would provide the right price signals to resources for market entry and exit
- Competitive electricity markets are also criticized for not accounting for certain social costs and benefits, such as fuel diversity, resilience, and environmental attributes
 - › Some believe that participants are instead given to maximizing near-term individual benefit rather than system-wide, long-term benefit

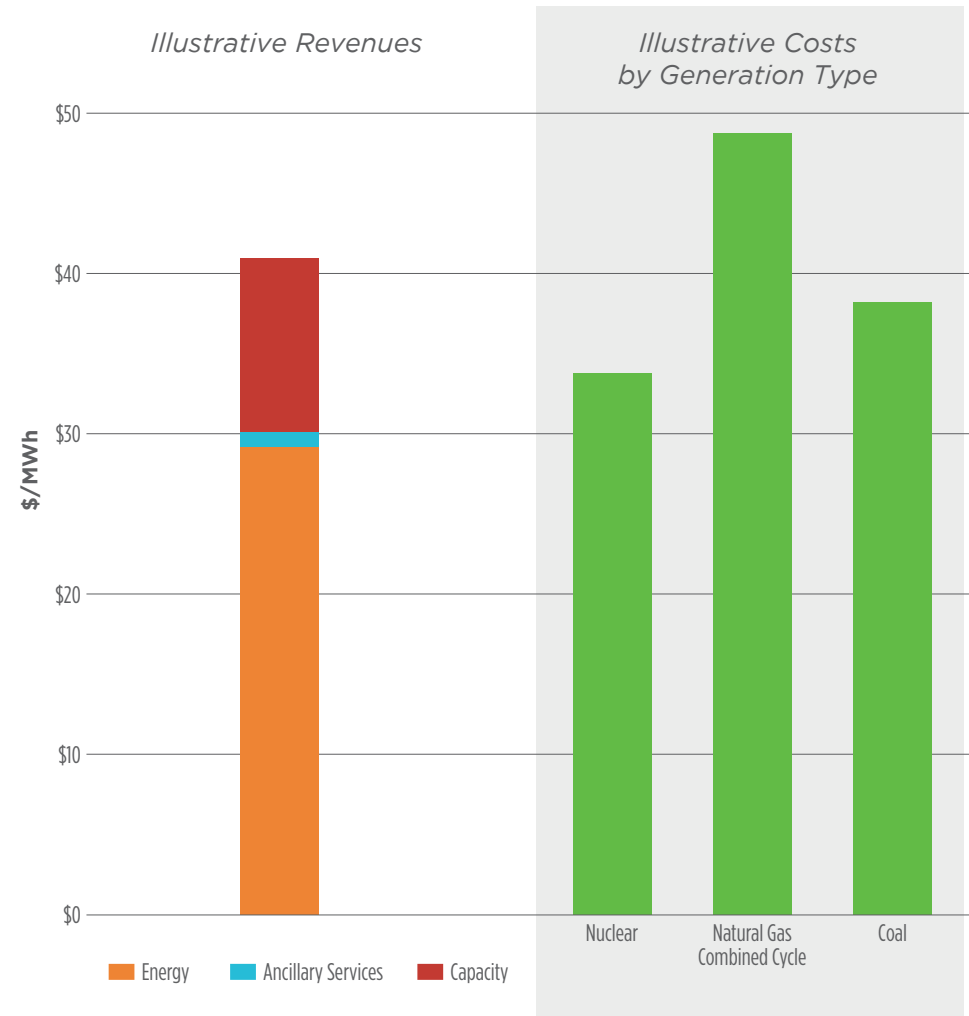
Tweaking the Market Construct: A Recent History



The Microeconomics

- In response, states are subsidizing supply to reflect their economic development, emissions, and other goals, adding supply to already over-supplied markets
 - › This supply is often at zero short-run marginal cost (SRMC)
 - › Because markets were born out of the dispatch system, SRMC is their “center of gravity.” But microeconomics tells us that long-run marginal cost (LRMC) is the proper basis for entry/exit price signals for long-lived assets
 - › So the price signal may already be too low based on microeconomic theory, and it is depressed further by low natural gas cost
 - › Pouring zero SRMC generation into an over-supplied market exacerbates this, lowering both energy and capacity costs
- Market players with higher fixed costs, many of which provide useful grid services and fuel diversity, find themselves disadvantaged by this set of circumstances, incurring operating losses that are becoming unsustainable
- So FERC, again, finds itself looking to solve the issue of the “missing money” (see next page)

Comparison of Costs and Revenues for Selected Generation Types



Sources: PJM; NEI; Institute for Energy Research

COMPETITION AT THE CROSSROADS

A Difficult Economic Problem that Evades a Simple Solution

- FERC and market participants have long recognized that least marginal cost hourly dispatch did not necessarily ensure a diverse set of capacity resources and long-run total cost recovery of long-lived assets—the so-called “missing money” problem
- Capacity markets in some competitive wholesale markets were formed to solve this problem
 - › While not purely market based, capacity markets are administrative constructs to provide “guard rails” to ensure proper monetary incentives exist for resource adequacy
 - › Various mechanisms have been used to manage unintended price impacts and distortions, particularly the FERC-approved minimum offer price rule (MOPR), which applies to RTO auction markets

What’s Different Now, and What’s the Concern?

- There are an increasing number of “outside-of-market” mechanisms to address state policy preferences not solely driven by economic efficiency or reliability—e.g., state solicitations of renewables, zero emissions credits, and baseload capacity support
- Subsidized entry can lead to imbalance (artificial surplus), changing market outcomes for other (including existing) resources
- Power markets are not yet designed for difficult multivariate optimization, including all attributes valued by states
- A key concern is that, at some point, the amount of capacity priced using “outside-of-market” mechanisms might reach a tipping point
 - › Bid-based markets effectively become bilateral markets
 - › Capacity markets then become residual markets with distorted price signals and ultimately cease yielding “just and reasonable” prices

Selected Comparison of Policy Objectives and Priorities of States and Competitive Wholesale Power Markets

	Price	Reliability	Resource Mix/Attributes	Other Social Goods
What FERC-Regulated Wholesale Markets Are Designed to Provide	<ul style="list-style-type: none">• Just and reasonable rates• Economically efficient prices	<ul style="list-style-type: none">• Reliability• Resilience	<ul style="list-style-type: none">• Technology neutrality• No “undue discrimination”—level playing field	
What States Want from Their Power Sector	<ul style="list-style-type: none">• Affordable (low) prices	<ul style="list-style-type: none">• Reliability• Resilience	<ul style="list-style-type: none">• Renewables goals• Fuel diversity• “Baseload” attributes• CO₂ non-emitting resources• Distributed energy resources• Energy efficiency	<ul style="list-style-type: none">• Economic development• New energy technologies (electric vehicles, energy storage, etc.)

Decreasing alignment between states and wholesale markets and among different states

FERC Is Giving This Problem a Close Look

- In May 2017, FERC held a technical conference to discuss state policies and wholesale markets operated by ISO New England, New York Independent System Operator, and PJM Interconnection
- FERC has considered a range of options (see next page), as the Department of Energy is calling for the end of study on price formation and for expeditious action by FERC

Some Themes Have Emerged in Stakeholder Discussions

- States will preserve their sovereignty and pursue their own policies, regardless of wholesale market construct
- Some stakeholders are interested in an accommodation of state goals but are also concerned that this approach will lead to revisiting these same issues in a few years
- There is potential for spillover effects between states with different policy priorities—some observers suggested a “border tax” to compensate for policy differences
- Market operators believe they can tailor market mechanisms to accommodate state-driven resource interests by monetizing their impact via, e.g., a carbon adder or clean energy capacity market
- States generally want centralized markets to be part of procuring and retaining resources for reliability but may not trust FERC solutions, especially where they might run counter to state public policy goals
- States and other observers note that they do not believe in markets for their own sake but as a means to an end—but is there really agreement on exactly what that end is?

Commentary on the Current State of Affairs

“ I have said very many times there are three basic ways this could go: a design market solution, a litigated outcome or a planned change in the regulatory construct of how we handle resource adequacy. [These doors are not mutually exclusive.] The fourth outcome, an unplanned change in the regulatory construct, or unfounded piecemeal regulation is one that I think we should avoid because I think it would be a bad outcome for customers and market participants in terms of cost, reliability, and regulatory certainty.

—FERC Commissioner Cheryl LaFleur (May 1, 2017) ”

“ The current constructs that exist in Eastern U.S. capacity markets cannot long endure restructured states wishing to procure a large portion of their needs around the market....I am skeptical of whether further dissection of administrative auctions into state-sponsored resources and competitive resources can succeed. The complexity of these administrative constructs is remarkable as it exists today. Layering ever more auctions, set-asides, and carve-outs onto the current construct may ultimately tumble the house of cards.

—Former FERC Commissioner Tony Clark (July 2017) ”

FERC poses questions and potential paths forward, focused on the MOPR.

Big Questions Proposed at FERC's May 2017 Technical Conference



Potential Paths Forward

Status Quo	Limited or No MOPR	Expanded MOPR	Accommodation of State Actions	Pricing State Policy Choices
Rely on existing tariff provisions applying MOPR to some state-supported resources and continuing case-by-case litigation	Limit MOPR only to state-supported resources where federal law pre-empts state action or do not apply MOPR at all to state-supported resources	Expand existing scope of MOPR to apply to new and existing resources that participate in capacity market and receive state support	Allow state-supported resources to participate in wholesale markets and, when needed, obtain capacity obligations subject to adjustments to market prices consistent with market results if resources had not been subsidized	State values targeted attributes (e.g., resilience) or externalities (CO ₂ emissions) in a way that can be integrated into markets in a resource-neutral way (e.g., carbon price adder)

Issues for Stakeholders to Consider

- Principles and objectives to guide the path forward
- Degree of urgency for reconciling wholesale markets and state policies and whether separate near- and long-term approaches are required
- Expected relative roles (long term) of markets and state policies in shaping quantity and composition of resources for reliability and operations
- Procedural steps that FERC should take

PJM and ISO-New England are working with stakeholders to seek potential solutions to the market vs. state policy conundrum.

Integrating Markets and Public Policy (IMAPP)

A focused New England Power Pool stakeholder process to identify and explore potential changes to the wholesale power markets that could be implemented to advance state public policy objectives in New England

ISO-NE-proposed forward capacity “substitution auction”

- Key concept: coordinate entry and exit of resources
- Primary forward capacity market primary auction same as today, with MOPR to eliminate “uncompetitive entry”
- Proposal to eliminate Renewable Technology Resource exemption, making auction technology-neutral
- Second substitution auction in which existing or new resources awarded capacity supply obligations (CSOs) may transfer their obligations to new, subsidized resources that do not have CSOs (i.e., did not clear due to MOPR)
- Auction effectively awards severance payment to retiring, non-subsidized resources

PJM Capacity Construct/Public Policy Senior Task Force

Created to conduct an assessment of the Reliability Pricing Model (RPM) in an effort to ensure potential state public policy initiatives and RPM objectives are not at odds. Based on the identified factors, the group will discuss whether modifications are required to RPM

Three initiatives/approaches being discussed:

- *Initiative #1:* Supporting state actions through development of a regional and subregional template
 - › Impose a cost on emission externality or environmental attribute
 - › Explore “border adjustment mechanisms” that would address leakage challenges
 - › Isolate pricing impact of policy choice to only those consenting states in the subregion
- *Initiative #2:* Market reforms in response to individual state subsidies (state policy accommodation)
 - › Capacity market repricing proposal to allow subsidized capacity to be recognized as meeting PJM installed reserve margin (not pay twice) while insulating market clearing price from effects
- *Initiative #3:* Energy market reforms and focus on resilience
 - › Improve transmission, investigate additional reserves, and examine pricing “value of diversity” to preserve resilience

SOURCES:

FERC Technical Conference, State Policies and Wholesale Markets operated by ISO New England, New York Independent System Operator, and PJM Interconnection, Docket No. AD17-11-000 (May 1-2, 2017) (proceedings and pre- and post-technical conference comments); T. Clark, Wilkinson Barker Knauer, *Regulation and Markets: Ideas for Solving the Identity Crisis* (July 2017); Morgan Lewis, *Market Design Proposals and the Impact on Nuclear Generation* (July 18, 2017); IMAPP papers and proceedings, available at www.nepool.com/IMAPP.php; PJM Capacity Construct/Public Policy Senior Task Force papers and proceedings, available at <http://www.pjm.com/committees-and-groups/task-forces/ccpstf.aspx>; PJM Interconnection, *PJM’s Evolving Resource Mix and System Reliability* (Mar. 30, 2017); DOE Lawrence Berkeley Nat’l Lab, *The Future of Centrally-Organized Wholesale Electricity Markets* (Mar. 2017) and related presentation (Mar. 24, 2017); industry news; ScottMadden analysis

MIXING IT UP: FUEL MIX FOR POWER GENERATION CONTINUES TO SHIFT

Markets and players adapt to shifting fuel mix, with long-term implications still to be seen.

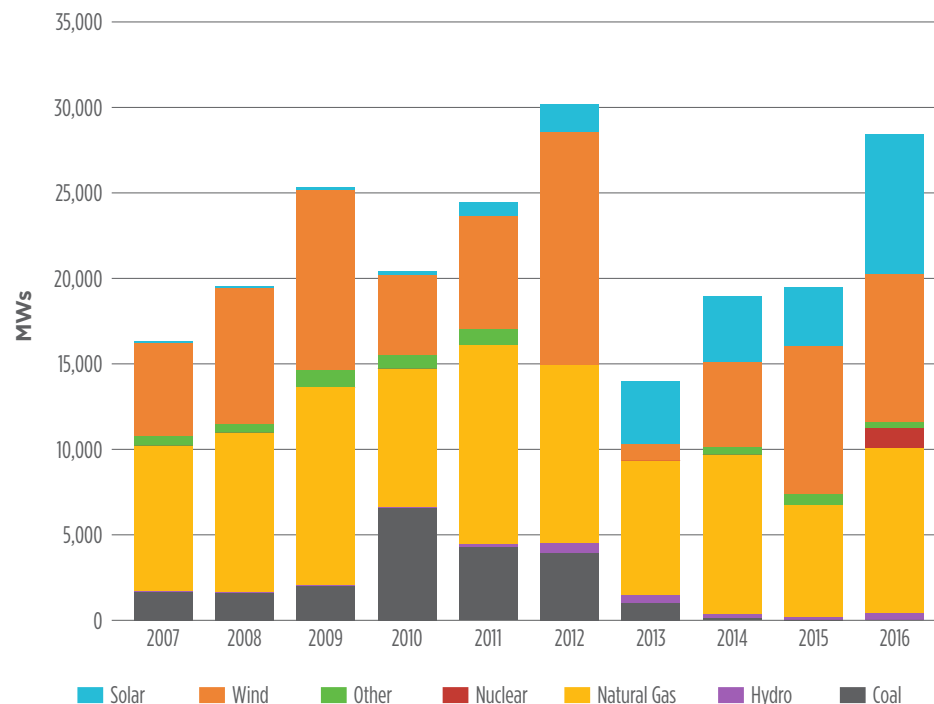
More of the Same

- Gas and renewables continue to comprise most incremental new capacity in the United States and North America, generally
- The influx of these zero and near-zero marginal cost units is making its mark on the market, reducing power prices and significantly altering the fuel mix
- EIA projects that by 2025 renewables will comprise 24% of net generation in the power sector, with gas comprising 26%

Merchants Feeling the Pain, Seek Options

- Merchant generators, whose plants must recover their cost through the markets, are paying a significant financial toll as they seek capital from private equity and other equity investors with longer time horizons, look to consolidate, and/or divest assets to improve their balance sheets
 - › In August, Calpine announced that it would sell itself for nearly \$5.6B to a private investor group led by Energy Capital Partners
 - › Less than two years after being spun off from PPL Resources, Talen Energy was acquired by existing stakeholder Riverstone in December 2016
 - › Prompted by activist investors, NRG is developing a strategy to reposition its portfolio, remaining in the thermal generation business but repositioning 6 GWs of existing assets, including a sale of renewables and some thermal assets
 - › Merchant Dynegy says it “continue[s] to assess the market to see if any future premium asset sales make sense” (while being rumored as a possible acquisition target)

U.S. Power Generation Capacity Additions by Fuel Type



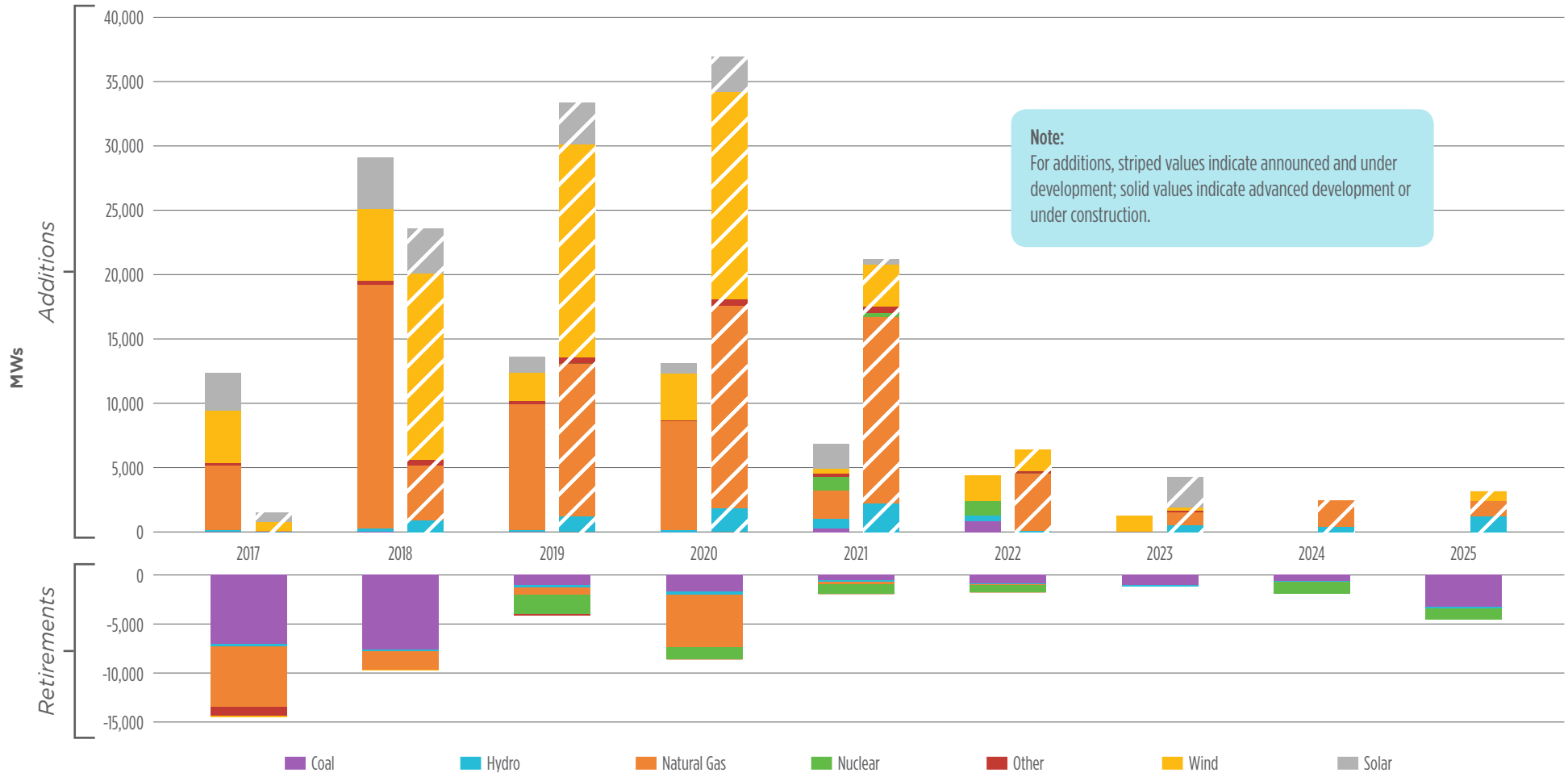
Source: SNL Financial

More Than Money: Implications of Growing Levels of Gas-Fired and Renewable Generation

- Onsite fuel availability and fuel interruptibility for gas
- Limited operating history and dynamics with new mix that now includes demand patterns influenced by distributed energy resources and intermittent resource “back-up” needs
- Difference in flexibility among resources (e.g., reactive support)
- Uncertain long-term fuel costs for gas
- Gas-power market coordination issues

Large amounts of natural gas, wind, and solar capacity are expected to be added to U.S. power supply, although much is in early development.

Projected U.S. Capacity Additions and Retirements by Fuel Type

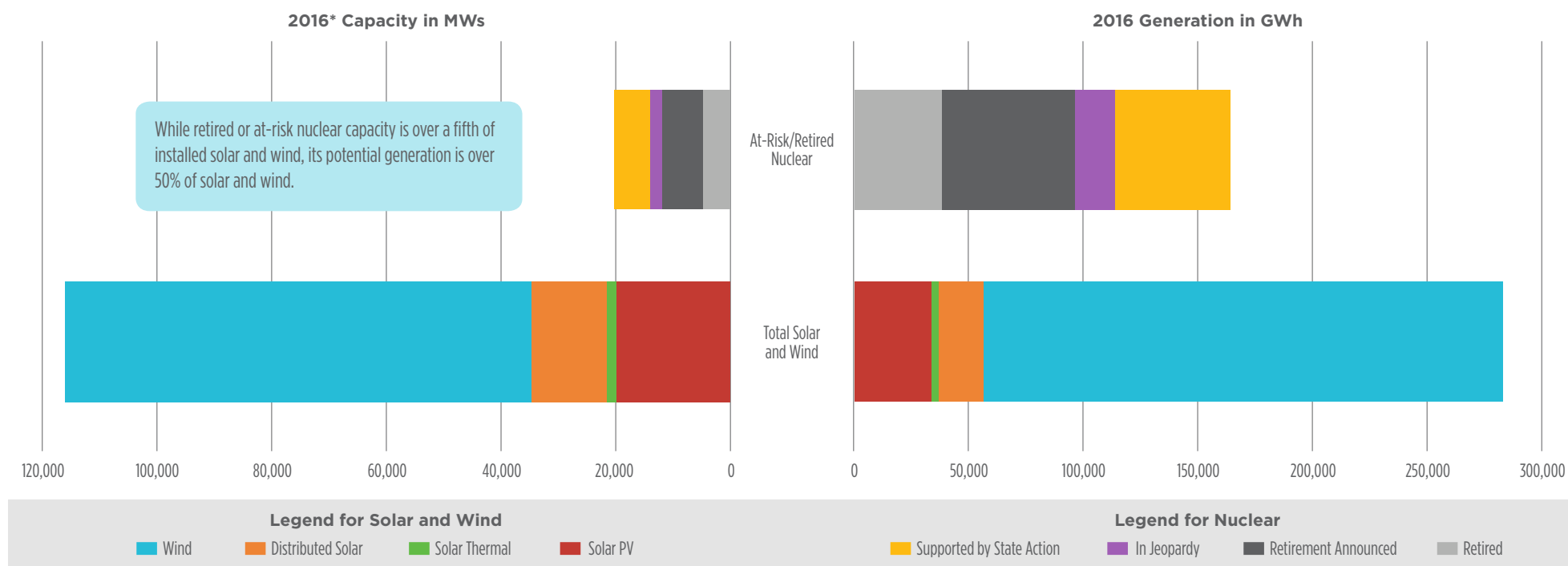


Sources: SNL Financial; ScottMadden analysis

Two Steps Forward, One Step Back

- The United States has added significant non-emitting generation, notably wind and solar, but much non-emitting nuclear generation is at risk or retiring
- This loss of nuclear generation, if it occurred, would wipe out more than half the gain in non-emitting generation from wind and solar
- Zero-emissions credits have been instituted in some jurisdictions (NY, IL) and considered in others (NJ, OH), but it remains unclear whether this stopgap will provide sufficient compensation for these non-emitting resources

Comparing Selected Non-Emitting Capability: Nuclear (including Recent Retirements) vs. Installed Solar and Wind (as of Year-End 2016)*



Sources: EIA; SNL Financial; ScottMadden analysis

NOTES:

*Amounts include wind, solar, and estimated rooftop photovoltaic as of 2016 and nuclear capacity in operation as of 2016 or retired between 2009 and 2016, specifically Kewaunee, Vermont Yankee, Fort Calhoun, Crystal River 3, and San Onofre 2 and 3. Generation for nuclear units is estimated based upon assumed 92.5% capacity factor. Renewable generation is actual as reported by EIA

SOURCES:

Energy Information Administration, *Electric Power Monthly* (Mar. 2017), Tables 1.1 and 6.1; SNL Financial; industry news; S&P Ratings webinar, "Nuclear in 2017: An Industry in Crisis" (Sept. 26, 2017); NEI; ScottMadden analysis

NUCLEAR POWER: LIVING ON THE EDGE

One major nuclear new build project has been abandoned, one forges ahead, and others are taking a cautious stance.

Status of Selected New Build U.S. Nuclear Projects

Project	Recent Activity
Down for the Count <i>V.C. Summer 2 & 3</i> <i>(South Carolina)</i>	<ul style="list-style-type: none"> The Summer expansion project was cancelled by SCANA and Santee Cooper on July 31, following the bankruptcy of Westinghouse Electric, the project's construction contractor The project was several years behind schedule and billions over budget, with a total projected price tag of more than \$20B Various government and utility stakeholders have entertained proposals to save the project and the financial future of its owners, including a potential sale of Santee Cooper, although utility executives suggested that efforts to revive the project face hurdles In the face of a South Carolina House committee review, SCANA is also expected to resubmit a petition to the SCPSA to create a regulatory asset to recover \$4.9M more in capital costs tied to the abandoned project
Keeping the Faith <i>Vogtle 3 & 4</i> <i>(Georgia)</i>	<ul style="list-style-type: none"> In a late August filing with the GPSC and also in the wake of contractor Westinghouse's bankruptcy, Georgia Power Company (GPC) recommended the completion of its Vogtle expansion, based upon economic analysis and six "critical assumptions": Toshiba paying its guarantee, Congress extending production tax credits, the U.S. Department of Energy providing further federal loans, the NRC signing off on inspections, Westinghouse meeting obligations, and workers maintaining productivity GPC, which owns 45.7% of the new units and has invested approximately \$4.3B in capital costs in the project, estimates its share of cost to complete the project is \$4.5B (total capital cost of entire project of about \$19B) GPSC has already approved \$5.68B in capital costs for GPC's share of the project, and with \$1.7B in anticipated payments from Westinghouse, the company's additional capital costs are approximately \$1.4B GPSC's decision on GPC's recommendation is slated for February 2018
Backing Off: Recent Project Announcements <i>Lee (South Carolina)</i> <i>Levy (Florida)</i> <i>North Anna (Virginia)</i>	<ul style="list-style-type: none"> In August, Duke Energy scrapped plans to build the Lee Nuclear Station, noting that "continuing the project as originally envisioned is not in the best interest of customers." It seeks a regulatory asset to recover \$53M in development costs per year over 12 years. However, the company will retain the recently acquired combined license in case circumstances change Also in August, Duke announced that it will not proceed with building the Levy Energy Complex, and customers will not pay any further costs associated with the project. According to a proposed settlement, the utility would write off \$81.9M in retail costs, \$36.6M in AFUDC, and \$34M in termination fees to Westinghouse, and it would remove \$94.1M in land value from rate base In early September, Dominion Resources announced that it has shelved plans to construct a third unit at North Anna, despite receiving a combined operating license on May 31. Sunk costs include \$600M in pre-interest project costs, \$301M of which has already been recovered in existing rates from Virginia ratepayers. However, the utility suggested that the decision may be temporary if federal and/or state carbon regulations result in a better outlook for the plant in the future

Bottom Line

It continues to be a challenge to construct new nuclear generation plants in the United States: the permitting process has been streamlined with NRC's combined operating license applications, but other promises (e.g., improvements in construction costs and schedules) have not yet been realized.

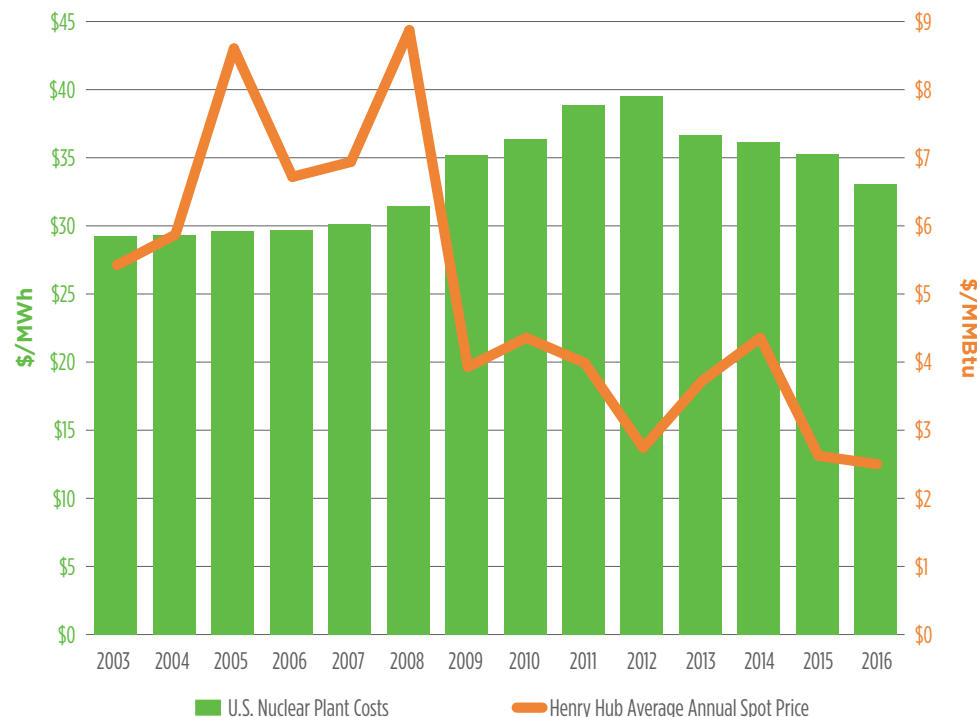
States Are Responding to Challenging Nuclear Economics

- Persistently low natural gas prices have created a context in which nuclear power cannot compete purely on marginal cost with certain other forms of generation, particularly zero-marginal-cost renewables and new efficient gas combined-cycle units
- This is particularly an issue for units in bid-based markets, which may not currently provide adequate mechanisms to value the carbon-free attributes of nuclear power, as well as its performance in various weather conditions that affect fuel supply or output from other resources
- But some states have implemented (or are considering implementing) policy supports for nuclear power

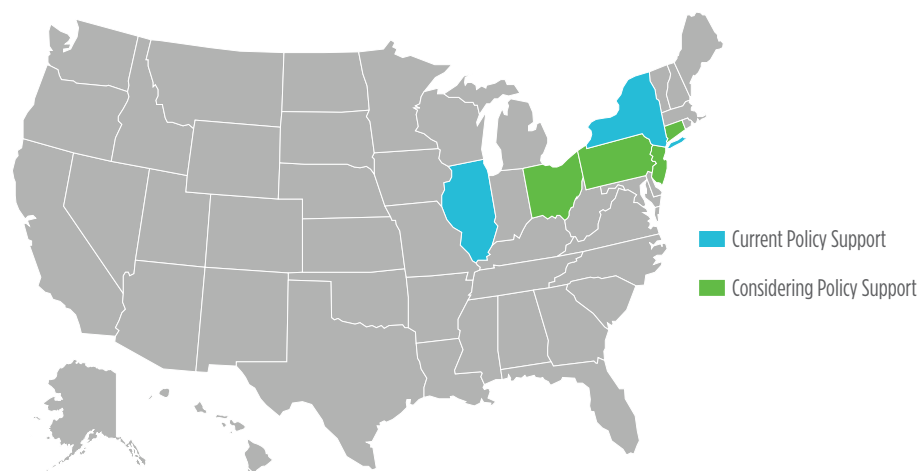
Trying to Make Progress Against a Tough (Fuel) Competitor

- The nuclear industry continues its ambitious initiative to reduce costs, launched in late 2014, called “Delivering the Nuclear Promise” (DNP)
- Nuclear Energy Institute (NEI) estimates that \$650M could potentially be saved annually by the nuclear power industry
- 46 “Efficiency Bulletins” have been published targeting potential improvements resulting in cost savings, with 95% implementation rate across the U.S. fleet
- Between DNP and other individual operator cost-reduction efforts, progress is being made: U.S. nuclear plant costs have gone from \$40.25/MWh in 2012 to less than \$34/MWh (in 2016\$)
- While the adequacy of the industry response to cost challenges is yet to be seen, the risks associated with failing to deliver the promise include continued closures of uneconomic current operating plants due to insufficient revenues, loss of an experienced and knowledgeable nuclear workforce, and the potential loss of U.S. nuclear leadership on the world stage

U.S. Nuclear Power Production Costs* vs. Natural Gas Prices



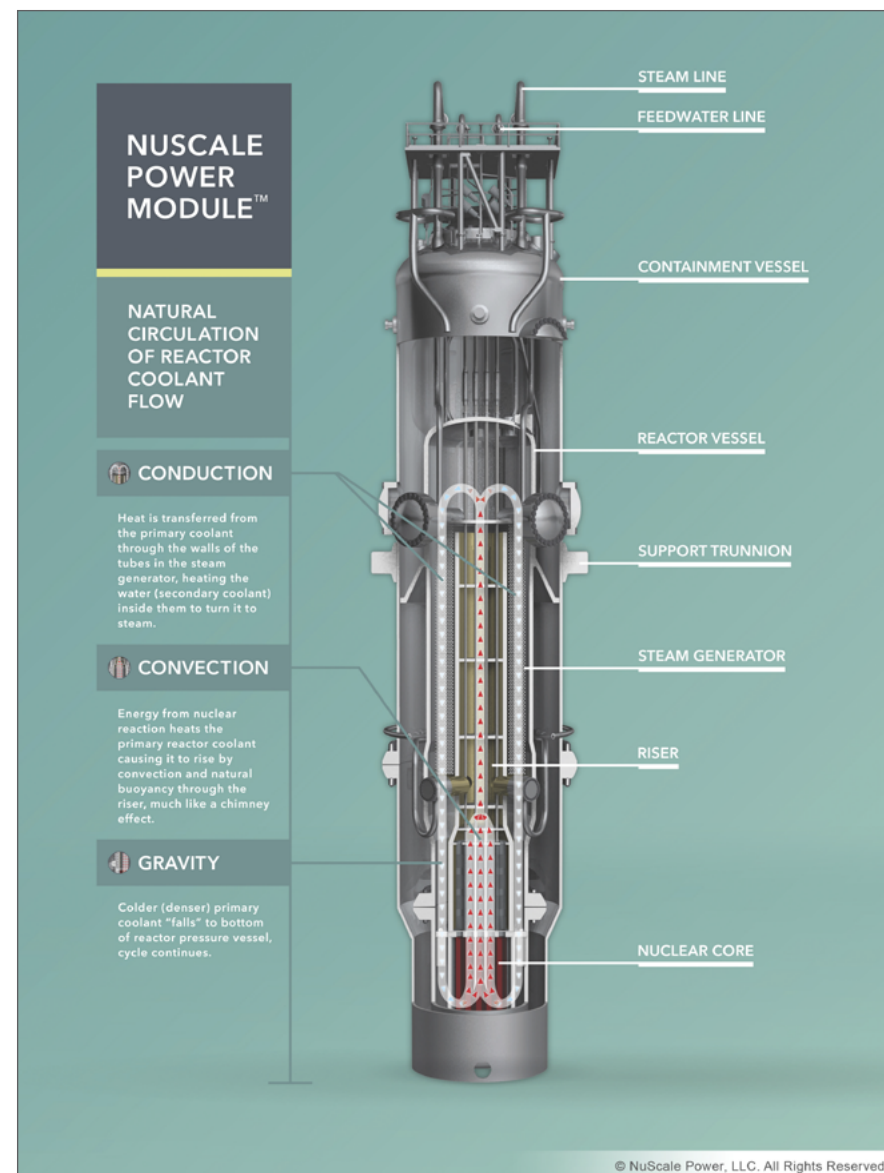
States Providing or Considering Policy Support for Nuclear Power



On the Bright Side, Small Modular Reactors (SMRs) Continue to Generate Interest

- Given more modest scale and carbon emissions-free characteristics, interest in SMRs has increased
 - Smaller upfront capital requirements may make these units easier for utilities to finance, and the construction period may be shorter
 - SMR designs benefit from modularity and reduced number of structures, systems, and components
- According to IAEA, there are 50 designs or concepts in various development or planning stages around the world, with four in advanced construction in Argentina, Russia, and China
- The Department of Energy (DOE) has voiced support of SMRs, including Energy Secretary Rick Perry's inclusion of SMRs as part of DOE's recommended "all of the above" energy strategy, although DOE's available R&D budget is unclear
- NuScale, the most visible vendor in the market, submitted to the NRC the first design certification application ever for an SMR
- TVA is looking at installing SMRs on its Clinch River site, seeking an early site permit from the NRC, with additional documents and reviews extending through late 2019
- Advances are not without some skepticism and caution:
 - SMRs still face "no nukes" opposition (e.g., environmental groups opposed to the TVA project) and security concerns remain with dispersed, small installations
 - Cost is still a factor, and economics are still unproven: NuScale's 12-module configuration, e.g., will cost around \$3B (\$5K per kW); cost reduction must come through shorter construction times, features that reduce regulatory expenses, and scaled-up supply chains
 - Nuclear regulatory hurdles, such as design certification, construction and operating licensing, etc., can be comparable to those for larger units

NuScale Power Module Diagram



NOTES:

*Includes fuel, capital, and operating costs; SCPSC means South Carolina Public Service Commission; GPSC means Georgia Public Service Commission; AFUDC means allowance for funds used during construction; IAEA means International Atomic Energy Agency; NRC means U.S. Nuclear Regulatory Commission; TVA is Tennessee Valley Authority

SOURCES:

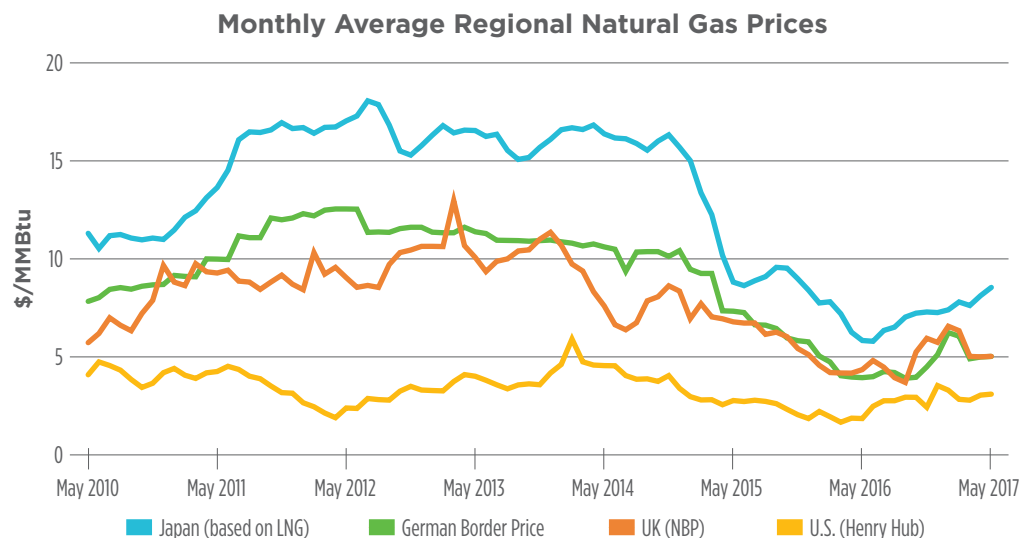
U.S. Nuclear Regulatory Commission; World Nuclear Association; Nuclear Energy Institute; OECD-NEA, *Small Modular Reactors: Nuclear Energy Market Potential for Near-Term Deployment* (Sept. 2016); SNL Financial; *MIT Technology Review*, "Small Reactors Could Kick-Start the Stalled Nuclear Sector" (July 17, 2017); *Electric Light & Power*; Utility Dive; ScottMadden analysis

LIQUEFIED NATURAL GAS: TOO MUCH OF A GOOD THING?

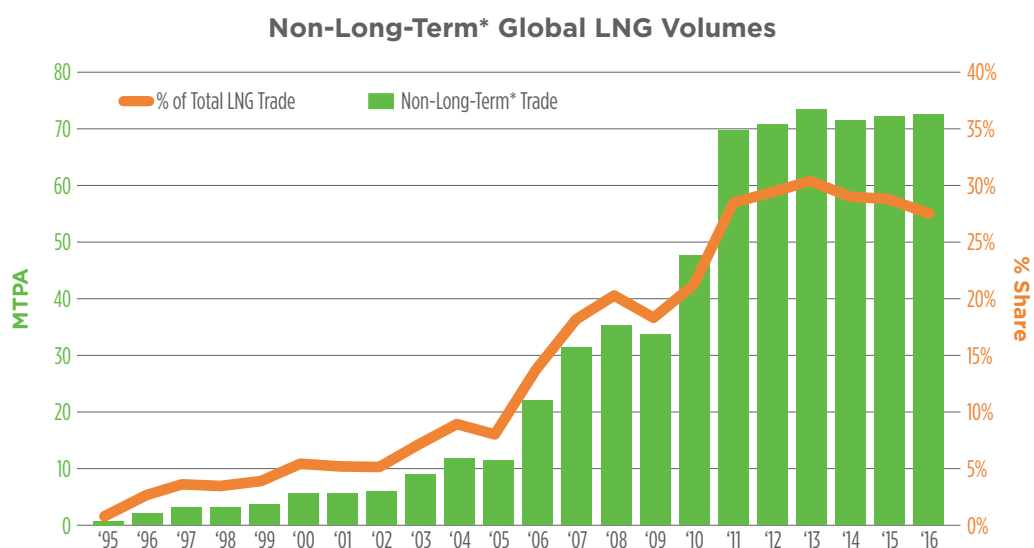
As U.S. liquefied natural gas (LNG) export capacity is set to grow, worldwide LNG trade heats up.

Worldwide, LNG Use Is Expected to Grow as Contract Dynamics Change, but the Market Seeks Balance

- Worldwide growth in gas-fired generation is expected to help drive gas and specifically LNG usage over the next decade
 - Global demand for gas generally is expected to increase by 2% per year through 2030
 - LNG demand is expected to rise at double that, at a rate of 4% to 5% per year
- Abundant shale gas resource and anticipated U.S. export capacity are pressuring usually dominant global LNG exporters Qatar and Australia
 - An expanded Panama Canal helps U.S. export accessibility to Asia, where Japan and Korea consumed about 45% of global LNG in 2016
 - But competitive response can be significant since global LNG market participants include many state sponsored entities, increasing geopolitical implications
- Global gas prices are down; even if demand increases in the early 2020s as forecast, it is unclear at what level prices will equilibrate
- Importantly, market dynamics are changing
 - Traditionally a market driven by long-term (20-year) contracts, about 30% of global LNG volumes now trade in short-term markets
 - Part of this change is increasing flexibility in delivery destinations both in LNG supply contracts and via increasing liquefaction capacity, including floating storage regasification unit technology



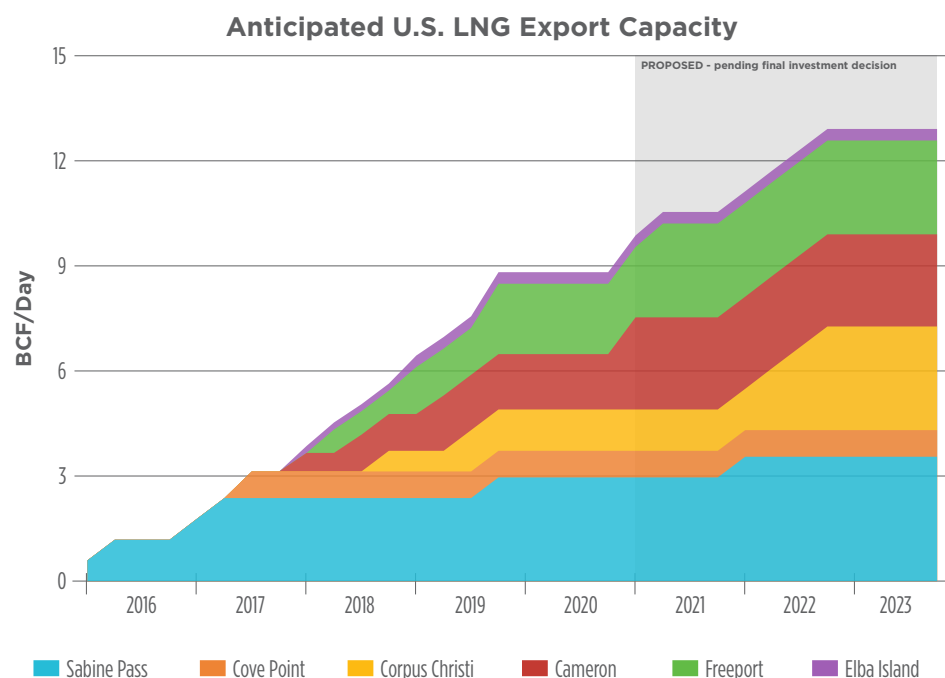
Source: IGU



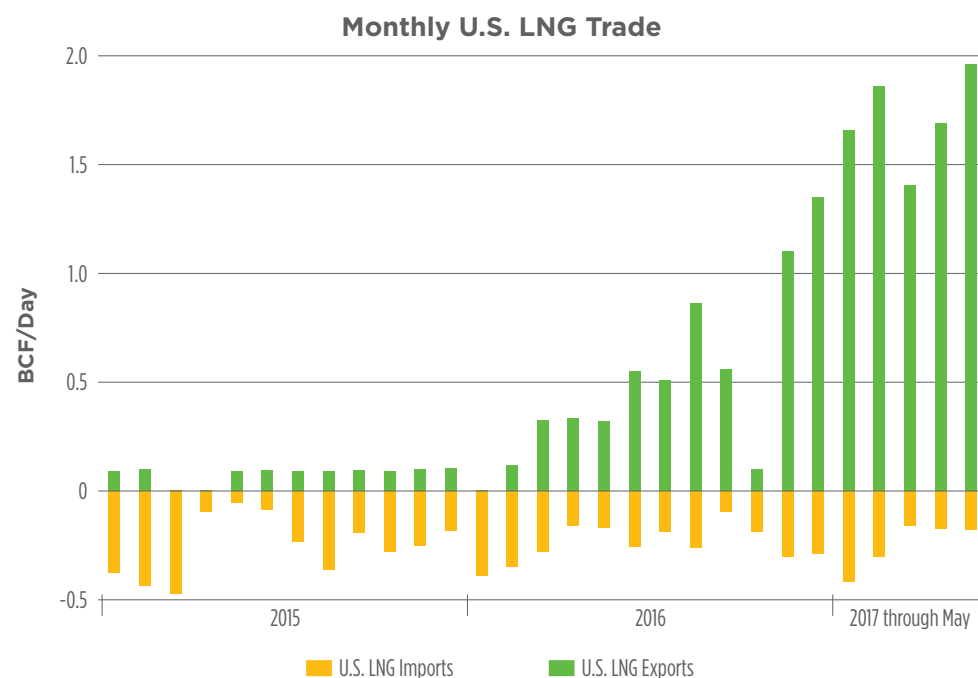
Source: IGU

Despite Continued Expansion, U.S. LNG Export Capacity Faces Challenging Market Conditions

- Low natural gas prices continue to plague U.S. producers, but that has not discouraged continued production in prolific shale plays
- LNG export terminals are coming online, giving domestic gas another market, and restoration of a quorum at FERC is expected to accelerate approvals
 - › Based upon current queue of projects, more than 10 BCF/day of U.S. LNG export capacity is expected by late 2020
 - › This compares with U.S. dry gas production of 72.5 BCF/day and is the equivalent of more than 20% of current global LNG export capacity
 - › Another point of comparison, U.S. end-use natural gas consumption totaled more than 25.2 TCF in 2016, or about 69 BCF/day
- Current first movers like Cheniere, a major player, may have some advantages
 - › Significant upfront capital costs result in lower marginal costs once a facility is placed into service; therefore, being first to market may have oversized importance
 - › Some models—e.g., where the facility has tolling contracts—can allow for some risk diversification (LNG market price risk is held by off-takers), while capital recovery risk is held by the facility owner, at least for the duration of the off-take contract
- But challenging economics and local opposition remain hurdles, even as export volumes and capacity builds under existing projects
 - › With more of the LNG market moving toward shorter-term contracts and spot transactions, exporters may experience higher cost of financing, tighter debt covenants, and limits on leverage
 - › And some proposed projects (like Jordan Cove project in Coos Bay, OR) face local opposition



Source: IGU



Source: EIA

Implications for North American Markets: Bearish Conditions Continue, at Least for Now

- The swing in investment from LNG imports a mere decade ago to conversion to exports now demonstrates the risks of investment in uncertain global gas markets
- While gas supply is currently outpacing demand, it is unclear when that dynamic will turn, especially with global power generation demand for gas rising
- If strong LNG export demand emerges, it would place pressure on the Henry Hub price, thus causing more and higher basis “discounts” to emerge, e.g.:
 - › Marcellus gas could trade at an increasing discount to Henry Hub
 - › Price of Alberta supply, which may not have access to LNG exports, could see increasing negative basis
- LNG imports to the United States and Canada will primarily be from the ENGIE Everett facility in Boston and the Repsol’s Canaport facility in New Brunswick

Some Key Questions Remain

- Does the United States have to worry about the “Australia effect”—potential government intervention and market distortions from gas exports that lead to tight domestic gas supplies and rising prices for natural gas for power generation?
- What about market and geopolitical responses to abundant U.S. LNG—will Qatar and other leading LNG exporters compete to retain global LNG market share?
- Given market dynamics, will there be sufficient capital to support proposed projects beyond the current projects under construction?

NOTES:

MMBtu means million British thermal units; MTPA means million tons per annum; BCF means billion cubic feet; *non-long-term trade includes spot and short-term (agreements <2 years) and medium-term (contracts between 2 years and <5 years) LNG transactions

SOURCES:

IEA; S&P Global Platts, *U.S. LNG: A Benchmark for the Future* (May 2017); International Gas Union (IGU), *2017 World LNG Report*, Figs. 3.15; Energy Information Administration, Today in Energy, “In new trend, U.S. natural gas exports exceeded imports in 3 of the first 5 months of 2017” (Aug. 8, 2017); Energy Information Administration, *Monthly Energy Review* (July 2017), Table 4.1 (Natural Gas Overview) (natural gas production); International Energy Agency, *Gas 2017: Analysis and Forecasts to 2022*, Executive Summary; *Shell LNG Outlook 2017*; SNL Financial, “US to become 2nd-biggest LNG exporter by 2022, IEA says” (July 13, 2017); industry news; ScottMadden analysis

INFRASTRUCTURE AND TECHNOLOGY

PREPARING FOR THE FUTURE: ILLINOIS PREPARES FOR DISTRIBUTED ENERGY RESOURCES

Thanks to grid modernization efforts and proactive ratemaking, Illinois has laid the foundation for distributed energy resources (DERs).

Increasing Interest in Accommodating Distributed Energy

- As advancements in technology (and reductions in cost) have led to increasing availability of smaller, distributed energy technologies and improved computation, communication, and control technologies, interest is growing in grid access for those technologies and potential energy-related services they enable
- In December 2016, the MIT Energy Initiative released a report that examined how provision and consumption of energy services is likely to evolve over the next 10 to 15 years
 - › **Its key question:** How will electricity services that are primarily provided in a centralized, top-down manner today be provided in the future?
 - › **Its conclusion:** A set of proactive reforms to electric regulation, policy, and market design are needed to enable efficient evolution of the power sector over the next decade (and beyond)
- Some jurisdictions, like Illinois, have been considering how to modernize their grids, foster economic development, and provide operational flexibility, enabling the rapid growth of DERs contemplated by the MIT study

MIT's Proposed Regulatory Framework for an Evolving Electricity Sector

- Establish a comprehensive and efficient system of prices and regulated charges (e.g., rates or tariffs) for electricity services that reflect, as accurately as possible, the marginal or incremental cost of providing these services
- Implement improvements to the regulation of electric distribution utilities that reward cost savings, performance improvements, and long-term innovation
- Carefully assign responsibility for the core functions of distribution system operation, network provision, market platforms, and data management
- Improve wholesale market design to better integrate DERs, reward greater flexibility, and minimize distortions from policy supports for various technologies

PREPARING FOR THE FUTURE

Not Just Coastal: DERs Embraced in the Midwest

- While New York and California are often identified as leading the charge on innovative energy policy, Illinois has quietly solidified its position as a market to watch
- ScottMadden and the Smart Electric Power Alliance (SEPA) studied developments in Illinois, focusing on the following questions:
 - › What is the state of the electricity market in Illinois today?
 - › How have recent legislative developments led to transformation in the electricity market?
 - › How have utilities modernized their grid to be flexible and ready for rapid growth in DERs?

Snapshot of Illinois' Electricity Market Structure

Service Territory Characteristics	Mixed (urban and rural)
Utility Types	99% investor-owned utility <ul style="list-style-type: none"> • ComEd 74%, Ameren 24%
DER Penetration	Low
Utility Structure	Wires only (T&D)
Wholesale Market	Organized markets (PJM and MISO)
Retail Market	Fully deregulated
Renewable Policy	Renewable portfolio standard: 25% by 2025
Net Energy Metering (NEM)	NEM capped at 5% of peak demand

Enabling Illinois Legislation Facilitates “Utility of the Future” Capabilities**Energy Infrastructure****Modernization Act (2011) (EIMA):**

Drives modernization of the grid, authorizing significant investments for ComEd and Ameren, and establishes performance-based formula ratemaking

- \$3.2B for grid improvements and smart meter investments
- Checkpoints with Illinois Commerce Commission (ICC): annual rate case events
 - › Formulaic distribution rate cases, with assessment against certain metrics
 - › Allowed return on equity uses market-based numbers, with adjustment based upon performance
- Authorized investment
 - › ComEd: 10-year, \$2.6B grid modernization program, with installation of AMI across service territory
 - › Ameren: \$648M grid modernization program, including the deployment of smart meters to 62% of customers

Future Energy Jobs Act (2016) (FEJA):

Expands energy efficiency, addresses issues in RPS implementation, and creates a pathway for compensating distributed generation (DG) based on grid value

- Sets demand reduction targets
 - › ComEd: 17% by 2025 and 21.5% by 2030
 - › Ameren: 13% by 2025 and 16% by 2030 (recently adjusted by Illinois regulators)
- Increases energy efficiency spending caps from 2% to 4%; potential for energy efficiency to be put into rate base
- Orders \$25M per year to be spent on programs that increase the energy efficiency of low-income households (\$325M total over bill term)
- Allocates \$140M per year to enhance the Illinois RPS by authorizing the Illinois Power Agency to purchase renewable energy credits (RECs) for RPS compliance
- Includes carve-outs for the solar portion of the requirements: 40% from utility-scale solar projects; 50% from DG projects (2% from brownfield solar projects; 8% discretionary)

Measures Afoot

- Enabled and encouraged by legislation and regulatory efforts of the ICC, Illinois electric utilities have developed programs that facilitate current and future integration of DERs and renewables
- Illinois is leading in degree of transformative change taking place with the physical assets being installed across the utility systems and the variety of options and efficiencies being made available in the retail market

Degree of Change Reflected in the Current State

Retail Market Design



- Retail choice provides options, but more is needed
- At >5% NEM, DER customers can get compensated for locational, temporal, and performance-based value to the grid
- AMI enables transformative rate plans (e.g., ComEd PJM hourly energy pricing)

Wholesale Market Design



- Ongoing work in PJM, MISO regarding DER participation
- DER role limited by classifications, especially for storage
- Behind-the-meter resources not yet included

Utility Business Model



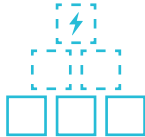
- Traditional cost of service dominates
- But performance-based formula rates introduced and ComEd has embraced a “utility as a platform” model
- New approaches tested through smart grid initiatives
- Future DER rebates may be treated as virtual regulatory assets (like energy efficiency), earning a return

Rates and Regulation



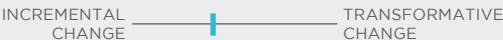
- Myriad rate plans—ComEd residential customers, e.g., have 94 rate plan options
- ICC NextGrid initiative: Collaborative process seeking “21st Century Regulatory Model”

Asset Deployment



- Significant upgrades in distribution systems
- Projects include distribution automation, communications infrastructure, substation metering, smart switching on high-voltage distribution lines, and smart grid test beds
- Smart meters across ComEd and Ameren territories by 2018 and 2019, respectively

Information Technology



- Distribution automation, data-sharing programs, and enabling secure communications networks








The Foundation for DER Enablement Has Been Laid

- Illinois has laid an excellent foundation that positions it well for increasing penetrations of DERs and renewables. When DERs arrive at scale, the state will be ready
- Transformative grid modernization completed under the EIMA provides the technical and operational capability for utilities to manage fluctuations in load brought on by DER, energy efficiency, and demand response programs
- Hardware and software upgrades have been accompanied by innovative programs such as real-time pricing programs for retail customers and the piloting of many new technologies and business models through the utilities' smart grid test beds
- The requirements, incentives, and directives of the FEJA are expected to encourage renewables and DERs

However, Challenges Remain

- A rapid acceleration of demand for DER will be facilitated by the important work to date; however, that does not mean the integration of DER and evolution of the business model will be easy
- A big challenge with two competing goals:
 - › Ensuring the ongoing viability of the state's utilities and their requirement to manage a reliable network
 - › Integrating DERs provided by third parties in a way that provides customers the most cost-effective alternatives
- Illinois has done the work necessary to set the stage for a grid that can accommodate these resources
- The next challenge will be to evolve the regulatory construct to the benefit of all parties, particularly customers and the utilities responsible for the reliable operation of the network. The requirements, incentives, and directives of the FEJA are expected to encourage renewables and DERs

Looking Ahead: Things to Watch in Illinois Market Development

-  Treatment of energy efficiency expenditures as a regulatory asset earning a return
-  Extension of formula rate plan for distribution assets with added performance incentives for energy efficiency expenditures
-  Post-net energy metering pathway of DG compensation in statute tied to locational grid benefits
-  Utility ability to treat DG compensation for those systems allowing utility control facilitated by smart inverters as a regulatory asset earning a return
-  Investments and deployments for modernizing distribution grid operations
-  Evolution of the platform business concept
-  NextGrid and the 21st Century Regulatory Model

Sources: SEPA; ScottMadden

NOTES:

AMI means automated metering infrastructure; RPS means renewable portfolio standard

SOURCES:

I. Perez-Arriaga, J. Jenkins & C. Batalle, "A Regulatory Framework for an Evolving Utility Sector: Highlights of the MIT Utility of the Future Study," *Economics of Energy & Environmental Policy*, vol. 6, no. 1 (2017); MIT, *Utility of the Future* (Dec. 2016); Smart Electric Power Alliance & ScottMadden, "51st State Perspectives: DERs Are Coming and Illinois Is Ready for Them" (June 2017); Database of State Incentives for Renewables & Efficiency, at <http://programs.dsireusa.org/system/program/detail/2700>

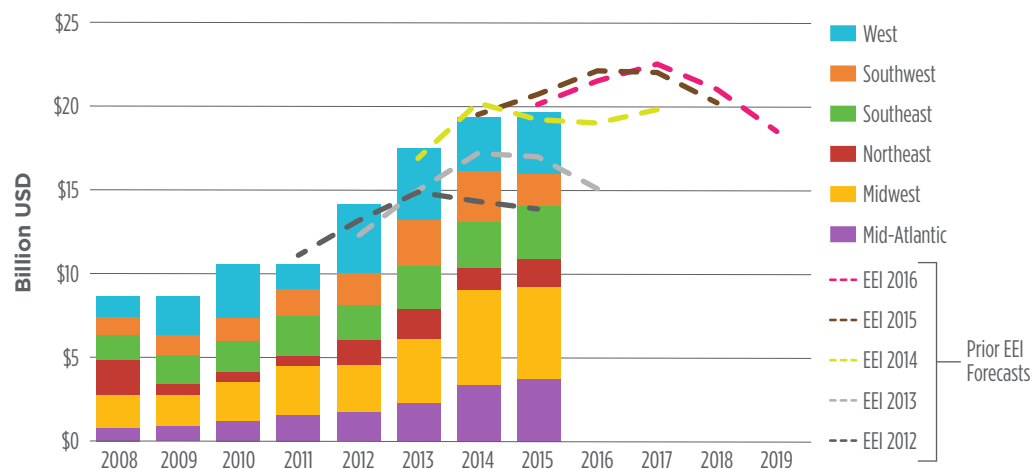
GRID INVESTMENT: NOT THE SAME OLD WIRES

Even as distributed resources grow in interest and on the ground, continued transmission investment is needed.

Trends in Grid Investment

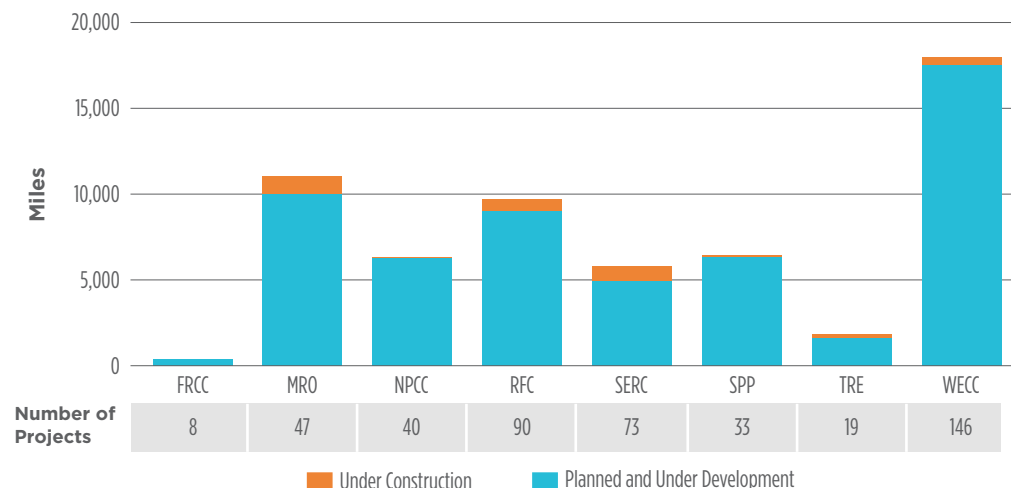
- Investment in power transmission is significant but is projected to decline after 2017, although this reflects a common pattern of projected spending as near-year spending is more certain
- The planning process promised by FERC Order 1000 has not yielded the level of development hoped for by the industry
- Moving renewable resource power to load centers and ensuring grid flexibility with those resources continue to be areas of interest for transmission investment. Some examples:
 - Renewable energy developers declare that Southwest Power Pool transmission is inadequate for planned capacity of renewables
 - Private equity firms are backing both the building of renewable energy projects and the transmission to transport that energy to load centers
 - Massachusetts has included transmission projects in its solicitation for 1.2 GWs of “clean” energy, although a similar three-state New England solicitation rejected all proposed transmission projects
- One emerging trend: Transmission development is focusing on more than planning for peak. Grid operators are planning for shoulder months when renewables output can be high relative to demand, which has implications for the kinds of investment needed
- However, getting major projects funded, approved, and constructed has become more challenging, as the time horizon for investment has increased with more local and environmental resistance to siting

Historical and Projected Transmission Investment*



Sources: SNL Financial; EEI

U.S. Transmission Projects by NERC Region
(Planned, Under Development, and Under Construction)



Source: SNL Financial

GRID INVESTMENT

Some Themes of Transmission Investment Are Emerging—Some Old, Some New

**Replacement of aging infrastructure**

The 240-mile, \$320M 345-kV Lower Rio Grande Valley project upgraded aging infrastructure and was North America's longest energized re-conductoring

**Congestion relief**

Western Region Economic Project, a \$154M project in the Entergy Texas area, aims to reduce congestion through a new 230-kV line and an upgrade to an existing 25-mile, 138-kV line

**Voltage upgrades**

Panama City Area Voltage Improvements, a \$20M project completed in 2015, provides dynamic voltage support to the Panama City, Florida area

**Expand to new resources/markets**

Great Northern Transmission Line, a new \$677M, 500-kV line from southern Manitoba to northeastern Minnesota, will provide Minnesota Power and other utilities in the Upper Midwest access to reasonably priced, predominantly emission-free energy supply, including 383 MW of hydropower and wind storage energy products

**Connect geographically diverse, complementary resources**

TransWest Express, a 730-mile, 600-kV bi-directional line, will carry wind from Wyoming to the Desert Southwest, and solar from the Southwest to Wyoming

**Achieve clean energy goals**

Moses-Adirondack Smart Path Reliability project will rebuild 78 miles of transmission, upgrading to 345 kV, to "help New York reach its nation-leading clean energy standard" pursuant to NY Gov. Cuomo's NY Energy Highway Blueprint

One Executive Comments on the Current State of Affairs in Transmission Development



Outdated ideas about transmission investment as something to avoid should be abandoned in favor of a forward-looking planning approach that recognizes the need to build now to reap the major economic, reliability and resilience, and public policy benefits of transmission in the foreseeable future and down the road.

—WIRES President Kathy Shea, Eversource Energy



Returns on Equity in Transmission Appear to Be Converging with Utility Returns on Equity

- Returns on equity (ROEs) approved by state commissions for electric utilities fell from 10.3% in 2006 to 9.6% in 2016
- Transmission returns on equity did not follow suit initially but have recently been challenged and are being revised downward
- The revisions have left transmission ROEs notably close to the electric utility ROEs
- As state regulators, public power, and others have challenged FERC's "upper midpoint" (75th percentile) of returns methodology for transmission ROE, those ROEs risk going even lower, exacerbating the current trend and potentially pushing them below utility returns
- Meanwhile, transmission and distribution spending is expected to represent about 45% of total capital spending for selected major utilities in the years 2016 through 2018, according to Regulatory Research Associates
- Given challenges of getting transmission constructed and the emerging "downstream" investment needs for grid modernization and accommodation of DERs, we might expect to see a shift in investment from transmission to distribution assets

Going Down: FERC Transmission ROEs Are Shrinking

Parent Company	Filing Entity	Previous Base ROE (%)	Revised Base ROE (%)	FERC Order Date
N/A	ISO-New England	11.14	10.57	Oct. 2014
National Grid US	Niagara Mohawk Power	11.00	9.80	May 2015
FirstEnergy	American Transmission Systems	12.38	10.38	Oct. 2015**
Xcel Energy	Southwestern Public Service	10.77	10.00	Oct. 2015
Duke Energy	Duke Energy Florida	10.80	10.00	Nov. 2015
Exelon Corp.	Atlantic City Electric	11.30	10.00	Feb. 2016
Exelon Corp.	Baltimore Gas & Electric	11.30	10.00	Feb. 2016
Exelon Corp.	Delmarva Power & Light	11.30	10.00	Feb. 2016
Exelon Corp.	Potomac Electric Power	11.30	10.00	Feb. 2016
Westar	Westar	10.80	9.80	Mar. 2016
N/A	MISO	12.38	10.32	Sept. 2016
Duke Energy	Duke Energy Carolinas	10.20	10.00	Nov. 2016
Duke Energy	Duke Energy Progress	10.80	10.00	Nov. 2016

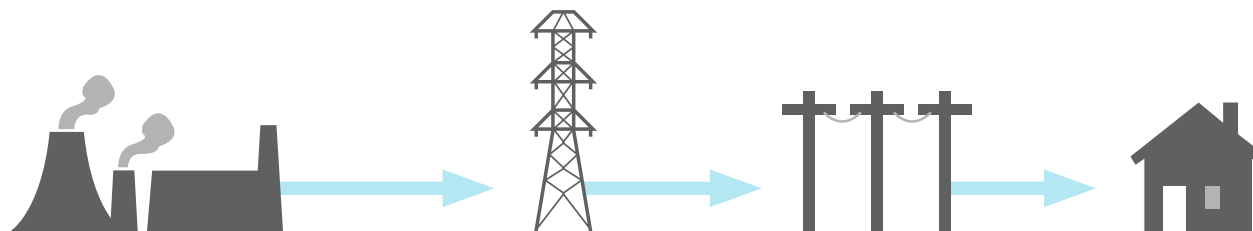
Source: SNL Financial (Regulatory Research Associates)

Grid Investment in a Distributed World

- Divisions between transmission and distribution are blurring as DERs scale up
- With the blurry lines between wholesale and retail as well as transmission and distribution, issues of cost causation and who pays for grid enhancements to accommodate DERs make a thorny issue more perplexing

Grid Development Drivers Are Changing

Historical Model: "Power Cord for Source-to-Sink"



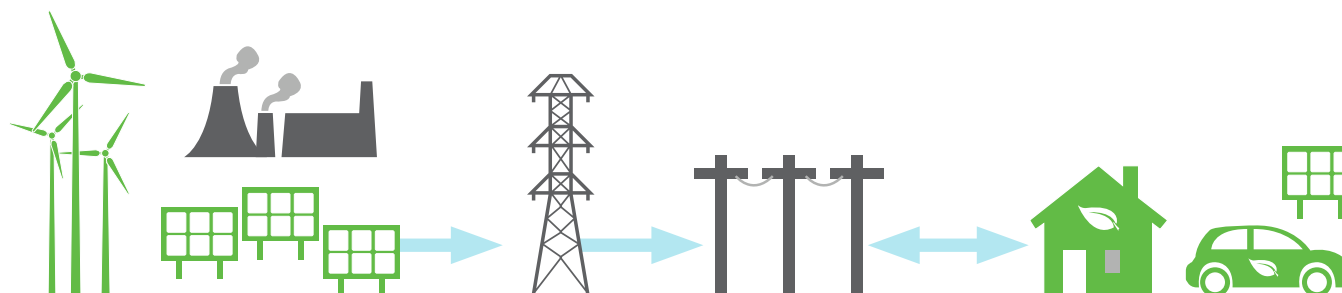
Features

- Large-scale units
- Fuel diversity
- Source-to-sink transmission
- Built-in redundancy
- Less complexity

Grid Implications

- N-2 planning criteria
- Planning for peak demand
- Focus on line-loading, vegetation management

Developing Model: "Backbone for Bi-directional and Intermittent"



- Generating units of varied scale and technology
- Intermittency and "duck curve" effects
- Less fuel diversity (gas)—single point vulnerability
- Need for cyber resilience
- Complex input-outputs including backfeed

- Planning for low demand and intermittent resources
- Increased need for frequency response awareness and essential reliability services
- More detailed risk assessment and operational readiness
- Increased need for visibility into more granular assets

Spending Shift

From 2011 to 2016, growth in spending on infrastructure additions for listed electric and diversified utilities grew (on a compound annual rate) by **4.7% for power production** versus **8.6% for distribution** facilities and more than **16% for transmission**.

- As grid development drivers change and utility investment seeks attractive risk-adjusted returns, more utilities are proposing grid modernization initiatives
- There is no universal definition of grid modernization; however, one observer defines it as “actions making the electricity system more resilient, responsive, and interactive,” a broad definition that includes business model and rate reform, market access, advanced grid technologies, microgrids, and non-wires solutions (e.g., energy storage)
- In January 2017, Eversource proposed a \$400M Grid-Wise Performance Plan, including investments over five years in an advanced distribution management system, remote sensing and switching capabilities, and hosting capacity maps to provide customers with information about interconnection in specific locations, as well as a revenue-cap formula performance-based ratemaking plan

Viewpoint	<i>“The transmission system backbone needs to be strengthened”</i>	<i>“The days of building large-scale transmission lines are over”</i>
The Rationale	The existing grid was not built for intermittency on both sides of transmission that can be caused by utility-scale renewables in large quantities on the supply side and intermittency and “backfeed” on the demand side due to incorporation of DERs	Energy efficiency and demand response will manage peaks via wholesale market participation

Advanced Metering Infrastructure

Smart Grid Technologies

Microgrid

Energy Storage

>2 Technologies

Source: NC Clean Energy Technology Center

*EEL figures are from respective annual financial reviews, which show projected spending for report year and subsequent three years. **FERC order reduced ROE to 10.38% effective Jan. 1, 2016

Edison Electric Institute, *2012-16 Financial Reviews and 2017 Statistical Review*; Edison Electric Institute, *Transmission Projects at a Glance* (Dec. 2016); Pierce Atwood, "Massachusetts Issues New RFP For Clean Energy Projects; Seeks 9,450,000 MWh Annually" (Apr. 3, 2017), at <http://www.jdsupra.com/legalnews/massachusetts-issues-new-rfp-for-clean-28463/>; "5 major transmission, hydro and wind partners bid into Massachusetts Clean Energy RFP," masslive.com (July 28, 2017); National Law Review, "Massachusetts Receives Nearly Four Dozen Bids in Response to Request for Proposals for Renewable Energy Generation" (Aug. 25, 2017); NERC, *The State of Reliability* (June 2017); Russell Gold, "Investors Are Building Their Own Green-Power Lines," *Wall Street Journal* (Apr. 6, 2017) at <https://www.wsj.com/articles/investors-are-building-their-own-green-power-lines-1491471009>; Richard Martin, "Building TransWest Express like playing '3D chess,' says CEO," *S&P Global* (July 11, 2017); Governor Andrew Cuomo Press Office, "Governor Cuomo Announces Plan to Rebuild 78 Miles of Power Transmission Infrastructure in the North Country" (July 21, 2017), at <https://www.governor.ny.gov/news/governor-cuomo-announces-plan-rebuild-78-miles-power-transmission-infrastructure-north-country>; TransWest Express LLC, Quanta Energized Services (re: Lower Rio Grande Valley Project) websites; SNL Financial; Regulatory Research Associates; UBS Global Research; Foley Hoag; Massachusetts Dept. of Public Utilities; ScottMadden analysis

RATE AND REGULATORY ISSUES

COMMUNITY CHOICE AGGREGATION: AVOIDING UNINTENDED CONSEQUENCES

As communities use aggregation to secure renewable resources, questions arise as to who pays for existing utility commitments and how.

What Is Community Choice Aggregation (CCA)?

- A not-for-profit aggregator, usually a municipal or local government (but not a utility), that procures electricity in wholesale markets on behalf of a customer base within its boundaries
- Typically, the programs are opt-out, with all residents in the CCA “territory” automatically enrolled and obligated to pay for CCA-procured power unless they opt out, i.e., actively choose to exit the program and continue to receive and pay for electricity supply from the incumbent utility
- CCAs can be used to implement or support certain state-specific policy objectives, such as supporting renewable energy or implementing energy efficiency programs
- CCAs have become popular as vehicles for renewable energy purchases, although many of those purchases are not necessarily from nearby resources
- CCAs generally differ from municipalization. CCAs do not own energy delivery infrastructure. The incumbent utility delivers the purchased power through its transmission and distribution assets and typically continues to handle billing, metering, and customer service
- CCAs are not subject to the same rules as public utilities; instead, they are designated as “energy service providers”

Origins and Growth of CCA

- In 1995, Massachusetts was the first to authorize CCA. Cape Light Compact is the nation’s first CCA and still serves more than 200,000 customers
- But it is California that is making headlines
 - › California authorized CCAs in 2002, but it was years until Marin Clean Energy formed California’s first CCA, now serving about 255,000 customers
 - › About 915,000 California customers receive energy from CCAs, and significant growth is expected as localities with populations totaling more than 15 million consider forming CCAs—roughly 40% of the population

COMMUNITY CHOICE AGGREGATION

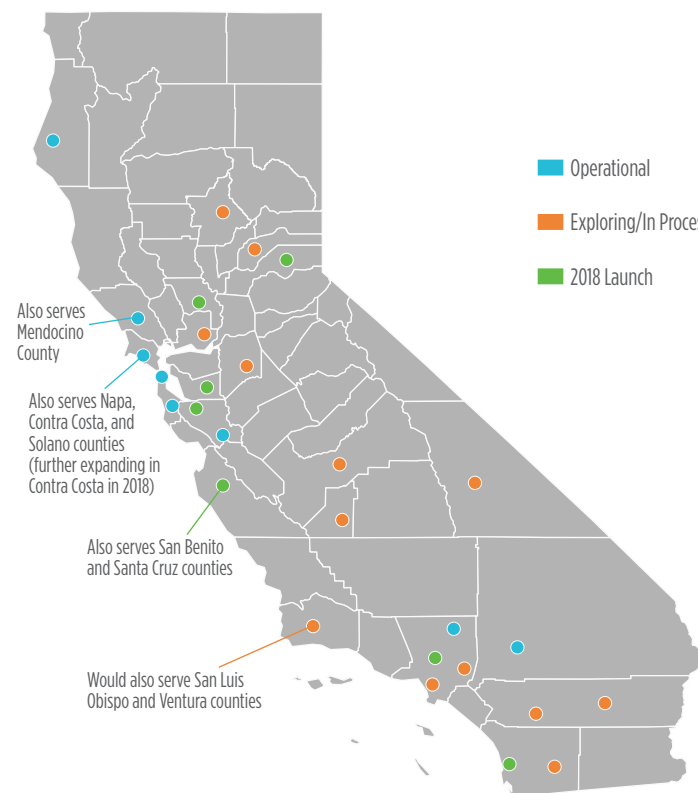
Is California About to Reach a CCA Tipping Point?

- As CCA continues to advance in California, incumbent utilities, regulators, and other stakeholders are concerned about the potential effect of unfettered migration from bundled retail electric service
- With CCA, utilities are left with legacy assets, including power purchase agreements, incurred to serve all customers. So, there is concern about cost shifting from migrating customers to remaining customers
- For example, Pacific Gas & Electric estimates that \$180M of costs in 2017 will be shifted to remaining non-CCA customers, growing to \$500M by 2020. There is concern about the “most vulnerable” customers being left without options if the utility scales back or abandons power procurement
- This shift is gaining speed: Eight California CCAs bought 3.75 million MWh of power in Q2 2017, a 408% increase compared with purchases made in Q2 2016 and 4.7% of wholesale sales in the California ISO
- The California Public Utilities Commission (CPUC) has begun a multi-stakeholder discussion of the impact of continued CCA expansion and potential needs for regulatory changes, including a possible road map for retail competition

De Facto Retail Choice

Although California has limited retail electric choice, CPUC estimates that, between customer-sited generation (rooftop solar), CCAs, and direct access providers*, 85% of retail load will be served by non-investor-owned utilities by the mid-2020s.

**A Trickle to a Flood:
Operational and Potential Customer Choice Aggregators in California**



Source: Local Energy Aggregation Network

CCA both holds promise and presents challenging issues.

The Promise of CCA: Getting Local Control and Scale

- Increased amount of “locally sourced” clean energy in a power supply portfolio
- Increased choice for residential and commercial customers sometimes underserved by competitive retailers
- Aggregation entity provides immediate scale in volume and allows for limited overhead needed for origination
- Using scale for market efficiency, such as bulk buying power or demand response participation
- Possible collaboration with transmission and distribution utilities in new grid management models (e.g., virtual power plants, microgrids)

The Perils of CCA: Areas of Inquiry in California

Resource Planning

- Application of CPUC’s rigorous IRP approach becomes uncertain with greater share of load served by CCAs (e.g., unpredictable demand profile)

Reliability Assurance

- Incumbent IOUs are tasked with capacity procurement for resource adequacy, but jurisdictional issue exists as to whether and how CPUC can allocate costs to CCAs

Cost Allocation

- Question of who pays for existing power supply agreements and physical resources purchased for a larger set of customers (pre-CCA)
- California is revisiting fairness of current Power Charge Indifference Adjustment, which provides non-bypassable charges to CCA customers who migrate from bundled service. Few are satisfied with methodology
- Issues of proper allocation of grid and social costs remain

Universal Service

- As de facto retail choice emerges: who remains the “provider of last resort” and what should be the process for procuring power for opt-out customers?

Rate Design

- Current volumetric-based rates must be revisited for grid cost recovery
- Potentially skewed price signals when mandatory time-of-use rates are implemented by IOUs in 2019—potential for more migration

NOTES:

*Direct access providers are energy service providers that can serve non-residential customers, and the amount of load permitted to be served is capped in each investor-owned utility service territory (see <http://www.cpuc.ca.gov/General.aspx?id=7881>); IOU means investor-owned utility; IRP means integrated resource planning; CCA means community choice aggregation or community choice aggregator, as appropriate

SOURCES:

Smart Electric Power Alliance; Platts Megawatt Daily; California Public Utilities Commission, Staff White Paper, “Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework” (May 2017), and CPUC website; SNL Financial; Utility Dive; Local Energy Aggregation Network (LEAN Energy U.S.); ScottMadden analysis

CLEAN TECH AND ENVIRONMENT

THE SOLAR TRIFECTA: A PATH TO SMART UTILITY-SCALE SOLAR

Improvements in solar technology offer the promise of energy plus multiple grid services competitive with gas-fired generation.

Moving from Traditional to “Smart” Solar Power

- Utility-scale solar has become an important and growing part of the electric generation portfolio in the United States. However, operational challenges are becoming evident in markets with high penetrations of traditional utility-scale solar
- These challenges include variable output, lack of robust ancillary services, and dispatch limitations
 - › The California duck curve is the most pronounced example of operational challenges. The California ISO faces oversupply risk during midday from utility-scale solar production followed by steep ramps in evening hours as solar production declines and demand peaks
 - › Outside of California, increasing penetration of traditional utility-scale solar could create new and extreme operational challenges to electric systems in the United States unaccustomed to high amounts of solar power generation
- A common response to this challenge is to simply pair utility-scale solar with flexible natural gas generation. However, this is not the only option as utility-scale solar holds the potential, if operated differently, to address some of these issues on the electric grid on its own

“Traditional” Utility-Scale Solar

- Traditional solar is defined as utility-scale solar systems designed and operated to generate and deliver the maximum amount of electricity in real time
- Key characteristics include the following:
 - › Consists of stand-alone utility-scale solar photovoltaic (PV)
 - › Operated to provide energy only, maximizing output

“Controllable” Utility-Scale Solar

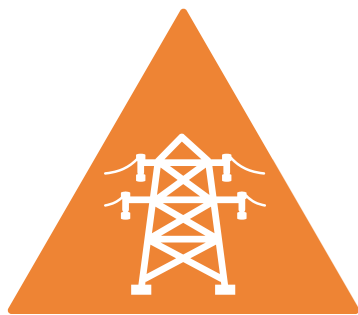
- Controllable solar is defined as utility-scale solar systems that use existing technology to trade some energy output for more constant/predictable output and expanded ancillary services
- Key characteristics include the following:
 - › Consists of stand-alone utility-scale solar PV
 - › Operated with targeted curtailments using reserve for dispatchability within range or ancillary services

“Smart” Utility-Scale Solar

- Smart solar is defined as utility-scale solar systems capable of offering operational attributes that are comparable to conventional generation assets
- Key characteristics include the following:
 - › Consists of utility-scale solar PV plus storage (PV+S)
 - › Provides benefits of controllable solar
 - › Plus, offers the potential for dispatchable energy and capacity during evening and nighttime load

Smart Utility-Scale Solar Is Dependent on Three Market Requirements

- Smart solar could become a reality with the convergence of the three market requirements we call the “solar trifecta”
- In combination, the three requirements could address the constraints of traditional solar and advance the deployment of smart utility-scale solar



Value from Good Grid Citizenship

- The common view is traditional solar has not been a good steward of the grid (e.g., variable output, lack of certain ancillary services)
- This has required other resources to respond to solar-related grid integration challenges
- With smart inverters and software, solar PV systems can provide more constant output by withholding a portion of output and ramping up and down to achieve desired output
- Recent demonstrations prove smart solar is capable of providing a broad suite of ancillary services



Energy When You Need It

- By exporting all available generation in real time, traditional solar is often unavailable to meet evening load
- PV+S addresses this challenge by providing energy and capacity during evening or even nighttime load
- A recent analysis shows the addition of storage can increase the capacity factor during a summer evening load from 50% to 98%
- PV+S systems can be more cost effective than previously thought when “smartly” targeting the actual hours and load when they are needed



Cost-Competitive Resource

- Smart solar becoming cost competitive depends on continuing to reduce the installed cost of utility-scale solar and battery pack costs
- The installed cost of fixed-tilt utility-scale solar dropped 37% since 2015 and remains below \$1/W-dc
- Meanwhile, the cost of battery storage packs has also declined 73% from 2000 to 2016
- In May 2017, Tucson Electric Power signed a power purchase agreement with a PV+S system for less than 4.5 cents per kWh

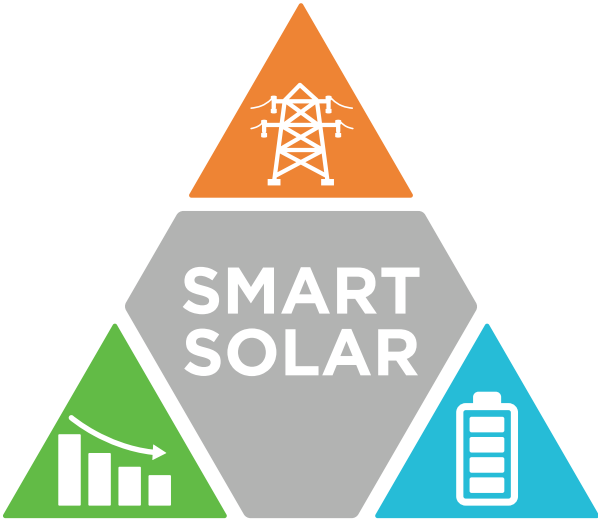
On the Horizon: The Dawn of Smart Utility-Scale Solar

Where Are We?
How Utility-Scale Solar Evolves to Meet Solar Trifecta Requirements*

Type of Solar	Value from Good Grid Citizenship	Energy When You Need It	Cost-Competitive Resource**
Traditional			✓
Controllable	✓		✓
Smart	✓	✓	✓

Watch for the Signs

- Several market developments could either hamper or accelerate advancement of the solar trifecta and ultimately the deployment of controllable and smart utility-scale solar. Signposts to watch:
 - › **Recognition of good grid citizenship** – Most power purchase agreement (PPA) structures do not compensate or set minimum requirements for solar assets to provide broad ancillary services. New and innovative PPA structures and market rules could accelerate the learning curve and encourage future utility-scale solar systems to be model grid citizens
 - › **Success of early PV+S systems** – For evening and nighttime dispatchable solar to gain broad industry acceptance, early PV+S systems must prove their ability to reliably and consistently deliver energy and capacity during evening load periods
 - › **Continued learning-curve effects** – With increasing installed capacity, both solar PV and battery storage costs have benefited from learning-curve effects as installed capacity grows. Continued declines in technology cost will be important if smart solar is to become cost competitive



Are We There Yet?

An initial milestone will be controllable utility-scale solar becoming commonplace, supplanting the deployment of traditional utility-scale solar. Longer term, a critical milestone will be a PV+S system outcompeting a new natural gas peaking plant and successfully providing energy, capacity, and a broad suite of ancillary services.

NOTES:
A more detailed discussion of the “solar trifecta” can be found in the ScottMadden white paper, “The Solar Trifecta: A Path to Smart Utility-Scale Solar”; *table reflects requirements met by each type of solar, not necessarily current state of market; **cost competitiveness is dependent on location and available solar resource
SOURCES:
Electric Power Research Institute; National Renewable Energy Laboratory; California ISO; First Solar, Inc.; Alevo; GTM Research; Solar Energy Industries Association; Bloomberg New Energy Finance; Utility Dive; ScottMadden analysis

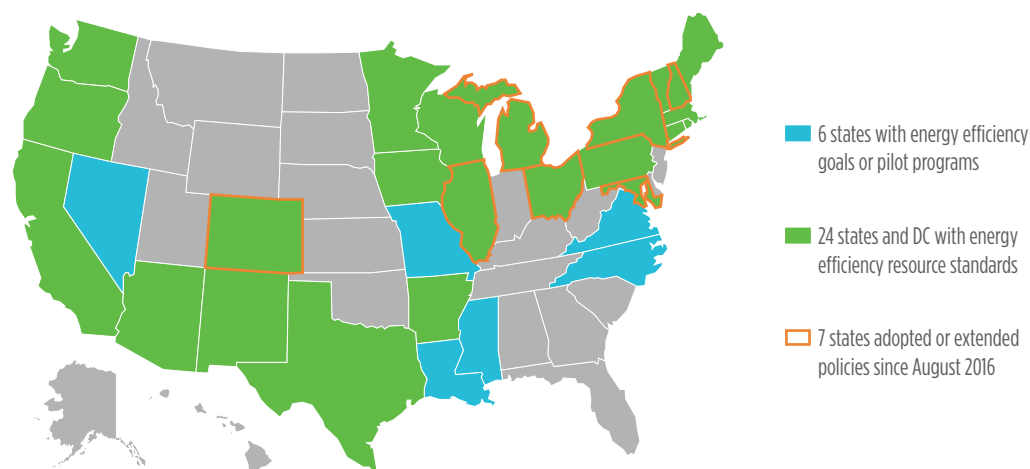
ENERGY EFFICIENCY: LITTLE BY LITTLE






States continue to target energy efficiency, and its potential remains high, fortified by technology improvements.

Electric Energy Efficiency Efforts Continue

- Thirty states have either energy efficiency resource standards (EERS), goals, or pilot programs, with a number of states recently adopting or extending their policies. EERS are state policies that require utilities to meet specific targets for energy savings according to a set schedule
- Retail electric utility 2015 incremental program costs for energy efficiency totaled \$5.7B, generating estimated energy savings of 26,189 GWh (or about 0.64% of 2016 total U.S. consumption) and estimated realized peak demand savings totaling more than 6 GWs*
- Increasingly, states with IRP requirements are looking at energy efficiency as a resource
 - › These approaches include efficiency as a low-cost resource that is evaluated on a comparable basis with supply resources
 - › Some jurisdictions, such as California, have established a “loading order” that calls for first pursuing all cost-effective efficiency resources, then using cost-effective renewable resources, and only after that, using conventional energy sources to meet new load
 - › Massachusetts’ Green Communities Act, for example, requires that electric and gas utilities make acquiring all cost-effective energy efficiency a higher priority than using other resources, and utilities must “provide for the acquisition of all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply” for three-year prospective budgets and goals in coordination with an Energy Efficiency Advisory Council

States with Energy Efficiency Savings Targets (as of July 2017) and Selected State Details



	Long-term goals average about 1.15% of retail sales electricity through 2024
	Vary by utility, averaging 1.77% of sales from 2018 to 2021, 2.08% from 2022 to 2025, and 2.05% from 2026 to 2030
	Targets EE savings increase to 2.95% of annual sales in 2018
	From 2016 to 2023, utilities must ramp up programs by 0.2% per year, leveling out at 2% incremental savings per year (over 2016)
	REV efficiency transition implementation plans with incremental targets varying from 0.4% to 0.9% for the period 2016-2018

Opportunity Awaits

- Declining costs and expanding capabilities of technology-enabled efficiency measures provide opportunities
- Improvements in building efficiency offer promise, although replacement and retrofit of existing stock requires a multi-generational time horizon
- A DOE Berkeley Lab report found the following regarding building (including housing) energy efficiency potential:
 - Appliance and equipment efficiency improvements have been, and will continue to be, a key driver in lowering electricity demand in the residential, commercial, and industrial sectors
 - Connected devices and energy management control systems are decreasing in cost and improving in functionality
 - The efficiency of new buildings (very low or zero-net energy) is rapidly increasing across all sectors
 - While considerable progress has been made in improving the deployment of retrofit investments in existing buildings, there remain significant opportunities for more savings

Avoiding Bounceback

- Behavior can impede efficiency efforts: a “curse” of cost savings
- With increases in achieved energy efficiency (perhaps compounded by lower costs and perceived greener sources), customers may offset savings by consuming more than they would without those savings
- Program designers are considering ways (such as automation) to ensure promised efficiency savings are achieved

NOTES:

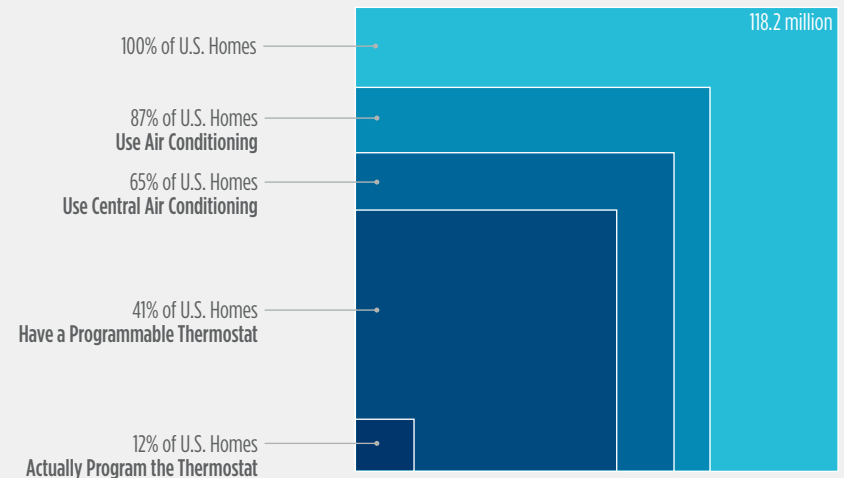
*From aggregated data from FERC Form 861 filers. Excludes demand response programs. Figures represent Incremental Annual Savings, which are those changes in energy use and peak load caused in the current reporting year by new participants in demand-side management (DSM) programs that operated in the previous reporting year and participants in new DSM programs that operated for the first time in the current reporting year. These figures may include estimated annualized savings from programs that started during the year. These figures exclude, to the extent possible, energy and demand savings that are not attributable to DSM program activities. Non-program-related effects include changes in energy and demand attributable to: 1) government-mandated energy-efficiency standards that legislate improvements in building and appliance energy usage; 2) natural operations of the marketplace (e.g., reductions in customer energy usage due to higher prices); and 3) weather and business-cycle fluctuations. Costs include both customer incentives and other costs. Customer incentives are the total financial value provided to a customer for program participation. Costs include all costs for the programs for years prior to the incremental year if these costs were incurred as part of the startup of the program. DOE means U.S. Dept. of Energy; EIA means Energy Information Administration

SOURCES:

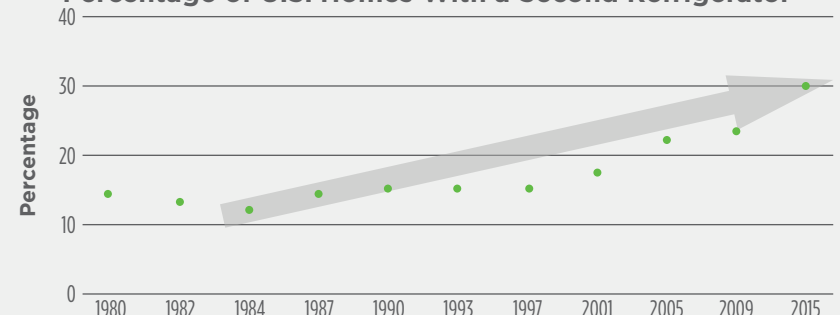
Energy Information Administration; American Council for an Energy-Efficient Economy; Lawrence Berkeley National Laboratory, *Electricity End Uses, Energy Efficiency, and Distributed Energy Resources Baseline: Executive Summary* (Jan. 2017), available at https://emp.lbl.gov/sites/default/files/executive_summary_end_use_baseline.pdf; Utility Dive; Politico; California PUC; *The Energy Journal*; industry news; ScottMadden analysis

As EIA unveils findings and observations from its latest residential energy usage survey, it reveals some potential opportunities—and challenges—for efficiency.

Air Conditioning and Programmable Thermostats in U.S. Homes



Percentage of U.S. Homes With a Second Refrigerator



Source: EIA

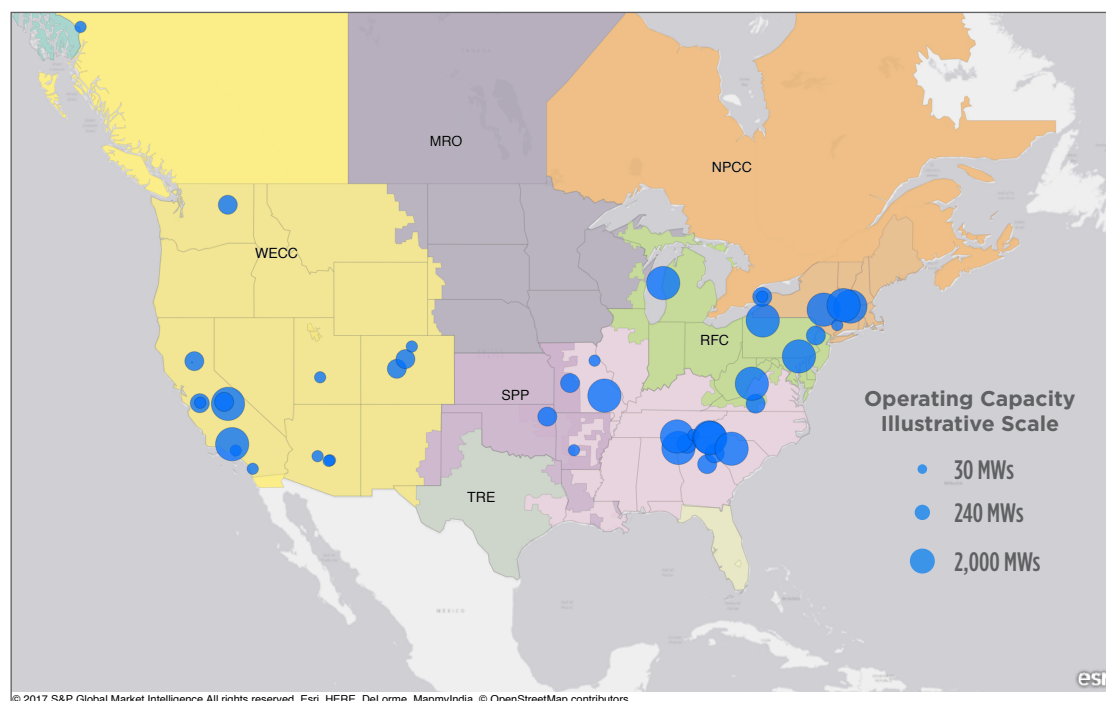
PUMPED STORAGE HYDROPOWER: NEW LOOK FOR OLD TECH?

A large installed base of energy storage may get a bit larger.

Pumped Storage Hydropower (PSH) in Context

- PSH may not get the headlines but still dwarfs all other utility-scale storage in the United States
- As of September 2017, 39 PSH plants in the United States comprised about 22.6 GWs of capacity and the majority (93%) of utility-scale electricity storage in the United States
- PSH plants were originally built to accompany large baseload coal and nuclear units, consuming energy for pumping during high-output, low-load hours, and then providing peaking power when needed
- PSH units can operate at high rated power levels for longer periods of time than most other current storage technologies and can provide both energy and grid services
- Interest in new PSH is growing: As of early 2017, there were 19 PSH projects totaling 14.8 GWs with preliminary permits and 8 PSH projects totaling 6 GWs with pending preliminary permits from FERC, mostly in the western United States

Installed Operating Pumped Storage Hydropower in the United States (as of Sept. 2017)



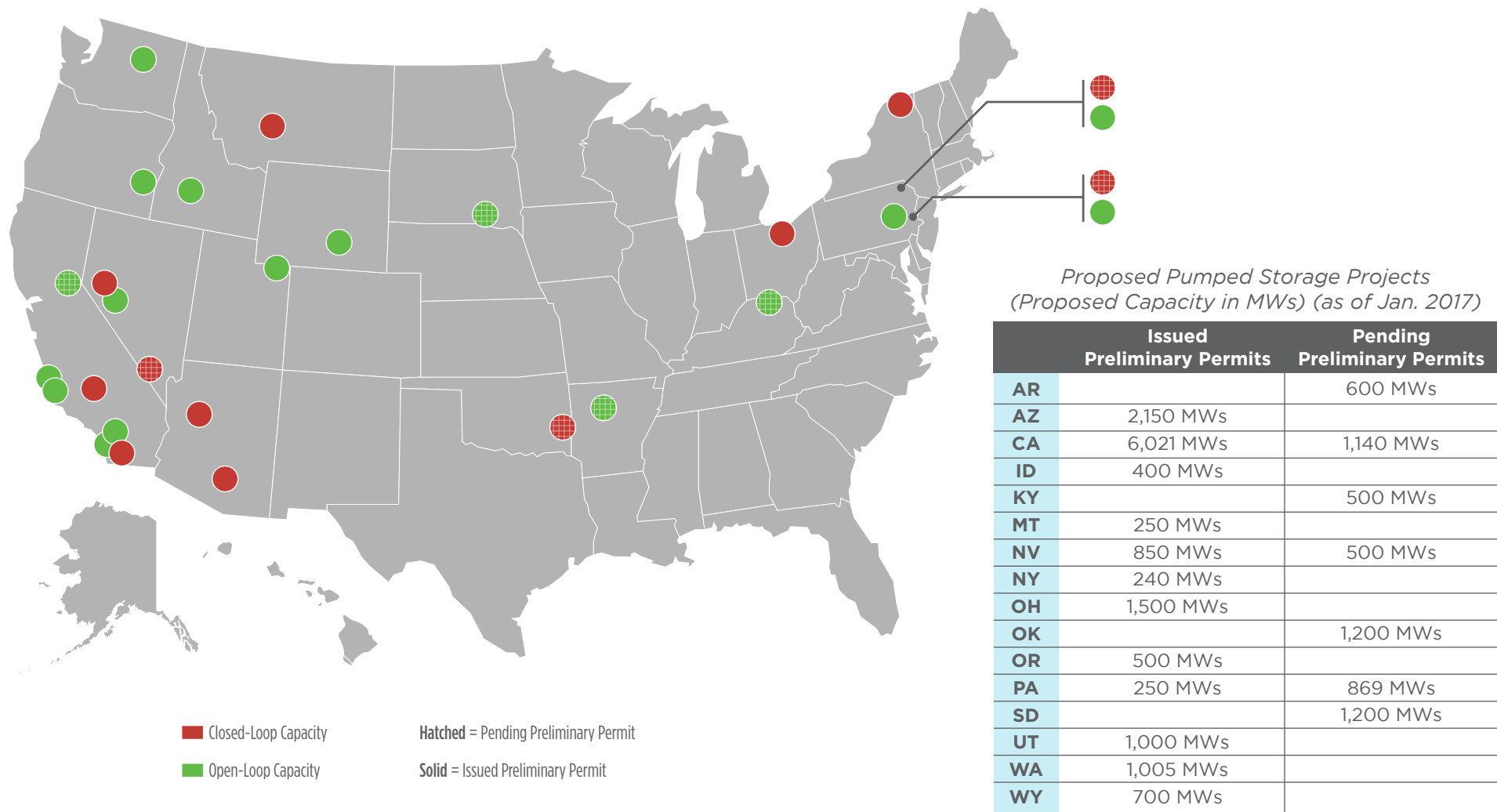
Source: SNL

PUMPED STORAGE HYDROPOWER

But There Are Challenges to PSH Expansion

- PSH can be difficult to site or expand for environmental reasons
- Much of installed PSH capacity is open-loop, meaning that reservoirs are part of a naturally flowing water feature, such as a river
- Open-loop systems can pose environmental and permitting challenges
- Moreover, like many storage technologies, some power market rules do not have a mechanism to compensate for all grid services
- Further, PSH is often optimized to minimize generation costs for the system as a whole and minimize wear and tear on thermal power generation, so this value might not be monetized under current market rules

Proposed U.S. Pumped Storage Hydro Capacity by Type, Location, and Status



Source: FERC

PUMPED STORAGE HYDROPOWER

Interest Is Growing With Improved Technology

- Closed-loop systems—composed of two man-made reservoirs not connected to natural body of water—are of interest as they reduce (although not eliminate) environmental issues, and FERC has experimented with expedited licensing process for those systems
- The increase in variable renewable resources on the grid has led to increased interest in PSH technology, which can bring potential balancing services
- New technologies are available now, such as adjustable speeds and more modular (smaller) designs, which allow for better tailoring of operating characteristics
- Interestingly, potential locations for PSH include abandoned coal mines, where an upper, surface reservoir can be teamed with a lower reservoir in the mine. One example: Dominion Virginia Power announced it is considering a roughly \$2B, 446-MW to 870-MW PSH facility in southwest Virginia, with cost recovery through a rate adjustment mechanism
- DOE estimates that adding generating equipment to non-powered dams could add 12.1 MWs of hydro capacity, while new PSH could add an additional 36 GWs
- But cost remains an issue: Estimates for capital costs of a new variable-speed PSH facility range between \$1,800/kW and \$3,200/kW

Same Idea, New Concept: Alternative Types of PSH

Aquifer	<ul style="list-style-type: none"> • Uses permeable aquifers as reservoirs • Water pumped off-peak and stored above ground • When power is needed, water is allowed to fall back to aquifer
Below-Ground Reservoir	<ul style="list-style-type: none"> • Similar concept as aquifer, except uses old mine shafts, depleted natural gas formations, or tanks as lower reservoirs
Energy Island	<ul style="list-style-type: none"> • Proposed for North Sea application • Ring-like dike around internal lake 100 feet or more below surrounding sea level • Excess wind power pumps water out of lake • When wind power is low or at peak demand periods, sea water permitted to flow back in
In-Ground Storage Pipe	<ul style="list-style-type: none"> • Storage shaft of 6 to 10 meters wide, housing a concrete/iron piston • Water placed above or below piston to store or release energy
Above-Ground Reservoir	<ul style="list-style-type: none"> • Wind turbine's base acts as storage reservoir

Some New Market Rules May Be Needed to Compensate and Incentivize PSH

- Full optimization in day-ahead and real-time markets
- Pricing mechanisms that account for situations where providing ancillary services in one hour results in a lost opportunity to provide energy in another
- Make-whole payments for PSH operation where optimized by market operator for system benefit
- Sub-hourly prices that have opportunities to use PSH fast response to meet real-time pricing swings
- Pay for quality of performance for regulating reserves
- Market and pricing for frequency response, flexibility reserves, and voltage control
- Capital cost compensation that treats PSH as a regulated, rate-based, transmission-like resource under system operator control

SOURCES:

Dept. of Energy Global Energy Storage Database, <http://www.energystorageexchange.org/>, accessed Sept. 18, 2017; Dept. of Energy, *Hydropower Vision: A New Chapter for America's First Renewable Electricity Source* (July 2016); Nat'l Renewable Energy Laboratory, *The Role of Pumped Storage Hydro Resources in Electricity Markets and System Operation* (May 2013); FERC; CNBC; industry news; ScottMadden analysis

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.

Clean Tech & Sustainability	<ul style="list-style-type: none"> • <i>The Solar Trifecta: A Path to Smart Utility-Scale Solar</i> • <i>Understanding Wind Energy Potential in the Southeast</i> • <i>Making Sense of Solar: New Methods to Assess Penetration and Oversupply Risks</i> • <i>Seeking Answers Down Under</i>
Grid Transformation	<ul style="list-style-type: none"> • <i>51st State Perspectives: DERs Are Coming and Illinois Is Ready for Them</i> • <i>20 Years of Net Energy Metering in California</i>
Rates, Regulation, & Planning	<ul style="list-style-type: none"> • <i>Department of Energy Orders Study Examining the Impact of Clean Energy Policies on Baseload Power Resources</i>
Fossil Generation	<ul style="list-style-type: none"> • <i>Major Trends in the Large Power Generation Equipment Market</i> • <i>Operations Risk: It Doesn't Have to Be This Way</i>
Nuclear Power	<ul style="list-style-type: none"> • <i>Functional Area Gap Reviews</i> • <i>Georgia Power Recommends Completing Vogtle</i>
Natural Gas	<ul style="list-style-type: none"> • <i>Aliso Canyon Natural Gas Storage Facility Cleared for the Resumption of Operations</i>
Public Power & Electric Cooperatives	<ul style="list-style-type: none"> • <i>Advancing Sustainability for Public Power</i>
Energy Markets	<ul style="list-style-type: none"> • <i>Energy Imbalance Market</i>
Utility Management and Strategy	<ul style="list-style-type: none"> • <i>Seven Steps for Achieving Sustainable Cost Reductions</i> • <i>Fiber Networks as a Non-Traditional Utility Growth Opportunity</i> • <i>The Smart City Opportunity for Utilities</i>

To view these and other insights, please visit our [**Insights Library**](#).

Get the latest highlights and noteworthy developments on Energy, Clean Tech & Sustainability, Grid Transformation, and Rates, Regulation, & Planning with our topical **Minute** series. See [**scottmadden.com**](https://scottmadden.com) for more.

ENERGY PRACTICE: SCOTTMADDEN KNOWS ENERGY

About ScottMadden

ScottMadden knows energy from the ground up. We have worked in every kind of company, business unit, and function in the sector. We understand that each client's challenge calls for a unique solution. So we listen carefully to you and personalize our work to help you succeed—by solving the right problem in the right way and delivering real results.

We have supported 20 of the top 20 energy utilities—and hundreds of others, large and small. Our industry-leading clients trust us with their most important challenges. They know that chances are, we have seen and solved a similar problem. Our consultants have earned this confidence through decades of experience in the field and are ready to share industry-leading practices and management insights.

We can be counted upon to do what we say we will do, with integrity and tenacity.

Stay Connected

ScottMadden is proud to have joined the Smart Electric Power Alliance (SEPA) in a fact-finding mission on October 1-6, 2017, to explore the renewable energy market and grid modernization efforts of Belgium and Netherlands—as well as the greater European Union. Stay tuned for future articles discussing findings from this mission.

We look forward to presenting learnings and insights from the trip. If you are interested in receiving a copy of our key findings, please contact us at info@scottmadden.com.

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