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2015 STRATEGIC DIRECTIONS: U.S. ELECTRIC INDUSTRY REPORT

Black & Veatch Insights Group

A NOTE ABOUT DESIGN

The annual *Strategic Directions* report series captures Black & Veatch's global engineering and thought leadership expertise across key elements of the critical human infrastructure market. Just as advising our clients requires mastery of design, strategy development and project construction and execution, so too does selecting a report theme that reflects the dynamics of change across industries.

For 2015, the idea of the universe, which encompasses distinct yet overlapping galaxies, stood out as analogous to the continuous evolution of utility services. Interdependence and convergence, as illustrated by ongoing conversations about the energy/water nexus and consumer and utility technologies, are tangible examples.

From a design perspective, what you see reflected in the report's cover and in the graphic elements found throughout its pages, is purposeful art. Our aim is that this creative approach produces reports that are informative and engaging resources for its readers.

This report, in particular, examines how electric utilities balance the frequently intersecting interests of regulation and reliability with increased customer participation in the grid.

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INTRODUCTION

Welcome to Black & Veatch's 2015 *Strategic Directions: U.S. Electric Industry* report. Now in its ninth year, the report has historically captured the industry's mindset through extensive surveying about the topline issues affecting the business. This year's report finds the emerging trends and challenges of years past fully arrived in 2015, presenting both stiff tests and real opportunities for utilities.

The 2015 *Strategic Directions: U.S. Electric Industry* report looks at how utilities are readying their assets and strategies to deal with technology and a shifting regulatory construct. How are they altering their systems to cope with these changes? How are they deploying assets and engaging an increasingly evolving customer base?

To find cover in an uncertain political and regulatory climate, some utilities are understandably closing ranks around traditional business models and investments. However, the industry is transforming; utilities understand the challenging marketplace, and this year's survey shows that they are ready to adapt and respond. Our report joins those survey responses with expert analysis to help providers manage this exciting new landscape.

We welcome your questions and comments regarding this report and/or Black & Veatch services. You can reach us at **MediaInfo@bv.com.**

Sincerely,
DEAN OSKVIG | PRESIDENT & CEO
Black & Veatch's energy business

JOHN CHEVRETTE | PRESIDENT
Black & Veatch management consulting

The Black & Veatch Analysis Team

EXECUTIVE SUMMARY

Dean Oskvig is President and CEO of Black & Veatch's energy business, a position he has held since 2006. Oskvig joined Black & Veatch in 1975 and has served on a variety of global energy and telecommunications projects and roles within the company. He was elected to his first term on the company's Board of Directors in 2006 and is Chairman of the Electric Power Research Institute's Advisory Council. Oskvig also serves as Vice Chair for North America of the World Energy Council and is a member of the United States Energy Association Board of Directors.

Joseph Mahendran *(Perspective: South African IPPs)* is Operations Manager for Black & Veatch South Africa. He develops and maintains client relationships, working in project management in more than two decades of international work across multiple industries. With experience in both traditional engineering and EPC and turnkey operations, he speciazlies in project controls, strategic and risk management, competitor analysis, change management and advanced statistical analysis.

Webb Meko *(Perspective: South African IPPs)* is a Regional Business Development Manager for Black & Veatch South Africa. He has provided technical expertise, management, and advisory services for more than 20 years to South African and international clients in the energy sector within Africa. His areas of expertise include power system planning and electrical power system design, electrification, project management, program management, feasibility studies, private power projects development, and power plant maintenance.

Ryan Pletka *(Renewables Integration)* is an Associate Vice President in Black & Veatch's energy business and serves as Director of the Western Region for the company's renewable energy group. Pletka has more than 15 years of experience in the industry and has participated in assessments of more than 200 renewable energy projects and technologies since joining Black & Veatch in 1998.

Bill Roush *(Renewables Integration)* is a Renewable Energy Consultant in Black & Veatch's energy business. He has more than 15 years of experience within the industry. Roush currently serves as President of the Heartland Solar Energy Industries Association and is a former Advisory Committee Member of the Solar Electric Power Association for the Solar Power International conference.

Neil Copeland *(Natural Gas)* has more than 16 years of experience in preparing energy asset revenue forecasts, providing detailed assessments of market fundamentals, managing data gathering and price forecasting databases, and performing asset valuations for various power plants. He has supported project development and financing for construction of new generation and acquisition, divestiture, or refinancing of existing assets. He has completed numerous consulting engagements for diverse stakeholders, including regulatory agencies, project developers, load-serving entities, generating companies, banks, private equity and investment banks.

Denny Yeung *(Natural Gas)* is a principal in the oil & gas strategy practice within Black & Veatch's management consulting business. Yeung has expertise in natural gas fundamental market analysis, asset valuation and financial analysis. He has led numerous engagements in market assessments and due diligence review of midstream assets, as well as detailed modeling of fundamentals factors in the North American natural gas market, including the impact on price basis of proposed natural gas infrastructure.

Ted Pintcke *(Independent Power Producer Shifts)* is Vice President and Senior Project Development Director in Black & Veatch's energy business. Pintcke has more than 37 years of experience at Black & Veatch, serving in a variety of roles throughout his career including Chief Engineer, Project Director and Executive Sponsor. He has also led the development of a number of initiatives and business lines for Black & Veatch covering a variety of fuels and technologies, including conventional gas turbine projects, biofuels, hybrid power and desalination plants and compressed air energy storage.

Ed Walsh *(Independent Power Producer Shifts)* is Executive Vice President and Executive Director for Black & Veatch's energy services projects. Walsh's responsibilities include overseeing and implementing strategies, processes and tools to further enhance the company's service offerings and continued growth. Walsh has more than 40 years of global experience and has been with Black & Veatch since 2003, serving as a Senior Vice President and Senior Project Director. Prior to joining Black & Veatch, he served in a variety of executive and senior management positions in businesses and on energy infrastructure projects including combined cycle combustion turbine, nuclear, hydropower, waste-to-energy, and transmission and distribution.

Andy Byers *(Perspective: Environmental Regulation)* is an Associate Vice President and Director of Environmental Services in the Black & Veatch energy business. He currently serves as the energy business Environmental Regulatory and Legislative Policy Advisor, responsible for tracking developments and advising on risks and opportunities arising from key federal legislative, regulatory and judicial initiatives.

James H. (Jim) Schnieders *(Perspective: Renewables in Indonesia)* is a Vice President and is the Country Manager for Black & Veatch in Indonesia. Schnieders is located in Jakarta, Indonesia, and has more than 25 years of experience at Black & Veatch. He has extensive experience working on large international power projects, with diverse international contractors and equipment suppliers, including both conventional fossil-fueled and combined cycle power plants.

Russell Feingold *(Rates and Regulatory)* is a Vice President within Black & Veatch management consulting where he leads the financial and regulatory services practice. He has more than 37 years of experience serving electric and gas utilities on a broad range of utility ratemaking and regulatory related projects. He has prepared and presented expert testimony submitted to the Federal Energy Regulatory Commission (FERC), the National Energy Board (NEB) of Canada and several state and provincial regulatory commissions dealing with the costing, pricing and marketing of electric and gas utility services.

Ed Overcast *(Rates and Regulatory)* is a Director in the finance and markets practice in Black & Veatch management consulting. Overcast has more than 40 years of experience at investor-owned utilities (IOUs), government-owned electric and gas utilities and as a consultant practicing in the rates, regulatory and strategic planning areas. During his career, he has held various management- and officer-level positions.

Jeremy Klingel *(Customer Engagement)* specializes in the design and implementation of customer-facing and critical infrastructure utility programs that capitalize on enabling technology. Skilled in crafting and integrating energy management, energy efficiency and demand response solutions, Klingel previously founded a practice serving IOUs with specific focus on behind-the-meter product development, time-of-use rate design and progressive customer engagement models.

Bob Brnilovich *(Customer Engagement)* is the Technology Business Line Lead for Black & Veatch's management consulting business, focusing on helping energy and water utilities, and telecommunication companies manage complex system integration efforts. The majority of his 27 years of experience has been with direct involvement on the implementation of new CIS and ERP solutions—from CRM through billing and collections. For two decades he has been the engagement partner on many large electric and gas utility consulting assignments, and he has extensive experience leading all phases of complex technology projects including design, selection, acquisition, implementation, and support.

Andrew Trump *(Perspective: Utility 2.0)* has more than 25 years of experience working with utility and energy organizations in areas of regulatory development and rulemaking, project financial evaluation and business case development. He has a broad understanding of North American energy markets, experience leading business development licensing activities for a major North American merchant power plant developer and expertise in the business and financial evaluation of smart grid and advanced metering infrastructure (AMI) investments.

Ernie Wright *(Project Delivery-EPC)* is Senior Vice President and Managing Director for the Americas in Black & Veatch's energy business. For more than 30 years, he has overseen the operation of multiple large profit centers focusing substantially on engineering, procurement, and construction (EPC) and construction related services. Among other areas, he specializes in project management, cost control, procurement, equipment utilization, estimating, on-site personnel coordination, and all other aspects of project execution. Wright has also served in Board of Director and Executive Committee level positions.

Jim Hengel (Project Delivery-EPC) is Senior Vice President and Senior Project Director for Black & Veatch's energy business. He serves as a project executive and project manager for electric utility projects, independent power producers, and cogeneration developers. He has responsibilities for development of new business and client relationship management within the solar photovoltaic and air quality control environments.

Daniel Rueckert *(Physical Security and Cybersecurity)* has 35 years of experience in maintenance and asset management, information technology, security, project management and business consulting. He is responsible for the Security & Compliance practice in Black & Veatch management consulting, and he has been responsible for large program development and implementation for physical security and cybersecurity programs.

Chip Handley *(Physical Security and Cybersecurity)* is a project manager in Black & Veatch's power generation services business. Handley has a combined 25 years of experience at a major utility, two industrial control system manufacturers and Black & Veatch. He is a member of Black & Veatch's Cybersecurity Community of Practice, where his background in industrial control system engineering helps him support power generation North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) compliance efforts.

Mazen A. Alami *(Saudi Arabia Power)* is Black & Veatch's Managing Director for the Middle East. He oversees and is responsible for all of the company's operations in the Gulf Cooperation Council region. He has more than 35 years of experience in the power and oil and gas sectors. His expertise extends to a broad spectrum of technology, solutions management, design and manufacturing. His project experience includes work at power plants and on transmission lines, as well as in safety and loss prevention.

CLOSING COMMENTARY

John Chevrette is President of Black & Veatch management consulting and works closely with clients to address key challenges affecting today's electric, water and gas utilities. Chevrette has more than 20 years of industry consulting experience and has worked with domestic and international clients in the electric utility, energy technology, gas pipeline, telecommunications and water industries.

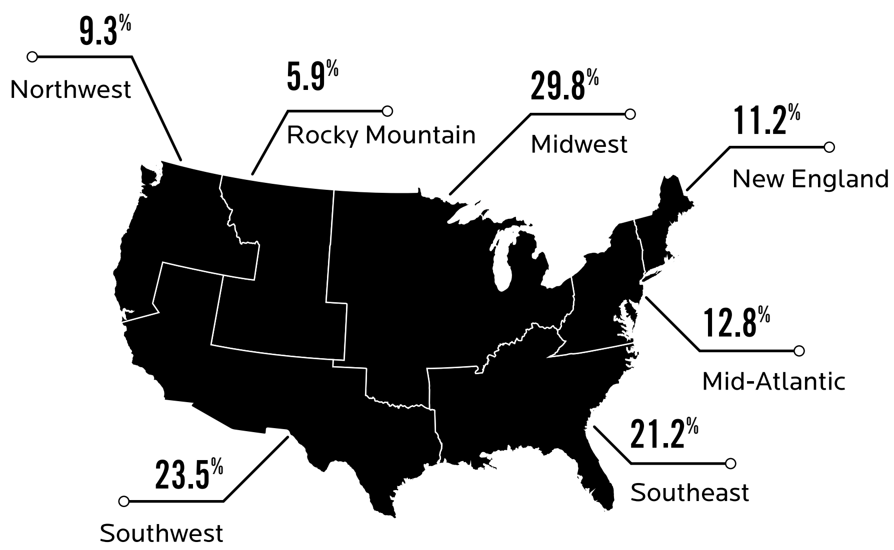
2015 Report Background

The ninth annual Black & Veatch *Strategic Directions: U.S. Electric Industry* report is a compilation of data and analysis from an industrywide survey. This year's survey was conducted from 14 May 2015 through 5 June 2015. The online questionnaire was completed by 435 participants who, through a series of screening questions, identified themselves as electric utility or electric industry stakeholders.

The overall results of the survey have a precision of +/-4.7 percent at the 95 percent confidence level. Statistical significance testing was conducted on the final survey results to identify key differences by various groups of respondents. The following figures provide additional detail on the participants in this year's survey. Unless otherwise noted, survey data presented within this report reflect the opinions of respondents who represent a utility organization.

For more information on Black & Veatch, please **visit www.bv.com.**

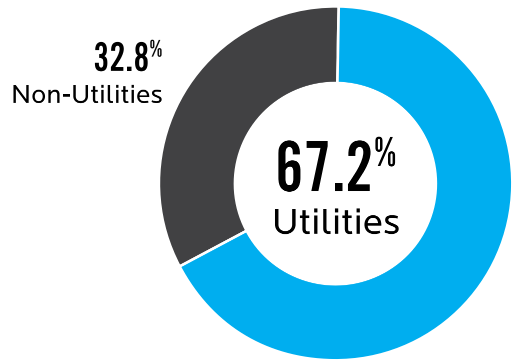
Primary Business Region



19.4% U.S. - Multi-Regional	16.4% Canada	13.2% Other Countries
6.6% Other U.S. Locations	6.6% Mexico	

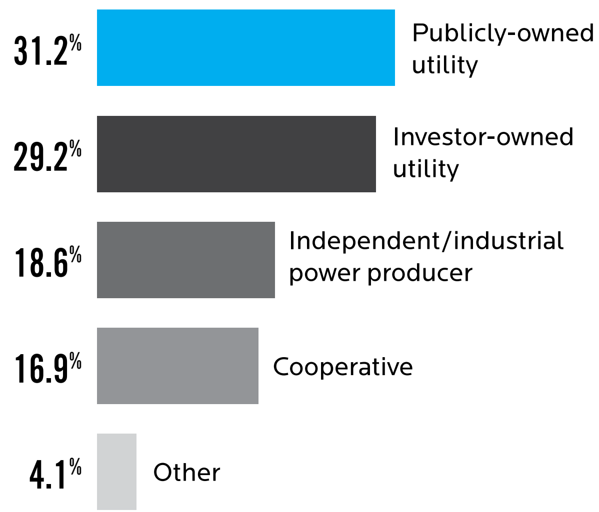
Source: Black & Veatch

Industry Type



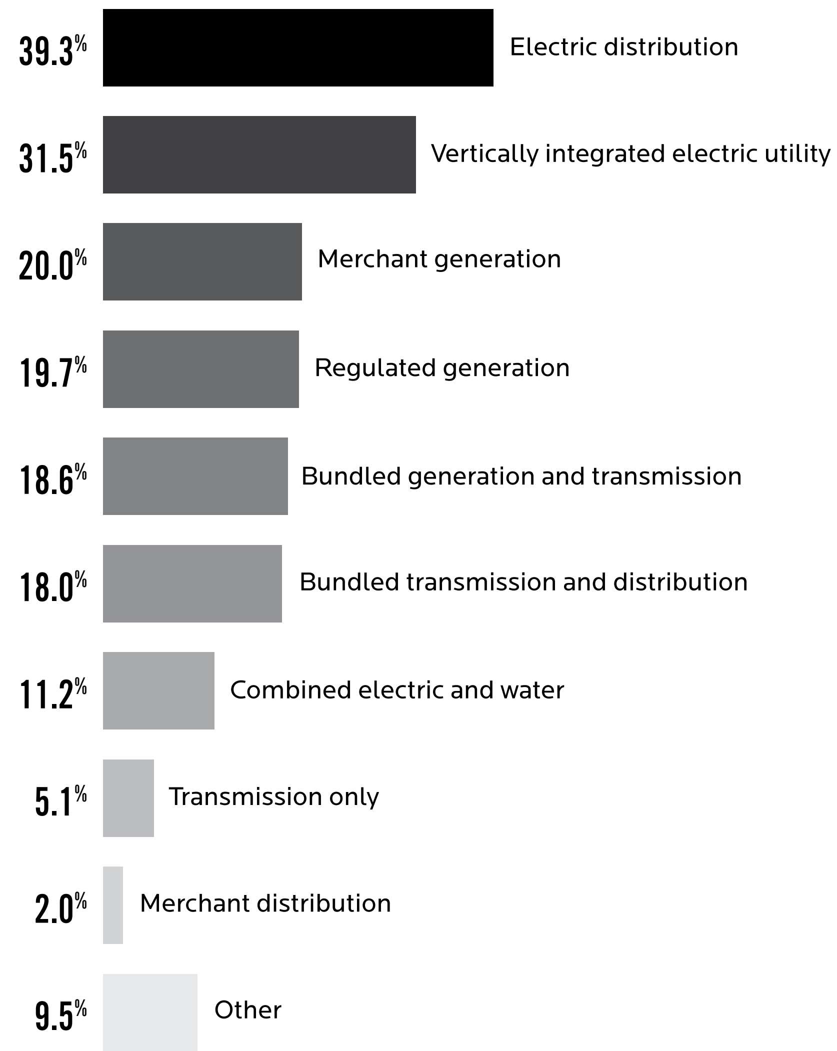
Source: Black & Veatch

Survey Participants by Type of Utility



Source: Black & Veatch

Utility Services Provided



Source: Black & Veatch

EXECUTIVE SUMMARY

Disruptive Technologies Provide Opportunity for Utilities to Set the Agenda

By Dean Oskvig

Disruptive forces predicted by electric industry pundits have arrived and are redrawing the power supply and consumption chains in the United States and abroad. New technologies affecting both sides of the meter clash with a regulatory construct struggling to keep pace with rapid innovation. Utilities must maintain generation capacity and transmission networks to safely deliver reliable electricity, even as residential consumers avail themselves of cost protections and new methods of generating, conserving and, in some cases, selling power back to the grid.

For the past two years, the Black & Veatch *Strategic Directions: U.S. Electric Industry* report has eyed the disruptive capability of distributed generation (DG), renewables, consumer technology and emerging investment practices on the industry's traditional business model. In 2015, our report sees these forces actively challenging utilities and altering their strategies for maintaining reliability, resilience and shareholder return.

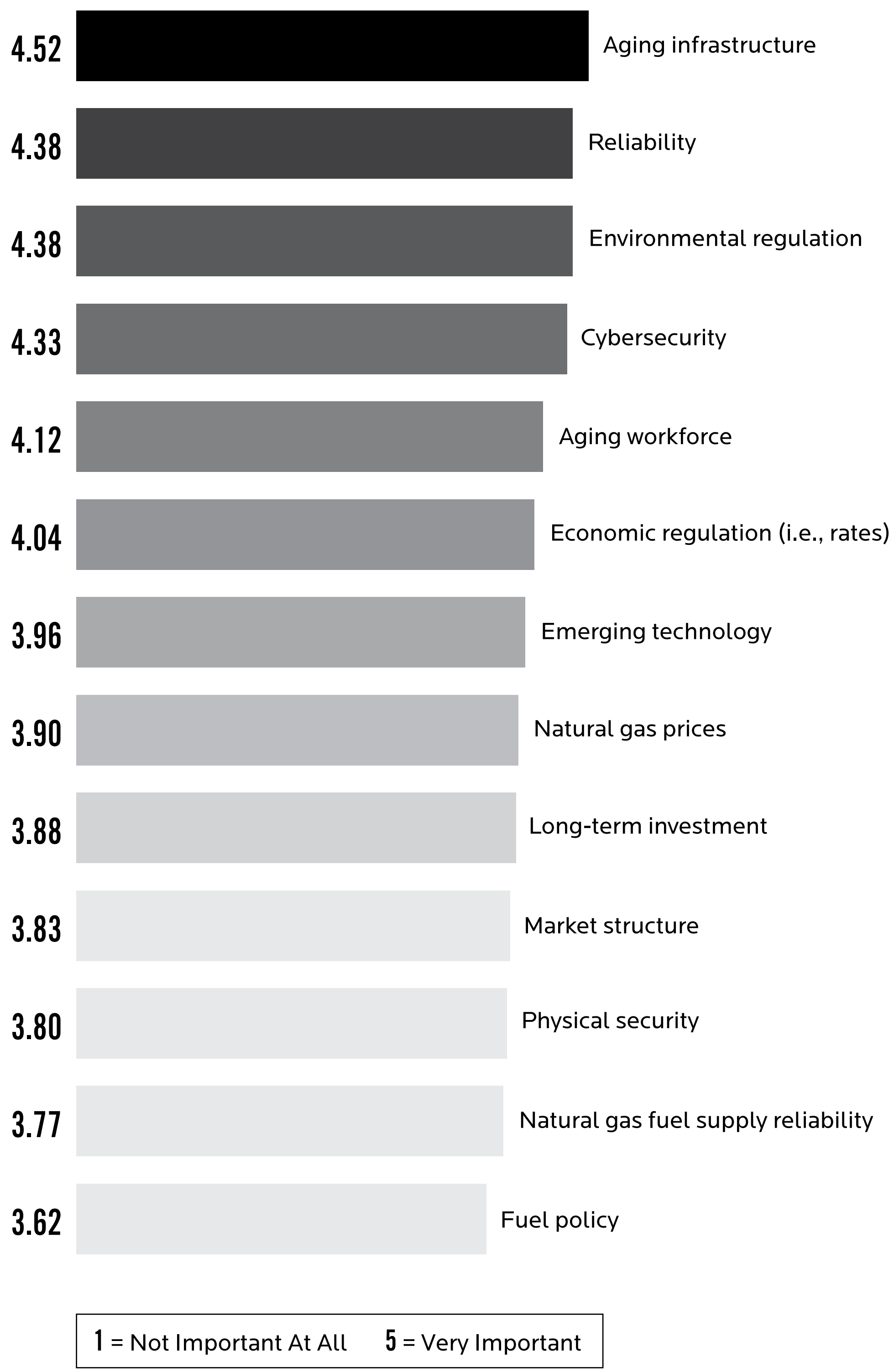
These challenges are increasing even as familiar issues pressure the generation sector. This year's report finds aging infrastructure, a perennial issue, gaining renewed prominence as utilities' most important challenge (Figure 1).

The numbers underscore the value of, and need for, aggressive asset management programs, in which utilities actively assess the age and condition of their equipment, evaluate the risks of repair or replacement, and plan for replacements and upgrades long before system shocks occur.

Assets, comprising a utility's financial resources as well as its physical facilities, must be monitored, assessed and managed to ensure the level of service customers expect. Utilities understand the peril of waiting on equipment to fail. A recent forecast by the Edison Electric Institute predicts that investor-owned utilities will spend nearly $60 billion through 2017 on grid modernization and reliability, new transmission lines and substations and other improvements.

Figure 1

Rate the importance of each of the following issues to the electric industry using a 5-point scale, where a rating of 5 means "Very Important" and a rating of 1 means "Not Important At All."



Source: Black & Veatch

Other key issues addressed in this report include:

Regulation and natural gas: Confidence in the availability of low-cost natural gas remains high, with the vast majority of respondents indicating it will take market share away from higher cost nuclear and retiring coal assets.

Cybersecurity: Headline-grabbing security breaches are on the minds of electric utilities. More than half of North American-based utilities felt they were prepared to address the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) low-impact cybersecurity system requirements that are set to become effective in April 2016. Interestingly, more than a quarter of electric respondents did not know how their utility was planning to manage the need for cybersecurity solutions.

Rates: Governments and public utility commissions must begin to balance their regulatory treatments of utilities and consumers to reflect the increasing integration of distributed energy resources (DER). Asked to rank the top rate and regulatory practices required by utilities over the next five years, respondents listed balanced regulatory treatment between the utility and consumer, regulatory recognition and recovery of stranded costs associated with increased DER, formula rates and the unbundling of utility services and rates as the top practices (Figure 2).

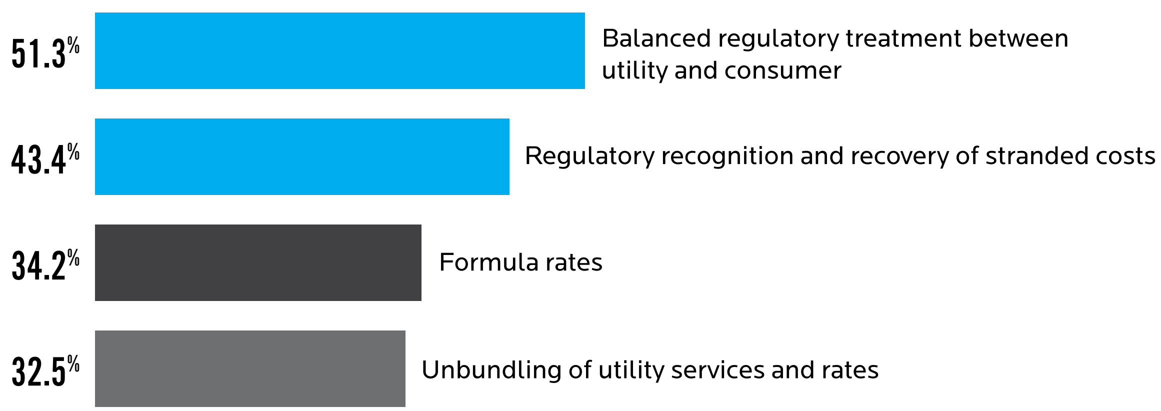
Customer engagement: Electric utilities see renewables combined with battery storage as the demand response trends that will most affect their business. Nearly two-thirds of respondents reported they plan to increase their use of data over the next two to three years to measure consumption behavior and other customer patterns.

Global efficiency: Our report also notes significant market shifts abroad. In the Gulf Cooperation Council (GCC), Saudi Arabia's expanding population and rising wealth is raising the demand for power while increasing calls for efficiency is propelling development of renewable energy and combined cycle power stations. In Indonesia, mining operators coping with slumping commodity prices are also turning to renewables in an efficiency bid. Meanwhile, South Africa's power market wrestles with rising demand and an aging fleet as new megaprojects and renewable resources enter service.

Distributed generation: 80 percent of electric utilities believe that DG, particularly solar photovoltaic (PV), represents a serious challenge to their business. More than a third considered the issue major or moderate. Survey results suggested that utilities who had been in the electric industry for more than 30 years felt less threatened by DG technology; this group gave significantly higher ratings that they felt DG represented only a moderate threat.

Figure 2

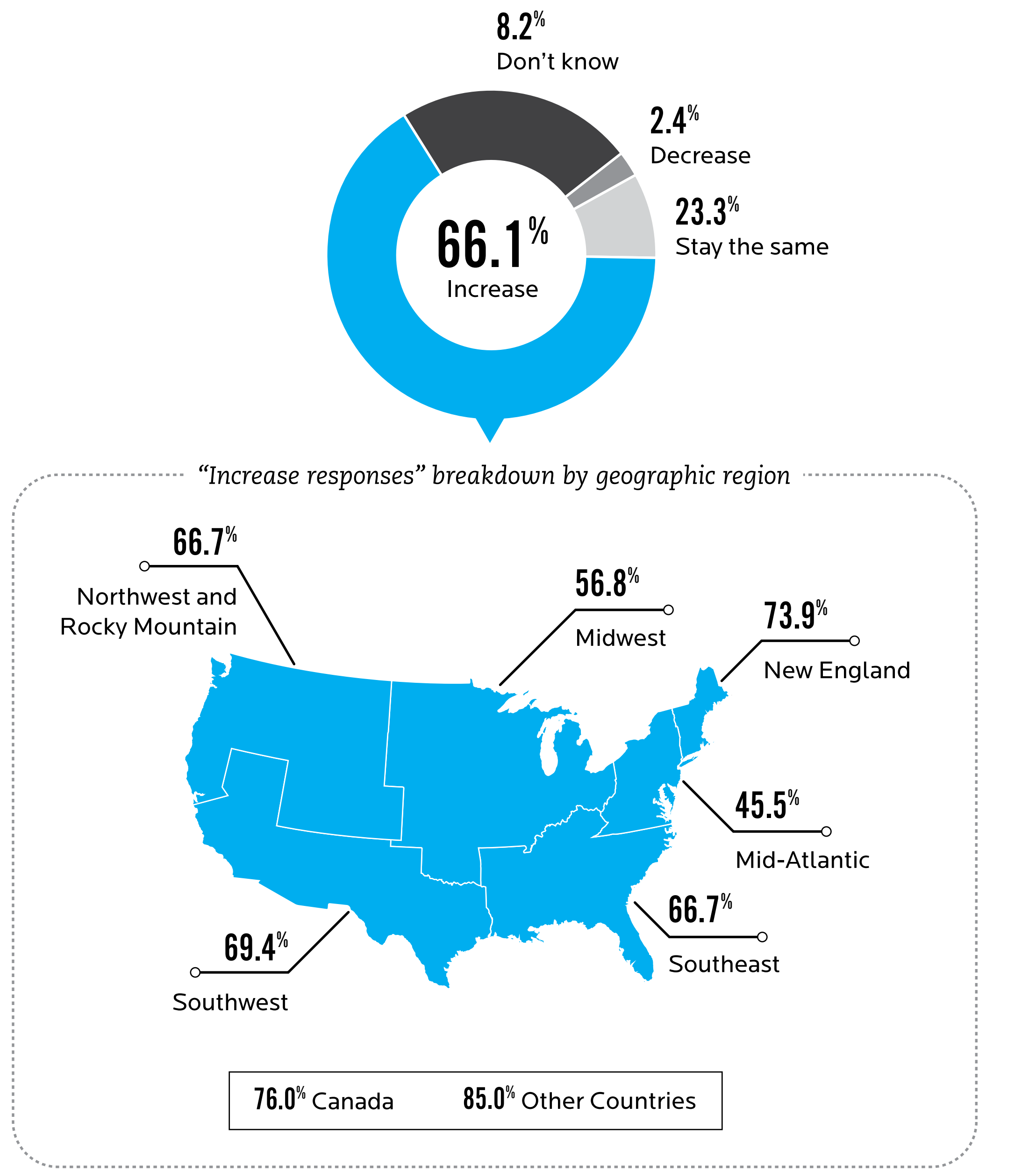
What are the top three rate and regulatory practices required for your company over the next five years?



Source: Black & Veatch

Figure 3

How do you expect your level of renewable energy generation investments to change over the next five years?



Source: Black & Veatch

We believe that while many utilities see DG as a near-term challenge, the data shows encouraging signs that many providers are embracing these technologies through investments. Nearly three-fourths of electric utilities reported that they anticipate or are considering "behind-the-meter" and "distributed grid infrastructure" as potential new investment segments for their company. Two-thirds of electric utilities reported they expect their level of renewable energy generation investments to increase over the next five years (Figure 3).

THE QUESTION OF REGULATION

One of the most dramatic data points in the survey revolves around the growth of DG, with more than half of respondents believing that 6 to 10 percent of all U.S. power generation will come from DG by 2020. At the top end, such production would effectively double the nation's current DG output and raise the profile of customer-generated energy (Figure 4). Nearly one-third of electric utilities said they were currently reviewing policies on net metering, which allows consumers to sell power back to the grid to offset traditional utility energy costs. Many believe the practice creates distortions in the utility finance model as well as social equity concerns.

These transformative shifts put a spotlight on how the pressure of regulation, or lack of it, is bearing down on utilities. The EPA is finalizing the CPP, which seeks to regulate carbon dioxide (CO_2) emissions from fossil fuel-fired power generation facilities but is expected to face legal and political challenges. New cybersecurity rules are forcing utilities to shore up their systems against breaches.

The absence of regulation creates its own uncertainty. Rates are a prime example: Once jointly managed by utilities and regulators, rates were traditionally based on anticipated demand and accounted for regulatory limits. But the landscape is changing rapidly. Distributed resources, net metering, efficiency and changing consumer behavior are changing the equation, leaving many of today's utilities struggling to determine rates by traditional models. This challenge is compounded when the cost of generating and providing reliable services to meet regulatory mandates are not covered by returns on consumption alone.

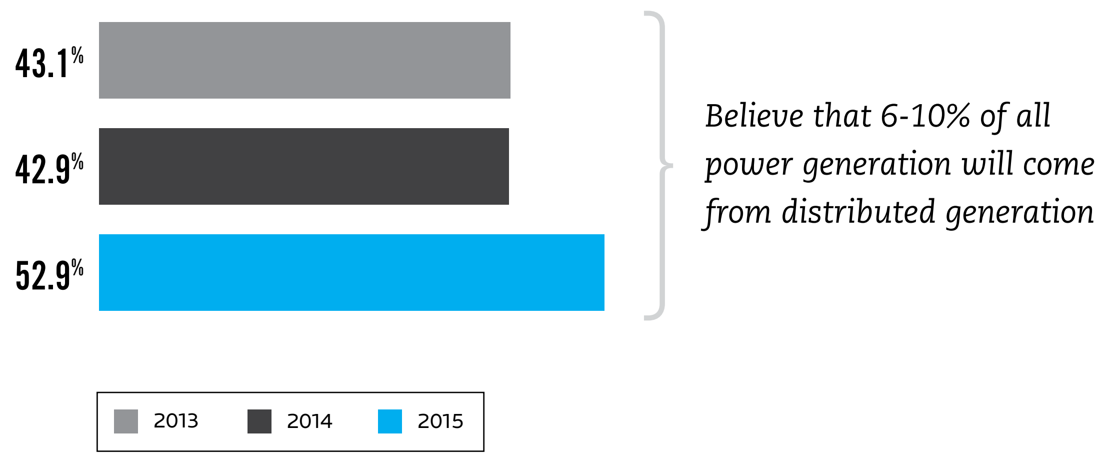
The proliferation of DG, especially in the form of continuously operating microgrids, is seen by many utility executives as inevitable. What is also clear, however, is that each trend highlighted in this report offers utilities a chance to set the agenda for power delivery. Utilities will innovate and deploy new technology on both sides of the meter to not only stay relevant but also to help cement their brand as the vehicle for reliable power systems. Proven technology is available, and it is becoming cheaper.

In an anxious political climate, Black & Veatch believes any strategy must involve the hard work of determining how these changes will work technically and financially in the context of balanced government regulation. Utility policies are built around the notion of a fixed-grid operator selling power to its customers. But in a time when customers are able to generate their own power, as well as put it back on the grid, host utilities must maintain their complex infrastructure to meet government mandates for reliability. So how do utilities achieve investment return? What is a fair recovery of costs? (Some utilities, such as Hawaiian Electric, have instituted or are considering fixed charges that can eventually recover those costs.)

Utility leaders, long the operators of the central plants that keep the power flowing, must continue engaging stakeholders and regulators in ways that exploit technological efficiency and environmental gains while maintaining the reliable grid that consumers expect. We see utilities educating regulators and policymakers on the technical realities of these advances and the ways providers can partner with consumers to keep costs low while maintaining a dependable grid.

Figure 4

What percentage (on a MW basis) of all U.S. power generation do you believe will come from distributed generation (power assets with a capacity less than 20MW) by 2020?



Source: Black & Veatch

READINESS

Perceived IPP Impact Relies on Geography, but New Breed of Utility Providers are Flexing Their Muscle

By Ed Walsh
and Ted Pintcke

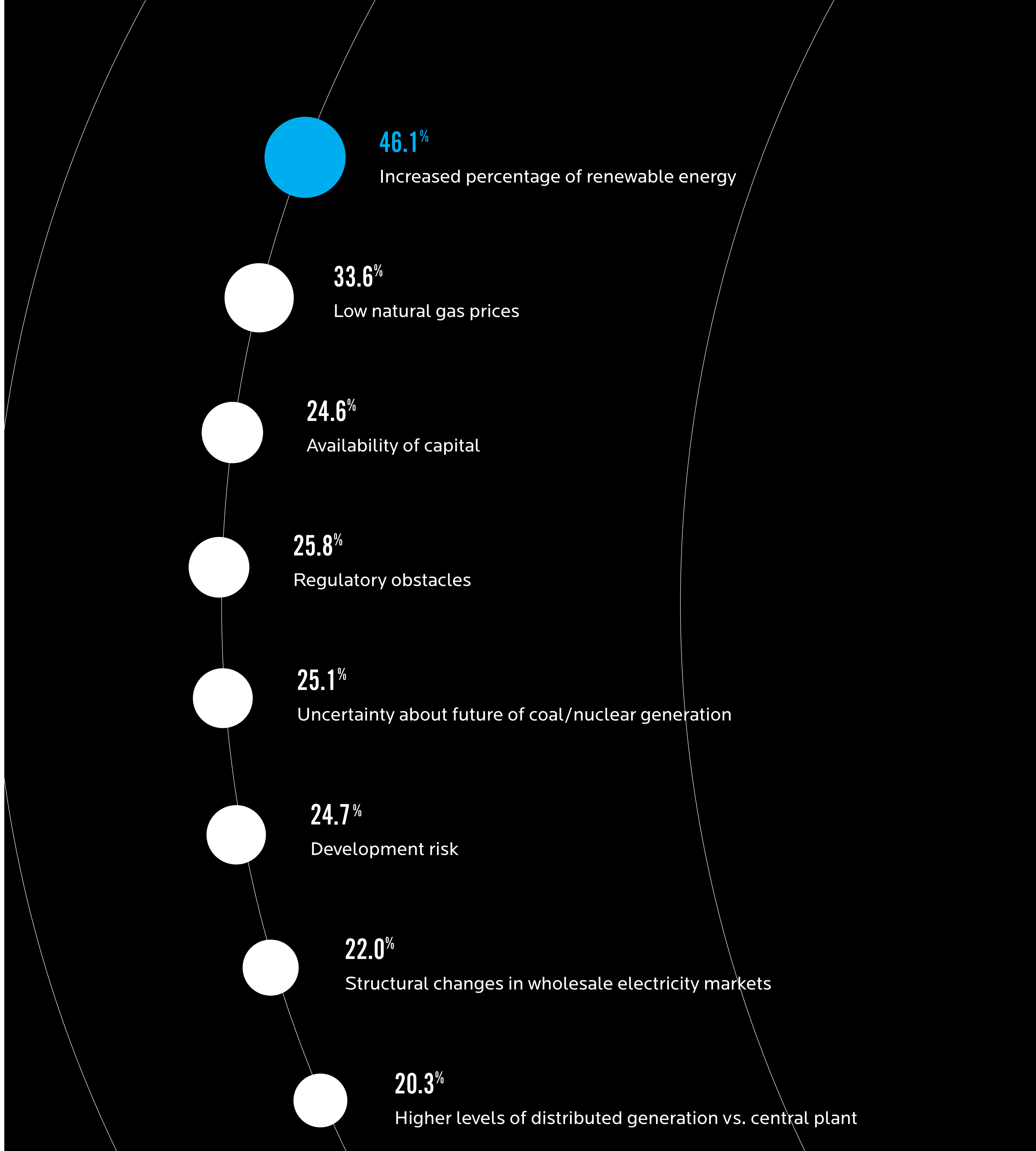
In markets that have been deregulated, the influence and activity level of independent power producers (IPPs) on new generation capacity has grown. There are also numerous indicators that they will remain significant power suppliers in regions that are also experiencing heightened interest in renewables and DG. This is not to suggest that utility providers are soft on new projects. Having survived the market shift from coal, air quality control (AQC) retrofits and unit retirement planning, utilities are actively engaged in their own buildouts of renewables and their role in microgrids.

While their impact on the nation's power supply has turned upward in recent years, and particularly in the renewables sector, the IPP sector itself has been around long enough to experience its own turmoil. Cycles of expansion and contraction have hit the segment in recent years as some IPPs, which unabashedly sought short-play profits, quickly succumbed to market downturns. IPPs with longer outlooks have blended traditional coal and natural gas plays with sizeable, balanced investments in DG and other low-carbon strategies.

Renewables are a major force driving new generation among both IPPs and distributed resources. Increased renewable energy is seen as the top driver of IPP-sponsored generation versus utility self-generation (Figure 5).

In markets that have been deregulated, the influence and activity level of independent power producers (IPPs) on new generation capacity has grown.

Figure 5
What are the top three most significant drivers of IPP-sponsored generation versus utility self-generation?



Source: Black & Veatch

IPPs are seen as having lesser influence on new generation capacity in the Southeast and Midwestern United States, where the regulatory footprint favors traditional utilities and demand for renewables has not reached levels seen elsewhere.

GEOGRAPHY HELPS TELL THE STORY OF IPP INFLUENCE

IPPs are seen as having lesser influence on new generation capacity in the Southeast and Midwestern United States, where the regulatory footprint favors traditional utilities and demand for renewables has not reached levels seen elsewhere.

For instance, half of Southeastern respondents believe IPPs will generate 20 percent or less of all new capacity through 2018. Conversely, nearly one-third of respondents from the Mid-Atlantic region, where demand for renewables and DG technology has been higher as traditional coal and other assets are retired, say 60 percent or more of capacity will be generated by IPPs during the same period.

Overall, there is pessimism among traditional utilities that IPPs will develop large capacity in the near term. Sizeable numbers of respondents from traditional providers believe IPPs will be capable of generating 20 percent or less of new capacity over the next three years (Figure 6).

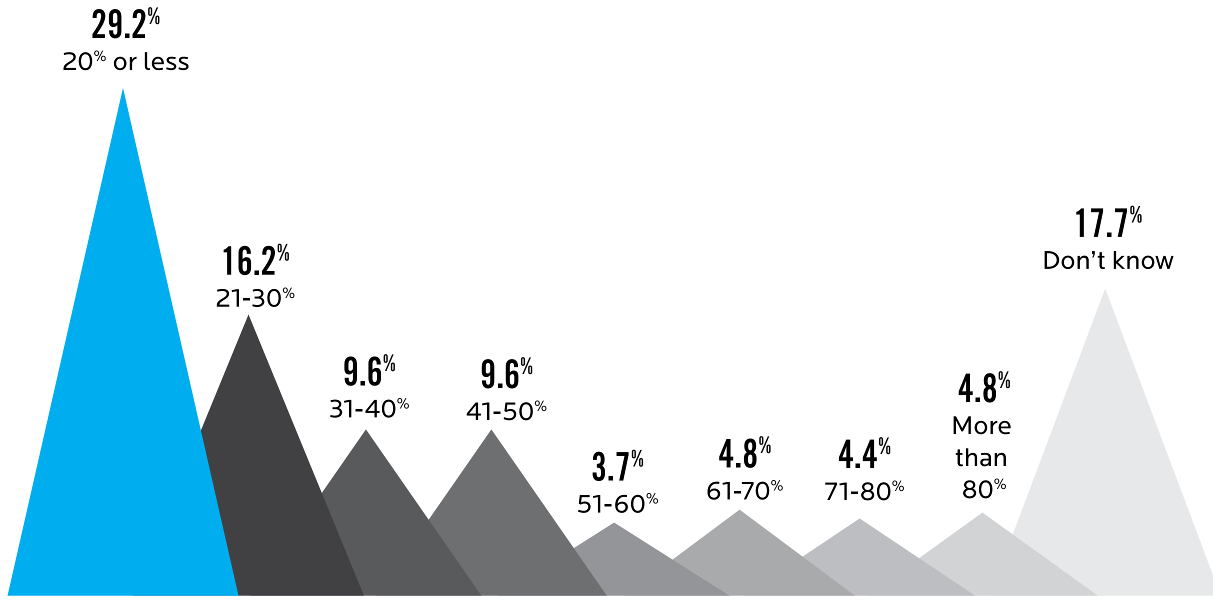
RETURNING TO ROOTS

Regardless of such predictions, rising IPP participation in the grid , along with the increase of DG provided by third parties, is altering the strategies of traditional utilities. In many ways, utilities are "hunkering down" by focusing even harder on traditional, regulated assets that offer a guaranteed return as they wait for public utility commissions (PUCs) across the nation to update their rules to account for advances in DG and other technologies. (Regulatory anxiety has hit IPPs, too: Some IPPs that operate coal-fueled plants say Environmental Protection Agency (EPA) proposed carbon dioxide (CO_2) emissions reductions will be expensive to implement.)

Utilities say they are responding to the heightened presence of IPP generation by focusing anew on their transmission infrastructure and other investments in their own assets (Figure 7).

Figure 6

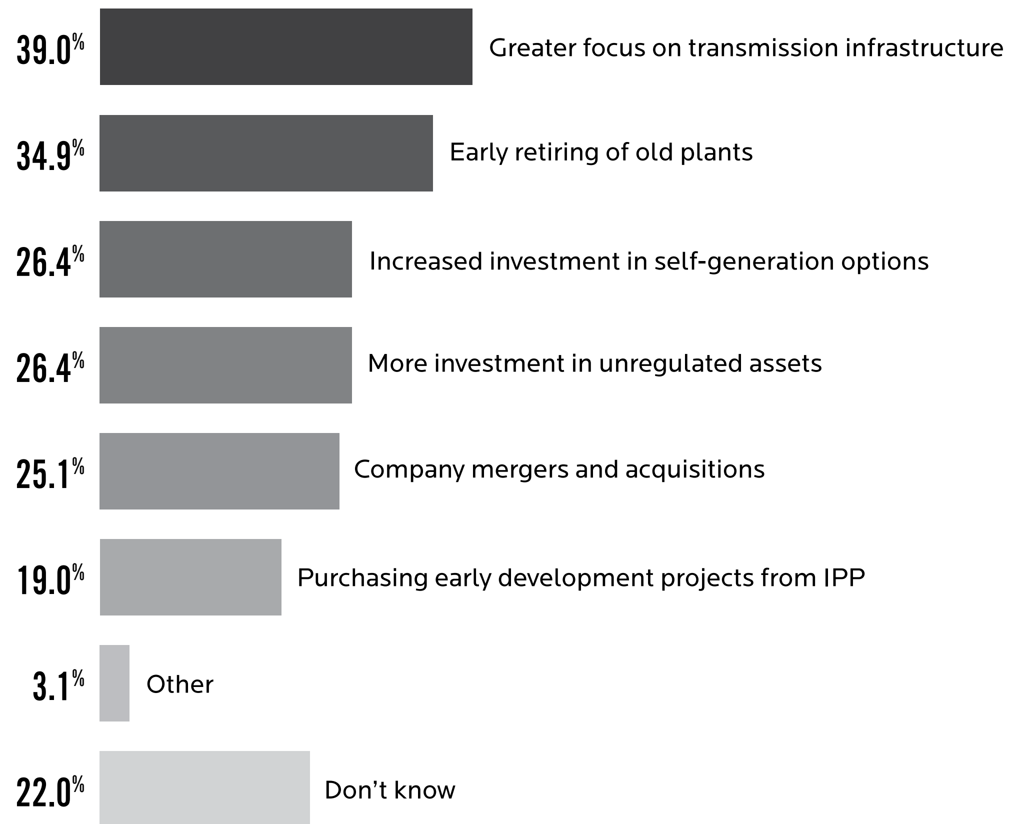
What percentage of new generation capacity do you think will be developed by IPPs, as opposed to utility self-generation, over the next three years?



Source: Black & Veatch

Figure 7

Major ways utilities are changing their business models in response to greater participation by IPPs in power generation:



Source: Black & Veatch

**Respondents were instructed to select three choices.*

PERSPECTIVE

South Africa Power Landscape in Transition

By Joseph Mahendran and Webb Meko

The global energy landscape is undergoing a period of fundamental transformation driven by factors such as evolving fuel market dynamics, climate change considerations, development and sustainability goals and the rise of renewables. For governments around the world, including South Africa, this has placed the onus on optimally managing available energy resources to promote growth and prosperity.

For decades, the primary energy source in South Africa has been fossil-based coal, augmented by crude oil, natural gas and petroleum products. Nuclear energy has played a minor, but important, role since the 1,800 megawatt (MW) Koeberg facility was commissioned in 1984, while renewables and waste resources more recently began contributing to the grid. South Africa's reliance on coal for power generation has been largely influenced by the availability of rich coal reserves, water scarcity concerns, limited traditional natural gas reserves and a reliance on imported oil.

Coal is not only the major indigenous energy resource, it is also relied on as the base for a significant proportion of liquid fuels. Hence, more than 90 percent of South Africa's electricity is generated from the burning of coal. Coupled with a wealth of domestic technical expertise, the rich coal reserves contributed to South Africa having the largest installed generation capacity in Africa and its development as a net exporter of electricity in Southern Africa.

However, currently South Africa's energy sector is facing a challenge of power generation capacity constraint that has resulted in load shedding across its commercial, industrial and residential customer base. Aging generation assets have impacted reliability, while the success of a nationwide electrification program increased overall demand for power. In addition to the need for new baseload capacity projects, the resulting service interruptions reflect a series of challenges facing the industry, including the following:

- The slow pace of market liberalization encouraging private investment in power.
- The need to optimize other energy resources.

The challenges facing South Africa's power sector have brought about calls for a radical transformation by the Department of Energy. In the next three to five years, things look positive as a path toward stabilization of power supply is bolstered by advancing construction of two of the Southern Hemisphere's largest power projects (Medupi and Kusile), a renewed focus on generation asset maintenance and operational efficiency, traction in a world-class renewable energy program and steps under way to allow new independent power producers (IPPs) to contribute up to 17 gigawatts (GW) of power by 2022.

At 4800 MW, the Kusile Power Station is one of the Southern Hemisphere's largest power generation projects.

These steps are part of a long-term goal of expanding generating capacity through an estimated capital expenditure of R300 billion (US$24.2 billion), resulting in 20,000 MW of new capacity to the grid by 2025 and 42,000 MW by 2030, including nuclear.

In addition to overall capacity additions, South Africa aims to reduce the role of coal in the power generation mix from a current 84 percent to 48 percent. This suggests that South Africa has placed a greater emphasis on the reduction of greenhouse gas (GHG) emissions and depicts a fundamental shift in the energy policy direction. New coal power generation projects would account for 6.3 GW compared to a combined capacity increase of nuclear and renewable energy of 17.8 GW during the same period. Imported hydropower generation of 9.6 GW supports a long-term vision of reducing the country's carbon footprint.

This latter goal is reflected in South Africa's emphasis on including imported power in the future generation mix, a clear departure from the region's historic power flows. In addition, the development of natural gas and hydropower resources is heavily reliant on neighboring countries such as Mozambique and the Democratic Republic of Congo, respectively, to complete development projects.

At this time, resources such as nuclear that are earmarked for development are relatively expensive compared to coal, and this implies that the price of electricity will increase for end users in the near term. It also reflects the ongoing challenges that developing nations around the world encounter when balancing an emphasis on GHG emissions reduction against available energy resources within a country.

On the renewables front, current observations regarding limited capacity allocated to concentrated solar power, such as the central receiver technology, indicate that the available resources are not fully optimized. The REIPPP (Renewable Energy Independent Power Producer Programme) has brought about liberalization of the power sector because the development of the renewables energy market has been mainly driven by the private sector. This liberalization of the market offers exciting prospects as major international developers, including U.S.-based NRG Energy, seek to expand opportunities because of South Africa's abundant solar and wind resources.

However, coal, as an energy resource, still remains an important factor in the South African power mix, and opportunities exist to invest in technologies to produce energy from coal and coal equipment in a cleaner manner. Use of technologies, such as carbon capture and flue gas desulfurization equipment, to reduce emissions from coal should also be considered as part of the long-term strategy.

Biomass co-firing is one of several proven technologies that can be employed to reduce the existing power generation fleet carbon footprint. Biomass co-firing can be applied to existing coal-fired boilers, which currently account for more than 30 GW of capacity and could significantly contribute toward carbon dioxide (CO_2) emissions reduction.

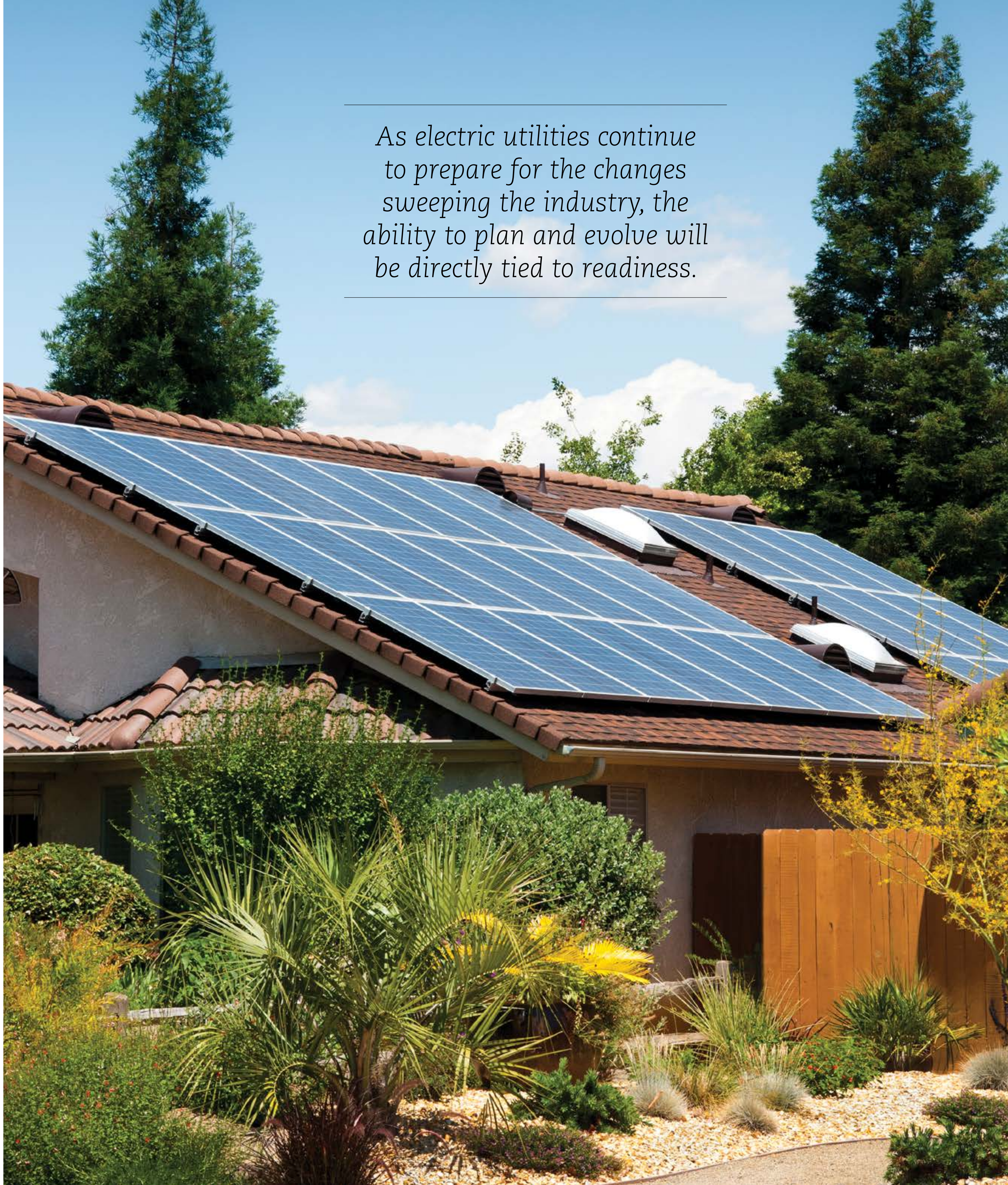
Although there are challenges, South Africa provides many opportunities for astute investors. Critical among the risks needed to be overcome is a need for power sector investments to be coordinated with industrial investments and other infrastructure development programs. This ensures that capacity additions will service actual buyers, and investments are not stranded by lack of demand.

The power journey rests on the decisions and leadership needed to take policy to practice – so that the material and political costs are minimized and South Africa can retain its status as a crucial force on the African continent.

Renewables, Energy Storage, and Distributed Generation

By Ryan Pletka and Bill Roush

Increasing customer interest in and adoption of solar, energy storage and distributed generation (DG) are causing a rising number of utilities to rethink their approach to these resources. The increased feasibility of customers to substantially lower their power consumption and potentially go "off-grid" finds electric utilities becoming more proactive about the integration of DG into their business models.



As electric utilities continue to prepare for the changes sweeping the industry, the ability to plan and evolve will be directly tied to readiness.

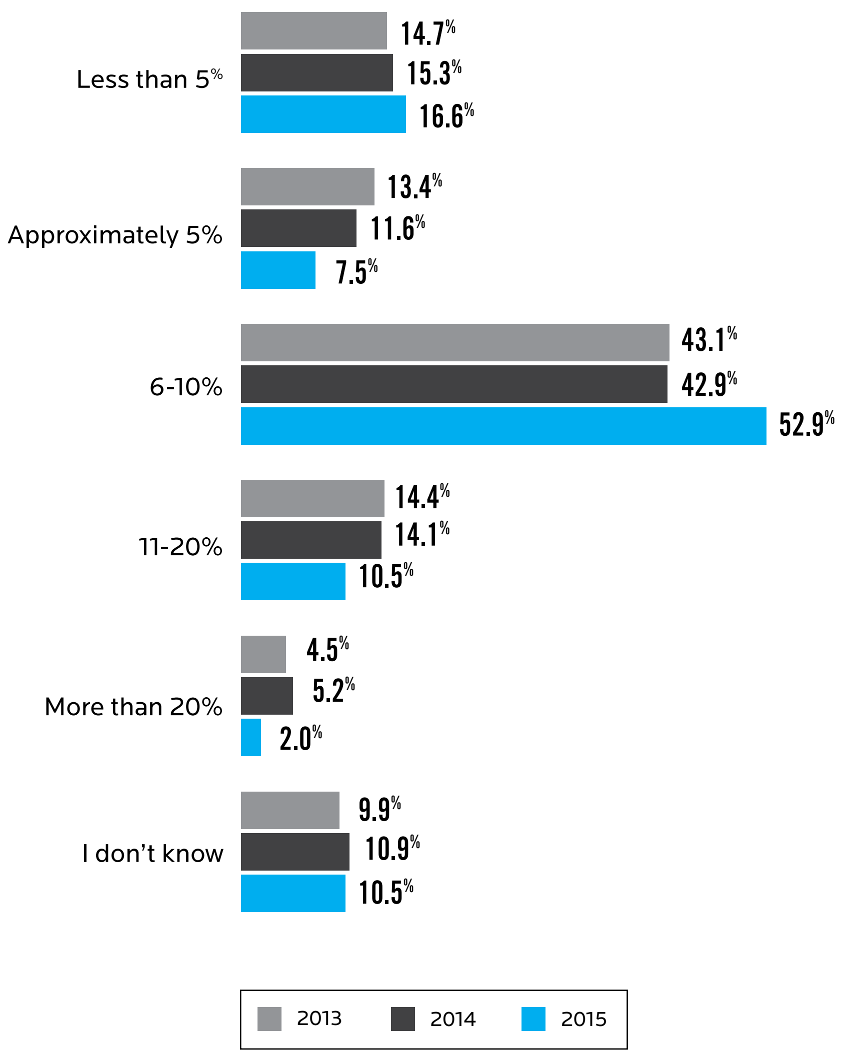
DISTRIBUTED GENERATION RISING

U.S. electric utilities are increasingly confident that DG – or power assets with a capacity less than 20 megawatts (MW) – will grow significantly from today's current levels of approximately 5 percent of total U.S. power generation. More than half of respondents felt that six to 10 percent of all U.S. power generation will come from DG by 2020 (Figure 8). This represents a significant increase over survey years 2013 (43 percent) and 2014 (43 percent).

Given this acknowledgment, how ready is the industry for increased adoption of DG by their customers? To answer this question, it is important to examine how participants view DG's effect on their business. Eighty percent of respondents believe that DG, particularly solar photovoltaic (PV), represents a threat to their business. Almost two-thirds expect the impacts to be significant – ranging from a complete "rethink" of their business to those who expect lesser impacts but still with significant long-term repercussions (Figure 9).

Figure 8

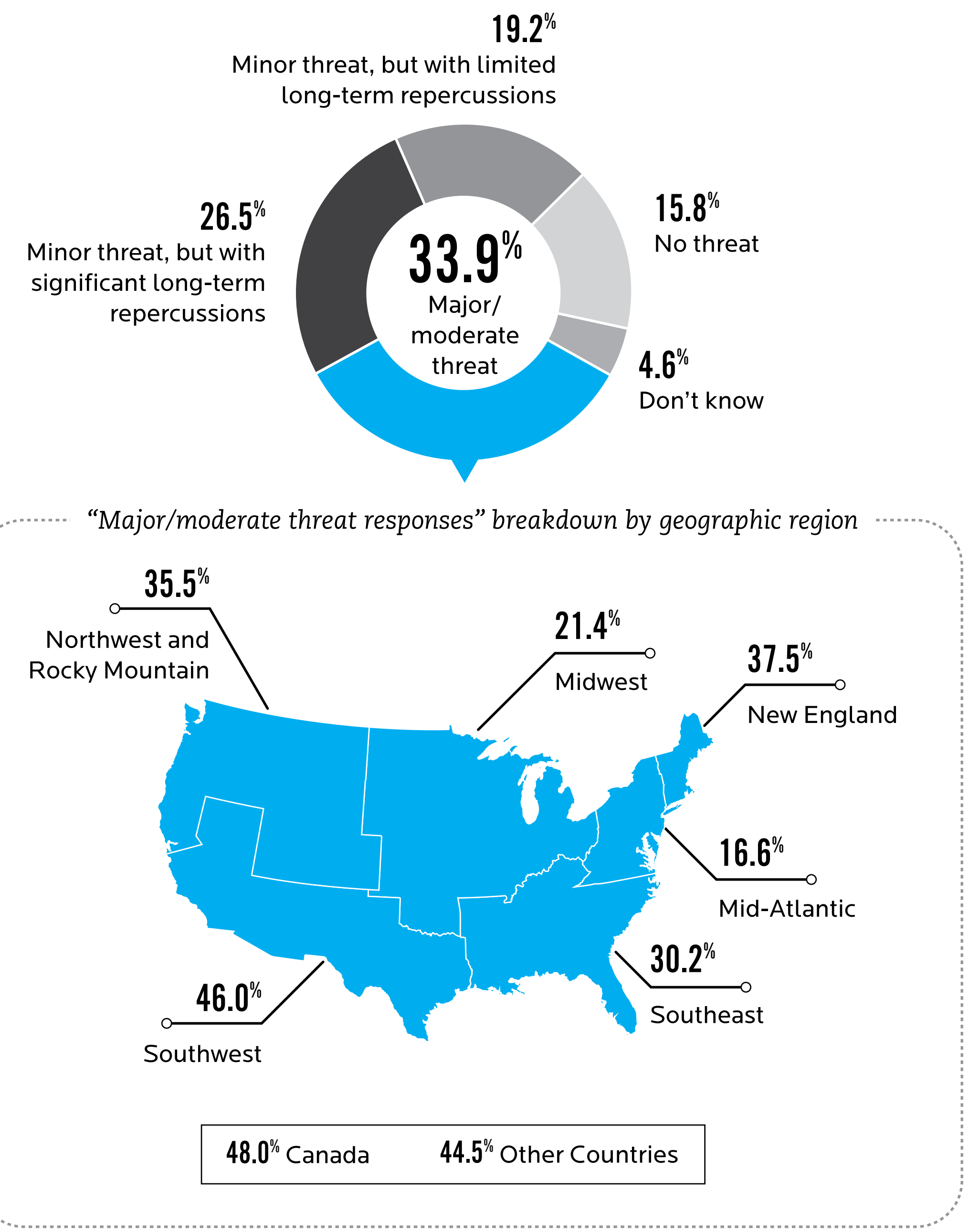
What percentage (on a MW basis) of all U.S. power generation do you believe will come from distributed generation (power assets with a capacity less than 20MW) by 2020?



Source: Black & Veatch

Figure 9

To what extent do you believe distributed generation, particularly solar PV, represents a threat to your business?



Source: Black & Veatch

In reality, many utilities are still in the review stage when it comes to assessing how they will manage DG. A key indicator of this approach is the utility respondent view of net metering. Nearly one-third of respondents are reviewing their policies internally or working to change net metering tariffs to account for the policies' net costs/benefits (Figure 10).

While some utilities might view DG as a threat, they are, perhaps surprisingly, open to considering investments in it and related technologies. Nearly 75 percent of respondents are open ("Yes" or "Maybe") to investing in behind-the-meter and distributed grid infrastructure (Figure 11), and two-thirds say they will increase their renewable energy generation investments in the next five years.

In the 2014 *Strategic Directions: U.S. Electric Industry* report, Black & Veatch encouraged utilities to become more proactive and flip the distributed energy equation. Proactive steps included direct ownership of distributed resources, restructuring customer rates to remove cross-subsidies, compensating DG customers fairly for benefits to the grid and developing proactive transmission and distribution plans to accommodate DG growth. At the time, Black & Veatch was working with utility clients on the first steps of the process. Twelve months later, there is an increasing tide of activities ranging from utility-driven efforts such as those by Arizona Public Service to regulatory-driven initiatives such as New York's Reforming the Energy Vision (REV). This activity shows the increasing recognition of both the potentially disruptive nature of distributed resources and the potential benefits they might bring.

UTILITIES BRING CUSTOMERS TO THE PLANNING TABLE

Third-party energy storage technologies are also altering how electric utilities function. With the Teslas and Daimlers of the world manufacturing and contracting with other non-utility actors to install behind-the-meter battery storage for commercial and industrial utility customers, electric utilities are facing a variety of challenges and opportunities.

Black & Veatch has worked with utilities that are rethinking their approach to planning in the face of third-party innovation and disruption. Some are using segmentation, more often seen in the marketing arena, to get a better understanding of how to communicate, collaborate and deliver the services that fit the needs of their customers.

READINESS

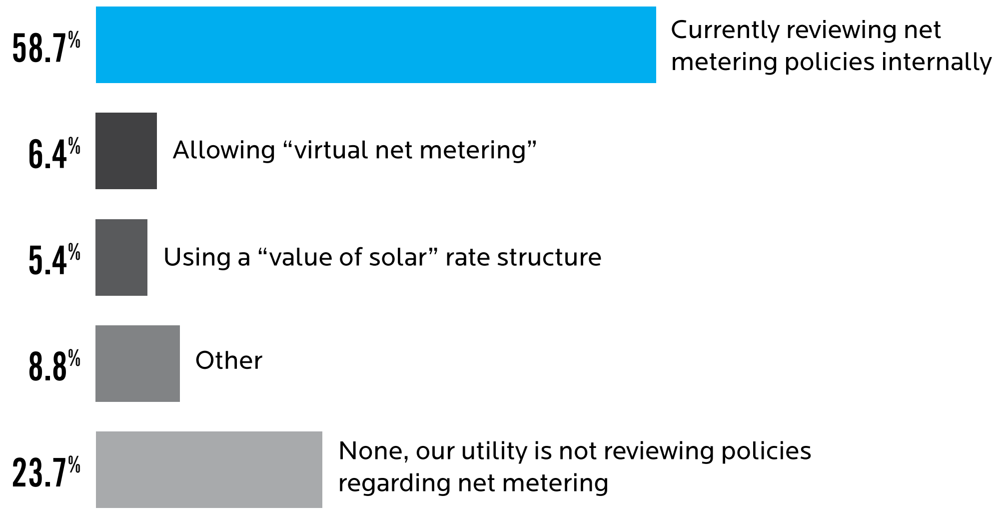
As electric utilities continue to prepare for the changes sweeping the industry, the ability to plan and evolve will be directly tied to readiness. While no one entity can fully predict outcomes, Black & Veatch recommends that, where DG is concerned, electric utilities begin to gauge their ability to transition using the following checklist:

1. Are you currently equipped financially and operationally to meet regulatory requirements?
2. What is your relationship with your customers?
3. Do your models currently account for a decline in revenue from sales of electric power?
4. What is the condition of legacy infrastructure?
5. What investments have you made to ready infrastructure for DG?

Answers to those questions will go far toward determining a utility's ability to move with, and capitalize on, the changes sweeping across the marketplace.

Figure 10

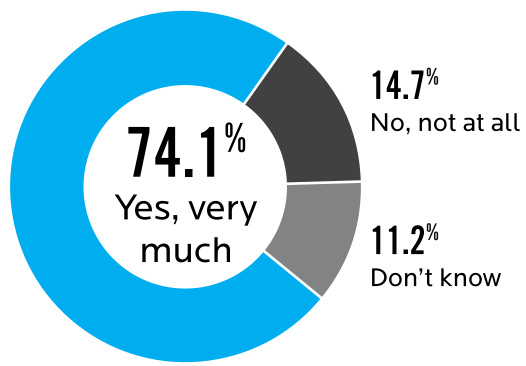
In response to rapid growth of distributed solar generation, some utilities are reviewing policies regarding net metering. Which of the following is your utility pursuing?



Source: Black & Veatch
**Respondents were instructed to select all that apply.*

Figure 11

Do you see "behind the meter" and "distributed grid infrastructure" (microgrids, energy storage and distributed generation) as potential new investment segments for your company?



Source: Black & Veatch

Natural Gas Will Reshape the Power Markets, but Challenges Remain

By Neil Copeland and Denny Yeung

Fueled by consistently low prices, production efficiency gains and regulatory drivers, the U.S. natural gas industry continues to shift from its primary role as fuel for heating and cooking to the dominant fuel of choice for U.S. electrical power. Yet in key markets across the United States, the "rush to gas" creates critical uncertainties about whether abundant supplies will get to where they need to be to meet local or regional demand. In addition, how the gas and electric industries work to more closely align their businesses will be essential to the success of each and to ensuring the stability of the grid as legacy assets retire and renewable resources continue to grow as a source of generation.

With more power being generated with natural gas, there are regions … that now, or may in the future, experience demand for pipeline capacity that exceeds availability.

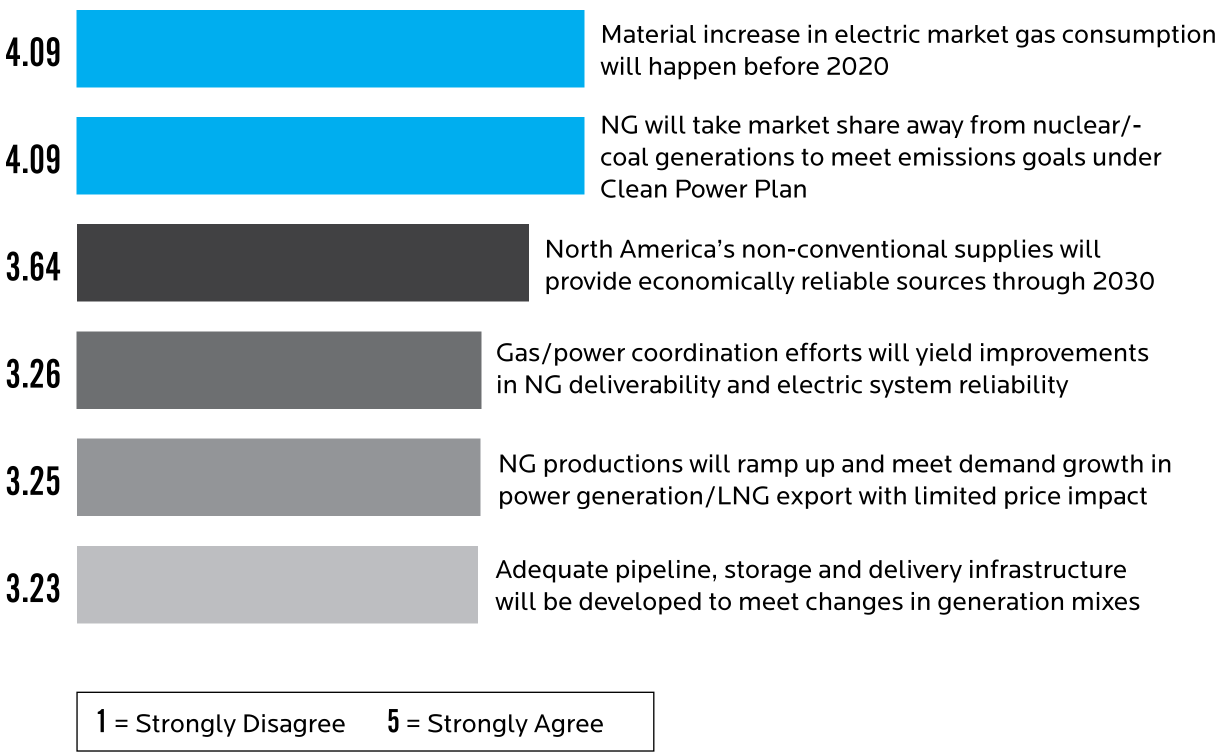
Expectations for an increased role for natural gas in the power sector are apparent across the country (Figure 12) and particularly acute in the Mid-Atlantic and Northeastern United States where large numbers of coal assets will retire by 2017.

We note, however, that across the country, only 11 percent of respondents selected new baseload generation as the primary driver (Figure 13). This outlook indicates that the natural gas generation market is more of a replacement game than one focused on new builds because of relatively flat overall demand growth.

However, with nearly a quarter of respondents indicating a role for natural gas as fast response backup for renewables, nontraditional drivers for gas generation continue to have a material impact on the market's development. This relationship was particularly strong in the Southwest United States, where 40 percent of respondents expect new gas generation to support renewable resources.

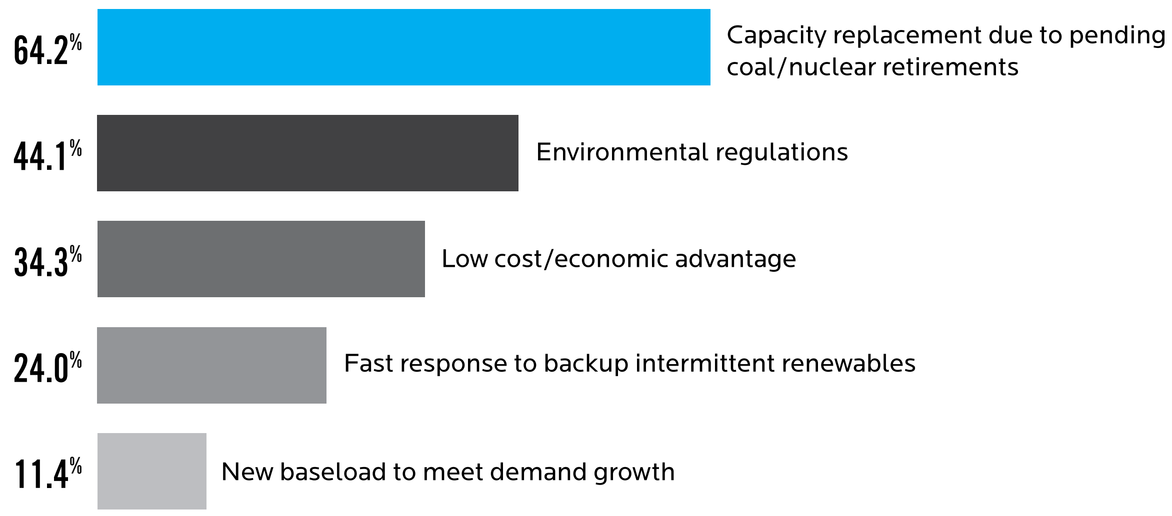
With so much optimism, it is important to note that access to pipeline capacity is a material issue facing the industry (Figure 14). For decades, U.S. natural gas pipeline infrastructure centered on the needs of its local distribution company customers providing heating and cooking fuel. Pipelines were developed to support these customers, and the abundance of coal and nuclear resources made it easy for gas generators to secure pipeline capacity on an as-needed basis. But, with more power being generated from natural gas, there are regions such as New England, the Mid-Atlantic and the Southeast that now, or may in the future, experience demand for pipeline capacity that exceeds availability.

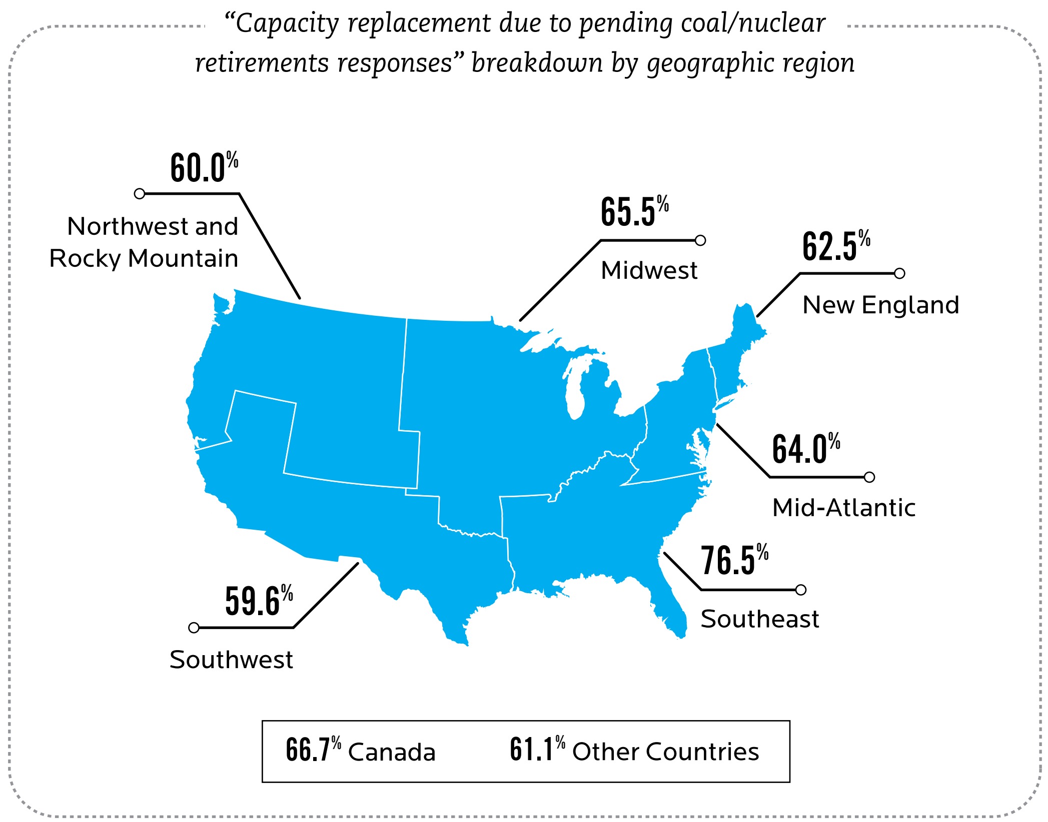
Figure 12
On a 5-point scale where a rating of 5 means "Strongly Agree" and a rating of 1 means "Strongly Disagree," please rate your agreement with the following statements.



Source: Black & Veatch

Figure 13
What are the primary drivers of planned natural gas-fueled generation?

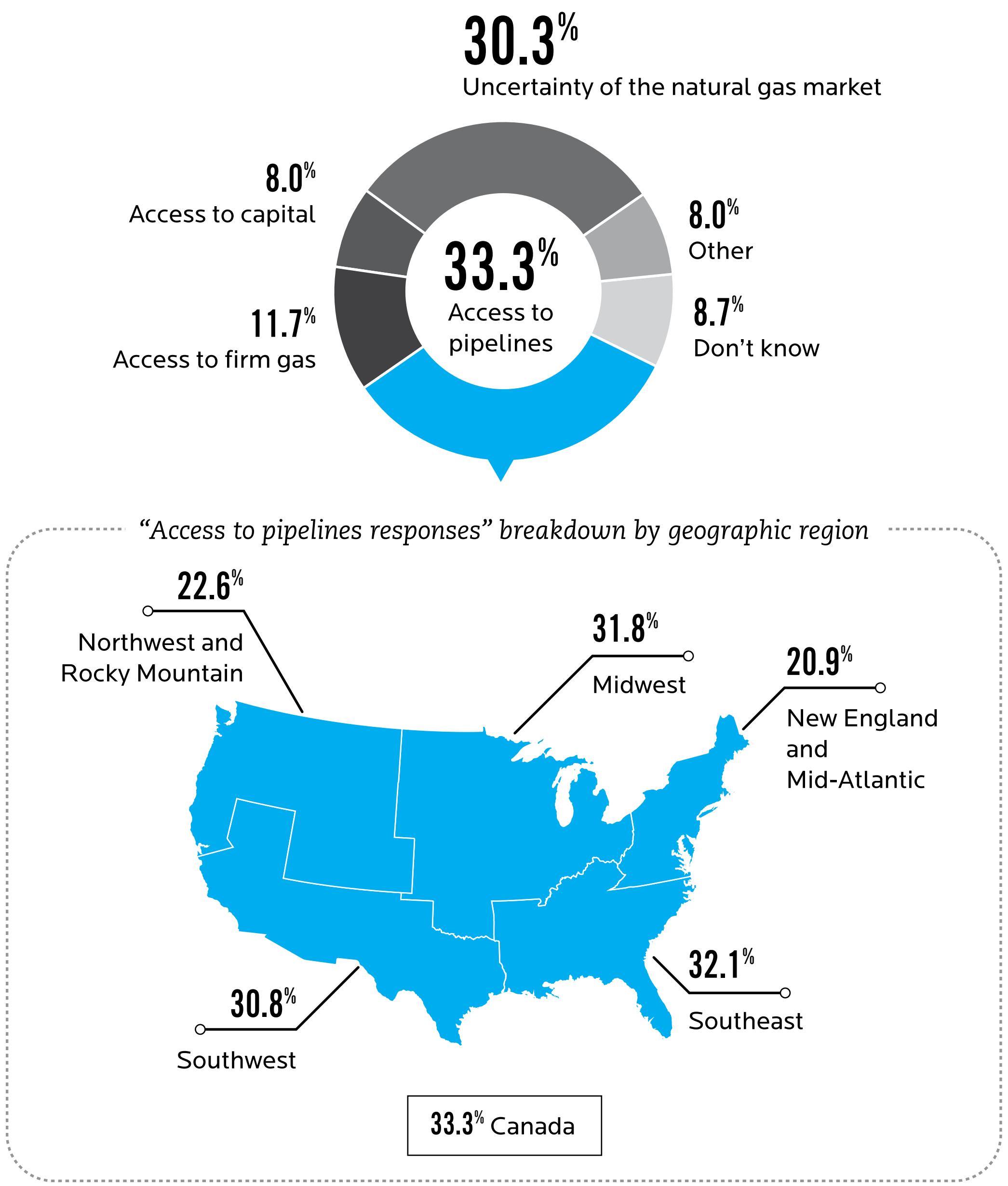




Source: Black & Veatch

**Respondents were instructed to select two choices.*

Figure 14
What is the most significant barrier to developing new natural gas generation?



Source: Black & Veatch

The issue of pipeline constraints has been widely documented in New England and New York where natural gas prices during peak winter months in 2013 and 2014 occasionally exceeded the Henry Hub price by a factor of 10 or more. Along with PJM, these regions with older, smaller coal facilities, dispatch priority for lower cost gas resources and proximity to the Marcellus Shale formation have seen a flood of interest from developers and utilities seeking steady returns from power generation assets. However, the competing priorities of residents, municipalities, regulators and pipeline developers, and the overall difficulty of completing pipeline projects, reflect the realities on the ground.

As an indication of the lack of coordination between the natural gas market and electric sectors, the survey data concerning barriers to natural gas generation show an interesting take on gas fuel supply reliability (30 percent). Given continued improvement in extraction techniques (gas production has increased even as rig counts have fallen) and stable domestic markets since 2008, it seems that the opinions of many electric sector respondents may be influenced by their experiences with gas in the pre-recession years. Another consideration may be that pipeline capacity issues were grouped into the generic term "uncertainty of gas market" for those who have long held this view. In this instance, it is possible that access to pipeline capacity is just the latest in a series of long-standing concerns about the reliability of natural gas as a source for power generation.

Overall, there is a lot of industry interest in developing natural gas assets, thereby explaining why access to capital is not viewed as a major issue (8 percent). With regulations and market drivers such as capacity performance evolving, one area to watch will be the role of gas in firming renewable resources. This is important as the cost of acquiring firm gas supply is growing exponentially, with the pipeline capacity market the most significant area to watch.

As we look to the future, it is imperative that the natural gas and electric power generation industries begin to find ways to work together on a more collaborative basis. Recent activities at the Federal Energy Regulatory Commission (FERC) have attempted to address this issue, but both sides remain unfulfilled and skeptical of one another. Positive steps, including the addition of another daily nomination cycle for the gas pipelines, will help to bridge the gap between the two industries, but further steps still need to be taken. The electric industry is now considering adjusting the definition of its "electric day" to perhaps match the definition of the "gas day" on the pipelines.

While these steps help to address the mismatch of the two industries, they do not fully address the issue of the need for new pipeline capacity. Regulators and market participants must come to the realization that to provide "firm power," one needs access to firm fuel. For coal plants, the firm fuel was located on the coal pile adjacent to the plant and the long-term coal supply and rail transportation contracts that provided the fuel. In the natural gas business, firm fuel means a commitment to firm pipeline capacity, firm gas supply and the ability to deliver the gas to the plant when it is called upon. For the industry to successfully accomplish this goal, all market participants must continue to work together in a collaborative fashion, recognizing that there is no easy fix to this problem and that additional investment in infrastructure may be required to ensure that we continue to have access to safe, reliable, affordable energy well into the future.

The regulators and market participants must come to the realization that to provide "firm power," one needs access to firm fuel.

PERSPECTIVE

EPA Rules Will Pose Challenges to Future Power Planning

By Andy Byers

The U.S. Environmental Protection Agency (EPA) is expected to soon finalize its proposed Clean Power Plan (CPP) rule to regulate carbon dioxide (CO_2) emissions from existing fossil fuel-fired power plants. While EPA's final rule will set forth targets and guidance for achieving emissions reductions, the challenges and uncertainty it has unleashed onto the power generation industry will not be settled until after all the requisite state and inevitable legal actions are resolved several years into the future.

As proposed, EPA's rule seeks to reduce CO_2 emissions by approximately 19 percent from 2012 (or 30 percent from 2005) industry levels. EPA is promulgating this rulemaking under Section 111(d) of the Clean Air Act – a unique and seldom used provision that will present many new approaches and challenges to regulating the power industry in the United States.

Section 111(d) provides for EPA to set goals and standards for reducing emissions from a designated category of sources based on the "best system of emission reductions" (BSER). EPA has used this statutory directive to propose a variety of measures that would achieve emissions reductions from not just the power plants themselves, but all the way through the electricity system from dispatch of units to demand management and efficiency at the consumer end of the system. This systemwide approach to achieving emissions reductions would substantially alter how the entire power generation, supply and utilization sector operates in the future.

PROCESS WILL LEAD TO STATEHOUSE DEBATES, LEGAL CHALLENGES

The Section 111(d) process only authorizes EPA to establish guidelines in its final rule for individual states to use in crafting their own plans for achieving the target emissions reductions through measures they determine to be BSER within their own jurisdictions. The state plans are to be submitted to EPA for review and, if approved, will be implemented as outlined in the plans. However, if EPA does not approve a state's plan, or a plan is not submitted, it can then impose a federal implementation plan on that state. As of the time of this writing, EPA was expected to finalize its CPP rule in the summer of 2015, which would allow for states to have a little more than a year to develop and submit their plans to EPA, with possible one- to two-year extensions for more complete individual and multi-state plans.

After the EPA publishes its final CPP rule, the floodgates will open on the inevitable legal challenges. There are a host of issues to be sorted out in the courts, including EPA's authority under the Clean Air Act to impose requirements beyond the actual emissions source (the power plants). Inherent conflicts in Section 111(d) itself that limit EPA's authority to regulate pollutants and sources that are regulated under other provisions of the law will need to be resolved by the courts.

Additionally, if the basis of EPA's final rule for regulating CO_2 emissions from new fossil-fuel power plants is invalidated by the courts, this could undermine the agency's authority to implement the CPP altogether under the Section 111(d) process. But since it will take years before all legal challenges and appeals are exhausted, states will need to proceed to develop and submit their implementation plans.

AGGRESSIVE GOALS AND TIMING

One of the most controversial and challenging provisions is the reduction goals to be achieved by states over the interim period from 2020 to 2029. These interim goals have been described as a regulatory “cliff” by many stakeholders, who believe the goals are set so high that they limit the options that can be used to achieve these goals within the time allowed.

While the reductions are to be averaged over the 10-year interim period, the math still does not allow sufficient time to build the new electric power lines and natural gas pipelines needed to deliver the lower carbon-intensive renewable power and fuels. Building larger gas pipelines can take up to three years, and the process hinges on companies securing customers – and capital – and maneuvering an increasingly crowded permitting queue.

New electric transmission lines can take even longer – up to five years – from planning to completion. The EPA has acknowledged these concerns and, based on comments made by top agency officials, is likely to revise these interim goals in its final rule.

Another concern related to the interim goals’ front-loading of emissions reductions is the effect it may have on the reliability of the electricity grid. Many in the industry have questioned EPA’s assumptions that states can shift substantial baseload from existing coal-fired power plants to existing combined-cycle natural gas units by 2020 without risking disruptions to the electricity supply system. Industry leaders have urged the Federal Energy Regulatory Commission (FERC) to weigh in by becoming involved in the development and review of individual state plans prior to EPA’s final approval action. But to date, the FERC has only expressed a willingness to be involved in a “safety valve” process to consider requests for waivers or adjustments to compliance requirements or timelines to ensure bulk-power system reliability.

IMPACTS TO THE ELECTRICITY SECTOR

In addition to potentially causing a fundamental restructuring of the generation mix and delivery and operations of the national electricity system, the resulting annual compliance costs to the electric utility industry have been estimated to range from EPA’s projected $7.3 billion to $8.8 billion, up to $40 billion, as projected by the American Coalition for Clean Coal Electricity. As essential stakeholders, utilities have been actively participating in EPA, FERC and state hearings and workshops, filing comments on the proposed rulemaking and preparing for the upcoming litigation and state plan development process. At the same time, utilities have been intensely assessing what measures may need to be taken to position themselves for a new and uncertain future.

Inside their plant fence lines, heat rate improvement projects will be studied to assess reductions to be achieved across utilities’ coal generation portfolio. Overhauls and tuning of existing natural gas combustion turbines to enable increased dispatch and operating capacities will be considered. Utilities will look at opportunities for converting existing simple cycle combustion turbine units to combined cycle and converting existing coal units to natural gas. Retiring existing coal units and replacing or adding new natural gas or renewable generation will certainly be evaluated. Outside the plant, associated enhancements to supply and distribution systems will also need to be studied. The construction of new gas supply pipelines to meet increased demand in the power sector, along with new electric transmission lines to deliver power from new renewable sources and improve system operating efficiencies, will need to be planned out to meet potentially stringent deadlines in the final EPA rule. The challenges of increased demand-side response and management programs will also be thought through.

The ultimate fate of EPA’s endeavor will be borne out in state legislatures and federal courtrooms. Whatever the outcome, the next several years will be filled with intrigue and challenges that will roil the power industry until the dust ultimately settles.

This system-wide approach to achieving emissions reductions would substantially alter how the entire power generation, supply and utilization sector operates in the future.

PERSPECTIVE

In Indonesia, Market Slumps Renew Focus on Renewables as Viable Energy Play

By Jim Schnieders

Slumping commodity prices worldwide are putting strong pressure on mining companies to reduce the costs of doing business. In the midst of the Indonesian government's 35,000 megawatt (MW) expansion program and electricity tariff reform, mining operators are considering self-sufficient as well as renewable energy solutions.

The price of coal alone has dropped to its lowest level in Indonesia since 2009. Since energy costs comprise an ever-increasing portion of mining operators' expenses, attention is focused on the price of diesel fuel and the cost of transportation to remote sites together with the critical availability and reliability of power from the grid.

Worldwide, new interest is being shown for renewable energy as a viable complementary option for mines. Renewable energy sources such as hydropower, wind and solar are already being incorporated into broader power supply portfolios in key mining regions outside of Indonesia, such as the United States, Canada, Australia and Chile.

Renewable energy can complement on-site power generation from diesel, which remains in Indonesia a nonsubsidized fuel at mines and a significant expense. Its drag on cost is most pronounced in remote areas where grid power is unavailable. Delivering diesel fuel to remote sites such as Ambon, North Maluku and Manokwari is costly and challenged by inadequate available infrastructure, often delayed further by harsh weather conditions such as heavy rain and high tidal waves.

Grid connection, if available, is preferable, but reliability and consistency of supply remain critical to mining operations.

At the 2015 Mining Indaba Conference in Cape Town, South Africa, former UK Prime Minister Tony Blair implored mining industry leaders to recognize the importance of a secure, sufficient and sustainable energy supply to the continent's growth. Closer to home, Indonesian Mineral Entrepreneurs Association Head, Poltak Sitanggang, underlined the importance of electricity supply for mining operations in August 2014, suggesting savings from fuel subsidy adjustments under way could be reinvested back into infrastructure, including power plants.

Other reforms to electricity tariffs, however, are geared to encourage mining operators to be self-sufficient.

New tariffs for industrial consumers came into effect in June 2014. For example, the tariff for exchange-listed companies in medium-scale industries – classified as I3 consumers – was raised by 38.9 percent, while the tariff for large-scale industries – classified as I4 consumers – rose even more, by 64.7 percent.

A broad, two-tier system is evolving. Households and light industry continue to receive subsidized electricity, while heavier industry pays more and compensates for the subsidized price. This system also encourages a separate industrial market determined by the more intensive needs of large industrial consumers such as mining operators.

The message from Indonesia's Ministry for Energy and Mineral Resources has been clear. It has urged mining companies to develop their own thermal or renewable power supplies. The alternative to self-sufficiency is to source a higher quality of reliability and availability through privately financed independent power producers (IPPs), a group earmarked to develop 25,000 MW of the 35,000 MW planned by the government by 2019.

A number of mining companies are already complying with self-sufficient thermal solutions or sourcing electricity supply through existing IPPs, easing the strain on the existing grid. Much more is encouraged, and as we have seen in other parts of the world, renewable energy could become a more prominent and complementary power source for large industrial users in Indonesia. There are already such examples of hydropower being used. The smelting and nickel ore processing facilities at mining operations in Sorowako, for example, have been harnessing renewable energy from water for decades.

Today's market reforms and global commodity price pressures are creating a case for renewable energy as mining operators take greater interest in the potential for cost savings, as well as its potential to answer public and shareholder demands to reduce greenhouse emissions.

Capital costs are associated with adding renewable energy to the mix, but investing upfront capital may generate overall cost savings. Depending on the specific location and availability or suitability of renewable power, low- to medium-penetration renewable power systems can be integrated with diesel power to meet 10 to 30 percent of the mine's energy demand. This results in a direct fuel cost savings and a reduction in the number of fuel deliveries required. The mining operation will realize lower risk and more certain energy cost forecasting, offsetting the upfront capital cost.

In addition to improving the security of power supply, mining operators in Indonesia have a golden opportunity to demonstrate a more progressive sustainability side of the business as they plan and invest in their future operations. Most importantly, the opportunity offers significant cost-containment at a time of a changing and demanding market. Favorable environmental factors such as plentiful solar or hydropower in Indonesia make renewables a sensible addition to the mining operation's power portfolio mix in terms of cost and boosting reliability of supply.

The message from Indonesia's Ministry for Energy and Mineral Resources has been clear. It has urged mining companies to develop their own thermal or renewable power supplies.

EVOLVE

Business Models Will Require Nimble Regulations, Focus on Resilience

By Russell Feingold and Ed Overcast

The electric utility industry is experiencing significant changes affecting virtually every part of the traditional utility business model. These changes and their associated challenges are recognized by a broad spectrum of industry stakeholders, including a growing number of state utility regulators.

These changes include the following:

- Low customer growth.
- Low or negative growth in energy consumption.
- Requirements to replace or retrofit aging infrastructure.
- New infrastructure demands associated with renewable resources and distributed energy resources (DER).
- Disruptive cost changes for the infrastructure supporting technological innovation (e.g., grid modernization) and cybersecurity.

As the electric utility industry grapples with how to manage these concerns, it has become clear that a one-size-fits-all approach will fail, because the overriding issues do not have the same impact on each individual utility.

From disparate markets and economic conditions to regional competition, some utilities are more exposed to change than others, but all will eventually have to address the issues driving such change.

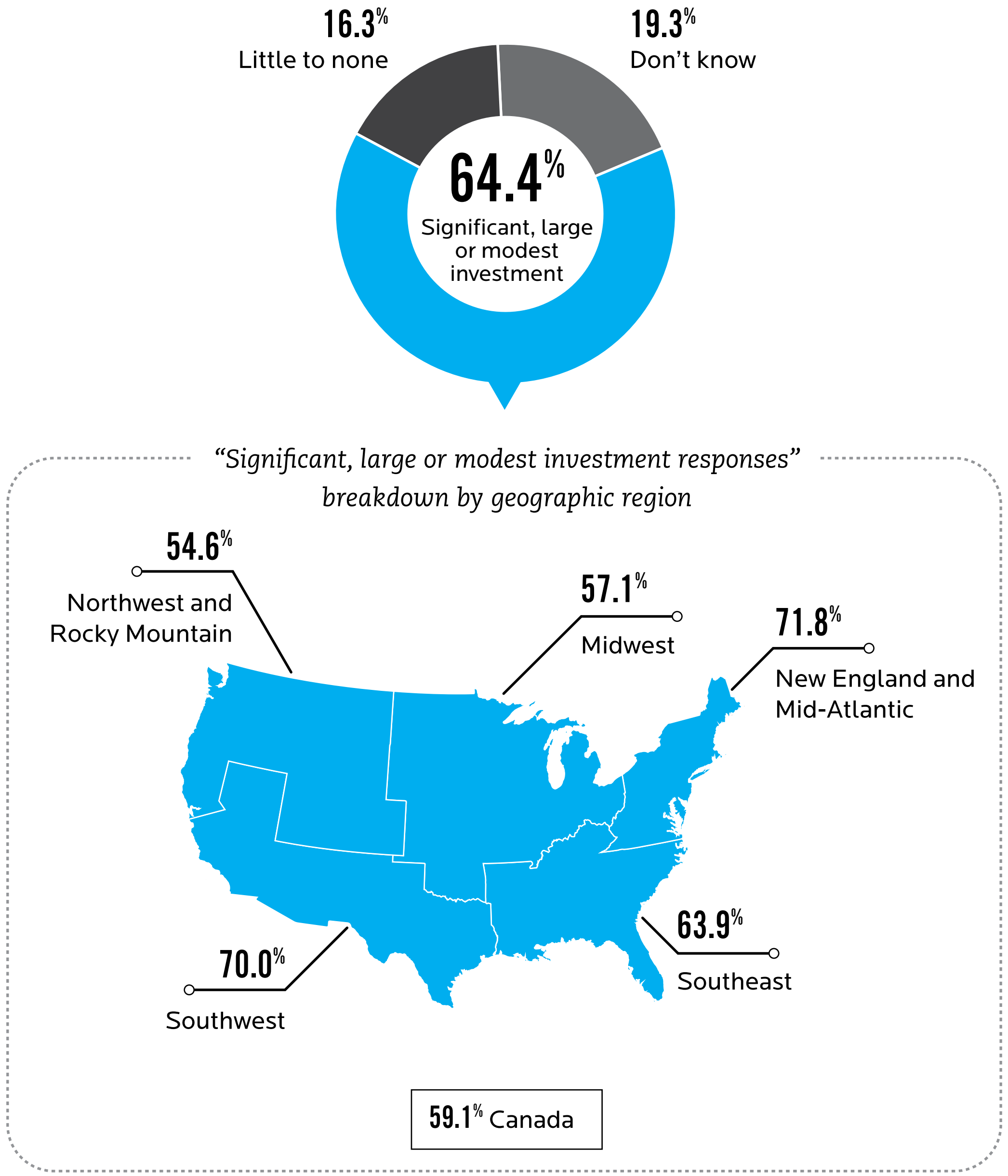
Every significant utility issue has business implications from a regulatory and ratemaking perspective. For electric utilities, the integration of distributed energy resources has highlighted significant questions related to regulators' ability to adapt to the pace of change. In addition, as electric utilities revisit their traditional business model, net metering and its effect on utility costs require scrutiny.

DISTRIBUTION INVESTMENT RELATED TO DER

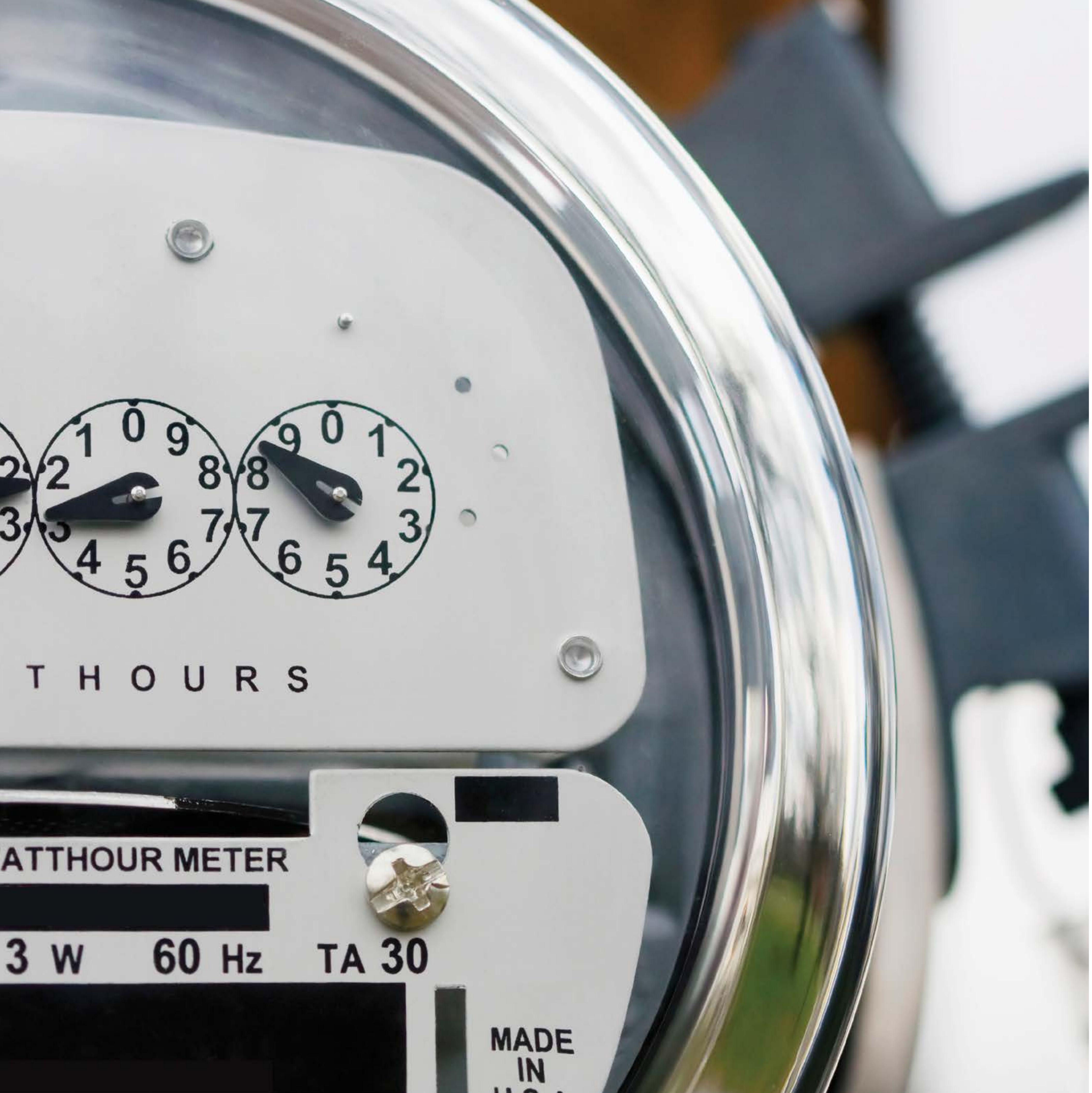
Distributed energy resources continue to increase their share of the fuel mix as federal and state regulators continue to prioritize Renewable Portfolio Standards (RPSs). In addition, the cost of solar photovoltaic (PV) has declined significantly. As a result, utilities are making efforts to ready their systems for continued adoption. 64 percent of utilities expect to make investments to accommodate the integration of DER such as solar PV (Figure 15). This result is not surprising when one considers the increased penetration of DER in more recent times in certain parts of the United States. DER integration and net metering together reflect the industry emphasis on issues that are driving the fundamental changes in the utility business model including low growth in sales, infrastructure issues and technology changes.

Figure 15

How much investment is required in your electric distribution system to accommodate the integration of distributed energy resources (DER), such as solar PV facilities?



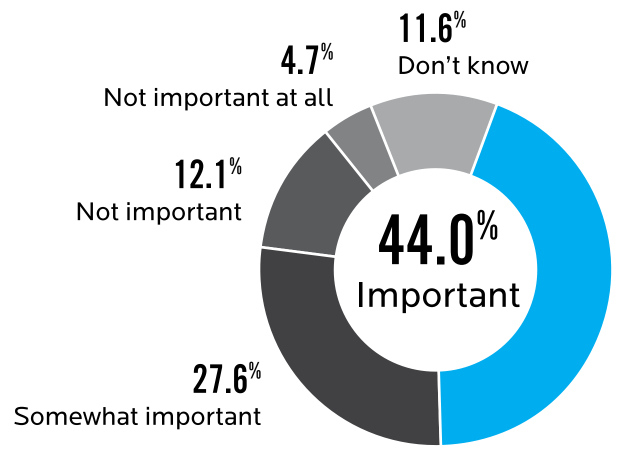
Source: Black & Veatch



THE IMPACT OF NET METERING

Net metering is recognized as a significant issue for the long-term financial viability of electric utilities. More than 70 percent of respondents viewed the issue as at least somewhat important (Figure 16). These numbers varied by utility type with 83 percent of electric cooperatives viewing the issue as at least somewhat important and only 68 percent of municipal utilities viewing the issue as at least somewhat important. This is likely a reflection of the differences in the importance of distribution costs per customer as it relates to customer density within the utility's service area. It is also consistent with the absence of a one-size-fits-all solution for the net metering issue.

Figure 16
How important is the impact of net metering to your company's long-term financial viability?



Source: Black & Veatch

THE CHANGING REGULATORY CONSTRUCT

The electric utility industry recognizes that this fundamental change in its business model requires decades-old regulatory models be altered to reflect those changes in the business model (Figure 17).

More than 90 percent of respondents recognized the need for changes in the regulatory model to accommodate the energy market's changing business model. Given that the survey included municipal and cooperative utilities that are not typically subject to the same regulatory models as investor-owned utilities (IOUs), it is reasonable to conclude that the fundamental changes in the electric industry are recognized across the entire spectrum of utilities. Regardless of the type of utility, all entities are looking for ways to accommodate the changes and respond in a manner that continues to support a viable, cost-effective and reliable energy industry.

KEY REGULATORY PRACTICES

The practices that utilities believed to be important in the near term reflect a variety of solutions that further confirm the idea that one size does not fit all. Rather, a continuum of rate and regulatory solutions covers a broad range of interests (Figure 18).

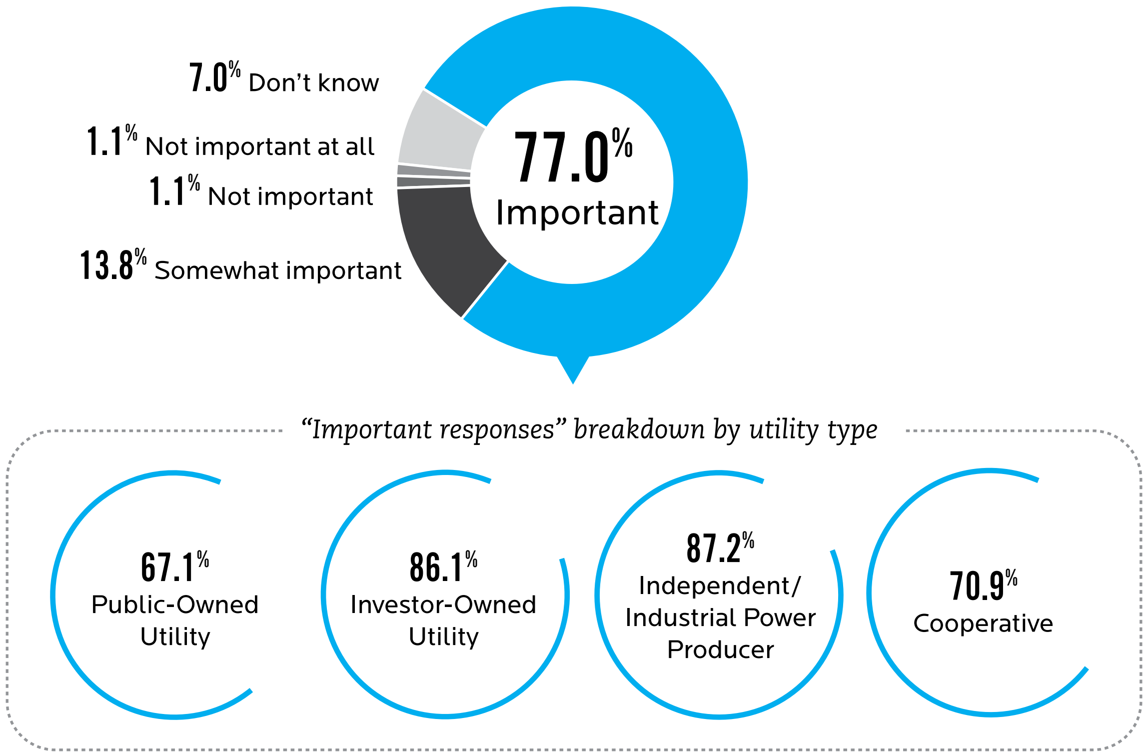
The top rate and regulatory practices that will be required by utilities over the next five years include balanced regulatory treatment between the utility and consumer (51 percent), regulatory recognition and recovery of stranded costs with an increased penetration of DER (43 percent), formula rates (34 percent) and the unbundling of utility services and rates (33 percent). Each of these top four changes reflects the basic issues that impact the business model. Utilities continue to seek a balance of interests that are important for finding acceptable solutions to meeting the challenges.

The data also demonstrate the concern of regulated entities for both the matching of costs and revenues coming from the utility rate case (i.e., forward-looking or future test years) and the timeliness of regulatory decisions. While formula rates were important for many utilities, the concept of performance-based regulation (PBR) and its associated formulaic approach to determining a utility's revenue requirement found its greatest support among independent/industrial power producers (38 percent) and merchant generation service providers (38 percent).

For electric utilities, ideal circumstances will be a perpetual moving target. They understand, however, that the best outcomes require an informed, nimble regulatory process; financial resilience; and the ability to keep pace with innovation. Getting there will take prioritizing readiness and resilience.

Figure 17

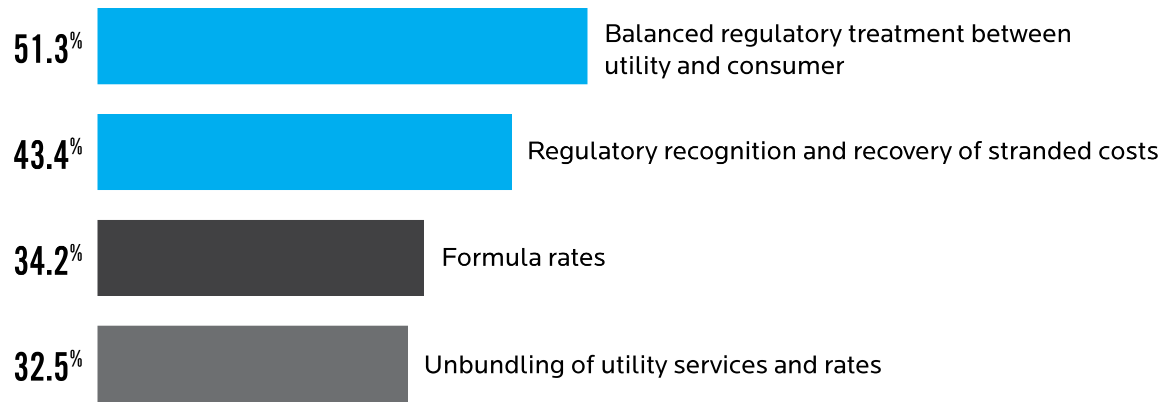
Importance of altering the regulatory construct to reflect the changing energy market:



Source: Black & Veatch

Figure 18

Please select the top THREE rate and regulatory practices that will be required for your company over the next five years.



Source: Black & Veatch

Technology, Social Media Alter the Customer/Utility Relationship

By Jeremy Klingel
and Bob Brnilovich

The utility of the future is multifaceted. Beyond what is happening at the grid's edge with distributed resources, demand optimization or interaction with smart city initiatives, the utility of the future includes investments in infrastructure that allow business-as-usual activities to be conducted using two-way communications with informed and savvy customers.

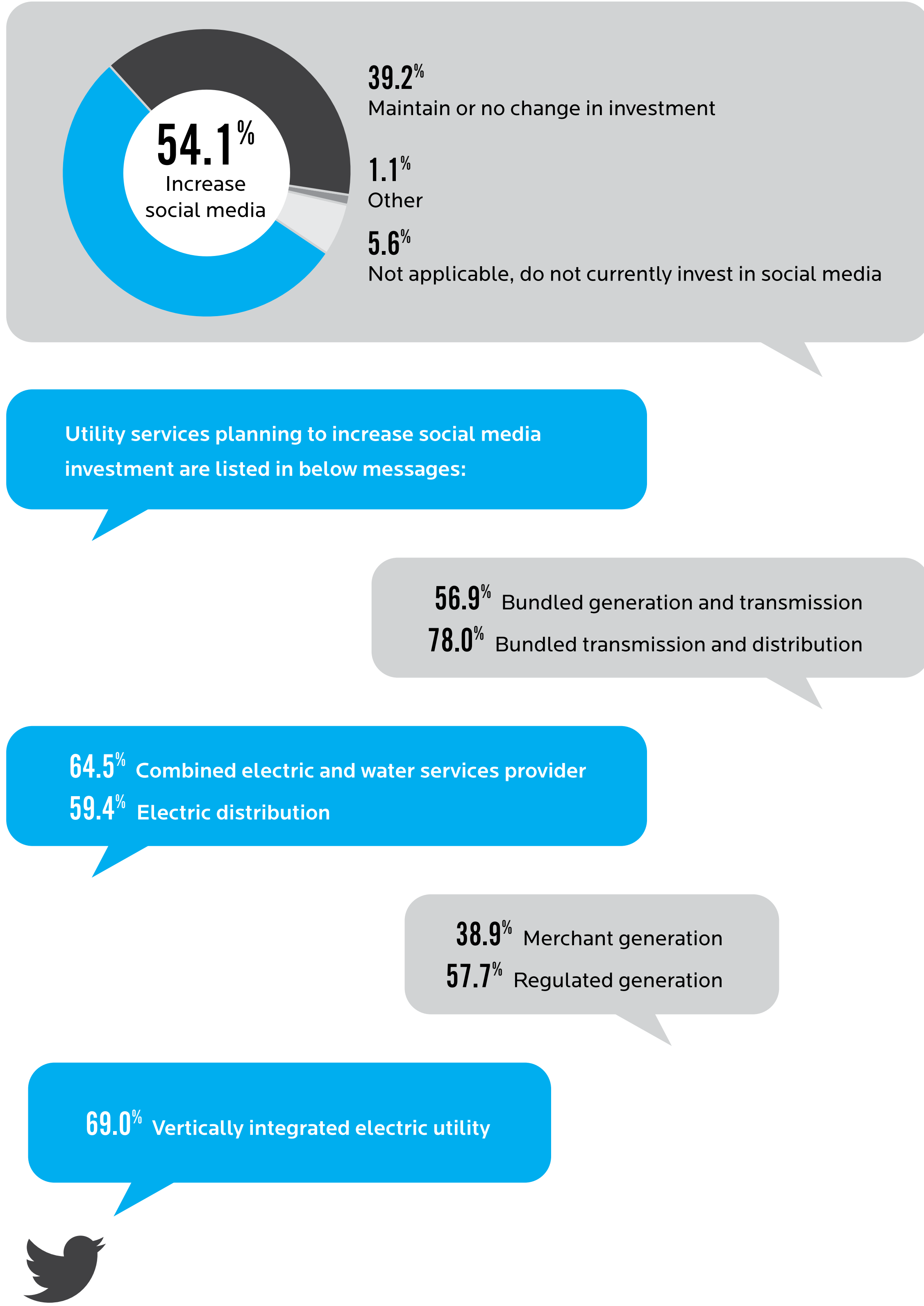
While there are many factors at play in this changing ecosystem, here we focus on three key initiatives and the interplay between them: demand response, energy efficiency and digital customer engagement.

While not necessarily new unto themselves, these topics are not only disruptive from a grid impact standpoint, but a renewed focus on customer interaction is also altering the way energy efficiency and distributed energy resources are deployed. In turn, this is changing the relationship among customers, utilities, technology and the markets to which we all connect. As a result, electric utilities are viewing the customer as a partner in their operational, financial and efficiency goals.

Over the past three years, better customer engagement has risen in prominence to become a key industry objective. At the same time, the notion of accountability and self-management has resonated with consumers. News media attention has followed consumer fascination with newer, sleeker takes on everyday appliances such as thermostats and security systems that when tied to a mobile technology give anytime, anywhere access to useful information and insights. These factors coupled with the proliferation of advanced metering infrastructure (AMI), behind-the-meter distributed generation and social interaction (energy comparison reports, behavioral demand response, etc.) have increased the level of exposure and communications possible between utilities and their customers.

Electric utilities are putting more thought into the messages they want to relay. Outside of the paper bill, utilities and customers are engaging in a public dialogue about billing, service issues, environmental stewardship, efficiency and the concept of "demand" versus overall energy use. Moreover, technology is enabling those conversations. In fact, more than 50 percent of electric utility respondents intend to increase their investment in social media in the next three to five years (Figure 19).

Figure 19
How do you see the level of investment in social media changing in your company over the next three to five years?



Source: Black & Veatch

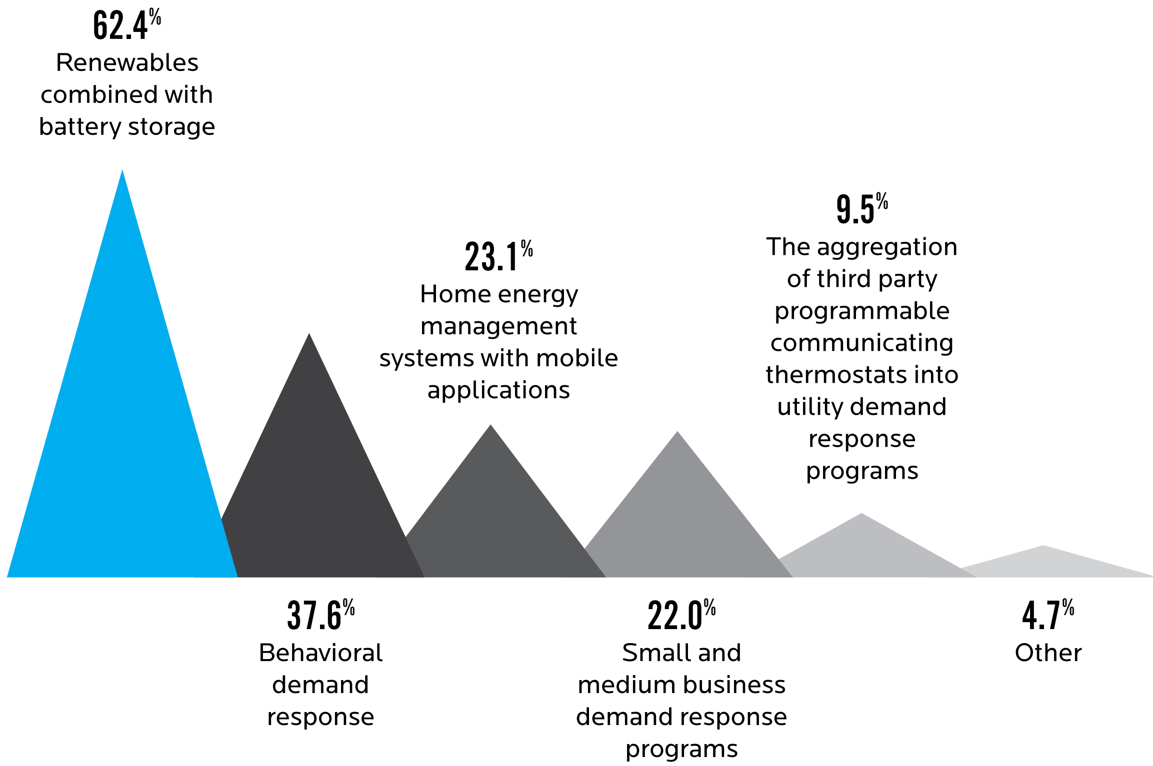
Positive outcomes are likely when utilities proactively engage with customers on the customer's terms.

With regard to social media, the old adage of customers being more likely to pass along negative experiences than positive ones becomes even more pronounced when one considers social media's ability to expand the customer's reach via followers, friends and connections. This concept of a real-time feedback loop and perpetual connectivity is a new challenge for electric utilities. Until recently, utilities have shied away from these types of interactions because of the constant need for monitoring and perceived lack of return on investment. However, proactive utilities are recognizing that an increased level of access can be leveraged to increase customer satisfaction. Instead of a lagging indicator, as many customer satisfaction measures are, they now have a medium to acknowledge and address issues almost instantly.

Positive outcomes are likely when utilities proactively engage with customers on the customer's terms. Bill inserts have long ago become little more than fodder for recycling bins. The way to a customer's heart is through their tablet or smartphone, meaning it must be mobile. Messages must be concise, customized and actionable. Similarly, utility investments in AMI and data analytics have created an environment where the ubiquity of data has given both parties increased visibility into individual energy use. Utilities must show they are using this resource intelligently and non-invasively. Communications are an opportunity to offer two to three targeted choices in terms of programs, billing and conservation offers based on a customer's usage, home, habits and, most importantly, preferences.

Prioritizing customer services is an especially important point given the resurgence of demand-side management measures being instituted that will require customer buy-in. According to survey respondents, emerging trends such as renewables combined with battery storage are among those perceived to have the greatest impact on utilities. Electric utilities also viewed behavioral demand response and home energy management solutions with mobile applications as emerging trends they could see impacting their business (Figure 20).

Figure 20
As demand response becomes more of an operational resource to utilities, what emerging trends do you see impacting your business?



Source: Black & Veatch
**Respondents were instructed to select two choices.*

We are beginning to see, and help develop, micro-segments to better understand and serve customers. This may not become as granular as a market-of-one, but understanding the technology interaction points, load profile and energy signatures between customer classes will be key. That is especially true when focusing on emerging markets such as small and medium businesses.

Ratemaking fundamentals are still instrumental to utilities and should not be overlooked, though not every program needs to be rate-based. Recovery mechanisms and riders are still going to be necessary to jump-start and support prosumer type technology. Customer satisfaction is going to become increasingly critical to utilities mitigating revenue erosion, and regulatory models will adjust to support this, much like with energy efficiency.

While prescriptive energy efficiency measures, such as compact fluorescent light (CFL) bulb giveaways, are waning, behavioral programs and the proliferation of programmable Wi-Fi thermostats will continue to drive efficiency.

Compelling customers to shift usage, rather than conserve it, in order to flatten peak demand is the prime goal. But utilities are facing the fact that the entire curve is shifting downward. Rate increases, demand charges and time-of-use (TOU) programs will become more prevalent in order to minimize lost earnings. In turn, only customers who are satisfied with their service and have visibility – through technology – into their part of the equation will understand and accept those developments.

PERSPECTIVE

'Utility 2.0' Will Force Heady Changes for Today's Electric Utilities

By Andrew Trump

"Utility 2.0" is often cast as a solution to a set of intractable problems: the reliability challenges associated with an aging distribution grid as well as energy efficiency's erosion of electricity sales. In addition, there are resiliency problems brought on by disruptive natural events or security breaches and increasingly obsolete rate structures ill-equipped to align customer choices and preferences with an equitable allocation of private and social costs.

But in its better sense, Utility 2.0 is a form of metaphor. It borrows linguistically from the concept of operating system versioning control. It creates a mental picture of both the need and the possibility of utility business model innovation and reform as an essential response to these value-destroying pressures. In many ways, Utility 2.0 is a call for a fundamental rewrite of the electric distribution utilities' playbook.

Many disruptions in the electric industry have been categorized as elements of Utility 2.0 change. Headlines around DG, battery storage and aggressive new efficiency mandates stir talk of disruption and question how utilities will react. For example, recently in California, Senate lawmakers adopted a broad set of efficiency and environmental standards that, among other things, would require electricity providers to buy half of their power from renewable sources.

Regardless of categorization, such developments – without aggressive steps by utilities to adapt and embrace the wave – would seem to set the agenda independent of the industry's input. That company management would be uncertain about the medium- and long-term needs of the business in this Utility 2.0 environment is understandable, if not rational.

Double binds abound. Consider that utilities are being asked to accelerate the expensive replacement of aging infrastructure, modernize the grid for the digital age, improve reliability and resilience (despite nature's often episodic and outsized influence), encourage and integrate more distributed resources under incompatible tariff arrangements and ensure that the grid and customer data are always safe. All that must be done while keeping prices and capital costs stable and low. Few industries have such a complex set of challenges to address.

One approach is to simply accept the Utility 2.0 reset challenge. That is a fair response, but it has its own conflicts. As recently reported in *The Economist*: "Businesses are bombarded with advice on strategy.... Bosses end up confused and cynical, with some lurching from one strategy to another and others concluding that they never want to hear the word 'strategy' again."

The New York Public Service Commission's Reforming the Energy Vision (REV) initiative is also wrestling with risk's proper role in the REV's emerging utility operating and investment framework shaping potentially the revamped distribution utility.

However, clarity on the perfect strategy need not wait for the important contributions that strategically assist the company in responding to Utility 2.0 threats. It is possible, through building organizational capacity, to serve a strategy's needs and aims in more tactical ways. In essence, there are easy, long-term bets that utility managers can take today, which involve business fundamentals and which occupy a central role in helping to sustain the business under a wide range of threat scenarios.

First, utilities will most certainly continue to compete for scarce dollars to fund essential investment, estimated by many to be in the hundreds of billions over the next two decades. Increasingly, as part of this effort, political realities will push the investing utilities to be held accountable for demonstrating the quality of its investments – both initial plans and eventual outcomes – through ever more transparent public processes involving powerful stakeholders with often-competing visions, goals, assumptions and biases. Increasingly, these deliberations will focus on risk reduction, which will be a difficult concept to operationalize in the planning process.

To secure the needed funds to sustain the business, utilities will need to consider revamping their stakeholder engagement models, preferably into ones that accept the nature of the sustained, long-term and messy negotiation they must have with stakeholders. Ideally, this will evolve as a deep and creative planning discipline, one associated with advancing principles, influencing thought leaders, shaping public perceptions and participating in, if not leading, policy change that is seen as broadly beneficial and fair. This process will also demand greater accountability, measurement, verification and transparency at every stage of the investment life cycle that is often the catalyst and focus of this work. In no small way, the engagement model may become a strategic asset in the utilities' ability to sustain the businesses with the reasonably priced investment capital the business requires.

Second, given how technology and capital are shaping distributed and renewable generation resources, rate structures are recognized as increasingly outmoded, requiring significant attention and reform. The utility may need to engage with a diverse set of stakeholders in difficult efforts to create and adopt rate structures that better align with cost causation principles and realities.

As Arizona Public Service (APS) learned through its net metering push back, gains are difficult and potentially incremental. APS sought to significantly rebalance tariff arrangements related to net metering customers, in sum, pushing more costs to solar customers, and it pushed aggressively on all fronts to accomplish this goal. APS' efforts also, no doubt, led the way for other states to pursue their own rate structure innovation. But for the long haul, rate reform will take serious and sustained management commitments to take on powerful stakeholder interests. This will not bear fruit unless such efforts are firmly rooted in shared or, at times, disputed yet transparent principles involving the goals of improved cost alignment, fairness, operational excellence, and financial and environmental performance.

Third, utilities will need greater intelligence about the performance of their assets and will need the ability to translate this information into risk-based operational procedures, postures and plans. Asset management disciplines will be essential in managing this evolution. They will include risk-aware portfolio management, which will help communicate to stakeholders the contingent nature of the utility business operating and asset management environment, and the important choices utilities face in response to conflicting and emergent conditions.

Asset management tools will also assist utilities in promoting and managing flexible investment programs that are responsive to changing market and operating environment conditions while maintaining their core, principled integrity. A good example of the emerging emphasis on risk-aware planning is demonstrated in the California Public Utility Commission's (PUCs) attention on risk assessment methods as part of its upgrade of general rate case methods and procedures. The New York Public Service Commission's Reforming the Energy Vision (REV) initiative in New York is also wrestling with risk's proper role in the REV's emerging utility operating and investment framework shaping (prospectively) the revamped distribution utility.

Stakeholder engagement practices, rate reform initiatives and a strategic focus on asset management and risk-aware planning disciplines are but three of several core areas requiring distribution utility attention to address Utility 2.0 challenges. If approached with confidence and conviction as precursors and enablers of strategic clarity – and through the insights gained and feedback loops exercised in their practice – the utilities may find they are pursing work that is, in fact, shaping strategic outcomes and not merely experiencing disruptive challenges.

DEPLOY

EPC Popularity Grows as Owners Consider Cost Certainty, Financing Flexibility

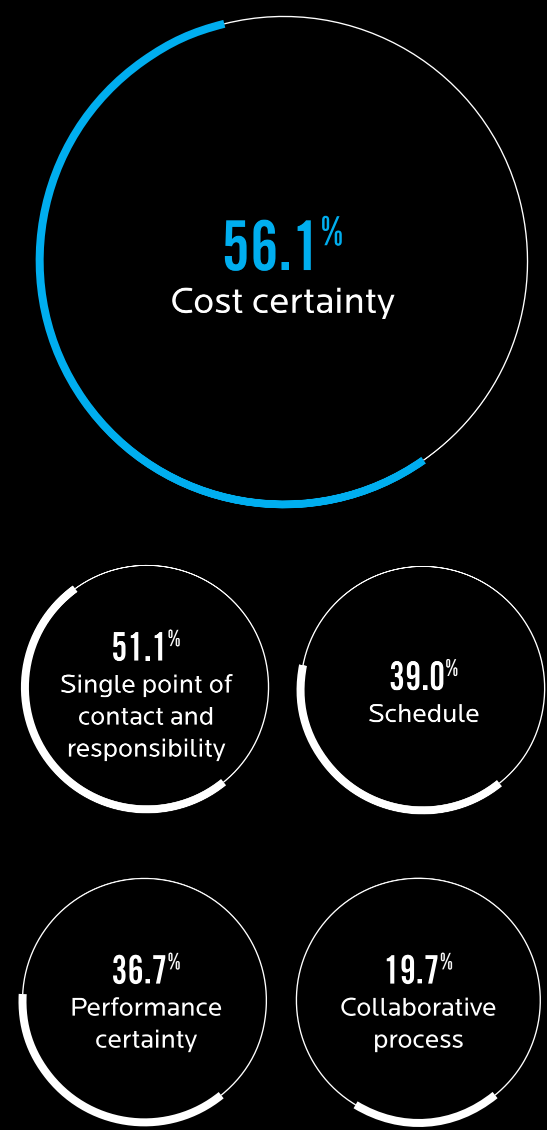
By Ernie Wright and Jim Hengel

Advantages of engineering, procurement and construction (EPC) services are well documented in the electric industry. Once an alternative delivery method that was merely gaining momentum, EPC has crossed into an industry standard as a strategy that gives project owners an end-to-end solution by putting nearly all aspects and phases of a project under a single contract.

Trend lines among organizations employing EPC across nearly all project lines – traditional power generation in addition to solar, wind and DG technologies – continue to rise. Certainty of schedule and cost, the convenience of having a single point of contact and their related performance advantages are considered top benefits to organizations (Figure 21).

Figure 21

What do you feel are the top three benefits of using an EPC model for your projects?



Source: Black & Veatch

**Respondents were instructed to select three choices.*

AMID EPC PROLIFERATION, THE VALUE OF EXAMINING THE UNSEEN

As energy providers explore future infrastructure projects, their most important decision may rest with the selection of the EPC provider. While the list of firms providing EPC services is growing, they operate in varied fashions – and some of those characteristics are less than obvious.

Lean practices: "Lean" can be defined as finding and eliminating waste, such as wasted effort, extra steps, and redundant materials and processes. The paybacks from a company versed in identifying and reducing these drags at a project's outset can produce gains in productivity, safety, and schedule and cost certainty.

Dedicated startup and commissioning professionals: Project owners should seek out EPC providers that offer full-time specialists in this area, and those teams should be fully integrated with the engineering and construction teams. Startup professionals should be involved from the very beginning of the proposal, immediately after a project award and at the construction site in the very early phases, during planning pre-commissioning and commissioning activities, and by supporting engineering and construction systems turnovers and integrating with the design engineers and construction personnel to make sure all the functions and features work exactly as planned when the final commissioning occurs. Startup is the riskiest phase of the construction process since there is little time to recover from any changes.

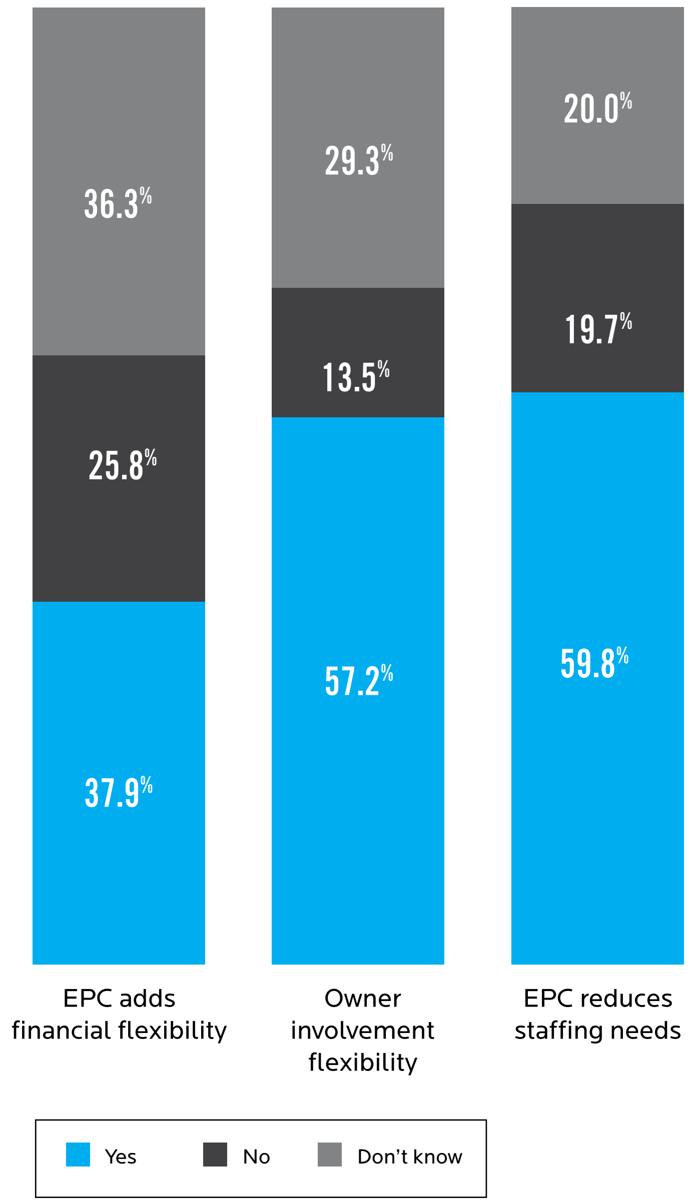
Ownership engagement: Successful EPC projects offer the project owner as much involvement as the owner wants. No utility management team should ever feel as if it has not been included in key decisions. An owner should be part of an integrated team and should seek an EPC provider that encourages its involvement. Owners may also find great satisfaction with open-to-closed-book contracting, which allows them to see big-ticket purchases and help select equipment manufacturers. On the other hand, some owners, such as independent power producers, need a single lump sum number that they can use for seeking financing. More than half of survey respondents felt EPC allowed for as much involvement in a project's lifespan as they desired (Figure 22).

No utility management team should feel marginalized during key decisions, unless it prefers the EPC provider to simply hand over the keys when the project is complete. (Such turnkey solutions are also growing in popularity.)

Culture of safety: Projects with few to zero recordable injuries and few lost-time incidents are more likely to meet quality and schedule standards. When examining an EPC company's credentials, owners should also ask for near-miss reports, because a company that aggressively seeks out near misses can take action to ensure the incident does not turn into a future real accident. Such intelligence can predict the odds of lower incidents at a prospective jobsite.

Figure 22

Agreement with questions related to the use of an EPC delivery model:



Source: Black & Veatch

DIFFERENT TYPES OF EPC CARRY ADVANTAGES

Utilities that are considering new large infrastructure projects should carefully evaluate whether to put the bid out for a lump sum contract – in which a fixed price is agreed to for the project's execution – or whether they want to use an open-book arrangement. Both methods have their advantages, depending on the owner's circumstances, and matching the best style for the given project can make a major impact on a project's success.

Regulated utilities, which usually finance projects on their own balance sheets, may have more time to consider options and explore open-book arrangements in which an owner works closely with the EPC company in the early stages. These arrangements include selecting equipment manufacturers, designing plant layout and deciding on suppliers.

With an open-book arrangement, the EPC provider seeks bids from manufacturers and subcontractors, and those bids are reviewed and decided upon jointly with the owner. The owner sees all the bids and prices for the major components. An EPC company gets roughly a quarter or a third of the way through a project with all critical pieces purchased. If the owner is happy with the progress and understands the pricing, the project becomes a closed-book contract, with the EPC company taking over from there. Among utilities who said they employ EPC, 15 percent cited the open-book to closed-book workflow as a top benefit.

SHARING RISK CAN LOWER THE OWNER'S PROJECT COST

Owners of large infrastructure projects naturally try to off-load as much of the risk of the project as possible, but that also can add significantly to the overall costs. As an alternative, owners should examine ways to lower their costs by accepting some reasonable risk and working with high-quality EPC providers.

Project owners can do this by shifting some of the focus on the "bankability" of the EPC provider, thus giving them a much higher comfort level in accepting risk. Bankability is measured as the comfort level that financiers have in the contractor by examining the provider's financial depth, history of cost and scheduling compliance and the sureties that the facility will perform to expectation.

By examining a provider's bankability, project owners can better determine whether they want to assume any of the risk and seek to lower some of their costs. EPC is seen by many in the industry as delivering financing flexibility to a project (Table 1).

Owners increasingly want to have a voice in project equipment selection, particularly if they are working with an open-book contract. Some owners are comfortable with carrying the cost of certain big-ticket equipment on their books and accepting some of the risk, thus reducing the need for complex contingencies in project contracts.

Such unknowns, particularly in a fixed lump sum contract where the owner assumes no risk, means an EPC company must carry risk premiums and contingencies. When an owner steps in to share in the risk by working with the original equipment manufacturer (OEM) it wants, overall costs can be lowered substantially.

With an open-book arrangement, the EPC provider seeks bids from manufacturers and subcontractors, and those bids are reviewed and decided upon jointly with the owner. The owner sees all the bids and prices for the major components.

Table 1

Does the EPC model add financing flexibility to your model?

Financing Flexibility of the EPC Model	By Electric Utility Type			
	Publicly-Owned Utility	Independent/ Industrial Power Producer	Investor-Owned Utility	Cooperative
EPC models adds financing flexibility to my model	29.9%	**63.3%**	37.7%	16.2%
No, EPC model does not adds financing flexibility to my model	29.9%	18.4%	24.6%	35.1%
Don't know	40.3%	18.4%	37.7%	48.6%

Financing Flexibility of the EPC Model	By Electric Utility Type							
	New England	Mid-Atlantic	Mid-west	South-east	Rocky Mountain and Northwest	South-west	Canada	Other Countries
EPC models adds financing flexibility to my model	54.5%	53.8%	28.6%	34.0%	42.9%	48.9%	33.3%	**72.7%**
No, EPC model does not adds financing flexibility to my model	18.2%	23.1%	24.7%	34.0%	39.3%	24.4%	40.7%	13.6%
Don't know	27.3%	23.1%	46.8%	32.0%	17.9%	26.7%	25.9%	13.6%

Source: Black & Veatch

Readiness for Cybersecurity and Physical Security Standards

By Daniel Rueckert and Chip Handley

2015 marks a turning point in the evolution of the U.S. electric industry's outlook toward security. The uncertainty surrounding the transition from North American Electric Reliability Corporation Critical Infrastructure Protection Version 3 to Version 5 (NERC CIP V3 to V5) diminished giving way to concerted efforts to identify and address security risks across electric utility system assets and their connectivity points. Similarly, the passing of time moved physical threats to electric infrastructure out of the headlines as security hardening activities ramped up because of CIP-014.

As this report goes to press, public interest in physical security and cybersecurity centers on the likelihood of nefarious activity targeting operational control networks and customer data more so than electrical transformers and outside plant. As noted in the Top 10 issues list, physical security dropped from the Number 9 issue (4.05 mean importance rating) in 2014 to Number 11 (3.80 mean importance rating) in 2015 (Figure 23). More than two-thirds of respondents indicated they are prepared to comply with NERC CIP-014 and general physical security standards (Figure 24). We believe this reflects a combination of events, including significant media coverage in 2014 and the absence of subsequent high-profile security events.

The NERC CIP V5 standards apply to the reliability of the grid from a cybersecurity and physical security perspective. Customer information can be governed by regulations such as Health Insurance Portability and Accountability Act (HIPAA), Payment Card Industry (PCI) or state regulations. For example, as a result of previous data breaches, New York state cybersecurity orders have been issued requiring utilities to develop enterprise cybersecurity plans.

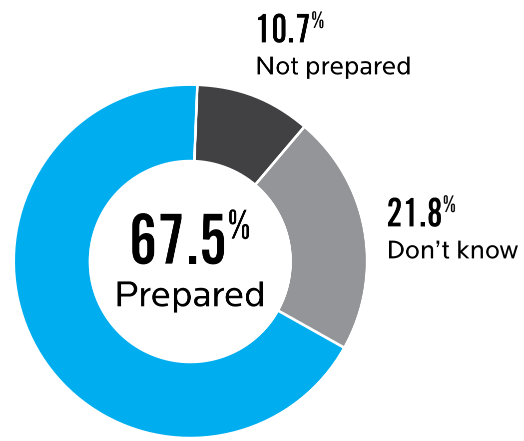
Figure 23

The importance of physical security to the electric industry, where a rating of 5 means "Very Important" and a rating of 1 means "Not Important At All."

Source: Black & Veatch

Figure 24

NERC CIP-014 and general physical security concerns are nudging the industry into a more proactive stance on physical security. How prepared is your organization?



Source: Black & Veatch

SIZE MATTERS

Echoing a theme across the *Strategic Directions* report series, security planning, both physical security and cybersecurity, is often influenced by the size of the respondent's organization or customer base. While more than 70 percent of respondents indicate some level of preparedness for compliance with NERC CIP low-impact system requirements (Table 2), data once again show that in terms of security, the larger the organization, the greater the level of progress in terms of preparations.

Two major factors affected these results. First, previous NERC CIP standard versions historically tended to focus only on large generation or transmission facilities, exempting the assets of many co-ops, independent power producers (IPPs) and other small service providers. Larger, investor-owned utilities (IOUs) or public-owned utilities with bigger plants and more infrastructure in place were already required to have CIP compliance plans in place and have undertaken multiple in-depth CIP audits. Second, without a mandate in place, small- to mid-size utilities felt the combination of their limited impact to the grid and lack of capable staff resources available to address cybersecurity concerns justified implementation delays.

Table 2

NERC CIP Low Impact Cyber System requirements are scheduled to become effective in April 2016. How prepared is your organization to address the requirements by the effective date? (Utilities by number of employees.)

NERC CIP Low Impact Cyber System Preparedness	By Number of Employees				
	Less than 100	100 – 499	500 – 1,999	2,000 – 4,999	5,000 or more
Very prepared; we have previous critical cyber asset compliance plans that are easily leveraged to the low-impact requirements	17.5%	14.9%	40.0%	30.6%	58.3%
Prepared; we did not have previous critical cyber asset compliance plans, but we are ahead of the curve on developing the required low-impact plans	17.5%	29.8%	20.0%	33.3%	12.5%
Somewhat prepared; we are beginning to closely study the low-impact requirements and are starting to build our plans	32.5%	23.4%	14.0%	11.1%	4.2%
Not prepared; we are hoping for an extension to the effective date, or we have not yet started to look at this closely	12.5%	4.3%	0.0%	2.8%	2.1%
Don't know	20.0%	27.7%	26.0%	22.2%	22.9%

Source: Black & Veatch

BLACK & VEATCH MARKET OBSERVATION:

Service providers are seeing an influx of requests from larger utilities that thought they were prepared to comply with NERC CIP V5 by the April 2016/2017 deadlines based on their level of preparation and compliance with V3. However, the increased industry understanding of V5 requirements has resulted in a dramatic increase in the number of assets that need to be reviewed and remediated by April 2017 *and* is driving requests for external support.

MANAGING NERC CIP V5

One of the biggest challenges associated with the transition from NERC CIP V3 to V5 centers on the inclusion of smaller facilities that had virtually no CIP compliance requirements in the earlier CIP versions. The V5 standards now require a tiered classification system for those electronic systems that control and protect the electric system. For some operators, this categorization has increased the number of assets accounted for in their security planning by a factor of 10 (or more) as virtually all generation and transmission electronic systems will fall into either the low-, medium- or high-impact classification tiers. Low-impact systems must be compliant with the new CIP standards by April 2017, and medium- and high-impact systems must be compliant by April 2016.

Although the requirements for low-impact systems are not as stringent, the implications of a transition from a low- to medium-risk asset are significant. For example, the new standard requires that increased logging and auditing ability be in place for low-risk assets, while medium-risk assets require the level of access and protection to go up dramatically. Greater awareness of system interconnection is forcing municipally owned utilities and co-ops that previously had been outside the scope of NERC CIP to evaluate their network to determine whether they are compliant and driving expectations that low-risk sites will be turning to medium-risk.

In some cases the new NERC CIP security standards have increased the number of assets accounted for in utility security planning by a factor of 10 (or more).

As new systems are put in place to support the drive toward NERC CIP V5 compliance, there is a level of long-term human resource overhead that will be required to manage these new systems. Knowledgeable, full-time support is needed to manage, monitor and maintain these new systems.

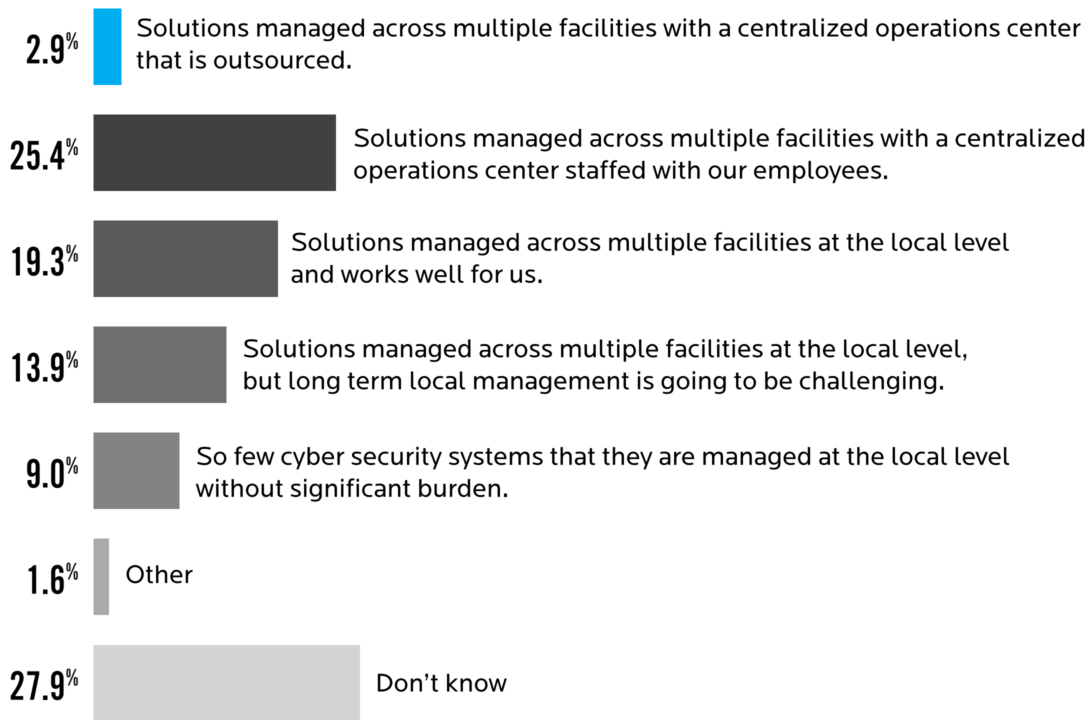
Currently, not many electric utilities are outsourcing their security support (3 percent) but are dealing with it via a central management facility (25 percent) or at the local level where each site manages their issues themselves (19 percent) (Figure 25). However, there is an evolution going on in terms of managed services as small-to-mid-size operators that cannot afford a chief information security officer (CISO) or other full-time staff explore other means of adding security support.

In general, the security landscape of the U.S. electric industry remains fairly dynamic. NERC is in the process of providing CIP standard revisions beyond Version 5. While some likely elements are taking shape, the further one projects into the future, electric service provider security standard requirements become less clear.

One thing that is certain is that security is an issue that will continue to evolve and become more mature as it is better understood by all utility management. The dependence and convergence of information technology (corporate level) and operational technology (plant control system level) security management and the desire to drive efficiencies through complex technology also make for challenging times. Given the practical need to secure electric system infrastructure, manage costs effectively and achieve compliance with regulations, utilities must adopt a life cycle approach to security.

Figure 25

The increasing need for cybersecurity solutions (hardware and software) at most transmission and generation facilities can create a substantial manpower burden as resources are needed to monitor and maintain those systems. How is your organization planning to manage this situation?



Source: Black & Veatch

PERSPECTIVE

In Arid Saudi Arabia, Water Demands Take on New Primacy in Power Generation

By Mazen A. Alami

Saudi Arabia is consistently one of the world's largest oil and gas producers. The kingdom has benefited hugely from the wealth exporting these resources have earned and is experiencing rapid industrialization and urbanization.

These trends, coupled with an expanding population and the increasing wealth of Saudi citizens, are giving rise to significant growth in the kingdom's energy requirements. Per capita energy consumption is twice the world average and growing at more than 5 percent annually, according to Abdulrahman Baashin, head of the Middle East Centre for Economic Studies. The Saudi Electricity Company (SEC), the kingdom's energy utility, predicts a 37 percent increase in demand by 2019. To meet future needs, the utility plans to add 47,711 megawatts (MW) between 2014 and 2024.

Oil accounts for 90 percent of the kingdom's exports and nearly 75 percent of government revenues. It is estimated, however, that the kingdom now consumes about one-quarter of the oil it produces. As a result, one of Saudi Arabia's biggest challenges is meeting businesses' and peoples' needs for power in a manner that will not impede the generation of revenues through oil and gas exports.

SEC's strategy to reduce its oil and gas consumption is multifaceted. The number of renewable energy projects has increased significantly. The utility is investing in more efficient distribution network equipment. Energy efficient technology is being used on an increasing number of new power plants, and the efficiency of existing power plants is being increased.

This strategy is bearing fruit. As SEC's 2014 Annual Report notes, improving the efficiency of power plants and the distribution network has so far cut fuel consumption by 12 million barrels. The utility envisions that, when complete, the program to enhance the efficiency of its older generation assets will save approximately 200 million barrels of fuel annually.

A program to convert simple cycle power stations to combined cycle has made a significant contribution to the improvement of generation efficiency.

It is estimated that conversion from simple to combined cycle can increase the efficiency of a power plant by around 20 percent. For SEC, which has a significant number of simple cycle plants, the benefits of conversion are attractive. As His Excellency Saleh Al-Awaji, Deputy Minister for Water and Electricity, stated in 2012, "Our average thermal efficiency in generation is around 30 to 35 percent. Converting our single-cycle plants to combined-cycle would tremendously increase thermal efficiency to 40 to 45 percent."

The majority of SEC's older power stations – which burn gas, diesel or crude oil – are suitable for conversion. Although most of the assets in the conversion program are between 10 and 20 years old, some have been in service for up to 40 years. Adjunct to the conversion program, SEC is ensuring that new simple cycle plants are engineered with future conversion to combined cycle in mind.

It is estimated that conversion from simple to combined cycle can increase the efficiency of a power plant about 20 percent.

Currently, SEC plans six more combined cycle conversion projects between 2014 and 2024 that, when complete, will generate 2,411 MW. This equates to about 5 percent of the 47,711 MW SEC is seeking to add during that period.

Although the principle for each conversion project is the same, the design for each project is customized. Combined cycle systems require considerably more equipment than simple cycle facilities: heat recovery steam generators, steam turbine generators, condensers, cooling towers, additional generator step-up transformers and water treatment systems. As a result, laying out the steam cycle equipment and its auxiliaries in a plant originally designed exclusively for simple cycle can be the most significant challenge. Typical problems are lack of space to accommodate the new equipment and carrying out construction work at a live power station.

Design of the new steam and water cycle system must take into account exhaust energy from the gas turbine. This varies according to operating conditions, so ambient temperature and altitude also have a significant influence on the design. Where the fuel has a high sulfur content, as in Saudi Arabia, the design also has to account for potential corrosion in some of the steam cycle equipment.

The interdependency, or nexus, of energy and water means that SEC's combined cycle conversion program has benefits other than saving fuel. Although it is a desert kingdom, Saudi Arabia consumes 91 percent more water, per capita, than the global average. It is estimated that the kingdom requires almost a billion gallons a day of additional desalination capacity to meet demand and reserve margin needs by 2020.

With water, as with fuel, the kingdom is seeking ways to reduce demand. Although power generation is water intensive, combined cycle plants generate nearly 66 percent more energy per unit of water used than do traditional gas-fired plants. So, along with more efficient generation, SEC is also achieving a reduction in demand for water – which is vital for such an arid country.

CLOSING COMMENTARY

Technology, Customer Shifts Propel Utilities Forward

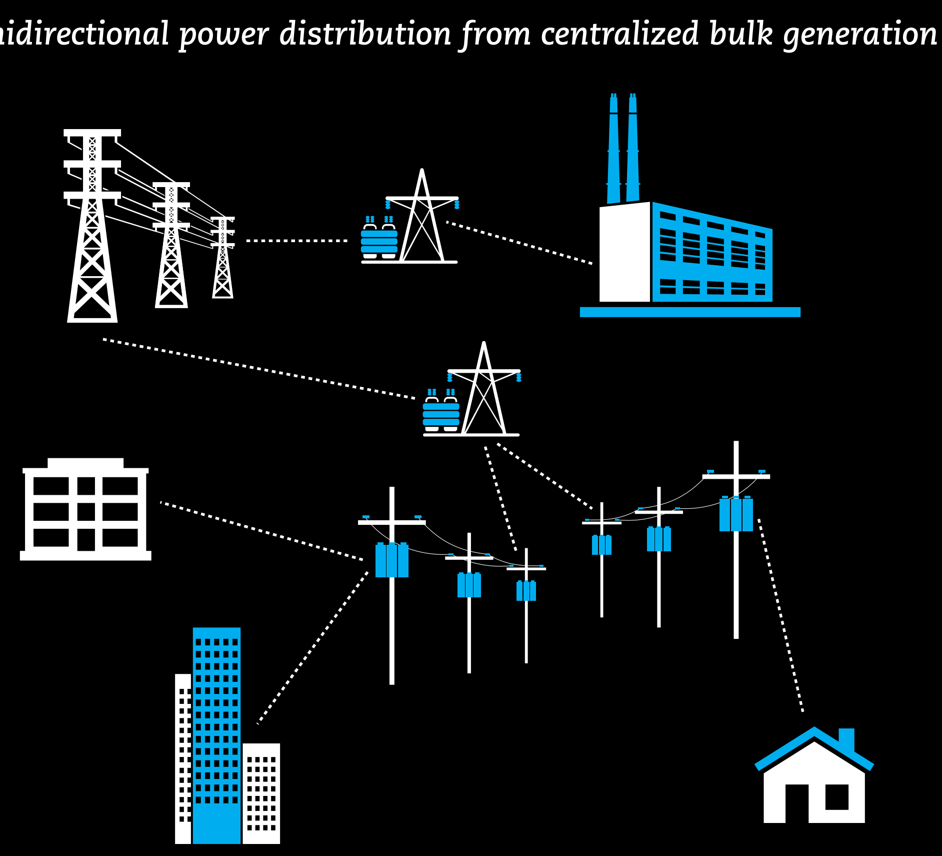
By John Chevrette

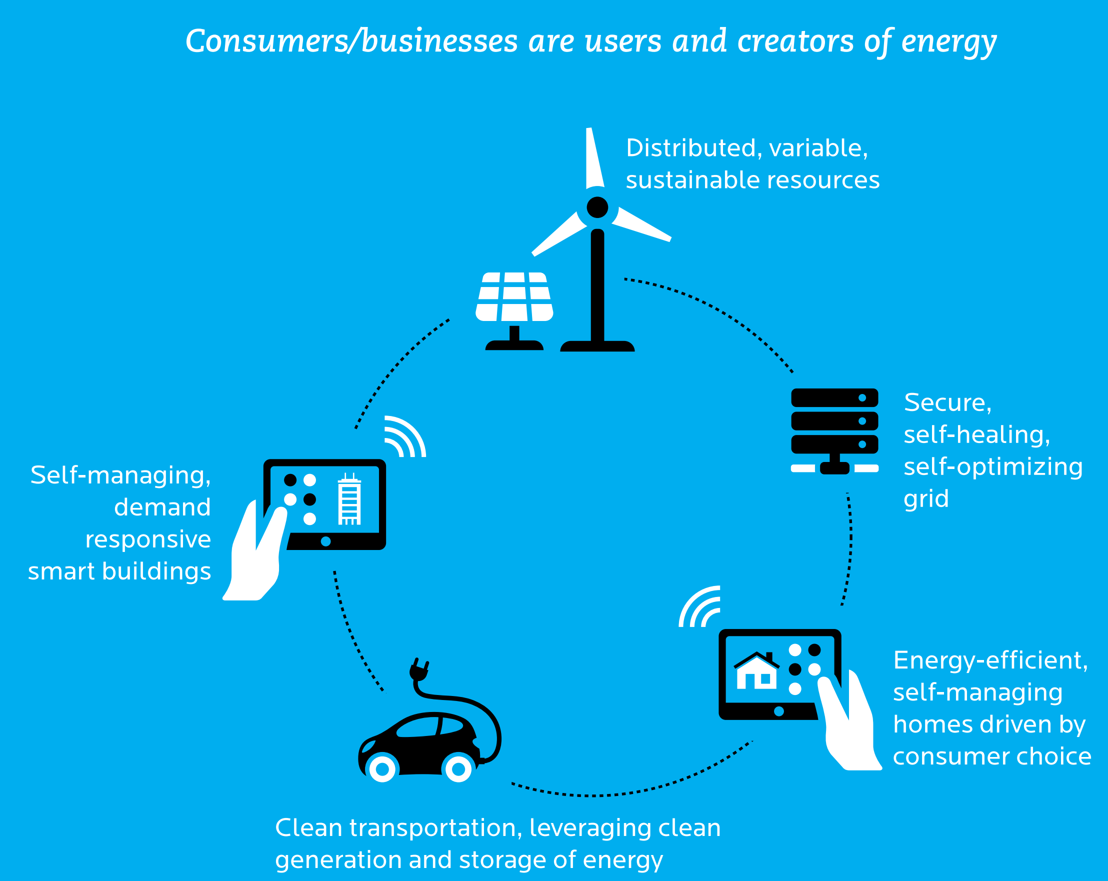
For service providers around the world, the traditional utility model faces a "perfect storm" of challenges. New technologies, environmental pressures, regulatory drivers and changing customer preferences are threatening the stability of a century-old business model. At the same time, stagnant growth exacerbates capital planning challenges as growth of distributed generation erodes the revenue base. Costs for customers who remain "on grid" are rising, giving those that can greater incentive to pursue self-generation options.

Despite growing customer reliance on electronic devices, from televisions and mobile phones to air conditioning and iPads, skepticism about the long-term utility model is growing. Headlines touting the "Utility Death Spiral" indicate the need for the industry to evolve. The industry term for this is "Utility 2.0," a highly appropriate software reference when considering what the utility of the future encompasses. The next-generation of electric utilities will be those entities that provide the logistics, transportation, security and billing services for millions of potential electric suppliers and buyers across the bulk power systems, distribution grids and microgrids (Figure 26).

The utility of the future also represents a key element of the Internet of Things where operations flow through robust communications networks and supercomputers crunch vast amounts of data in order to direct and redirect power flows based on weather, operating conditions and customer behavior. Given growing consensus that utilities must evolve to thrive in this rapidly approaching future, the question remains, "So how do we get there?"

Figure 26
How do we get from here to there?





Source: Black & Veatch

CREATE A VISION

No group has a better understanding of the grid system and all the components that make reliable and safe electric service possible than electric utility leaders. Industry leaders know their weak points and understand emerging threats and trends and what can be done within a range of confining factors including regulators and legislative bodies. Although adept at recognizing and adapting to macro trends, in general, utilities have faltered at understanding the microeconomics of their business and how slight changes can impact their revenues in a significant manner.

The emergence of distributed generation, particularly solar photovoltaic technology, highlights the need for greater understanding of how emerging technologies can impact the bottom line. Today, nearly half of vertically integrated utilities view distributed generation as a major or moderate threat, and only 31 percent of distribution utilities share this view (Table 3).

Now is the time for utility leaders to take a hard look at customer trends, emerging technologies and the current regulatory framework as key inputs in developing a vision for the future. For customers installing DG assets on their homes and businesses, utilities must understand the services they can provide to them and how they can measure and bill for those services. As more customers seek to go "off-grid," this can be as simple as providing a minimum bill to remain their provider of last resort.

Table 3

Distributed generation is becoming a more prominent part of the energy system. To what extent do you believe that this technology represents a threat to your business?

Distributed Generation's Effect on the Electric Utility Business Model	By Utility Services Provided							
	Bundled Generation and Transmission	Bundled Transmission and Distribution	Combined Electric and Water Services Provider	Electric Distribution	Merchant Generation	Regulated Generation	Vertically Integrated Electric Utility	Other
Major threat, this technology will change completely how we think about the business	5.8%	14.3%	0.0%	7.5%	3.9%	5.7%	9.4%	8.3%
Moderate threat, this technology will change how we think about our business to a large degree	17.3%	20.4%	16.7%	23.6%	21.6%	24.5%	38.8%	19.4%
Minor threat, but with significant long-term impacts	28.8%	20.4%	40.0%	31.1%	21.6%	22.6%	22.4%	27.8%
Minor threat, but with limited long-term impacts	28.8%	24.5%	23.3%	18.9%	15.7%	20.8%	15.3%	19.4%
No threat	7.7%	14.3%	16.7%	15.1%	**33.3%**	17.0%	12.9%	22.2%
Don't know	11.5%	6.1%	3.3%	3.8%	3.9%	9.4%	1.2%	2.8%

Source: Black & Veatch

DEVELOP YOUR ROAD MAP

The utility of the future requires the integration of customer engagement, operational technology, information technology, data analytics and, in many cases, a very different portfolio of power generation resources. At the highest level, industry leaders must re-examine and re-engineer future revenue models and identify new services, while unbundling other services from volumetric demand-based models. This latter transition offers electric utilities the opportunity to look across industries that are experimenting with rate structures. This includes water utilities now seeing decades of conservation and efficiency efforts reduce consumption and mobile/broadband providers seeking to maintain revenue as the cost of providing each unit of data service drops.

Future revenue models have to take into consideration the tremendous amount of investment needed to rejuvenate aging infrastructure. This is particularly important as transmission and distribution assets will be called upon to enable greater amounts of DG and storage to be tied into these complex networks. Significant investment is also needed in technologies and analytic tools, re-engineering of utility services, processes and organizational structure, and the security programs needed to keep operations and customer data safe.

An overall strategic plan, coupled with technology plans and communication infrastructure plans, provides the blueprint and business case for necessary investments. The ability to justify network investments, the corresponding customer rate adjustments and, perhaps most critically, quantifying the benefits customers will receive are absolutely critical to gaining regulatory approval for long-term strategic plans.

ENGAGE YOUR CUSTOMERS

Customer engagement is a necessary undertaking when considering how utilities will meet regulatory and legislative requirements that, like DG, pressure the traditional rate models. Demand response and energy efficiency requirements encourage customers to use less of the utility product. Meeting these requirements hinges on the utility's ability to engage its customers. Too many programs have failed because of customer confusion and cost barriers (both real and perceived). By placing a singular focus on the unique value of digital control and developing simplified messages, utilities can begin the change process.

Ease of use and flexibility of technology are critical components for customer engagement. Utilities should work to define customer participation in energy efficiency and demand response programs in terms of control, comfort and/or savings. Programs designed around comfort and choice are proven methods for increasing and sustaining enrollment.

On the operations side, utilities must begin integrating their systems, such as their customer information system, enterprise asset management system, meter data management systems and outage management system (OMS). By integrating systems, utilities can create a single view of their customers' usage and metrics. In turn, they can provide a single view to their customers on usage, billing data and other services. Perhaps most importantly, integrated systems provide more comprehensive data resources. When utilities put their data to work, the data will inform forecasting, device control and, ultimately, customer interactions that improve customer satisfaction.

WORKING WITH REGULATORS

Utilities with strong customer relationships and satisfaction metrics generally have better working relationships with their regulators. However, even with strong relationships, utilities must make their case for regulatory change, investment and rate adjustments. At the end of the day, the primary role and responsibilities of an electric utility are to maintain grid stability, reliability, safety and security. Fulfilling these responsibilities is becoming more complex and cost-intensive.

Necessary regulatory reforms that enable the transition to a new utility business model are already under way in states such as New York and California. However, in other states, controversy is rising on related issues such as net metering and the management of distributed generation resources within a broader generation platform.

THE UTILITY OF THE FUTURE

Electric utilities have a reputation for resisting and being slow to adopt change. The reality is that the industry has witnessed tremendous change throughout the last decade. The unbundling of generation from transmission and distribution services in several states, the great hope for next-generation nuclear capacity stymied by suddenly abundant natural gas resources and the emergence of renewable resources, both utility-scale and distributed assets, are all relatively new phenomena in the century-old industry.

Now, with an accelerated development of technologies that are bringing more choices to customers, significant regulatory pressure on environmental behavior and the requirements of a more reliable and resilient system, a new wave of transformation is coming. Utilities, customers and other interest groups have to play in a narrow space to envision a model where electricity continues to be an affordable and reliable promoter of development and welfare.

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11401 Lamar Avenue, Overland Park, KS 66211

P +1 913-458-2000 | **E** MediaInfo@bv.com | **W** bv.com

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