Black & Veatch Insights Group

ELECTRIC INDUSTRY REPORT

2017

STRATEGIC DIRECTIONS

BUILDING A WORLD OF DIFFERENCE®

BLACK & VEATCH

About This Report

The annual Black & Veatch *Strategic Directions: Electric Industry Report* explores progress made across the power generation and delivery sectors, with an eye toward their evolving landscapes. Over the last year, the sector has adapted to ongoing changes — the proliferation of renewable energy, a changing regulatory outlook and heightened focus on investment, infrastructure and regulation — all while navigating familiar but pressing challenges related to reliability and resilience.

The industry is charting its path forward by integrating advanced technologies, accommodating growing amounts of distributed energy resources exploring the possibilities created by energy storage. To their benefit, electric utilities are increasingly embracing new technology, understanding that data is critical because it will allow them to prioritize efforts, commit funding and allocate resources in a strategic manner.

Reliance on coal-fired power generation continues to give way to inexpensive and abundant natural gas, as well as increasing amounts of renewable energy from solar and wind.

The *2017 Strategic Directions: Electric Industry Report* examines how utility leaders are navigating these challenges — both old and new — and advancing for future growth. The report also addresses potential hurdles that may impede success. Concerns persist over security, aging infrastructure, environmental regulation and the management of long-term investments that will force utility leaders to innovate and meeting shifting customer demands.

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

Sincerely,

ED WALSH | President
Black & Veatch's power business

JOHN CHEVRETTE | President
Black & Veatch's management consulting business

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Executive Summary

INVESTMENT, INNOVATION, LONG-TERM PLANNING DRIVE UTILITIES FORWARD

By Ed Walsh

Ed Walsh is President of Black & Veatch's power business and is responsible for overseeing and implementing strategies, processes and tools to further enhance the company's service offerings and continued growth.

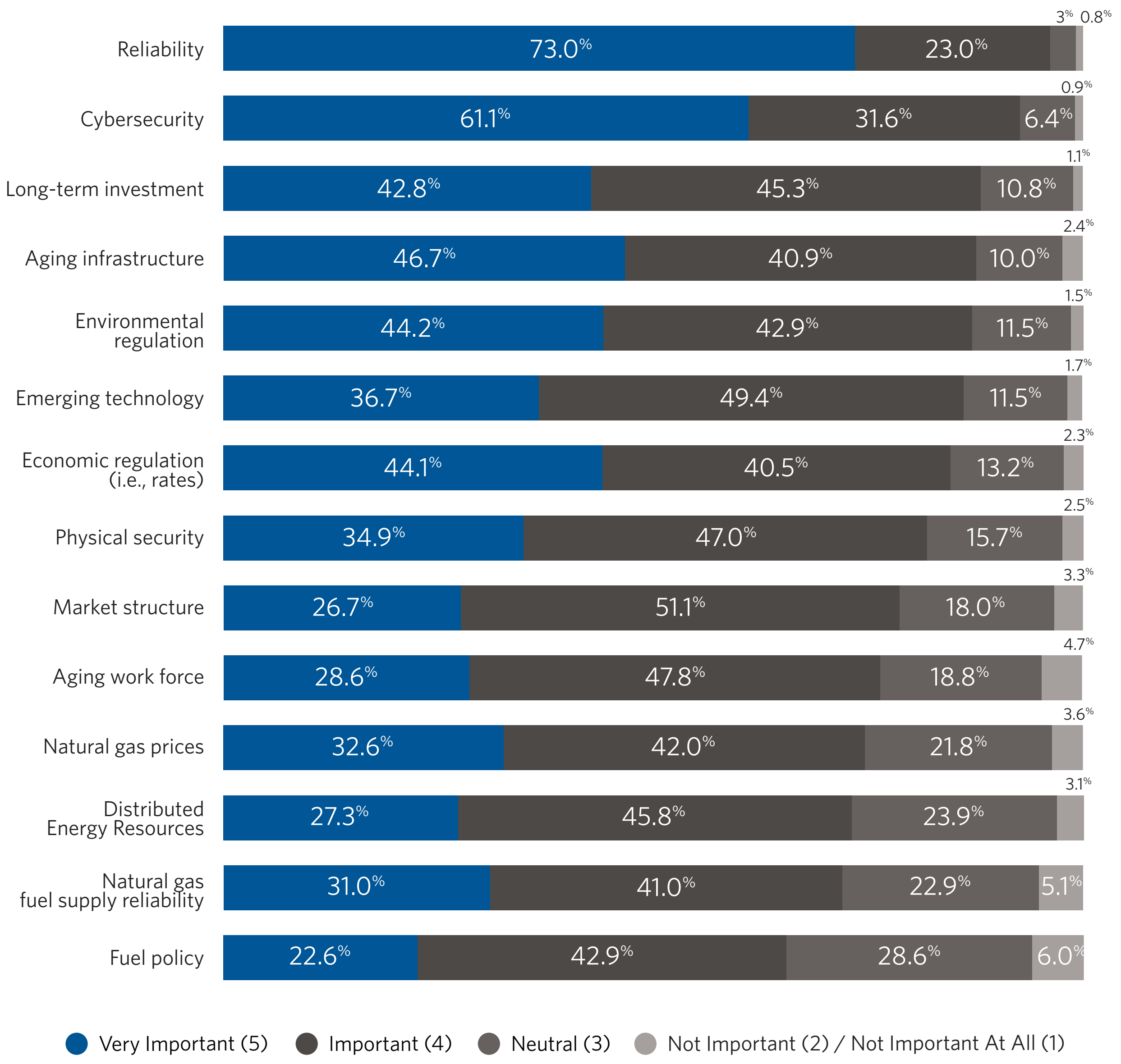
Reliability and resilience are the critical centerpieces of today's power industry. Even as utilities balance new, advanced technologies and changing regulatory mandates, organizational leaders are keenly focused on meeting evolving customer demand while delivering uninterrupted power flows.

Black & Veatch's *2017 Strategic Directions: Electric Industry Report* demonstrates the range of ways in which power providers — from generation to delivery — are broadening their views and adopting more flexible financial, planning and technology initiatives to meet these demands. Investments in transmission and distribution (T&D) are rising sharply. Innovation that speeds the adoption and integration of renewable energy is at a premium. Despite headlines suggesting potential rollbacks of emissions mandates, customer and shareholder pressures are driving power providers to stick to their long-term roadmaps, driving the grid further towards sustainability.

This year's report details actions taken by the industry over the past year, but findings suggest that long-held concerns in key operational and organizational areas are not yet resolved. Reliability remains a fundamental priority, with 96 percent of survey respondents rating it as "Very Important" or "Important." Cybersecurity is a close second, followed by the management of long-term investments, aging infrastructure and environmental regulation (Figure 1).

FIGURE 1

Please rate the importance of each of the following issues to the electric industry using a 5-point scale.



Source: Black & Veatch

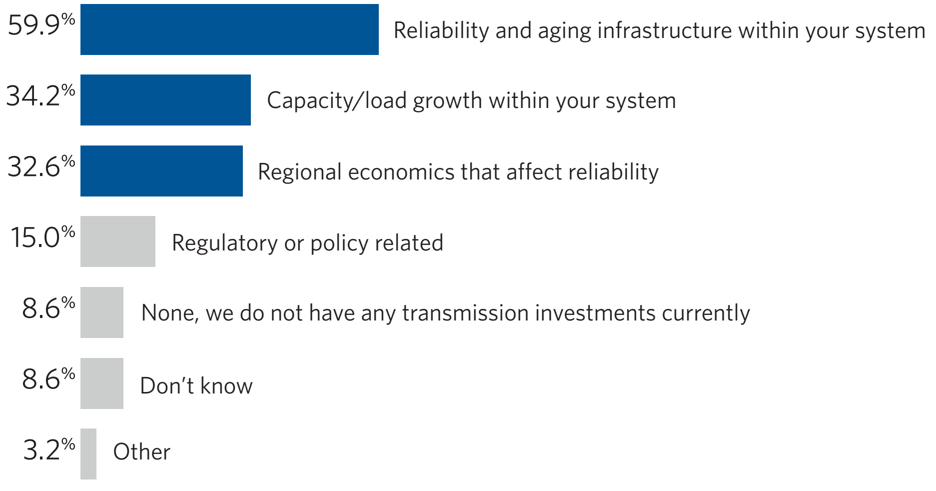
A NEED FOR T&D INVESTMENT

We are seeing heightened focus on investments in T&D, and it's no surprise that renewable energy assets are behind a surge in merger and acquisition activity aimed at bringing more renewables and distributed energy resources (DER) online. According to survey data, 60 percent of survey respondents named reliability and aging infrastructure as the major drivers of transmission investments (Figure 2). Combined with the swing away from legacy assets such as coal and nuclear, utilities are now reallocating capital expenditure (CAPEX) away from new generation assets and toward T&D and renewables.

The industry is well aware that advanced technologies such as energy storage, distributed generation and microgrids will impact transmission investments in the future, but debate over the scale remains active. A small number of respondents (8 percent) are already working to mitigate these impacts, while nearly two-thirds (65 percent) either recognize or are in the process of investigating the impacts going forward. The appeal of investment opportunities — particularly those in long-term, regulated transmission projects — is also encouraging more capital to be directed to transmission assets.

FIGURE 2

What are the top two major drivers of your company's transmission investments?



Source: Black & Veatch

At the residential level, customers continue to adopt solar and other behind-the-meter options to assert levels of grid independence that will challenge business plans of old.

INNOVATION PLAYS A GROWING ROLE

The power of innovation will become increasingly important as the industry faces micro and macro shifts that are reshaping the future of power as we know it. Large-scale plants and new-build prospects are evolving, coal retirements continue and renewables are on the rise.

Changes, big and small, are forcing reconsideration of long-held planning and delivery models. At the residential level, customers continue to adopt solar and other behind-the-meter options to assert levels of grid independence that will challenge business plans of old. Even large-scale power delivery is changing: Credit Suisse reported earlier this year that a quarter of U.S. shopping malls will close by 2022, driven out by the rise of e-commerce. This retrenchment in the brick and mortar space in favor of centralized retail is altering the commercial landscape and will likely catalyze alternative approaches to delivery to meet the unique needs of distribution hubs or other large, consolidated facilities.

Such shifts are motivating prominent firms to create positions devoted to listening and responding to customers — from homeowners to warehouse managers. Greentech Media recently reported that this new member of the C-Suite is becoming more popular among service industries. According to the Chief Customer Officer (CCO) Council, there were less than 30 CCOs in 2003; today, there are more than 400.

Renewable and DER integration is a priority, with almost half responding that they plan to add renewable energy sources — 44 percent from solar photovoltaic and 42 percent from wind turbines — to their systems within the next five years.

TRUSTING THE PLAN

Environmental regulations and frameworks such as the Clean Power Plan and the Paris climate agreement are in the headlines, but utility leaders are sending clear signals that they will stick with forward-looking business plans focused on efficiency, reliability and a reduced carbon footprint. As political discussions continue, the electric industry remains driven by market and customer demand, an approach that prioritizes a reliable, sustainable grid and assets that will scale and return value.

Respondents indicated that the industry is continuing down a path of decreased dependence on coal, with less than 2 percent of respondents naming coal a long-term source of generation (Figure 3). Renewable and DER integration is a priority, with almost half responding that they plan to add renewable energy sources — 44 percent from solar photovoltaic and 42 percent from wind turbines — to their systems within the next five years.

The following are among the major themes explored in this report.

Power Delivery and CAPEX

A significant shift is under way as capital flows from new generation assets toward T&D. Reliability drives most investment, but the disruptive potential of renewables requires more flexibility than aging transmission assets can provide. Delivery firms are continuing to invest heavily in the grid, as illustrated by National Grid's recent announcement that a new 1,200 megawatt (MW) project would bring clean energy from Canada to New England while new investors seek strong regulated return opportunities.

Power Generation and Portfolio Mix

Utilities are prioritizing natural gas and renewable energy for power generation, but administrative action has stoked discussion about whether reports of coal's demise may be premature. This year's report investigates whether utilities will delay retirements or continue down the path of retiring their coal assets. A slightly different story is playing out in developing economies, however, as coal is seen as a necessary, relatively inexpensive and reliable power generation source.

Renewables and the Pace of Change

Bolstered by decreasing costs, a reasonable rate of return and recent advancements in microgrids and battery storage, demand for renewables is increasing across the energy landscape. If this momentum continues, it appears that these once-nascent technologies will transform into reliable and profitable revenue generators. While some states such as California, Hawaii and New York have set aggressive adoption goals, questions persist over how quickly renewables and DER will achieve true parity with traditional generation sources.

Cybersecurity

Security remains a primary concern, with 93 percent of the industry ranking it "Very Important" and "Important." Technology has always introduced the potential for security vulnerability; today, the proliferation of smart systems and connected devices has created incalculable entry points for hackers to disrupt systems. Utilities are prioritizing security, risk and resilience mitigation to enable solutions that encompass both physical and digital security.

Regulatory

The last decade pushed the electric industry sharply toward a reduced carbon footprint, but with the Clean Power Plan on hold, utilities are left dealing with an uncertain regulatory and policy environment. Although more than a third of the industry sees this uncertainty as a major challenge, political change at the federal level may distract from more relevant regulatory action in local governments, which may have more impact on United States energy policy.

Change Is Constant

In 2016, this report noted the upheaval of a grid designed for centrally generated bulk power, flowing in one direction. That evolution has not abated, and as grid defection continues apace, yesterday's model will ultimately prove unstainable in many markets. The question is, how quickly will this occur? The key to reliability and resilience amid all this change lies in the constant reinvention that drives our industry forward.

Utility leaders must continue engaging customers to meet their demand for new technology and a lower carbon footprint. They must expand beyond legacy core services while maintaining their leadership position in the regulatory discussion. Doing so will allow for innovation and new models, all while keeping their foundational promise to a reliable grid.

Roadmap to Reliability

AGING INFRASTRUCTURE DRIVES POWER TRANSMISSION INVESTMENTS AS DER GAIN STEAM

By Dave Abrams and Judy McArdle

Digital technologies from apps to smart thermostats are rapidly changing the relationship between ratepayers and their electric service providers, but the century-old quest for reliability continues as the primary driver of investment in the nation's transmission grid.

Many elements of the U.S. electric grid approach or exceed their initial design lifespan. The 2017 American Society of Civil Engineers Infrastructure Report Card noted that most electric transmission and distribution lines were built between 1950 and 1969, with expected operating lifespans of 50 years. Aging infrastructure has been, and remains, a key sector concern while more recent worries over physical and cybersecurity issues also steer capital flows. Yet while the key drivers of investments in transmission infrastructure remain consistent, other parts of the sector are shifting in potentially dramatic ways.

David Abrams is an Executive Vice President in Black & Veatch's Power business, with an emphasis on directing the Power Delivery Business Line and Nuclear Business. In this role, he has full P&L responsibility for overseeing all Power Delivery initiatives, including electric transmission and substation design as well as engineering, procurement and construction (EPC) projects.

Judy McArdle is Senior Managing Director of the Advisory and Planning Service Offering within Black & Veatch management consulting. The Advisory and Planning team is comprised of the rates and regulatory practice for electric, gas and water rate studies; market analysis and integrated resource planning practice; and independent engineering for all types of electric generating technologies.

Many headlines have been written on the potential impacts of Federal Energy Regulatory Commission (FERC) Order 1000. Issued in July 2011, the premise behind the order was to create more competition in the transmission sector. While new build transmission-related projects have been slow to materialize, the pace is more tied to the challenges of environmental permitting and land rights acquisition than a lack of opportunities for non-traditional participants to get involved in transmission projects generating steady, long-term regulated returns.

The dynamics of the transmission market are also tied to the vast quantity of installed assets already in place. The bulk of work performed in the sector focuses on upgrades, maintenance and installations of existing network infrastructure on incumbent land and easements as assets age and loads shift due to changes in technology and demographics.

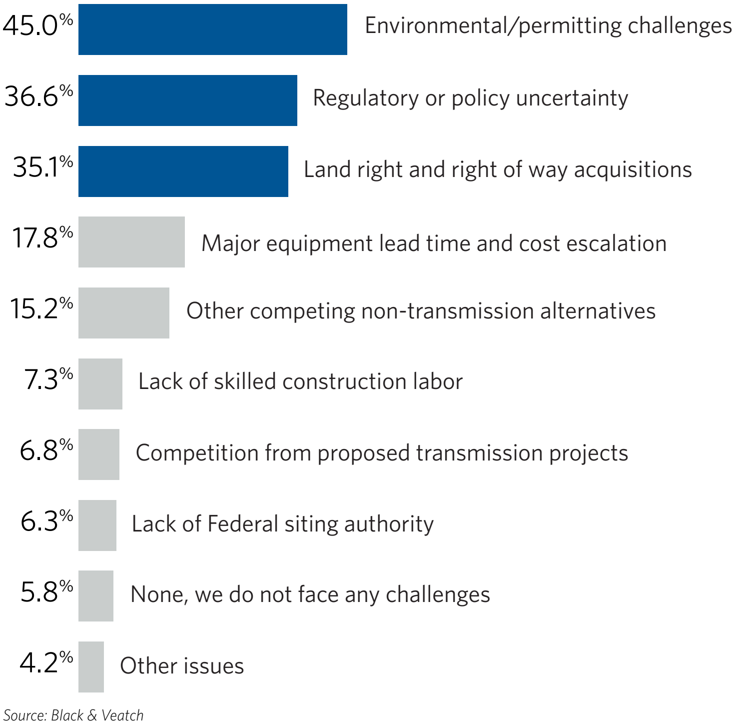
It is interesting to note that even with regulatory uncertainty ranking as the second major challenge to transmission projects, the industry widely views power delivery projects as sound electric sector investments (Figure 3).

This observation is critical as the "search for yield" has shifted from a focus on generation assets — which was prevalent as recently as the 2008-2015 timeframe — towards opportunities in transmission. From investor-owned utilities (IOUs) and incumbent service providers to private equity and alternative investment funds, investors with access to low interest rates and significant amounts of available cash are looking for solid, low-risk returns. Identifying appropriate vehicles has become increasingly challenging.

Twenty years ago, deregulation created a market pathway for developers to build power assets before seeking off-take agreements to

FIGURE 3

What are the major challenges your company faces in your ability to execute your planned transmission projects on schedule and within your budget?



Source: Black & Veatch

recoup their investments. Speculation was key to producing above-market returns. Current investments in emerging technologies like wind and solar have been influenced by strong incentive programs that are gradually being phased out as these technologies gain greater parity. For well-capitalized, risk-averse investors, transmission projects offer the ideal combination they seek.

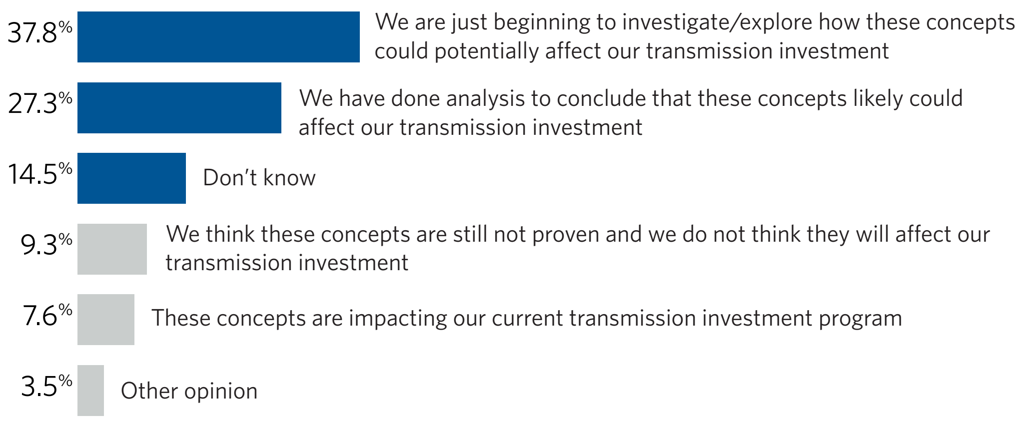
Specifically, if transmission developers don't have guaranteed off-take agreements, or nearly guaranteed agreements in place, the projects don't get built. This is not to say that projects move rapidly, or will not fall prey to classic NIMBY "Not In My Back Yard" concerns. To date, none of the major direct current projects have gotten underway because of the challenges of navigating local ordinances. But service providers, communities and government have to make choices. Do they want generation close or transmission projects? And at what cost?

A key area to watch across the transmission sector is the potential disruptive impact of distributed energy resources such as renewables, battery storage and microgrids, outlined in the DER section of this report. At the time of this writing, DER appear to fall under the banner of headline rather than substance; but of all industry trends, they seem to hold the most potential to radically transform all sectors of the power market.

For example, the decision by the New York State Public Service Commission to allow battery storage to feed into the grid from select commercial locations in Brooklyn and Queens was a factor in the cancellation of a $1 billion Con Edison substation project serving customers in those two boroughs. However, nearly 40 percent of respondents indicate they are just beginning to investigate how DER will impact their capital expenditure programs (Figure 4) and only 8 percent indicate they see the effects of DER today.

FIGURE 4

Which of the following statements best reflects your company's opinion regarding energy storage, distributed generation, and microgrids and how these concepts will impact your transmission investments in the future?



Source: Black & Veatch

In some ways, energy storage as a technology is where the solar industry was in 2008/2009 from an investment perspective — yet unlike traditional solar projects, battery storage is typically a component of the facility versus the entirety of the project itself. This reality is reflected in the current tax and incentive structure which has yet to level the cost of storage with generation.

Further, there are regions of the country where DER already have more of an impact than in others. Customers in Arizona, Nevada and California have different experiences than residents of Kansas, New York or New Hampshire in terms of renewable assets and incentive programs.

Given the challenges of utility-scale wind and solar integration, ongoing coal retirements and shifting customer demand, it's fair to say that anything that impacts the broader generation space creates potential opportunities in transmission. Whether building new natural gas plants, or closing nuclear, changing baseload power flows and the inevitable impacts of time on installed assets creates a need for capital to flow toward the power delivery business.

Roadmap to Reliability

POWER GENERATION — IS COAL REALLY MAKING A COMEBACK?

By Lynn Allen and Roger Lenertz

The current administration has revived debates over coal's role in the country's overall energy mix. Still regarded as one of the most economical generation resources in an industry heavily driven by cost and reliability, some believe coal may experience a revival of sorts; however, most forward-looking infrastructure investors and industry leaders are not as optimistic. To this point, BlackRock, the world's largest investment group, recently proclaimed, "Coal is dead."

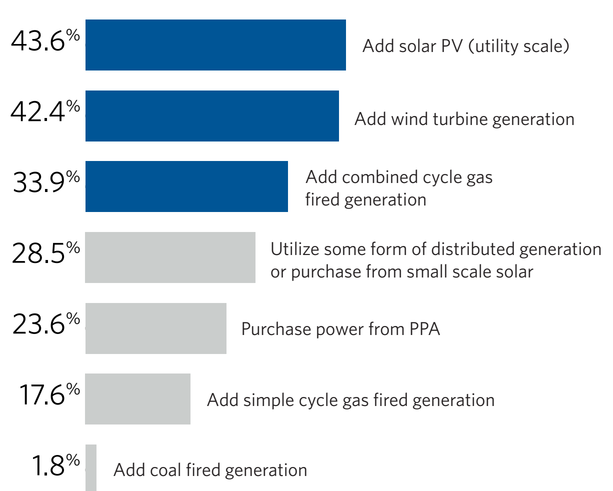
Lynn Allen is a Managing Director for Black & Veatch management consulting, leading business development and project delivery efforts within the transactions advisory group. He has 28 years of broad-based energy industry experience, including upstream oil and gas operations and power generation and delivery experience spanning the U.S. and European markets.

Roger Lenertz is the Director of Power Generation Services and Renewable Energy for Black & Veatch's power business. He handles business strategies, business development, sales, project execution, client management, business operations, industry technology leadership, and profit and loss results.

Respondents in this year's *Strategic Directions: Electric Industry Report* reflected this trend, with only 2 percent indicating that they are adding 50 MW or more of coal-fired generation to their systems in the next five years. Conversely, solar photovoltaic, wind turbine generation and combined cycle gas-fired generation were listed as the top forms of electric generation to be added by providers (Figure 5). Distributed generation (DG) is the fourth likely type of addition, but reluctance was noted because of the absence of microgrid/DG regulation.

FIGURE 5

Which of the following types of incremental electrical generation, greater than 50 MW, will you likely add to your system within the next five years?



Source: Black & Veatch

CHANGING MARKET DYNAMICS

While coal's long-term play might be limited in U.S. electric markets, it will continue to be an important bridge for utilities as they integrate more renewable energy. Beyond politics, the energy market is certainly changing and many operators are now evaluating the future of their existing coal-fired facilities — whether they should convert to natural gas-burning units or how they can keep pace with anticipated regulatory mandates as their assets age.

For many utilities, regulations — or the lack thereof — can be seen as a hindrance to integrating more DG, such as microgrids and even solar and wind. Sixty-one percent of survey respondents feel that the U.S. regulatory framework needs to be improved to help better manage electrical supply systems. Of the respondents who felt it needs to be improved, one-third felt the regulatory model should be updated to reflect changing DG market conditions. Market mechanisms and products would allow electric providers to recoup costs and encourage further DG and renewable deployment.

A key backdrop to this is the unresolved recovery of additional incremental costs incurred for these types of generation. The well-known "duck curve" net load profiles, in the absence of portfolio regulation, are already resulting in oversupply of solar generation capacity and implications for optimal thermal dispatch across some regions during peak periods.

Despite rate recovery impediments, natural gas, renewable energy and DG are becoming more economical. Even in regions where coal has historically been a part of the infrastructure backbone, customer and investor demand is giving way to more clean energy sources.

Many operators that have plans in place to retire coal-fired units are evaluating renewable options for replacing this capacity. For example, Kansas City Power & Light Co. recently announced that it would retire five coal-burning power units and will supplant some of this capacity with wind energy, increasing its renewable portfolio to more than 20 percent of its total generating capacity. Management listed declining wholesale power and natural gas prices, environmental compliance, and the improving economics of wind generation as major drivers in its decision.

American Electric Power (AEP) is another industry leader that recently announced that it is focusing on sustainable energy in an effort to "de-risk" their business. Their integrated resource planning process will include new wind and solar generation in the coming years. Natural gas-fired generation will serve as their primary choice for new 24/7 generation. Together, renewable and gas generators deliver a very clean, affordable and resilient generation mix. Carefully analyzing reliability and assessing risk is a critical part of many industry leaders' planning processes. AEP is working with Black & Veatch to conduct a comparative analysis of market drivers and innovative approaches to create better value propositions.

Black & Veatch is helping numerous clients evaluate their system needs under uncertainty, develop feasible generation alternatives, select optimal configurations and technology and plan for modifications to future system requirements as markets evolve and ever-changing demands dictate. Even the definition of reliability continues to evolve from assets and climate impacts to include cybersecurity and sustainability. Cybersecurity rose to the second most important issue within the electric industry in this year's report, surpassing aging infrastructure and environmental regulations.

Major corporations are gaining attention for their commitments to renewable energy use, with many looking to achieve energy independence from the grid at large.

COLLABORATING TO CREATE MARKET VALUE

Despite fluid market dynamics, electric providers must continue in their role as the trusted connectors that adapt to change delivery models in a continuous effort to add future value to their customers. Collaborating with industry professionals and market experts can help derive products and solutions for end users that can yield new revenue streams and business models as well as environmental benefits. Particularly with DER or microgrids, the "behind-the-meter" impacts on the distribution system and reliability must be factored into the decision-making process. These resources can provide a hedge against rising power costs and have been positively received by both end users and power providers alike. For example, military bases pursue self-generation for energy security, while power users in certain regions that experienced outages from major storms seek to ensure uninterrupted service for their communities.

An increase in power purchase agreements by commercial, industrial and utility players has also raised the question of who is in the best position to shape the balance in the emerging grid profile and control renewable generation's impact on the system. Major corporations are gaining attention for their commitments to renewable energy use, with many looking to achieve energy independence from the grid at large. Without proper industry collaboration, particularly with local utilities, grid reliability could be put at risk. As the electric sector is being supported by utility and non-utility owned renewable generation resources, the industry must find an efficient and effective way of working in partnership to orchestrate this transition.

To help manage these less predictable factors, many utilities are also turning to technology. Of this year's respondents, 45 percent indicated

that they are extremely or somewhat likely to invest $25 million or more over the next two years for operational improvements related to Big Data analytics, smart grid improvements and/or system monitoring. Survey results show a direct correlation between the population size served by a utility and the likelihood of adopting smart technology, but the reality is that these advancements could benefit organizations of any size.

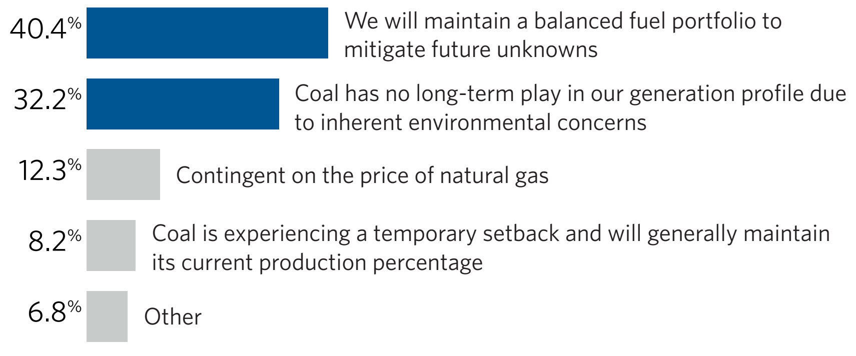
THE FUTURE OF COAL

Despite renewable energy's advantages over the long term, a diverse portfolio that includes fossil generation resources and renewable DER will be needed to maintain system reliability and achieve optimal economics. Forty percent of respondents indicated that they plan to maintain a balanced fuel portfolio to mitigate future unknowns; however, another 32 percent expressed that coal has no long-term play in their generation profile because of environmental concerns (Figure 6).

Resource planning efforts will require coordination and collaboration between suppliers and stakeholders to ensure reliable and affordable power supplies. Coal will not be leaving the grid anytime soon. However, market drivers, environmental compliance and the need for a more modular fossil generation portfolio to successfully integrate DER into the electric system will continue to put pressure on coal operations and erode economics. Comprehensive feasibility studies, contemporary analytical methods and a keen focus on distribution level impacts are required to inform the resource planning process and successfully integrate DER across the electric system as coal assets are supplanted by other generation resource options.

FIGURE 6

Which of the following statements best reflects your company's overall strategy related to coal-fired generation in any form?



Source: Black & Veatch

Roadmap to Reliability

ALL REGULATIONS ARE LOCAL: STATES STRIVE TO HELP SET CLEAN ENERGY AGENDA

By Andy Byers

Surface reads of recent headlines declaring the federal government's about-face on environmental regulations might suggest a similar shift in power generation sector trends. The roll back of numerous environmental regulatory policies aimed at reducing the nation's carbon footprint and mandating improvements to existing fossil fuel plants was a major campaign vow. These announcements are leading some to believe that power providers have new impetus to rewrite their long-term planning to account for these changes.

Instead, we find the power industry not only maintaining its pursuit of renewables, distributed energy resources and distributed generation as part of balanced power generation portfolios, but a widespread recognition that while federal rollbacks can set a tone, states will continue to drive the regulatory agenda for most utilities.

Andy Byers is Associate Vice President and Director of Environmental Services in Black & Veatch's power business. He currently serves as the power business Environmental Regulatory and Legislative Policy Advisor.

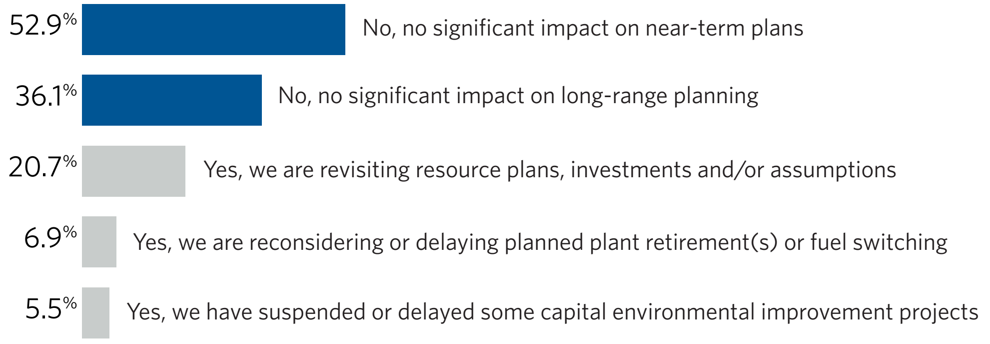
Since the start of the 115th Congress in January, legislators have worked with the Administration to repeal Obama-era regulatory actions. Within the first 100 days, President Donald Trump had issued an Energy Independence Executive Order directing reviews for revisions or repeal of the Clean Power Plan and greenhouse gas performance standards for new power plants, along with various other guidance and requirements tied to carbon emissions and costs.

Additional Environmental Protection Agency (EPA) announcements and proposals to suspend and reconsider final rules tightening ozone air quality standards, effluent limit guidelines, methane emissions and risk management programs have been published and taken effect. At the same time, the Department of Justice has been very successful in convincing courts to suspend ongoing litigation over these rules to allow for their reconsideration, which could take several years to complete.

Beyond these pronouncements and suspensions, as of mid-2017, the EPA has yet to take any formal procedural actions to undo these policies. To fully revise or rescind these final rules, the EPA will have to publish new proposed rules, go through a notice and comment period and then issue

FIGURE 7

Have the current administration's announcements to roll back environmental regulations impacted your organization's future planning?



Source: Black & Veatch

final rules — all of which will take about a year — likely followed by another year of even more court challenges. It could easily take two and a half years or more before the dust settles on these rollbacks.

Meanwhile, because of the nature of generation planning, these announcements are not likely to change the long view at many companies. Since these plans must look decades into the future, utilities will be reluctant to change course due to potential shifts in future government environmental and energy policies. This year's report finds organizations largely staying the course they set in recent years under a pro-regulatory political environment (Figure 7).

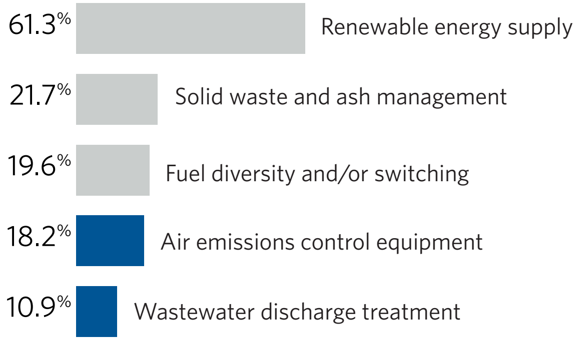
STATES TO DRIVE ENVIRONMENTAL AGENDAS

With the federal government signaling its intention to loosen the regulatory reins on the energy sector, individual states are primarily driving their own environmental requirements and policies. States have authority under most major environmental statutes to impose and implement more stringent requirements than the nationwide standards set by the federal government. Thus, while state legislatures may still impose some restrictions on themselves, states are not generally constrained by relaxation or absence of environmental rules by the federal government.

In response to the president's announced rollbacks and, more recently, withdrawal from the Paris climate agreement, many governors, state assemblies and utility regulators are setting policies that align and, in some cases, seek to exceed the carbon reduction mandates set out in the now-suspended clean energy rules. Several states are considering joining California and the nine states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont) in the Regional Greenhouse Gas Initiative carbon cap-and-trade programs. More than 12 states, including California, New York and Virginia (representing almost 20 percent of the nation's carbon dioxide emissions), have formed a climate alliance that pledges to still meet the Paris climate agreement, and are joined by mayors from over 200 major U.S. cities in signing a similar "We Are Still In" pledge.

FIGURE 8

Which of the following environmental requirements will your organization invest in most over the next five years?



Source: Black & Veatch

Currently, 29 states have renewable portfolio standards that collectively apply to 55 percent of electricity sales in the continental United States. Combined with the continuing federal tax credits (soon to be phased out), these state policies are driving investments in new generation and transmission line systems. There are a variety of unique and hybrid programs also being launched at the state level. New York has implemented a program that combines carbon emissions reduction, renewable energy penetration and energy efficiency goals. Others like Maryland have pioneered tax credits for energy storage. Several states are even looking to subsidize existing zero carbon emissions nuclear plants.

Although there are many states that likely will join EPA's bandwagon in pushing out deadlines and providing relief from burdensome compliance requirements, there are just as many states that have heightened scrutiny of power plant operations in response to mishaps that garnered news coverage and raised public concerns. As a result, utilities have to respond to varying policies and mandates of the states where their facilities are situated.

State renewable portfolio standards, air quality plans and water quality protection standards continue to influence generation plant upgrade investments and resource planning. The outcome of individual state initiatives could be a patchwork of differing standards and requirements across the country that presents even greater challenges to regional utilities that span several state lines. Meanwhile, survey respondents indicate that utilities will continue to invest in new renewable energy and environmental upgrades to existing assets in the foreseeable future (Figure 8).

Energy providers have to keep tabs on policy at all levels of government, but the surge in local emissions mandates and renewables adoption — as an answer to signals of federal-level rollbacks — will likely place new focus on state capitols. Distributed generation and renewables policies are increasingly a function of the states, as are energy prices. Business models are greatly shaped by this dynamic, especially at a time when utilities are eager to accommodate customer demand for renewable technology and alternative power delivery.

The outcome of individual state initiatives could be a patchwork of differing standards and requirements across the country that presents even greater challenges to regional utilities that span several state lines.

Roadmap to Reliability

ELECTRIC INDUSTRY LEADERS PLANNING CAPITAL INVESTMENTS

By Chris Klausner

While the White House's plans for a $1 trillion federal infrastructure program continue to coalesce, one recent estimate puts the depreciated value of the American electric infrastructure, including power plants, transmission lines, distribution lines, substations and transformers, at around $1.5 trillion to $2 trillion, with a replacement value of $4.8 trillion.

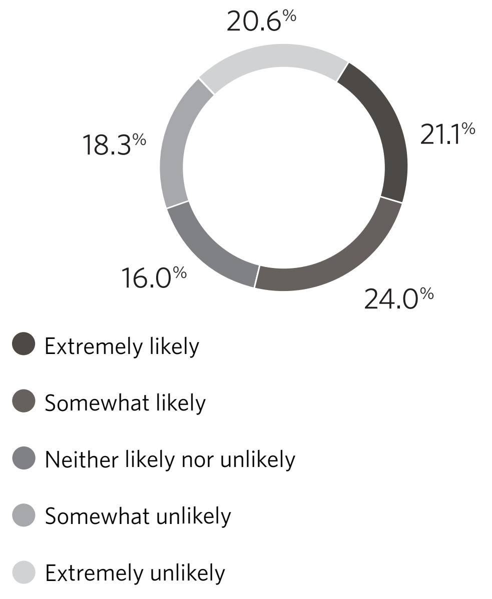
Wherever the actual costs may fall, it's clear that financing the nation's necessary infrastructure upgrades to ensure sustained reliability and growth will be a major challenge for utilities in the coming years. According to this year's *Strategic Directions: Electric Industry Report*, long-term investment, reliability and aging infrastructure are three of the industry's top five fundamental concerns. Combined, reliability and aging infrastructure were listed as the top drivers of utility transmission investments by 60 percent of survey respondents. This was nearly double the percent who listed increasing capacity/load growth as a major driver of transmission investments (34 percent).

Despite the costs, 45 percent of respondents are likely to spend significant capital investments ($25 million or more) into their systems in the coming two years (Figure 9).

Chris Klausner is a Klausner Managing Director in Black & Veatch management consulting with a power industry focus. He has more than 24 years of experience at Black & Veatch, serving in a variety of roles, including Mechanical Engineer, Consultant and Director.

FIGURE 9

How likely are you to spend a significant capital investment ($25 million or more) into your system over the next two years for operational improvements related to Big Data analytics, smart grid improvements and/or system monitoring?

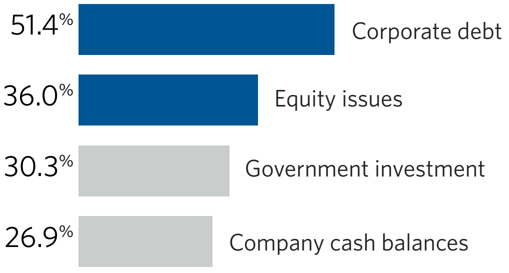


Source: Black & Veatch

This demonstrates confidence in their ability to secure funding for these improvements, most of which will come through corporate debt, with equity issues, government investment and cash balances accounting for much of the remainder (Figure 10).

FIGURE 10

Which of the following will be the major sources of financing for grid investments?



Source: Black & Veatch

Many utilities, especially IOUs, will continue to build and finance investments on their balance sheet, tapping equity as needed, because they can still make these kinds of investments and enjoy regulated returns and timely cost recovery. While this mostly traditional funding model holds true at the large scale, much of the funding for advanced technologies such as DG, storage and load balancing will happen on a smaller scale, allowing for more flexibility in funding models. For example, by putting a few small generators behind the meter from a new solar photovoltaic installation or combined heat and power facility capable of pushing power back to the grid, you've created a very different dynamic.

These new technologies — many coming from the solar, automotive and information technology sectors — are not only helping decentralize the generation and storage of power, they are also creating significant local economic opportunity. The combination of new technologies creates new dynamics such as demand stabilization, which alongside merchant power plants, renewable electricity portfolios and other new developments is significantly altering the power sector landscape.

This evolution of the power sector is leading to changes in finance models. While both IOUs and their counterparts, publicly-owned utilities (POUs), finance new projects on their balance sheets, their funding models differ in a few important aspects, especially in capital cost. They also differ in rating agency evaluations due in part to the lengthy cost recovery process many IOUs experience. Finally, as The Electricity Journal points out, the investor mix also differs with 50 percent of POU investor dollars coming from households.

Most new plants approved in California are merchant power plants, and the funding models of the independent power producers (IPPs) behind them can vary dramatically from those of POUs or IOUs. Whichever model they may adopt, there is a clear trend of merchant plants moving away from financing on the balance sheets toward more complex, non-recourse and innovative models.

There will be very different entities making smaller investments in DG and other innovative technologies, including both consumers and IPPs. Nearly 42 percent of survey respondents indicated that IPPs, developers and/or non-utility companies will play a major role in future DG investment.

Forty-three percent of respondents believe that the large capital requirements to maintain the reliability of electric service will fuel additional utility M&A transactions.

IPPs and their banks, however, are often looking for substantially larger projects than even the $25 million infrastructure investments used as the floor in the survey (Figure 11). Often these entities are looking for projects above the $50 million threshold, making it a challenge to fund projects smaller than that. One potential solution is to package a portfolio of smaller projects together to get necessary scale for financing.

At least three funding options exist at those smaller levels: smaller non-traditional banks, equipment vendors and project bundling or packaging in which smaller entities pool their projects to get the combined project portfolio size above the minimum threshold for more traditional funding sources. These can be supplemented with tax incentives and other government support; however, we don't see major direct state or federal investment in specific grid upgrade projects coming. Rather, IOUs are likely to have to fund a major part of the grid investments within the rate base.

FIGURE 11

Do you think utilities will seek to finance grid modernization projects with teaming or joint venture partnerships with third parties or other utilities to offset costs?

Source: Black & Veatch

Beyond the rise in packaging of disparate projects, the sector will continue to see a rise in merger and acquisition (M&A) activity as utilities seek other means of getting economies of scale. Our survey showed that 43 percent of respondents believe that the large capital requirements to maintain the reliability of electric service will fuel additional utility M&A transactions.

One recent example is the attempted acquisition of Westar Energy by Great Plains Energy, the parent company of Kansas City Power & Light Co. While this merger was ultimately rejected by Kansas' Public Utilities Commission, the regulator left open the possibility of approving future M&A activities under different terms, recognizing the possible benefits from a merger under the right conditions.

Change is inevitable, and the pace of change in the electric sector will continue to accelerate in the coming years. Utilities that can adapt to these changes, and evolve their own funding models as new investments are explored, will see the most success in the years to come.

Kansas' Public Utilities Commission ultimately rejected a recent attempted acquisition of Westar Energy by Great Plains Energy, the parent company of Kansas City Power & Light Co., but the regulator left open the possibility of approving future M&A activities under different terms, recognizing the possible benefits from a merger under the right conditions.

Roadmap to Reliability

STATES, LOCAL GOVERNMENT PLAY INCREASINGLY CRITICAL ROLE IN A SMARTER, CLEANER ENERGY FUTURE

By Forrest Small

Forrest Small is Senior Managing Director for Black & Veatch management consulting. He leads the Distribution Modernization and Customer Experience Service Offering. Small specializes in grid modernization strategy and planning and works closely with utilities in grid modernization and transformation programs across North America.

The federal government has long played a central role in shaping U.S. energy independence and security. This year marks the 10th anniversary of the Energy Independence and Security Act of 2007 (EISA). Over the last decade, federal programs have significantly influenced the energy sector, particularly in the development of smart grids and renewable energy.

Today, however, we stand at an inflection point where states, municipal governments and even corporations are stepping up to become the primary drivers of the future of clean energy.

The federal government has had a long relationship with clean energy, as outlined in the regulatory section of this report. Although recent moves by the administration — for example, President Donald Trump's March 2017 executive order on domestic energy policy that seeks to limit or reverse a broad set of climate and clean energy initiatives, including the Clean Power Plan — are changing the playing field, survey data shows that there is still a clear case for government involvement.

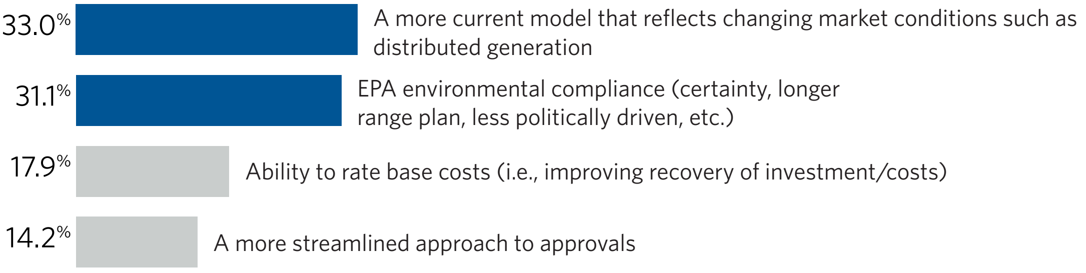
61.1%

UTILITIES SAID THAT REGULATORY FRAMEWORK NEEDS IMPROVEMENT TO BETTER MANAGE THE ELECTRICAL SUPPLY SYSTEM

For example, 61 percent of respondents feel that the regulatory framework needs to be improved to help better manage the electrical supply system.

FIGURE 12

Which area of the regulation making process in the U.S. do you feel is most in need of improvement?



Source: Black & Veatch

One-third (33 percent) indicated that there is a need for a more current model that reflects changing market conditions such as distributed generation, while 31 percent identified a need for improved EPA environmental compliance (Figure 12).

ENCOURAGING EVOLUTION WITH ENERGY INCENTIVES

America's history with federal energy subsidies can be traced as far back as 1789, when Virginia's representatives in Congress successfully argued for import tariffs on coal until the state could develop its mines. At the time, coal from England was so cheap it was being used as ballast by the country's ships.

In a 2011 analysis of federal expenditures to promote energy development, Management Information Services, Inc. outlined six categories of government-driven energy incentives, with tax policies such as special exemptions and credits accounting for the majority (47 percent) of incentives since 1950. This is followed by regulations (19 percent), research & development (R&D) programs to support new and emerging energy technologies (18 percent), and direct market involvement in hydroelectric and oil account (10 percent). Government services account for most of the remaining 7 percent, with disbursements in the form of direct federal grants and subsidies making up a negligible fraction.

In the years since, the U.S. saw shifts not only in the form of incentives, but also the industries that received them. According to a report published by DBL Investors, the oil and gas sector enjoyed the largest percentage of federal energy incentives over the last 91 years, with an average of $4.86 billion in investments every year (in 2010 dollars).

Nuclear came in second with $3.5 billion annually over 52 years; by comparison, biofuels came in third with $1.08 billion over 29 years, and renewables fourth with $0.37 billion over 15 years.

Most recently, there has been heightened interest in DER integration for reliability and energy costs savings, directly benefitting investment in energy storage and microgrids.

IMPLEMENTING POLICY MANDATES, TAX INCENTIVES AND PARTNERSHIPS

The government has also looked to policy mandates to encourage change. In 2009, the American Recovery and Reinvestment Act (Recovery Act) brought teeth to the goals that EISA defined, allocating $4.5 billion to the Department of Energy (DOE) to modernize the electric power grid. Meanwhile, the Smart Grid Investment Grant and Smart Grid Demonstration programs led to billions of dollars in investments in over 130 smart grid projects focused on grid modernization, cybersecurity, interoperability and data collection.

Another route has been tax incentives that support renewable energy technology. These incentives are helping to create new energy products and services and deploy clean distributed energy resources into the grid. Most recently, there has been heightened interest in DER integration for reliability and energy costs savings, directly benefitting investment in energy storage and microgrids.

Public-private partnerships are becoming an increasingly attractive option, with microgrids presenting an excellent opportunity for stakeholders to get involved in an evolving energy ecosystem. These options illustrate the many ways in which governments at all levels can play a critical role in stimulating and supporting grid modernization and contribute to a more sustainable, smarter electric grid.

OUTLOOK FOR TODAY, TOMORROW AND THE FUTURE

While the energy sector enjoys federal support, increasingly it is state and local governments and corporations that may have the largest direct impact on the vision and action plans for clean energy. California recently passed legislation to accelerate achievement of 50-percent renewable energy by 2026 (from 2030), and 100-percent renewable energy by 2045. Oregon, Massachusetts and Nevada have also enacted laws setting targets for energy storage. At the municipal level, mayors from over 100 cities across the U.S. have adopted goals to transition to 100-percent renewable energy no later than 2035.

While the industry expresses appreciation for the policy-driven approach taken by these states, they do have concerns about scope, speed and other factors. However, armed with greater flexibility and a better understanding of local and regional factors, states and smart municipalities are in the best position to enact meaningful change within our energy infrastructure and significantly impact the development and adoption of new energy technology.

At the municipal level, mayors from over 100 cities across the US have adopted goals to transition to 100-percent renewable energy no later than 2035.

Roadmap to Reliability

GLOBAL PERSPECTIVE – INDONESIA IN TRANSITION: MINEMOUTH COAL AND HYBRID RENEWABLE SOLUTIONS

By Dennis Gibson and Jim Schnieders

Indonesia, a nation of three time zones, thousands of islands and 250 million people, continues to experience major industrial and economic growth. Boasting vast untapped resources that include copper, gold, tin, nickel and coal, the mining sector will continue to play a significant role in the country's development.

Dennis Gibson is Chief Technical Officer, Mining at Black & Veatch. He has over 35 years of experience in civil engineering and mining, including safety and risk management, project management, environmental, sustainable development, mine closure, tailing, water resources, due diligence, studies and business unit management.

Jim Schnieders is Managing Director for Black & Veatch's EPC Power business in Asia and presides over the company's growing engineering and construction capabilities in the region. He focuses on topline EPC projects for traditional power generation as well as opportunities in renewable energy.

The provision of a secure, reliable power supply is critical for mining operations. Energy usage can account for up to as much as 50 percent of operating costs. Indonesia, as it races through its transitional development phase, continues to chase full electrification and grid stability. Load shedding by overstretched electric utilities can have a major impact on the profitability of mining operations.

Thousands of mining projects in Indonesia rely primarily on fossil energy such as coal and diesel to power their operations, but this existing model is waning.

Diesel generation is causing operational challenges. Fluctuating fuel costs, high consumption, unreliable delivery channels and risky storage tanks can cause sleepless nights for many financial and operations managers. In off-the-grid mining areas such as Kalimantan, Sumatra and other eastern parts of Indonesia, operators often use diesel generation to fuel their entire operation. This option carries a high cost in terms of sustainability as well as operations.

Indonesia's abundance of lower rank coal represents another pragmatic solution to fully electrify Indonesia as economically as possible while maximizing its indigenous resources.

Global shareholder pressures for more sustainable practices, uncertainty around local regulations and requirements as well as advances, availability and affordability of alternative technologies are also putting pressure on current practices.

Enter "hybrid" deployments. This is the local terminology for burgeoning microgrids at mining sites that blend and combine traditional and renewable power sources and present mining companies a pragmatic transition to cost-effective and more environmentally sustainable operations.

Low to medium penetration of renewable power systems with diesel can meet 10 to 30 percent of a mine's energy demand. By starting to integrate renewable energy sources into their power portfolio, mining operators in Indonesia can significantly reduce fuel transportation costs and reliance on diesel supply, and increase resilience of their power supply. By utilizing renewable energy, whether solar, hydropower or wind, operators can better balance reliability and financial demands with social and environmental pressures.

Mine operators in countries like the United States, Canada, Australia and Chile have incorporated renewable energy into their power supply portfolio through utilization of hydropower, wind and solar energy. Black & Veatch estimates that an average remote project, with a power demand of 5 MW, integrating wind power to generate 15 percent of the site's energy supply, could save 10 percent in energy costs.

In addition to the emerging hybrid captive power trend in Indonesia, the government is planning and encouraging multiple coal minemouth projects. As part of the government's 35 gigawatt power plan to close the nation's electrification gap, PT Perusahaan Listrik Negara, the national electric utility, envisages that 7,000 MW will be supplied through minemouth power.

Earlier this year, regulations were introduced that help establish an offtake price cap, which differs depending on where across Indonesia's economically divergent archipelago the proposed project is located. It means that independent power producers can now better calculate the viability of up to 7,000 MW of projects in different regions around Indonesia.

Not every coal mine site will be economical for minemouth power investment. What the regulations enable are more accurate and detailed early stage technical and financial assessments where developers can better understand the energy price as well as the capital and ongoing operations and maintenance costs of a proposed project.

Indonesia's abundance of lower rank coal represents another strategic solution to fully electrify Indonesia as economically as possible while maximizing its indigenous resources. How Indonesia balances these resources will be central to a prosperous and sustainable future.

Technology

PLANNING, BUDGETING AND DATA PIVOTAL FOR SMARTER ASSET MANAGEMENT

By Will Williams

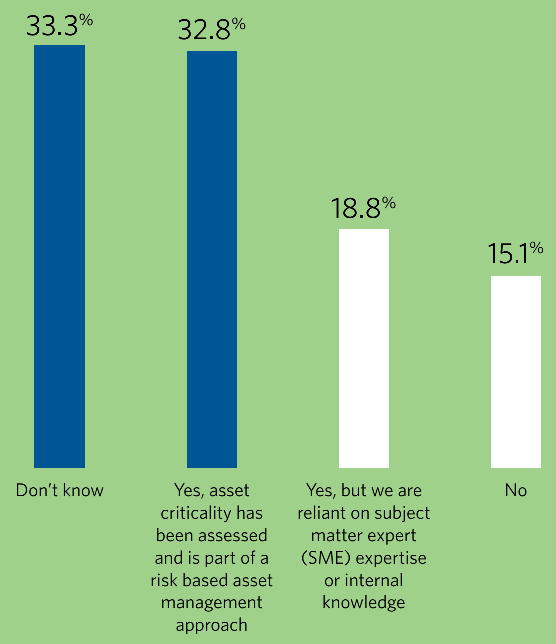
Amid interwoven and oft-cited concerns about reliability, cybersecurity, funding and aging infrastructure, this year's *Strategic Directions: Electric Industry Report* results again reveal that electric industry leaders view risk-based planning, long-term budgeting and preventive maintenance as key to ensuring that asset health and reliability are sustained.

Risk-based, proactive approaches to planning and investment prioritization are increasingly being adopted to better capture asset knowledge and monitor the condition of critical equipment while supporting budget needs in a more targeted manner. According to survey data, 33 percent of respondents say they are able to target maintenance and capital replacement on their highest risk assets through the implementation of a proactive risk-based prioritization approach. While encouraging, nearly 20 percent report that they rely on reactive strategies that are dependent just on institutional knowledge and subject matter expertise (Figure 13).

Will Williams is an Associate Vice President in Black & Veatch's Asset Management practice. He has more than 25 years of experience in asset management planning, including risk-based capital prioritization, ISO 55001 gap analysis, asset failure analysis, risk assessment, performance benchmarking, maintenance optimization and business change management, among other areas. Williams is based in Atlanta, Georgia.

FIGURE 13

Do you have a risk profile of your transmission and distribution assets?



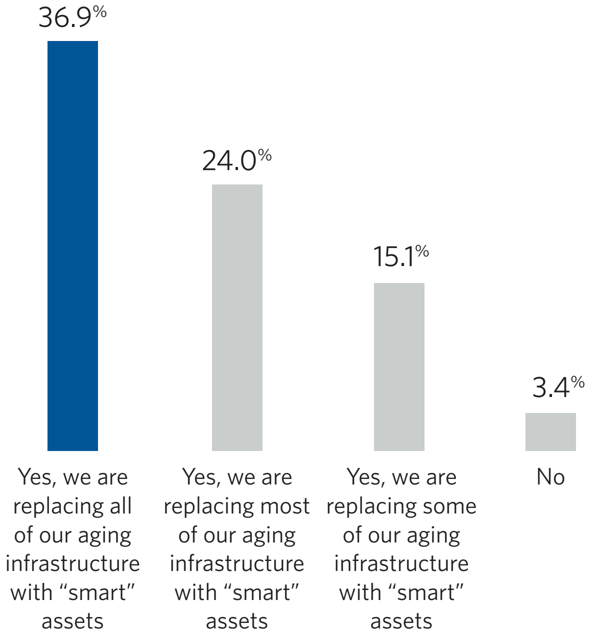
Source: Black & Veatch

The worry here, of course, is that essential asset data and knowledge may disappear when workers do, a situation faced by many utilities where large proportions of the current workforce are expected to retire within the next five years. In fact, 58 percent of industry professionals expressed concern that as new employees replace the current aging workforce, the condition and configuration of the most important assets may not be documented well enough to allow new employees to effectively maintain critical systems. Two solutions present themselves: capturing this information and storing it in an easily accessible format, as well as deploying remote monitoring on critical assets. These are both key investments utilities can make now to better understand asset condition and performance and in so doing, prevent future problems.

With an eye on reliability and resiliency improvements, the electric industry continues to look closely at ways to better monitor and gauge asset health with performance, cost and risk at the center of all sound and balanced asset management strategies. As aging infrastructure is replaced with "smart" components, utility operators will require advanced control and distribution management systems that can securely utilize new digital technology and asset data to inform system operations. According to survey results, a little over three-quarters of respondents indicated that they are swapping aging infrastructure with smart two-way communication-capable assets rather than like-for-like replacements (Figure 14).

FIGURE 14

As you replace aging infrastructure, are you installing "smart" two-way communication-capable assets rather than like for like replacements?



Source: Black & Veatch

At the heart of this electric industry and business model shift lies the need for utilities to collect high-quality asset data to improve strategic and tactical decision-making related to their energy delivery assets. The key focus is on improving reliability and levels of service to customers, whose expectations of what "good service" means have been steadily increasing over recent years. Thus, utilities are examining how the declining health of transformers, power lines and other equipment can be best and most cost-effectively addressed to minimize system stress and maximize asset performance and availability.

Many end users are beginning to take control of their home energy consumption and service through the use of remote monitoring systems, a movement that is expected to gain speed over the next few years.

Meaningful steps are being taken to address these issues, as 65 percent of survey respondents reported that they have strategies in place that incorporate remote monitoring and control of critical assets. This represents a seemingly significant trend that illustrates that electricity providers of all sizes and geographic areas are listening to customers and getting smarter about how they control their systems to meet changing and escalating consumer expectations. For example, many end users are beginning to take control of their home energy consumption and service through the use of remote monitoring systems, a movement that is expected to gain speed over the next few years.

The upside of replacing aging and underperforming assets with smarter modern equipment that can be controlled remotely is clear; however, along with increased electric grid intelligence comes the potential for greater cybersecurity vulnerability because there are more entry points into the system. Therefore, as reflected in the cybersecurity section of this report, it is paramount that as more critical assets gain the ability to communicate operational data, these assets are integrated into risk profiles, analyses and management.

For some electric providers this will mean stepping up efforts to collect newer and better quality data to determine asset vulnerability, criticality and health.

This year, 82 percent of survey respondents acknowledged having sufficient asset data to enable the assessment of criticality and likelihood of failure. However, more than half revealed that there are significant gaps in their data or that risk is not yet being evaluated to determine the potential impact of failure.

So what types of asset data are being collected by electricity providers? Survey results indicate that 73 percent of respondents are capturing asset performance data, with financial and process performance data also

prominently listed. The bigger question then becomes whether industry leaders are acting on the data being collected to enable faster, smarter decision-making and to improve asset performance.

Digging deeper, in describing how their asset data is being used to inform strategic and tactical investment decisions, 35 percent of industry leaders responded that they are doing so at a high level, analyzing past trends (budgets and performance data) and using this to evaluate how best to meet future year targets. A little over 28 percent reported that they combine a detailed analysis of performance over time with known required and desired future activities to make go-forward decisions. These moves are made on the balance between maintenance and capital investment as well as the future composition of the asset base and investment in "smart" assets and remote monitoring.

It is paramount that as more critical assets gain the ability to communicate operational data, these assets are integrated into risk profiles, analyses and management.

Painting a complete asset management picture cannot be done without addressing funding within a changing regulatory construct. The way federal and state regulators are looking at electric grid investment from rate cases toward risk-based approaches is shifting. States such as California, Indiana and New York, along with the United Kingdom, Australia and other countries, are leading this investment transformation. They do so in the face of always increasing expectations from customer populations that generally are averse to paying for infrastructure improvements no matter how badly they are needed. As noted in this report's finance section, grid modernization — including smarter asset management programs — is leading to changes in funding models that, in addition to government investment, depend heavily on corporate debt, equity issues and other sources of investment.

Technology

RENEWABLES, DISTRIBUTED ENERGY RESOURCES AND THE PACE OF CHANGE

By Jeremy Klingel and Ryan Pletka

Even with the ascension of natural gas on the back of lower prices, the falling costs of renewables and battery storage mean solar and wind are becoming increasingly competitive generation options. Many believe utilities that encourage renewable and DER adoption can stay ahead of this momentum, bringing their resources, size and scale to transform these once-nascent technologies into reliable and profitable revenue generators.

Few doubt that renewables and DER are here to stay, and this year's *Strategic Directions: Electric Industry Report* survey underscores a paradigm shift in how utilities regard renewables. Just a few years ago, a current of uncertainty ran through the marketplace over how DER would possibly disrupt and upend the industry. Today, after having time to digest both the impact and opportunity presented by these technologies, utilities are facing the issue head on with a healthy dose of rationale and are able to accept that distributed energy will have an impact, but will not necessarily redesign who they are.

Jeremy Klingel is Senior Managing Director for Black & Veatch Management Consulting, where he is responsible for developing and delivering the market strategy regarding end-to-end grid-related initiatives for electric utilities. Klingel has led over two dozen smart grid development projects, driving the operational roadmap behind advanced distribution management and end-user experience.

Ryan Pletka is the Associate Vice President for Growth and Innovation at Black & Veatch. He is a founding member of Black & Veatch's Growth Accelerator team, whose mission is to drive rapid, sustainable growth for the company. Pletka's responsibilities include identifying new trends, evaluating emerging technologies, developing new business models, and establishing partnerships with internal and external entrepreneurs.

THE HOLISTIC INTEGRATION OF DER

Global trends of decarbonization, decentralization and electrification of energy are driving critical changes for electric utilities. Utilities are starting to understand the role that renewables can play in ensuring reliability, an undeniable driver for the industry. Survey data shows that 66 percent of respondents heavily prioritize reliability, followed by cost (58 percent) and environmental sustainability (39 percent)

when considering which types of generation to add to their systems. While renewables are often seen as an environmentally driven choice, their greatly improved economics can make them a low cost generation source for many utilities.

With this in mind, the majority of respondents are beginning to look at renewable assets with a cautious optimism. Rather than view these resources as intermittent sources of energy that cannot be depended upon for reliable output, they believe that — armed with the help of energy storage and advanced distribution platforms — they can harness this distributed supply and improve system flexibility and resilience.

To that end, respondents indicated they are investing in solar photovoltaic (PV) (44 percent) and wind (43 percent) with plans to add these sources to their systems within the next five years. Solar and wind are the most popular generation options, with natural gas combined cycle coming in at third with 34 percent. This marks the first time that solar PV has appeared No. 1; although not entirely unexpected, it is a big change for the industry. Utilities are also looking to renewables to fulfill environmental requirements, with 61 percent of utilities identifying renewable energy as their biggest investment over the next five years.

In their quest to provide reliable and resilient service, utilities are also realizing the benefit of integrating DER across areas once considered foundational, such as long-term investment strategies and replacement of aging assets. Rather than act as an outlier, distributed energy has permeated the industry to the point where every piece or component — from market structure to security to emerging technologies — is affected by the increase in deployment.

That said, utilities are not upending their business models and strategic plans; rather, the rate of change has been gradual enough that utilities are able to take a more methodical route.

They are also looking for more holistic solutions — for example, shunning the idea of DER-specific management systems (DERMS) in favor of all-encompassing advanced distribution management systems that are flexible and capable of managing all asset types, as well as demand-side resources. The survey data supports this, with 45 percent of respondents not planning to implement DERMS versus 31 percent that either have a system already in place or are planning to use one.

ENERGY STORAGE

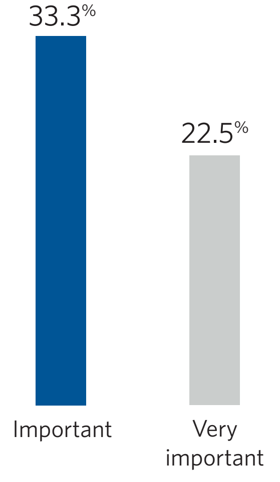
All this support surrounding renewables and DER has one sticking point — the ability to store that energy for use on demand. Although the maturity of storage technology is still in the early stages, utilities are cultivating a growing interest, with more than half of respondents (56 percent) viewing the use of energy storage to increase solar PV as "Very Important" or "Important" (Figure 15).

Today, large vertically integrated utilities are seriously looking at how to embrace storage along with small-scale PV. More than a quarter of respondents (27 percent) are either running or developing an energy storage pilot program, almost half (45 percent) have it on their technology roadmap, while 28 percent are not planning for energy storage at this time (Figure 16).

All this support surrounding renewables and DER has one sticking point — the ability to store that energy for use on demand.

FIGURE 15

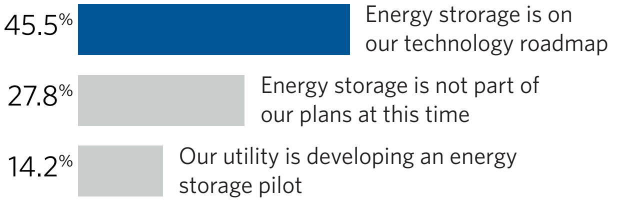
How important is the use of energy storage to increase the deployment of photovoltaics in your generation mix?



Source: Black & Veatch

FIGURE 16

Which of the following best describes your company's activity related to energy storage?



Source: Black & Veatch

OPPORTUNITIES FOR GROWTH

Utilities are already facing the burden of decreasing load demands, and it is likely that load growth will never return to the strong rate of years past. This might be a challenge for some utilities, forcing them to be more creative in discovering new opportunities across all constituent bases — industrial, commercial, etc. That said, a significant opportunity lies in the electrification of transportation and other sectors of the economy, such as agriculture and commercial. Smart utilities are already looking at this as an opportunity that may, in five to 10 years' time, allow them to maintain or grow their earnings.

As renewables and DER continue to proliferate and become part of the common ecosystem, the industry will also need to seek out and develop new business models that help to define the cost benefits for utilities. Considerations include the ownership and maintenance of assets, whether a hybrid model should be considered and the value of co-developed opportunities. Or will new business models look more like an economic development opportunity, with large industrial customers working with utilities to attract more customers? And if so, what model will it take? How will utilities monetize it to their customers?

THE TIPPING POINT

In the not too distant future, utilities will either embrace serving as more than just generators or "poles and wires" companies or be mandated to do so. Some must react and actively participate in the achievement of 100 percent of a state's supply coming from renewable sources, as already demonstrated by Hawaii and potentially California. Others will be called upon to create a new market mechanism — as illustrated by New York's Reforming the Energy Vision (REV), which has moved to a transactive open platform to integrate, trade and aggregate supply from any qualifying source, regardless of whether it comes from a tiny residential rooftop or a massive, commercially owned microgrid.

While most utilities will face a less drastic pace of change, factors including aging conventional generation, grid parity regarding the cost of renewables and DER, and customer demands in the age of self-service and technology will require utilities large and small to embrace renewables as an integral ingredient to delivering clean, reliable energy in a cost-effective manner.

Technology

DISTRIBUTED GENERATION STILL PART OF THE PLAN AS TECHNOLOGY ADOPTION MATURES

By Jason Abiecunas, Rick Azer and Tim Imlah

Distributed energy resources continue to drive change within the electric industry as both energy consumers and electric service providers are diversifying how electricity is generated and delivered. Spawned by the public embrace of clean energy, falling prices, and regulatory subsidies, solar photovoltaics, battery energy storage, and microgrids are being deployed in more places across the electric system.

This movement is requiring utilities to transform traditional centralized networks into flexible, distributed and integrated power networks that are starting to evolve from demonstration mode to more solid, longer-term investments that play an important part in developing new business models.

As many of these efforts move forward, organizations are working through the complexities to achieve the best economics for its distributed energy and microgrid customers while at the same time seeking to maximize benefit from the existing grid investments.

This is beginning to happen in San Diego, California, at the Marine Corps Air Station Miramar. The military base is in the process of establishing its own energy network that gives it the assurance and reliability needed to keep its operations in motion when regional blackouts occur. Along with that, it will also be in a better position to reduce demand charges and manage its electric load more efficiently while also contributing power into the grid.

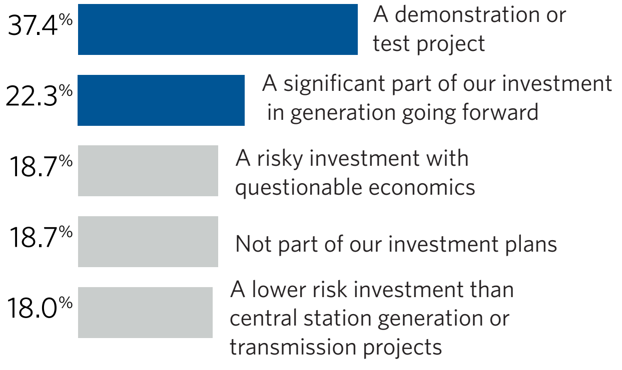
Jason Abiecunas is the Service Area Leader for distributed generation at Black & Veatch, and is responsible for business development, technical solutions and offerings development, and project execution. With over 15 years of experience, Abiecunas works closely with renewable energy technologies, energy storage, and fossil fueled technologies in microgrid, combined heat and power, and on-site utilities applications.

Rick Azer is an Associate Vice President at Black & Veatch and a founding member of the company's Growth Accelerator team. In this role, Azer leads the convergence of physical infrastructure, communications and data analytics to extend the value proposition of the Internet of Things across a wide array of clients and industries.

Tim Imlah is a Managing Director at Black & Veatch, where he advises utility and energy companies on achieving their business goals through technology, communications and business process changes. He has over 20 years of experience turning strategies into measured results.

FIGURE 17

What is your opinion of investments in distributed energy projects relative to your organization?



Source: Black & Veatch

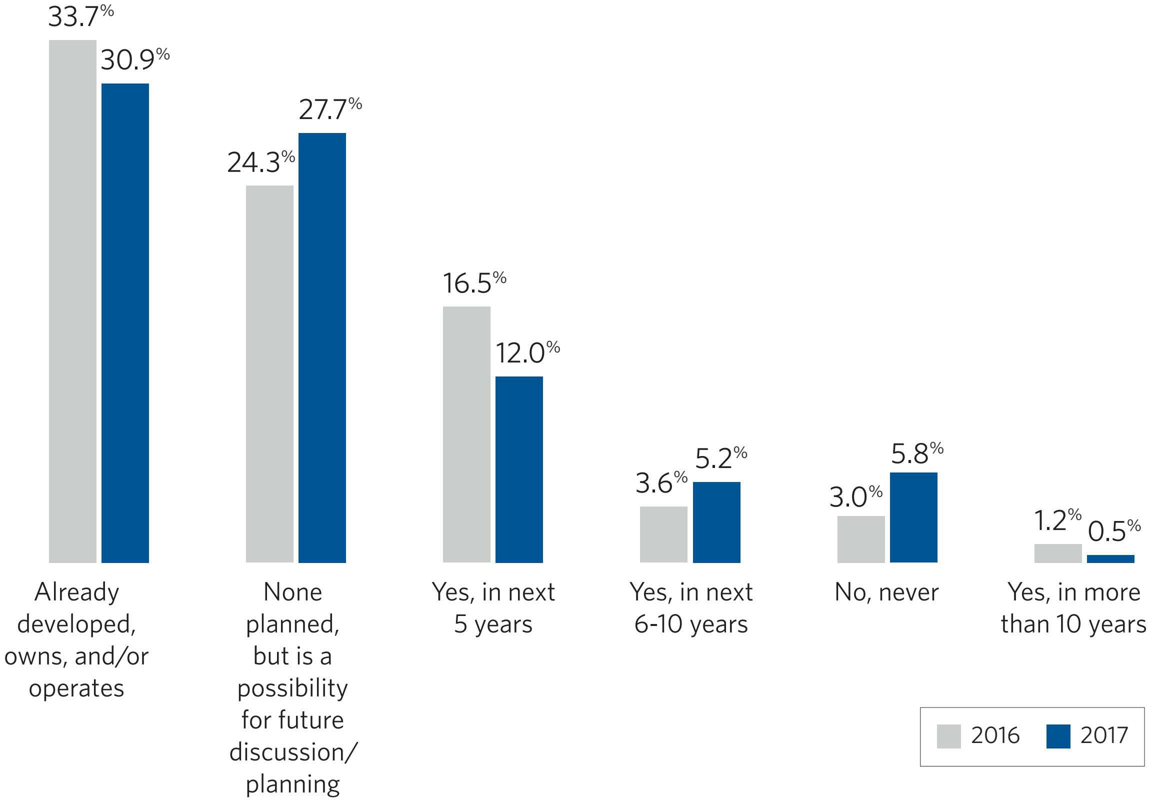
Black & Veatch and Schneider Electric are in the process of designing and building an advanced microgrid that takes advantage of the solar PV and landfill methane gas that already provide a combined 4.8 MW; the addition of diesel and natural gas generators is expected to produce another 7 MW of power.

Incorporating synchronized flow batteries and other energy management systems will allow the base to not only manage its own power, but to distribute it more efficiently across its own grid. This offers the base a significant opportunity to save money and streamline energy use.

That project is one example of the trends reflected in the responses to this year's *Strategic Directions: Electric Industry Report*, which found a slight increase among those utilities making DER a priority, while almost 40 percent of those organizations surveyed are still putting the bulk of that investment in demonstration or test projects (Figure 17). Further, the comfort level with these technologies has increased given the percentage of respondents who felt DER was a risky investment or questioned its economics decreased from 2016.

FIGURE 18

Does your company plan to develop, own, and/or operate distributed generation resources, including microgrids?



Source: Black & Veatch

Yet, contrary to this optimism, other data produced by the survey hints at the largest roadblock facing distributed energy resources — regulatory clarity in how utilities can invest in and receive a rate of return from distributed energy projects. But approximately 30 percent of respondents are already developing, owning or operating distributed generation resources (including microgrids), which is down 3 percentage points from 2016. While some anticipate doing something in the next six to 10 years, 28 percent (up from 24 percent in 2016) of utilities still have no plans to go in that direction (Figure 18).

Compelling results from pilots and demonstration projects combined with regulatory certainty are required to accelerate DER adoption. Additional time may be required for the indirect benefits of resilience to become evident.

Technology is maturing and continues to contribute to growth. Of the behind-the-meter DER technologies currently being deployed, solar PV continues to dominate, with almost 70 percent of respondents actively involved in solar efforts. More than half of respondents are executing energy efficiency, energy storage and demand response solutions. Surprisingly, even with federal and state programs promoting the installation of combined heat and power systems, only about 34 percent of the respondents are using it.

Hospitals and health care facilities are among the large-scale consumers of power who would benefit from DER.

Reliance on future revenue from DER is still fairly small despite the billions of dollars in investments being allotted for this area. Of all the respondents, roughly 42 percent see it as only a small revenue opportunity in the next 10 years, while 21 percent view it as a moderate revenue opportunity.

As more DER are put in use, it has become more evident where the economic sweet spots lie. Large consumers of power are the best candidates — armed with a clearer value proposition, they are positioned to see the largest savings. Hospitals and healthcare facilities are the top consideration (40 percent), followed by military bases, university campuses and industrial parks. Residential and small commercial applications have seen explosive growth of solar PV — principally in markets with higher utility rates and installation incentives. Rapid declines in the cost of solar PV and battery energy storage systems will make installation of these technologies in more markets viable.

With the broadening reach of the Internet of Things (IoT) and developments in management and control algorithms, DER operators will be able to aggregate independent systems into a fleet that can operate together as a larger system. As a result, new business models will emerge that "stack use cases or revenue streams" — provide services to the host site plus services to the utility or power grid — that will make networks of distributed energy assets more valuable.

For those moving forward, however, economics and regulation remain familiar barriers to growing DER projects. Forty-seven percent of respondents view economics as the main issue, while 41 percent point to the regulatory structure to support investment in DER. Roughly a third (28 percent) say that the permitting and interconnect process needs improvement before better growth can be seen, while 37 percent believe the cost of technology gets in the way. Solar PV and wind energy are competitive with fossil fueled resources at large scale. Declines in cost of these technologies plus rapid decline in the cost of battery energy storage will make these systems competitive with or cheaper than fossil fueled alternatives in the near-term in many markets.

Overall, Black & Veatch analysts see the DER movement continuing, but with some remaining barriers to large-scale, programmatic adoption. Some utilities now have dedicated personnel and executives whose primary role is to manage growth via these resources, indicating the increasing focus the industry is placing in this area. It's expected that project economics will improve as technology matures and the number and scale of DER increase.

As the energy industry evolves and centralization becomes less standard, wider use of DER and its place in business plans continue to be a key driver to where the power industry is heading.

As the energy industry evolves and centralization becomes less standard, wider use of DER and its place in business plans continue to be a key driver to where the power industry is heading.

Technology

CYBER ATTACK MITIGATION: ASSET PRIORITIZING, SECURITY RISK AWARENESS

By David Mayers

David Mayers is a Senior Managing Director and leads the Security, Risk & Resilience Service Offering in Black & Veatch management consulting. He has 26 years of management consulting experience, including 12 years in the banking industry and 14 years in the energy industry.

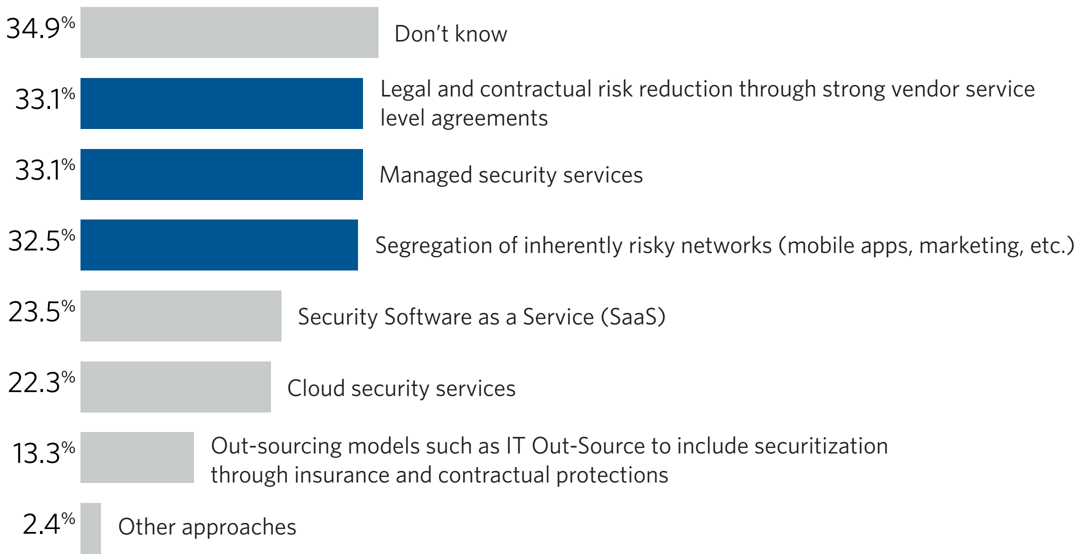
Although progress is being made by electric utilities in preparing for the inevitable attacks on their networks by hackers, this year's *Strategic Directions: Electric Industry Report* shows there are major gaps that need to be filled through asset security control and building a stronger culture of security risk awareness.

In this year's report, survey respondents ranked cybersecurity as second to reliability, by an increased percentage, among the top industry issues. This is driven by continually increasing security concerns caused by highly publicized hacking incidents and uncertainty about North American Electric Reliability Corporation (NERC) supply chain security standards, which are still in draft form and continuing to evolve.

There appears to be strong interest in the electric utility industry on legal contract risk reduction and employing managed security. It is vital that utilities focus on contractual language for contractor vetting, identity and access management. In addition, utilities should require that vendors fully understand that any vulnerability in their device software is disclosed so that the utility and its customers can take steps to protect themselves until a fix is implemented.

FIGURE 19

Is your company considering any of the following approaches to security?



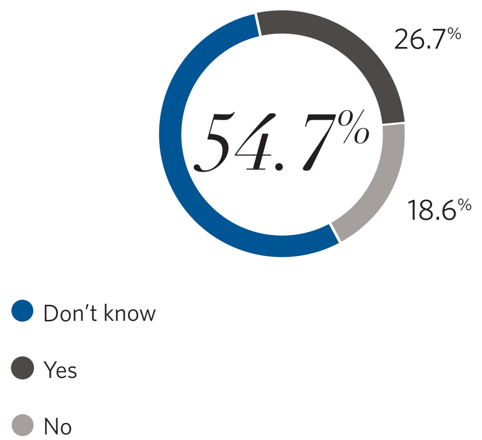
Source: Black & Veatch

The percentage of utilities considering procuring managed security services is surprising because they are traditionally adverse to relinquishing control in this sector (Figure 19). Utilities should consider developing this capability in-house by using a shared information technology (IT) and operational technology (OT) approach. This would provide a single and clear view of what is taking place across the entire electric network operation. Another option is to employ embedded contractors for utility staff augmentation as opposed to managed security services.

More than half (55 percent) of respondents don't know whether their organization has completed real-time OT monitoring (Figure 20). Without this capability, OT networks are allowing outside communications into their critical infrastructure without knowing their effect on operations. With real-time monitoring, the utility is able to quickly identify a hacker on its network and immediately react.

FIGURE 20

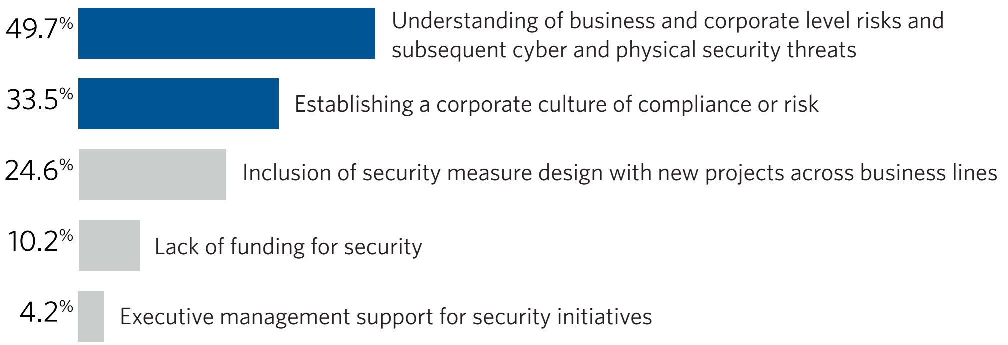
Has your organization completed a comprehensive real-time monitoring of your operational technology (OT) networks?



Source: Black & Veatch

FIGURE 21

What are your company's top security concerns?



Source: Black & Veatch

Ensuring that OT environments are secure is of paramount importance. Attacks on OT environments can cause real world impacts, including conditions that can cause not only operational impacts but also potential injury and loss of life. OT environments typically require 24/7 availability and, as a result are more challenging to secure through regular security hygiene such as patching and configuration. Utilities should combine their IT infrastructure and its staff's knowledge and skills with OT so they have an end-to-end clear picture of real-time network operation. This merging of OT and IT helps ensure greater security protection.

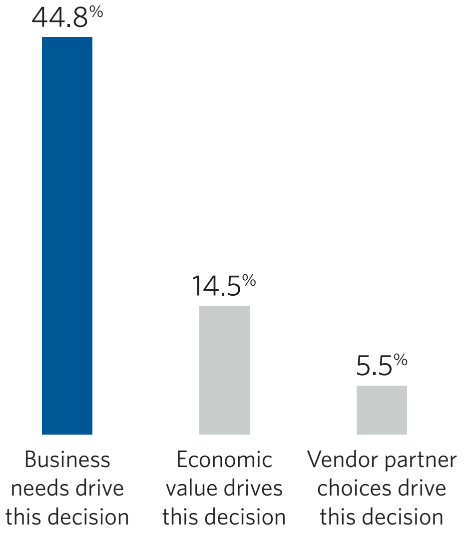
A top security concern among the electric utility industry is gaining an understanding of corporate-level risks because reputation risk is a key focus for senior utility management (Figure 21). Whether a hacker enters the system and extracts a few customer records or the entire database, the publicity surrounding an incident can be very damaging to the utility's reputation. Utility management must be able to respond that there is a robust plan in place to address and mitigate the issue and take steps to further strengthen network security.

A quarter (25 percent) of respondents were concerned about security measures being taken in new projects. This is a high priority area for utilities to address because security application in new projects adds costs but is imperative. When security measures aren't part of the project plan it becomes much more difficult and expensive to retrofit. Leading companies are addressing this need through the creation of an independent enterprise cybersecurity team that engages on projects and ensures consistent adherence to security policy and procedure.

Utilities should consider creating tiers for securing assets on the basis of not only regulatory requirements, such as NERC regulations, but also their business criticality. Such non-NERC related assets could include an electric substation that supports a large hospital or fire department. The security controls are customized on the basis of their criticality rather than a standard set of controls across the entire network, with labor and maintenance costs being an important consideration. For example, the electric utility may have seven or eight tiers of assets with the most stringent security controls applied to the top two tiers and other tiers having decreasing controls determined by criticality.

FIGURE 22

How are you determining what Internet of Things (IoT) devices will be permitted on your networks?



Source: Black & Veatch

Another security concern for the electric utility industry is Internet of Things (IoT) devices linking to electric networks (Figure 22). These include IoT applications such as smart parking meters, streetlights and thermostats, among other types of monitoring.

For example, a city municipality may want to install smart streetlights but doesn't have the staff or infrastructure to manage it. The city seeks to use the utility's network and also contract with a vendor to remotely manage the streetlights. As a result, the utility has two third parties with network access that are potentially on the same infrastructure as the electric grid control center.

The survey shows that only 12 percent of respondents say the utilities aren't permitting any IoT devices on their networks. The driver for allowing increased IoT entry is likely due to some vendors seeking access to the utility network by offering their products free of charge to the utility. There is also the aspect of vendors reaching out to elected officials in the electric service territory as well as the public utility commission staff to help drive IoT device acceptance by the utility.

To effectively protect assets in the cybersecurity realm there needs to be a culture of security risk awareness and response across the utility workforce. There is a tendency for utility employees to be wary of raising security issues because of concern for repercussions. It is vital that there is a security risk culture as strong as the engrained safety culture that the utility workforce has historically demonstrated. If workers see a security concern, they need to immediately speak out.

The security risk culture change requires senior executive support and ensuring that this is clearly communicated. It also requires grassroots commitment and continued focus through an education awareness program. In addition, employees directly responsible for cybersecurity need a senior utility leader who firmly stands behind them and enforces the mandate.

The electric utility industry will continue to battle against hacking events on its system operations; however, risks can be mitigated through proper asset prioritization and building a culture of security risk awareness. This includes the capability to effectively deliver well-defined messages on how security needs to be addressed and reasons for specific guidelines.

Technology

GLOBAL PERSPECTIVE — INTEGRATED LNG AND GAS GENERATION: A TIMELY CONSIDERATION FOR INDONESIA AND THE PHILIPPINES

By Rochman Goswami and Jim Schnieders

For growing maritime nations like Indonesia and the Philippines, planning for integrated liquefied natural gas (LNG) receiving terminals and gas-fired generation is a timely solution to balance the power generation mix and help meet 2015 Conference of Parties (COP21) commitments.

Both nations are vast archipelagos together totaling some 350 million people. Prospects for economic growth remain strong while full electrification remains a focused goal for both nations.

Rochman Goswami is Black & Veatch's Managing Director, Oil & Gas in Asia. He supports strategic growth in the region, focusing on the hydrocarbon sector and capitalizing on opportunities within the region, with operations focused in China and Indonesia.

Jim Schnieders is Managing Director for Black & Veatch's EPC Power business in Asia and presides over the company's growing engineering and construction capabilities in the region. He focuses on topline EPC projects for traditional power generation as well as opportunities in renewable energy.

Unlike its economic neighbors — Thailand, Singapore and Malaysia — coal has remained the predominant fuel choice for these two large developing nations. Cost-sensitivity, abundant supply and under-invested gas distribution infrastructure across their many islands are some of the key factors that maintain coal's predominant status. Developing coal plants, in many ways, is logistically simpler and the advent of more efficient coal technologies continues to improve economics.

For gas-fired generation development to gain momentum, a combination of forces must be in play to help overcome existing barriers.

Access to gas supply remains a primary challenge for gas-fired electricity production and, for island nations, this means more LNG infrastructure development is required. Liberalization of LNG trading that is underway in the region points to the potential of mid-scale receiving terminal development; it could also spur lower trading costs for gas that more accurately reflect the prevailing market forces of oversupply.

For gas-fired generation development to gain momentum, a combination of forces must be in play to help overcome existing barriers.

Since oil prices slumped, financing of LNG infrastructure has stalled. However, this is where co-locating mutually dependent electricity infrastructure can play a timely role in Indonesia, the Philippines and elsewhere in Asia. It is a proven way to optimize cost and improve project economics but it demands additional planning, strong government cooperation, and engagement of non-traditional gas sector stakeholders.

There are three broad and current trends that point to the opportunity for developing integrated LNG receiving terminals with combined cycle gas-fired power facilities in Southeast Asia:

1. There is an appetite for alternative thinking that unlocks the right price point for LNG project financing. Integrated planning of LNG and combined cycle power generation will provide a significant cost reduction that can help projects meet numbers and more readily secure the final investment decision. Asia accounts for 73 percent of global LNG demand according to the International Group of Liquefied Natural Gas Importers (GIIGNL), yet the trade of LNG throughout the region is still limited. Many nations want greater access to more abundant and cheaper natural gas supply.

2. LNG trading in Asia is on the cusp of change. The diplomatic isolation of the world's largest LNG exporter, Qatar (as at the time of this writing), the arrival of new LNG cargoes from LNG developments in Australia and North America and the efforts to create LNG trading hubs in China, Japan and Singapore are combining to unlock restrictive terms included in most of Asia's long term supply contracts. These forces could in effect help catalyze LNG market liberalization in Asia, shortening and loosening long term supply contracts and boosting spot trade. This liberalization would increase the affordability of gas in the region while also strengthening the case for smaller and more distributed LNG receiving terminals in locations such as Indonesia and the Philippines in the near term. The first wave of development would lend itself to utilizing some of the LNG supply for combined cycle generation with business cases for electricity supply potentially easier to establish ahead of alternative processing uses.

3. Gas-fired power generation will help meet energy security and environmental policy goals. Increasing the proportion of renewable energy as part of the generation mix will take many developing nations time given the technical issues such as pricing of storage and integrating intermittent renewable sources. Therefore gas-fired power generation can contribute to reducing proportional CO_2 emissions, help nations make progress on COP21 commitments and improve energy security by diversifying fuel supply. Locating new gas-fired power projects at the source of LNG supply presents solutions that should elicit central government support.

INTEGRATING POWER AND LNG RECEIVING TERMINALS

Synergies can be identified in how the two complex facilities use and share heat, water and cold energy. Using the power plant as a sink for the LNG cold significantly reduces, or even eliminates, the use of seawater for vaporization or fired vaporization. This reduces capital and operating cost savings and dramatically reduces environmental impacts. The integration is usually accomplished using a closed glycol/water, or equivalent, heating loop to capture the cold energy from the LNG and use it in the power cycle. Heat from the power cycle is then returned to the LNG vaporizers.

A recent facility development studied by Black & Veatch demonstrated the benefits. The design was based on a 7 million metric tonnes per annum (MMTPA) terminal and a 220 MW power plant. The two facilities were integrated by using a glycol/water loop to vaporize the LNG and condense the steam in the power cycle. An immediate capital savings of at least US$50 million could be realized through the integration. The savings were available while the capability to independently run each facility was maintained. The capital cost reduction could be even higher if the facilities were totally integrated with no stand-alone capability. However, of course, cost reduction will depend on the specific site requirements for redundancy and online expectancy for the two facilities.

The basic relationship is that for each 100 MW of power generation approximately 3.5 MMTPA of LNG can be vaporized. Inlet chilling can be added to the integration scheme with the same glycol/water loop. To inlet chill 100 MW of generation capacity, approximately 0.25 MMTPA of LNG can be vaporized. In most of the installations examined, substantial power plants can provide all the necessary heat for the associated LNG import terminal.

The extent of the integration is flexible and not all LNG receiving terminals will present the appropriate scale to realize benefits from co-locating combined cycle facilities. Simple cycle configuration can also be purposed to realize economic benefits.

Such integration, however, requires strategic business planning on behalf of the investors. Often these facilities are planned for in isolation, overlooking aspects of their mutual dependence. Technical and commercial knowledge and practices of both the power and LNG industry are critical for successful implementation. Schedule integration and supply chain coordination reduce the risk of one facility lying fully built and dormant while joint availability assessments help ensure both facilities are optimized commercially during their eventual operations. Such advanced and integrated planning, if done early and adequately, will create more bankable projects. Taken together with the other cost and operational benefits, integrated LNG receiving terminals could kick start gas sector development in the region.


L N G

Technology

GLOBAL PERSPECTIVE — INDIA, COAL PLANT EMISSIONS REDUCTION

By Rajiv Menon

With up to 400 million Indians lacking a reliable energy supply, the country is planning major investments in its power generation and distribution infrastructure. Most of the investment in new capacity will be for renewable energy. India has a 175 gigawatt (GW) target for renewable energy (100 GW solar, 60 GW wind and 15 GW biogas and others) by 2022.

The fact remains that most major agencies, including the Central Electricity Authority, agree that although little additional coal power capacity is needed over the next decade in India, coal will continue to be a significant source of electricity generation in the next two decades.

The Centre for Science and Environment estimates that if the country can meet the 2022 renewable energy target, India should be close to meeting half of its energy needs from non-fossil fuels by 2031 to 2032. The other half, however, would still predominantly come from coal. Early in 2017, the Minister of State with Independent Charge for Power, Coal, Renewable Energy and Mines, Piyush Goyal, noted that without a baseload of coal-based capacity, it would be difficult to add any more renewable capacity.

Rajiv Menon is Managing Director and Country Manager for Black & Veatch India. Menon is armed with more than 22 years of EPC and business development experience, and has held various senior positions with leading Asian and European companies.

In discussions about cleaner energy in India, the focus is almost always the government's drive for renewables but a critical component is often overlooked. Solar power works well when the sun shines, but stops at sunset, just as power demand soars to its evening peak. Partial thermal power has to remain idle during the day and be ready to pick up the slack when solar production stops. This forced idleness carries huge costs hidden by ostensibly inexpensive solar power. Renewable energy is essential to sustainably power future growth; in the present, however, when most of India's energy comes from coal, cleaner energy conversations need to be the focus.

India has a 175 gigawatt (GW) target for renewable energy (100 GW solar, 60 GW wind and 15 GW biogas and others) by 2022.

About 60 percent of India's installed power capacity is currently coal-based. This is set to increase to 70 percent in 2026, according to BMI Research. The electricity generation target of conventional sources from 2017 to 2018 has been fixed as 1229.400 billion units.

To date, the power industry in India has been facing less stringent emissions regulations than more developed countries because of the critical need to rapidly grow the generating capacity to bridge the gap between power supply and demand.

Supercritical technology is one route to cleaner coal for operators building new assets.

Now, for the first time, all of this coal capacity (new and existing assets) has to meet emissions standards for sulphur dioxide (SO_2), oxides of nitrogen (NOx) and mercury. In addition, there are significantly tighter standards for pollutants such as particulate emissions. The new emissions standards are expected to cut particulate emissions from new plants by 25 percent, SO_2 emissions by 90 percent, NOx emissions by 70 percent and mercury emissions by 75 percent compared with existing state-of-the-art plants.

The current deadline for compliance is December 2017, but an extension is likely. The cost of compliance, according to the Association of Power Producers, could be as much as Rs 2.5 trillion. NTPC Limited, India's largest energy conglomerate, has estimated that implementing the new standards could increase its cost of power production by 10 percent.

The path to compliance is challenging Supercritical technology is one route to cleaner coal for operators building new assets. The government passed legislation to ensure that all Ultra Mega Power Projects, and all new capacity built after 2017, uses supercritical technology. In addition, the government has identified old plants totaling 7,738 MW — owned by central and state agencies — for replacement with supercritical plants.

Complex, costly supercritical retrofits are also a possibility for operators of existing coal-fired power plants, but advanced combustion alone is insufficient. To ensure compliance with SO_2, NOx, particulate emissions and other new emissions norms, all coal power plant operators need to understand, procure, construct and operate air quality control systems with which they have little or no experience.

Because of the task's complexity, the Department of Science & Technology recently called for proposals for clean coal research and development. The project, however, will not report for three years. Signs that the new norms' deadline may change, or be phased, also increase the challenge. Last year, S.D. Dubey, Chairman of the Central Electricity Authority, said "Particulate matter emissions should be addressed in the first phase. The next step would be sulphur dioxide emissions and later on NOx. That's the direction we are moving in."

In February 2017, Livemint reported that the Ministry of Environment is likely to defer implementation to December 2019. The same article also suggested that standards for SO2 and NOx may be "revisited." This, however, is in the face of opposition from environmental groups and the government's very public backing for environmental improvement initiatives such as the Paris agreement on climate change and domestic Swachh Bharat Abhiyan program. What is clear is that the need to comply with some form of stringent new emissions norms, in the near term, is inevitable.

Closing Commentary

MASTER PLANNING: THE KEY FOR UNLOCKING DISTRIBUTED GENERATION POTENTIAL

By John Chevrette

Less than 10 years ago, master planning was a relatively straightforward exercise. Organizations would weigh demand growth projections against centralized power output capacity to determine whether they needed additional centralized power output.

Today, these plans must incorporate so much more because distributed generation touches every aspect of an organization — from billing and rates to field maintenance and operations.

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.

While there is no one-size-fits-all approach for integrating distributed generation into a local power grid, there is a process for planning, investing and optimizing the grid in a way that economically meets evolving customer and regulatory requirements. That solution is utility resource and distribution planning, or what we call an integrated master plan. Utility master planning is an essential exercise for utility leaders to remain financially viable, meet local and national regulatory requirements, maintain grid reliability and enable all breeds of generation into the grid system.

FINANCIAL VIABILITY AND RATE EQUITY

Before distributed generation, utilities grew through guaranteed rates of return from capital investments and expanding service territories. The utility alone controlled where power resources came from and resource plans identified investments in new, utility-owned generators and/or power purchase agreements from independent power producers (IPP). Customer rate structures were relatively simple: pay for what you use, no matter when you use it.

Today, anyone can be a power producer, from homeowners placing solar panels on the roof of their house to sophisticated microgrids at commercial, industrial and military complexes. This changes the economics of providing electric power services. While a simple, consumption-based rate structure worked well for nearly 100 years, it was built on the fallacy that higher kilowatt-hours (kWh) equaled greater cost to the utility and that less usage reduced utility costs. All kWh are not created equal. The concepts of distribution system capacity and overall system demand at a single point in time have evolved from the vilifying stories of utilities unable to sustain paying customers' retail prices for solar power sold back to the grid to understanding that provisions must be made to unbundle the cost of maintaining infrastructure, no matter who uses it or how it is used.

Self-generators, particularly homeowners with rooftop solar panels, can significantly reduce their overall demand for power from the utility but, in reality, create a significant cost burden because of potential infrastructure upgrades and work required to simply integrate that resource with the grid. Maintaining a consumption-based rate structure places the burden of this work and investment disproportionately on individuals who cannot implement distributed generation resources.

Today's master plans must identify and prioritize necessary investments on the grid and corresponding customer offerings to facilitate adoption of distributed generation resources in an efficient and cost-effective manner. Such plans should also support or incorporate cost-of-service and customer propensity studies to ensure fair and equitable distribution of cost across all customers and customer types.

ASSESS REQUIREMENTS AND RESOURCES

Meeting evolving regulatory and stakeholder needs as cost-effectively as possible hinges on a thorough understanding of existing resources and assets. What is your current generation portfolio? Do you have resources that must be retired or retrofitted in the time frame to meet regulatory requirements and/or power demands? Do existing resources provide the flexibility needed to meet shifting demand outputs and requirements as a result of greater integration of distributed resources?

TABLE 1

Does your company plan to develop, own and/or operate distributed generation resources, including microgrids?

	Which of the following best describes your organization?			
Column % by Utility Type	Investor-owned utility	Publicly-owned utility	Cooperative	Independent/ industrial power producer
Already developed, owns, and/or operates	28.4%	34.0%	28.0%	32.4%
Next 5 years	9.5%	4.3%	8.0%	27.0%
Yes, in the next 6-10 years	5.4%	10.6%	.0%	2.7%
Yes, in more than 10 years	.0%	2.1%	.0%	.0%
None planned, but is a possibility for future discussion/planning	24.3%	31.9%	44.0%	21.6%
No, never	2.7%	4.3%	8.0%	10.8%

Source: Black & Veatch

For service providers whose territory spans large geographies, assessing renewable energy potential across their operating system is complex, but necessary. The master plan should identify where, from a geographical perspective, the best resource areas are for distributed generation technologies, such as wind, solar, and combined heat and power facilities. Transmission and distribution assets should then be assessed to determine where the system would benefit from adding flexible supply, or conversely, where upgrades are necessary to handle distributed input. What is the condition and capability of these assets to integrate various distributed generation technologies? Are upgrades needed to substations, lines and transformers in high-potential areas?

Having a complete understanding of current system conditions and what is needed to meet future requirements enhances an organization's ability to justify investments to key stakeholders, improve reliability and, for regulated utilities, gain approval for rate recovery. It also enables the utility to work with its customer stakeholders to prioritize and plan sequential grid investments with distributed generation integration within targeted areas of their territory. Utilities and IPPs clearly have an eye on distributed generation, with initiatives already underway or roadmapped in the next five to 10 years (Table 1).

HOLISTIC VIEW

Today's master plans must account for more than physical assets, such as power generators and transmission and distribution infrastructure. Master plans should include network infrastructure and operational and information technologies needed to operate, maintain and manage a dynamic grid and technologies needed to enable customer choice to participate in these new offerings, implement new services and bill in a transparent and equitable manner.

Essentially, optimal master plans should be aligned and integrated with capital improvement, emerging technology, advanced networking, organizational readiness and customer pricing strategies. Completing each of these tasks in isolation from the others creates misalignment and, potentially, eliminates opportunities for efficiency and cost savings.

Change is accelerating across the industry at an unprecedented rate. Adoption of distributed generation is a common challenge for virtually all utilities, but the tactical solutions will be unique for each. A holistic master plan should provide utility leaders with a 20-year view based on current market conditions. It should also account for future scenarios, such as technology changes, fuel price and more stringent environmental requirements. A completed product should be dynamic and include a scorecard of results for feasible alternatives for each scenario that enables utility leaders to evolve their plans to meet future need.

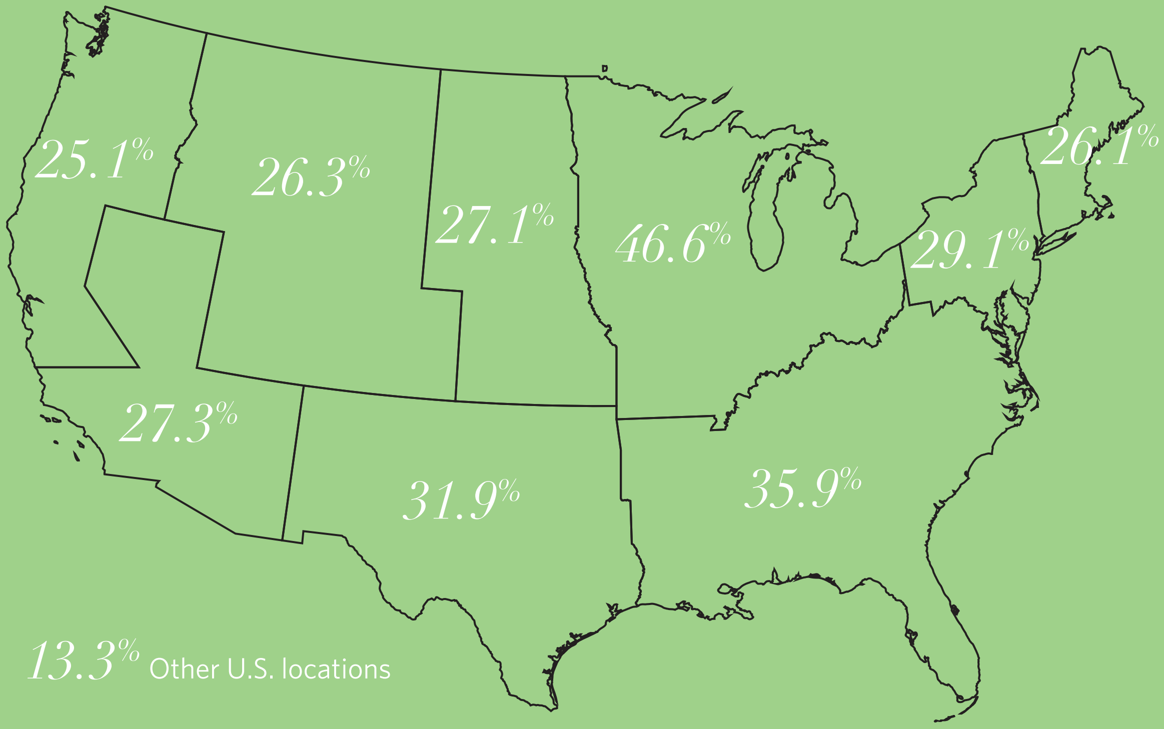
Today's master plans must account for more than physical assets, such as power generators and transmission and distribution infrastructure.

2017 Report Background

The 2017 Black & Veatch *Strategic Directions: Electric Industry Report* is a compilation of quantitative and qualitative data and analysis from industrywide surveys. This year's online survey was conducted from 9 May through 29 May 2017 and reflects the input of more than 500 qualified utility, municipal, commercial and community stakeholders.

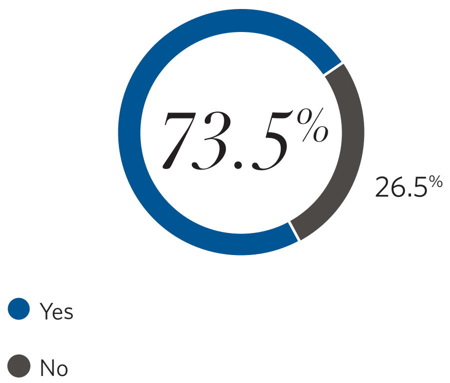
A total of 533 qualified utility, municipal, commercial and community stakeholders completed a majority of the survey. Because the survey was administered online, the amount of self-selection bias is unknown; therefore, no estimates of sampling error have been calculated. The following figures provide additional details on the participants in this year's survey.

Primary U.S. Business Region



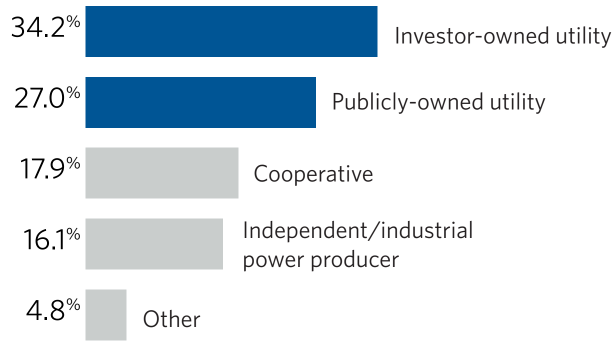
Source: Black & Veatch

Industry Type
Does your organization distribute, trasnmit, generate, retail or sell electricity?



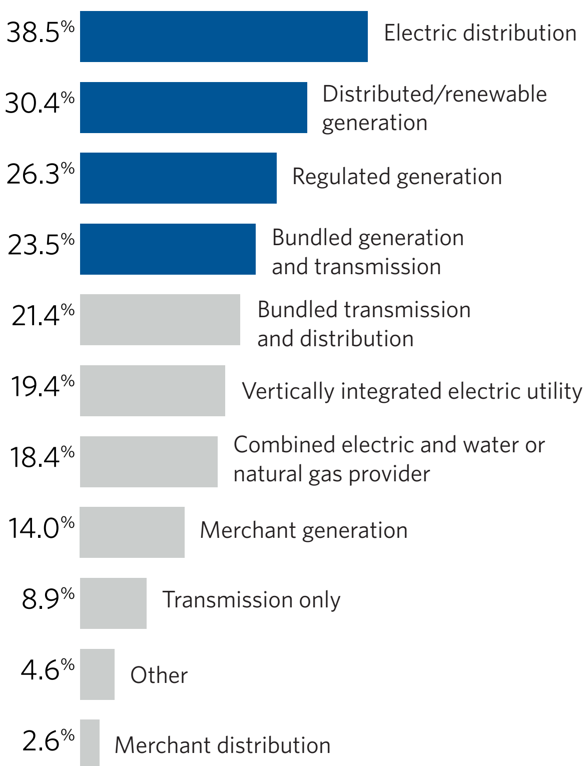
Source: Black & Veatch

Electric Services Povider Type



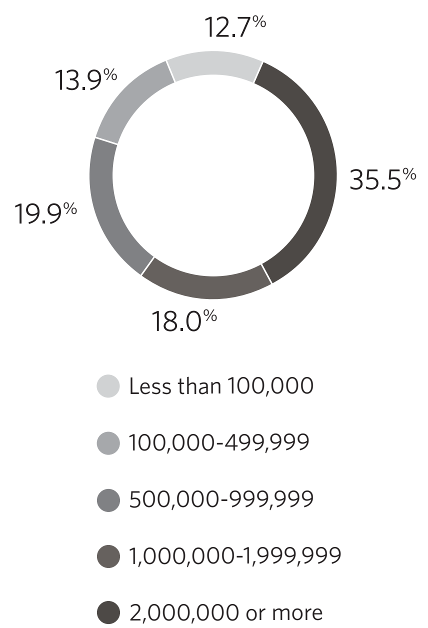
Source: Black & Veatch

Electric Services Provided



Source: Black & Veatch

Population Served



Source: Black & Veatch

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