BUILDING A WORLD OF DIFFERENCE®

Black & Veatch is an employee-owned, global leader in building Critical Human Infrastructure™ in Energy, Water, Telecommunications and Government Services. Since 1915, we have helped our clients improve the lives of people in over 100 countries through consulting, engineering, construction, operations and program management. Our revenues in 2012 were US $3.3 billion. Follow us on www.bv.com and in social media.
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Welcome to the 2013 Strategic Directions in the U.S. Electric Utility Industry Report. For seven years, Black & Veatch has worked to capture the industry’s viewpoint concerning ongoing and emerging issues by conducting our industry-wide survey. In addition to graphical interpretation of survey results, our full report provides expert analysis, recommendations and actionable intelligence regarding key industry trends and emerging challenges.

Primary findings from this year’s report show a tipping point is coming for the industry between meeting cost expectations and maintaining reliability and compliance requirements. Evolving environmental regulations, the projected dash to gas, the drive to meet renewable portfolio requirements and the integration of newer “smart” technologies all represent significant investments that may improve reliability as well as provide substantial societal benefits by mitigating certain risks and environmental externalities. However, these investments will ultimately result in higher rates as utilities seek to recover costs.

In addition to regulatory uncertainty and rising consumer costs, key findings from this year’s report highlight top challenges for implementing smart grid and asset management programs; recommendations for effectively planning new or expanding natural gas portfolios; and the impacts of the Federal Energy Regulatory Commission’s landmark Order No. 1000 ruling.

The confluence of challenges affecting the industry have far-reaching implications across a utility’s operations and, in some instances, its very organizational structure. Managing through this significant change will define today’s leaders and emerging stars. It is also an opportunity to redefine the industry’s relationship with electricity consumers.

On behalf of Black & Veatch, we thank all who participated in our 2013 survey. We also acknowledge our own subject matter experts who contributed their time, talent and knowledge for this year’s report. To continuously improve our products, we welcome your questions and comments. Please send your feedback to MediaInfo@bv.com.

Sincerely,

DEAN OSKVIG | PRESIDENT & CEO
Black & Veatch’s global energy business

JOHN CHEVRETTE | PRESIDENT
Black & Veatch’s management consulting division
The seventh annual Strategic Directions in the U.S. Electric Utility Industry Report is a compilation of data and analysis from an industry-wide survey. Since its inception, the report has served to provide insights on challenges and opportunities facing the electric utility industry.

This year’s electric utility industry survey was conducted from January 30 through February 18, 2013. A total of 607 qualified industry participants completed the 30-minute online questionnaire. Among these participants, 376 represented organizations that produce, transmit or sell electric power generation, collectively called “utilities” in this report. Unless otherwise noted, survey data presented within this report reflect the opinions of respondents who represent a utility organization.

Statistical significance testing was conducted on final survey results. Represented data have a 95 percent confidence level, or a margin of error at +/- 3.98 percent.

Figures 1, 2 and 3 provide additional detail regarding the types of utilities represented by respondents, services their organizations provide, and geographic regions served.
THE BLACK & VEATCH ANALYSIS TEAM

EXECUTIVE SUMMARY

John Chevrette is President of Black & Veatch’s management consulting division 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.

UTILITY OPERATIONS
Rates & Economic Regulations
Russell Feingold is a Vice President with Black & Veatch’s management consulting division where he leads the Ratemaking and Financial Planning Services Group. He has more than 30 years of experience serving electric and gas utilities on a broad range of projects.

Smart Grid
Kevin Cornish is an Executive Consultant in Black & Veatch’s management consulting division. With more than 25 years of experience in the industry, Cornish specializes in the integration of intelligent infrastructure systems into utility enterprise, such as GIS, AMI, MDMS, and OMS, among other areas.

Asset Management
Will Williams is a Director in Black & Veatch’s management consulting division where he leads and provides a full range of strategic and tactical asset management services for global water and energy clients. Williams has more than 20 years of experience in asset management planning, including asset failure analysis, risk assessment, performance benchmarking, maintenance optimization and business change management, among other areas.

POWER GENERATION
Natural Gas Fuel Supply Reliability
Ann Donnelly, Ph.D., is a Director in Black & Veatch’s management consulting division. Dr. Donnelly has more than 30 years of experience in all aspects of the energy industry, specializing in natural gas procurement and risk management, fuel market fundamentals and customer aggregation for power and fuel contract optimization, among other areas.

Richard Porter is a Director within Black & Veatch’s management consulting division where he leads the company’s Natural Gas Regulatory Advisory services. Porter has more than 30 years of experience in natural gas regulatory matters and works with clients on issues associated with ensuring regulatory compliance, engaging in rulemaking and policy analysis, strategic development and developing strategies for cost of service and rate design, among other areas.

Renewables
Ryan Pietka is an Associate Vice President in Black & Veatch’s global energy business and serves as Director of Strategic Planning Services for the company’s renewables and energy efficiency group. Pietka has more than 15 years of experience in the industry and has participated in assessments of more than 150 renewable energy projects and technologies since joining Black & Veatch in 1998.

William Roush is a Renewable Energy Consultant in Black & Veatch’s global energy business. He has more than 15 years of experience within the industry. Roush currently serves as President of the Heartland Solar Energy Industries Association and is a former Advisory Committee Member of the Solar Electric Power Association.

Environmental Regulations
Andy Byers is an Associate Vice President in Black & Veatch’s global energy business where he serves as the Legislative and Regulatory Policy Advisor, as well as a Senior Project Manager for both domestic and international development projects in the energy and industrial sectors.

Nexus of Energy and Water
Ted Pintcke is Vice President and Senior Project Development Director in Black & Veatch’s global energy business. Pintcke has more than 35 years of experience at Black & Veatch, serving in a variety of roles throughout his career including Chief Engineer, Project Director and Executive Sponsor. He has also led the development of a number of initiatives and business lines for Black & Veatch covering a variety of fuels and technologies, including biofuels, hybrid power and desalination plants and compressed air energy storage.

Michael Preston is the Chemical Engineering Section Leader in Black & Veatch’s global energy business. Preston has more than 25 years of experience supporting and consulting with energy clients on water and wastewater treatment systems for power generation units.

Michael Eddington is a Senior Consultant for Thermal Performance within Black & Veatch’s global energy business. With more than 30 years of experience, Eddington specializes in power cycle design for a wide range of power generation technologies. He is responsible for systems design studies, including the technical and economic analyses for various plant systems associated with the power cycle and heat rejection systems.

CLOSING COMMENTARY

Dean Oskvig is President and CEO of Black & Veatch’s global energy business, a position he has held since 2006. Oskvig joined Black & Veatch in 1975 and has served on a variety of global energy and telecommunications projects and roles within the company. He was elected to his first term on the company’s Board of Directors in 2006 and is a member of the Electric Power Research Institute’s Advisory Council.
MANAGING CHANGE AND UNCERTAINTY

BY JOHN CHEVRETTE

The collective results of Black & Veatch’s 2013 electric utility industry report demonstrate an intensifying level of concern across a range of issues. In our annual Top Ten Industry Issues rankings, once again reliability was the top concern for utility participants.

However, a look at just the previous five years demonstrates that utility participants are ranking virtually all issues with higher levels of concern. In some cases, chronic issues are becoming more severe. In others, changes in the business context, including a lingering recession, regulatory policy uncertainty and dramatic changes in commodity fuels markets, are exacerbating the effects of age-old concerns. For example, in 2008, reliability—the overall top concern for the industry—had a collective score of 4.37 on a scale of 1 to 5 (Figure 4). Today, that score would be eighth on the list.

This year’s report examines the challenges and underlying uncertainties affecting the entire electric utility value chain and is divided into three distinct sections: Utility Operations (corporate and back-office issues and operations considered “inside the fence”), Power Generation and Transmission & Distribution.

EXECUTIVE SUMMARY

UTILITY OPERATIONS

The challenge of balancing new regulatory mandates and emerging threats while maintaining affordable and reliable service is at the heart of the elevated anxiety levels. As more regulations are put in place, including environmental, cyber, reliability or others, utilities must find ways to fund, implement and manage these changes while ensuring that customers’ lights stay on. These changes represent significant investments that are necessarily recovered from consumers. As a result, average customer rates have and will, for most utilities, continue to rise (Figure 5).

FIGURE 4

TOP TEN INDUSTRY ISSUES

| Score | Reliability | Environmental regulation | Economic regulation | Aging infrastructure | Long-term investment | Cyber security | Natural gas prices | Technology | Fuel policy | Physical security | Source: Black & Veatch

Each year, Black & Veatch survey participants are asked to rate on a scale of 1 to 5 (where 1 indicates “Very Unimportant” and 5 indicates “Very Important”) the importance of a variety of issues to the electric industry. This chart represents the mean rating for each issue among utility respondents.

FIGURE 5

AVERAGE CUSTOMER ELECTRICITY RATES

Source: Black & Veatch

Utility respondents were asked to what extent did average electric rates to customers change during the past year. Nearly two-thirds indicated that customer rates had increased.
The industry continues to focus investments in the core operations of generation, transmission and distribution to update aging infrastructure, improve asset performance and utilization, and preserve reliability. A slightly higher number of utilities are focusing on environmental projects this year as compared to 2012 (Figure 6).

Concerns about economic regulation skyrocketed this year, jumping from ninth to third in our list of Top Ten Issues. The challenge of balancing the need for significant investments to shore up reliability and environmental compliance, while minimizing the cost to consumers, is putting tremendous pressure on utilities and public utility commissions to find middle ground.

As noted in the Rates & Economic Regulation section, the implementation of Smart Grid programs and the development of a fair and predictable approach to recovering these costs, represents the largest regulatory gap for utilities and regulators.

Nonetheless, the full implementation of these programs, and their integration into new, more efficient utility process models, represents one of the greatest opportunities for addressing growing demands for better operating, economic and societal results from aging utility infrastructure. The Smart Grid section of this report details specific change management issues that blur the lines separating utility operational and information technology departments.

The good news is that industry leaders and asset owners are not without options that can help stretch precious capital resources. Sound asset management practices and programs are gaining a foothold within the industry (see Asset Management section). Asset management programs are widely proven across the electric, natural gas and water industries for maximizing ratepayer and/or shareholders return on investments, extending asset life and reducing operational costs. However, similar to large-scale Smart Grid programs, successful programs require concerted efforts to change organizational culture, paradigms and, in some cases, structure.

FIGURE 6
AREAS OF CONCENTRATION FOR MAJOR INVESTMENTS

Source: Black & Veatch
Utility respondents were asked which area is spending most concentrated for their current investment cycle.

POWER GENERATION

Low prices and ample reserves are driving an unprecedented shift to natural gas for both fuel and feedstock applications through the U.S. economy. For most utilities, natural gas is essentially the only economically and environmentally viable option for new baseload power generation for the foreseeable future.

Throughout 2012 and 2013, much attention has and will be paid to how natural gas prices, combined with new and proposed rules and regulations related to air emissions, waste management, surface water intakes and wastewater discharges, will affect owners and operators of coal-fueled generating facilities (see Environmental Regulations section). Headlines citing Black & Veatch’s own Energy Market Perspective point to our projection that more than 62,000 megawatts of coal generation capacity will be retired by 2020.

It should be noted, however, that coal generation is not the only fuel/technology casualty. During the next 25 years, Black & Veatch projects that nearly 40,000 megawatts (approximately 35 percent) of current nuclear generation capacity will also be retired. While low natural gas prices continue to make the economics of new nuclear generation a challenge, the issue of nuclear waste has, in essence, placed the entire industry on hold for at least the next two years.

Last year, the U.S. Federal Court of Appeals struck down the Nuclear Regulatory Commission’s (NRC) waste confidence rule for not sufficiently analyzing the environmental effects of storing nuclear waste at the 104 existing U.S. reactor sites without a permanent solution in sight. The NRC responded by suspending all further license approvals for new nuclear plants, as well as relicensing of existing plants, until it completes the two-year requisite environmental analysis.

Nuclear waste challenges date back to 2010 when both the permit application and funding for a permanent nuclear waste storage repository at Nevada’s Yucca Mountain were rescinded. Following this decision, the tragic incident at Japan’s Fukushima reactor brought the issue of fuel disposal and storage to the forefront, jumping from ninth in 2010 in the rankings for Top Environmental Concerns to third in 2011. Today, the issue of nuclear fuel disposal and storage remains in the Top 5 Environmental Concerns for the industry, perhaps reflecting the industry’s continuing frustration over the need for a national policy and viable, permanent nuclear waste storage and disposal solution (Figure 7).

Despite current challenges, the industry does remain optimistic that the highly anticipated nuclear renaissance will, at some point, happen. Once again, utility respondents rated nuclear energy as the preferred environmentally friendly technology (Figure 8).

With looming retirements of coal and, potentially, nuclear facilities, utility leaders must move forward with new natural gas generating units to provide baseload power and to help integrate variable renewable energy resources. But, herein lies the next great challenge for the industry: integrating potentially significant new natural gas generating units onto existing inter/intrastate pipeline grids in a cost-effective manner that can achieve strict reliability standards. This issue is covered in-depth in the Natural Gas Supply Planning section.
The need for new transmission infrastructure is growing, particularly for large interstate lines designed to bring renewable energy from remote areas to large demand centers. Building new transmission, however, has traditionally been a risky, costly and time-consuming endeavor. Permitting, siting and other factors across multiple jurisdictions result in new transmission lines taking approximately 10 years to go from concept to energized, as compared to the two to three years to complete a new wind or photovoltaic generation facility.

To address many of these issues, the Federal Energy Regulatory Commission (FERC) issued its far-reaching Order No. 1000. The complex ruling seeks to remove transmission development barriers by increasing competition and regional coordination, while better distributing cost obligations to stakeholders. Black & Veatch asked utility participants to provide their opinions on various components of FERC Order No. 1000 and the results are provided in the Transmission section.

Also new to this year’s report is a look at the increasing role of telecommunications infrastructure in utility operations, most notably in the distribution system. With technology providing a greater level of understanding in system operations, new “smart” programs built upon robust telecommunications networks offer the opportunity to maximize utility efficiency. A closer look at the smart programs made possible by the convergence of energy and telecommunications can be found in the Utility Telecom & Distribution Systems section.

Balancing Act

This year’s survey results reflect an industry at the cusp of significant change, working hard to adapt to shifting customer relationships and an evolving, yet uncertain, regulatory landscape. The good news is that the industry continues to emerge from the shadows of the 2008 recession. Nearly two-thirds (62.6 percent) of utility respondents stated their current load growth rates are recovering as compared to just over half (50.9 percent) who indicated some level of growth in 2012 (Figure 9). The challenge will be determining how to best meet the often conflicting demands of future growth, sustainability and regulatory compliance while maintaining competitiveness in the future.

Power Delivery

While reliability has been the top concern for the industry since the inception of this report, recent actions by the North American Electric Reliability Corporation (NERC) have brought new levels of emphasis to ensuring critical transmission infrastructure is up to code. This includes such programs as better vegetation management, event analysis, cyber security, critical infrastructure identification and protection, and spare equipment inventories.

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RATES & ECONOMIC REGULATION

BY RUSSELL A. FEINGOLD

In the overall rankings of the electric industry’s Top 10 Issues, economic regulation made perhaps the biggest jump in the survey’s seven-year history, from ninth in 2012 to third this year. In many ways, this is not surprising given the pressure on electric utilities to implement capital-intensive programs that ensure reliability while meeting increasingly stringent environmental regulations. External factors that impact regulated utilities’ ability to recover investments through their regulated rates are areas of considerable concern when taking into account their long-term financial viability.

Because public power entities are not typically subject to regulation by federal or state utility commissions, this section specifically focuses on Investor-Owned Utilities (IOUs). According to respondents representing IOUs, regulatory uncertainty has the most significant impact on these utilities’ ability to recover operating costs and provide satisfactory earnings and to determine the level of system infrastructure investment that is acceptable to regulators (Figure 10). This was a predictable result given that these considerations are the most critical to an IOU’s continued financial health.

In regard to the preferred regulatory practices that would help improve the quality and efficiency of utility regulation, IOUs rated pre-approval of planned capital investments, formula rates and greater flexibility to recover one-time costs as the top three most valued regulatory practices, respectively. It should be noted, however, that IOU respondents collectively rated most of the listed regulatory practices as being very helpful (i.e., a rating of 4 or higher) in improving the quality and efficiency of utility regulations as measured by the ability to generate satisfactory earnings. Again, this is a predictable outcome considering that most of these practices address important considerations associated with the predictability and timeliness of regulatory outcomes, which in turn directly impact the degree of regulatory lag and earnings attrition experienced by IOUs.

The effect of regulatory uncertainty in the electric utility industry can have a fundamental impact upon an IOU’s consumer benefits that a number of utilities across the country are now experiencing. As a result, the industry still has a high-level of skepticism regarding the ability to recover the costs of Smart Grid programs (Figure 11).

Recovery of investments for Smart Grid programs, however, is proving to be much more challenging for utilities. In the past year, there have been a few high-profile rate cases where regulatory bodies have either denied a utility’s requested rate increases or limited the scope of investment for large-scale deployments, despite the claimed evidence of operational benefits, such as improved reliability and system performance, and tangible consumer benefits that a number of utilities across the country are now experiencing. As a result, the industry still has a high-level of skepticism regarding the ability to recover the costs of Smart Grid programs (Figure 11).

FIGURE 10
IMPACT OF REGULATORY UNCERTAINTY

<table>
<thead>
<tr>
<th>Rating</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.14</td>
<td>Ability to recover operating costs and provide satisfactory earnings</td>
</tr>
<tr>
<td>3.90</td>
<td>Level of investment made by your company in the electric utility industry</td>
</tr>
<tr>
<td>3.87</td>
<td>Costs associated with maintaining satisfactory regulatory compliance</td>
</tr>
<tr>
<td>3.75</td>
<td>Predictability of electricity prices</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

Utility respondents were asked what level of impact regulatory uncertainty has on each of the listed items using a scale of 1 to 5 (where 1 indicates “No Impact” and 5 indicates “Significant Impact”). The chart reflects the mean responses of participants representing IOUs.

FIGURE 11
CONFIDENCE IN RECOVERING SMART GRID INVESTMENT COSTS

Source: Black & Veatch

Utility respondents were asked to identify their level of confidence that utilities within their state will be able to recover the costs of Smart Grid programs in an effective and timely manner. A growing number are unconfident.

<table>
<thead>
<tr>
<th>Year</th>
<th>Very unconfident</th>
<th>Unconfident</th>
<th>Neither confident nor unconfident</th>
<th>Confident</th>
<th>Very confident</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>11.7%</td>
<td>27.6%</td>
<td>24.9%</td>
<td>22.2%</td>
<td>5.0%</td>
</tr>
<tr>
<td>2012</td>
<td>34.8%</td>
<td>26.7%</td>
<td>29.7%</td>
<td>9.3%</td>
<td>10.3%</td>
</tr>
</tbody>
</table>
The issue of Smart Grid deployment places regulators squarely in the middle of the sometimes controversial balancing act between utilities and their stakeholders that make up the Regulatory Compact. The Regulatory Compact seeks to balance the need of IOUs to be profitable and financially sound with consumer needs for reliable and affordable electric service. This year, we asked electric utility participants whether or not they viewed the Regulatory Compact as being fairly balanced between utilities and their customers. Approximately 6 percent of IOU respondents believe regulators favor utilities, as compared to nearly 40 percent who believe regulators, to some extent, favor consumer interests (Figure 12).

The relatively high level of skepticism regarding the recovery of IOU investment costs for Smart Grid programs demonstrates a fundamental difference within the business cases these utilities are making when seeking regulatory approvals for such investments. Given the challenges associated with gaining approval for Smart Grid programs, utilities collectively rated “Business cases do not produce strong enough financial justification” as the top obstacle to these programs (Figure 13).

It is relatively easier for a utility to justify investments in generation, transmission and distribution or environmental upgrades because they can clearly demonstrate current capabilities and the value of these assets to delivering electricity to customers. Utilities can also easily identify the gaps existing assets have or will have with current or new federal/state requirements. The transformative nature of Smart Grid programs, however, does not easily lend itself to traditional business cases because it is projecting benefits in areas where utilities have more difficulty quantifying current costs and projecting new costs for operations.

For example, utilities may not actively track and categorize the cost of fleet vehicles, labor and manual reading of meters into one expense category for the meter reading function. A well-publicized advantage of smart metering programs is the potential elimination of manual reading of meters, but without current and accurate data, utilities cannot definitively state the projected benefit over the level of today’s costs. In essence, if utilities cannot clearly and accurately detail what the current state of their organization is, they will not be able to clearly and accurately project quantifiable improvements as a result of a Smart Grid program. Defining the current situational assessment and possible final future states is a difficult process for anyone, particularly if they have not been through a similar process in the past. Minimizing regulatory uncertainty can be achieved in the future if both parties — regulators and utilities — commit to adopting best practices. For regulators, this could include providing predictability and direction that encourages longer term energy planning by utilities and their customers. Consistency across issues and market participants contributes to regulatory predictability. Finally, transparency in the regulatory process that provides a reasoned basis for specific regulatory actions and rulings further contributes to reducing overall uncertainty in this area.

Regulated utilities, in turn, should use proven methods for presenting information to regulators, specifically implementing full disclosure policies on presenting the facts to regulators on a timely basis. Frequent and open communication is essential to building trust between the two entities. In rate cases, there should be no surprises or hidden problems. Utilities will benefit by demonstrating a full understanding of business plans and operations to regulators, as well as being sensitive to the roles and responsibilities of the regulators.

Electric infrastructure across the country faces challenges associated with extreme weather, population shifts and aging infrastructure. Addressing these challenges requires significant investment. In an era fraught with uncertainty, utilities will benefit from working with consultants who specialize in business case development, smart grid planning and quantifying potential results of such programs to help facilitate regulatory review processes. Given the benefits early adopters of Smart Grid programs are demonstrating to the marketplace, the returns on these investments are increasingly more compelling.

As the electric generation mix continues to evolve, through increasing implementation of intermittent renewable resources, both utility-scale and distributed resources, coal generation retirements and new gas-fired generation, it will become increasingly important to modify utility networks and operations to accommodate these changes. The first and most important step in this process is gaining timely approval for these necessary investments.
The technologies commonly referred to in aggregate as the Smart Grid and other innovation-enabling tools are becoming an integral part of electric utilities’ operations arsenal. The promise of increased system reliability, improved operating efficiency and enhanced customer service are being realized by a growing number of utilities that are completing major Smart Grid initiatives.

While the pace of innovation in the utility industry has often lagged behind consumer goods and services industries such as banking and telecommunications, the pace of adoption of new technologies has been almost exponential in recent years. This uptick in adoption can be largely attributed to the availability and maturity of an increasing number of new and enhanced enabling technologies including Advanced Metering Infrastructure (AMI), Meter Data Management Systems (MDMS), Outage Management Systems (OMS), Distribution Management Systems (DMS), Enterprise Asset Management (EAM), mobile and more. Increasingly, utilities are implementing multiple smart grid solutions concurrently to obtain the synergies available from broader utility transformation. This is expected to continue into the future as electric utilities continue to take advantage of the capabilities of these and future smart grid solutions.

The Utility Telecom & Distribution Systems section of this report provides additional insight on the physical deployment of Smart Grid infrastructure throughout the electric distribution system of electric utilities. This section focuses mainly on issues related to the adoption and integration of the technology solutions into the utility. Where the Smart Grid is concerned, a significant percentage of opportunities and issues affecting electric utilities can be categorized related to organizational change management. The transformative nature of Smart Grid initiatives, and the capabilities and valuable information these programs provide, challenges the siloed functional organization that many utilities have traditionally used. Smart Grid solutions increasingly blend the line separating utility operations technology (OT) from utility information technology (IT) departments.

More than half (52 percent) of survey respondents identify business process redesign as the primary management challenge for integrating the Smart Grid into the utility enterprise (Figure 14). This is not surprising considering that as Smart Grid programs transition from project implementation to sustainment, significant changes to a utility’s technology systems and business processes have to be implemented. And, depending on the initiative, there are multiple departments that must oversee and operate these transformed systems. Black & Veatch is frequently called upon by utility clients to provide insight into best practices and to act as an independent advisor as IT and operations professionals re-evaluate the scope of their roles and responsibilities within the utility organization. The situation of initial isolation coupled with significant need for organizational redesign might also explain why 11 percent of respondents are unsure where their organization is in the process in terms of deployment.

Implementation of Smart Grid programs also presents significant technological and financial challenges for utilities in terms of managing data, integrating business processes and modifying legacy systems to work with new solutions (Figure 15). In the past, business processes tended to focus on a single functional area, but in today’s integrated environment, these processes can cross several boundaries. The business cases upon which the project was justified routinely require that the utility break down the isolation of systems and create synergies between the operational systems. Additionally, whereas many processes formerly contained manual elements, utilities are striving to remove these error-prone steps from business processes. The new capabilities provided by the enabling technologies, dependent on multiple integrated systems with multiple users in multiple organizations, require utilities to better understand who is doing the work, not just how and where. This results in the need to address areas of job redesign, training and new skills development.

Just as legacy roles and responsibilities often need to be modified, so do legacy systems. This can be a difficult undertaking because such systems were likely not designed to manage significant data loads and/or specific attributes that are needed to gain desired operational benefits while, at the same time, maintaining ongoing reliable operations. Many of the systems have been heavily customized or are a version no longer supported by original system vendors, resulting in pockets of specific knowledge within the utility and the high risks associated with breaking open the applications or systems for modification. This risk is, inherently, why the utilities have lived with the less-than-ideal situation as long as they have. But the introduction of new Smart Grid technologies can be the forcing function for utilities to replace additional legacy systems that they might otherwise consider to be out of scope.
is the area of greatest concern for the industry.Utility respondents were asked to rate their level of concern for cyber security risks for various aspects of their organization’s operations using a scale of 1 to 5, where 1 indicates “Least Concerned” and 5 indicates “Most Concerned.” For the second straight year, computers and networks are signification changes required of the utility customer information and billing system (CIS). Modifications of the CIS alone can be complicated and expensive. However, replacing the CIS likely represents a much greater investment that may not be justified or feasible at the time of advanced metering implementation. The integration aspects of smart grid initiatives can thus be as challenging as the organizational and business process redesign components.

It is also important to note that having a smart meter or other smart endpoint device that provides a lot of information for the utility and its customers does not necessarily ensure the receipt of anticipated value unless the utility has the ability to meaningfully act on the data. “Big Data” has become a buzz word for the challenge and opportunity that utilities face as they implement new integrated smart grid solutions. And, as the industry passes from the initial technology adoption phase into the mass implementation phase, utilities are increasingly focusing on the strategic interdependencies and synergies of the new information sources.

Unfortunately, full-scale replacement of legacy systems is often not feasible in the desired project period or in the optimum sequence. For instance, when migrating from manual meter reading to advanced metering, there are signification changes required of the utility customer information and billing system (CIS). Modifications of the CIS alone can be complicated and expensive. However, replacing the CIS likely represents a much greater investment that may not be justified or feasible at the time of advanced metering implementation. The integration aspects of smart grid initiatives can thus be as challenging as the organizational and business process redesign components.

On the basis of conversations with clients, Black & Veatch is seeing a willingness to explore the benefits of working together uniformly and with regulators. Larger utilities view new regulations as another addition to pre-existing cyber security strategies. Mid-tier to smaller companies are not always as advanced and may still be trying to figure out how to appropriately manage the challenge. Regardless of size, all utilities will benefit from scenario planning and the use of tabletop exercises with regard to cyber security planning and readiness. As noted in the Rates & Economic Regulatory section, regulators are not necessarily convinced that utilities are adequately managing and protecting their data. Outage management systems and other enabling technologies. However, for some solutions at the front edge of their maturity curve, this can be difficult to meet, and a degree of industry proof is required to demonstrate the maturity and value proposition of the technology.
Regulators are also increasingly sensitive to constituent sentiment, particularly as it relates to smart meter programs. In today’s communication age, vocal minorities have demonstrated an ability to influence public perception. Regulators, who are sensitive to constituent sentiment, encourage utilities to engage with and assuage these groups. The issue of public engagement is a challenge to utilities who initially were predominantly focused on making the business and regulatory cases for adoption to a much smaller audience.

Well-publicized and highly disruptive events that utilities have faced with smart meter programs demonstrate the consequences of not performing customer engagement activities. Today, the industry is adapting and is now prioritizing the communications activities surrounding Smart Grid programs. When asked which tactics are the most effective for improving understanding of Smart Grid programs, utilities demonstrated a focus on engagement and direct customer marketing (Figure 17). Even with the growing focus on stakeholder engagement, in many ways, the industry is returning to traditional mechanisms in how utilities plan, justify and implement technology enablement programs. Utilities have long deployed automation solutions, control and monitoring applications and cross-system initiatives. The difference with the broader context of Smart Grid may be the extent to which today’s solution can transform the utility and impact internal stakeholders and customers alike. This requires significant attention to organizational and resource issues.

Just five or six years ago, many utilities raced to put together business cases and project plans for Smart Grid programs to obtain funding associated with the U.S. Department of Energy’s Smart Grid Investment Grant (SGIG) program. These early adopters have helped develop best practices, experience and knowledge that can be leveraged by other utilities planning and implementing similar programs today, the most successful of which are using the experiences of others to inform their own strategic plans. And these early adopters have moved beyond project implementation to focus on transitioning to new operational models and developing synergies among the various initiatives to deliver the additional strategic values that the foundational systems were envisioned to provide once fully deployed and operational.

### Figure 17
**IMPROVING SMART GRID UNDERSTANDING**

<table>
<thead>
<tr>
<th>Method</th>
<th>Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stakeholder and interest group engagement</td>
<td>3.76</td>
</tr>
<tr>
<td>Direct customer marketing</td>
<td>3.58</td>
</tr>
<tr>
<td>Proactive regulatory engagement</td>
<td>3.52</td>
</tr>
<tr>
<td>Industry association activity</td>
<td>3.26</td>
</tr>
<tr>
<td>Trade show participation</td>
<td>2.78</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

Utility respondents were asked to rate the effectiveness of the listed items on improving understanding of Smart Grid programs among their stakeholders using a scale of 1 to 5 (where 1 indicates “Least Effective” and 5 indicates “Most Effective.”) Direct interactions with stakeholders and customers were widely viewed as the most effective options.
ASSET MANAGEMENT

BY WILL WILLIAMS

As noted in the Executive Summary, reliability, economic regulation, aging infrastructure and long-term investments make up four of the top five industry issues, as ranked by survey respondents. Although not uncommon to many service industries, for electric utilities these challenges take on added significance because of the sector’s high visibility – consumers and organizations rely on electric utilities to operate.

The fundamental need to maintain 100 percent reliable electric service is driving the focus of capital investments. As noted in Figure 6, more than 40 percent of respondents identified ensuring asset reliability as the area of greatest concentration for current capital spending programs. The need to invest in infrastructure is constrained by competing capital needs, such as large-scale environmental programs, and an uncertain regulatory environment regarding a utility’s ability to recover investments through the rate base. Sound asset management programs represent a proven methodology for maximizing ratepayer and/or shareholders return on investment, extending asset life and reducing overall life cycle costs.

Implementation of asset management programs is an area of opportunity for most U.S. electric utilities, because less than one-third (32.1 percent) of utility respondents stated their organization has an improvement program under way (Figure 18).

Interestingly, nearly 9 percent of respondents stated they are implementing an improvement program but did not conduct a formal assessment. This is the equivalent of seeing your final destination on a map but not knowing your current location – you can’t get to where you want to go without knowing where you are. In other words, it’s hard to implement an effective program without first identifying existing gaps and priorities for improvement.

So, what does it take to implement an effective program? As noted in Figure 6, more than 40 percent of respondents identified ensuring asset reliability as the area of greatest concentration for current capital spending programs. In contrast to public power entities, nearly half (44.5 percent) of investor-owned utilities (IOUs) stated their organizations have carried out necessary assessments and are implementing improvement programs. This suggests an increased focus on cost-efficiency based on the need to deliver positive earnings for shareholders as well as pressure from regulators to be more efficient (Figure 19).

FIGURE 18
STATUS OF ASSET MANAGEMENT MATURITY ASSESSMENTS

<table>
<thead>
<tr>
<th></th>
<th>No asset management maturity assessment/review carried out but no improvement program in place</th>
<th>Maturity assessment/review carried out and improvement program being implemented</th>
<th>Improvement program being implemented, but no formal asset management maturity assessment/review has been carried out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Source</td>
<td>Black &amp; Veatch</td>
<td>Black &amp; Veatch</td>
<td>Black &amp; Veatch</td>
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<tr>
<td>50%</td>
<td>41.0%</td>
<td>32.1%</td>
<td>8.9%</td>
</tr>
<tr>
<td>40%</td>
<td>38.9%</td>
<td>25.4%</td>
<td>11.1%</td>
</tr>
<tr>
<td>30%</td>
<td>51.3%</td>
<td>25.4%</td>
<td>44.3%</td>
</tr>
<tr>
<td>20%</td>
<td>31.9%</td>
<td>22.2%</td>
<td>10.1%</td>
</tr>
<tr>
<td>10%</td>
<td>33.3%</td>
<td>13.3%</td>
<td>7.8%</td>
</tr>
<tr>
<td>0%</td>
<td>35.3%</td>
<td>18.0%</td>
<td>11.1%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

FIGURE 19
STATUS OF ASSET MANAGEMENT ASSESSMENTS BY UTILITY TYPE

<table>
<thead>
<tr>
<th></th>
<th>Public</th>
<th>IPP</th>
<th>IOU</th>
</tr>
</thead>
<tbody>
<tr>
<td>No asset management maturity assessment/review carried out but no improvement program in place</td>
<td>31.9%</td>
<td>22.2%</td>
<td>13.3%</td>
</tr>
<tr>
<td>Maturity assessment/review carried out and improvement program being implemented</td>
<td>35.3%</td>
<td>18.0%</td>
<td>11.1%</td>
</tr>
<tr>
<td>Improvement program being implemented, but no formal asset management maturity assessment/review has been carried out</td>
<td>33.3%</td>
<td>18.0%</td>
<td>11.1%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

This is particularly an area of opportunity for public power organizations, where more than 50 percent of respondents stated their organization had no asset management maturity assessment/review or improvement program under way. In contrast to public power entities, nearly half (44.5 percent) of investor-owned utilities (IOUs) stated their organizations have carried out necessary assessments and are implementing improvement programs.

SOUND ASSET MANAGEMENT PROGRAMS REPRESENT A PROVEN METHODOLOGY FOR MAXIMIZING RATEPAYER AND/OR SHAREHOLDERS’ RETURN ON INVESTMENT, EXTENDING ASSET LIFE AND REDUCING OVERALL LIFE CYCLE COSTS.
MANAGING RISK

Effective asset management can be described as achieving the optimal balance between cost, risk and performance, of which risk management is a key component.

Since utilities are subject to potentially wide fluctuations in operational and financial performance as a result of volatile commodity costs and regulatory uncertainty, understanding risks and building risks into the decision-making process is critical to meeting financial expectations, particularly for investor-owned utilities (IOUs). Risk assessments help utilities identify critical assets, establish the likelihood of failure based on current conditions and estimate the impacts of potential failure. This information helps utilities prioritize capital improvements, enabling them to get the most value from precious capital resources.

The majority of respondents indicated that they have some form of risk management processes in place and are using risk to develop asset renewal and replacement programs across their utility enterprise. However, these results also demonstrate that the industry is not fully utilizing risk and asset management principles. Nearly 20 percent of respondents stated their organizations had not identified critical assets within their utility organizations and had assessments carried out on them (Figures 20, 21 and 22).

Source: Black & Veatch
Utility respondents were asked to select the appropriate response for each statement in each asset classification.

**FIGURE 20**
**ASSET RISK MANAGEMENT STATUS – GENERATION ASSETS**

Source: Black & Veatch
Utility respondents were asked to select the appropriate response for each statement in each asset classification.

**FIGURE 21**
**ASSET RISK MANAGEMENT STATUS – TRANSMISSION ASSETS**

Source: Black & Veatch
Utility respondents were asked to select the appropriate response for each statement in each asset classification.

**FIGURE 22**
**ASSET RISK MANAGEMENT STATUS – DISTRIBUTION ASSETS**

Source: Black & Veatch
Utility respondents were asked to select the appropriate response for each statement in each asset classification.
Further, responses on prioritizing Capital Improvement Programs and development of asset renewal programs based on risk indicate that the industry is still in the early to midstages of fully implementing risk management. There are some jurisdictions where rate adjustment mechanisms, a highly valued regulatory practice that enables the more timely recovery of investments through utility rates, are in place. In these locations, utilities must submit some type of asset optimization plan for review before the regulator will approve costs to be recovered through this mechanism.

However, even in the absence of this mechanism, risk management can benefit utilities seeking cost recovery from necessary capital investments. With increasing upward pressure on utility rates from necessary capital investments, utility regulators and other stakeholders will be examining these investments much more closely than in the past. This means utilities must be prepared to provide strong evidence to demonstrate their investment programs are well-conceived and can provide desirable results. The more a utility is able to demonstrate to regulators and stakeholders that its infrastructure replacement programs are based on the right balance of cost, risk and performance – essentially proving they are “getting the most bang for the ratepayer buck” – the less debate there will be around the cost of these investments in utility rate cases. Furthermore, such programs can reduce the chance of a utility having to defend against prudency challenges from other parties.

In addition to potentially more streamlined regulatory proceedings, utilities also benefit from improved reliability performance. Outages represent a significant cost to utilities and can quickly escalate into the tens and hundreds of millions of dollars per day. While large storm systems bring the issue of reliability to the forefront, nonstorm-related reliability improvements provide significant benefits for customers and the utility’s overall financial performance. Regulators (federal and state) have the authority to levy massive fines on utilities with poor reliability metrics such as the System Average Interruption Duration Index or System Average Interruption Frequency Index, and these organizations are paying close attention to reliability performance. A risk-based asset management process and system will help utility leaders focus on and make decisions to improve the riskiest assets and issues on their systems.

THE MORE A UTILITY IS ABLE TO DEMONSTRATE TO REGULATORS AND STAKEHOLDERS THAT ITS INFRASTRUCTURE REPLACEMENT PROGRAMS ARE BASED ON THE RIGHT BALANCE OF COST, RISK AND PERFORMANCE, THE LESS DEBATE THERE WILL BE AROUND THE COST OF THESE INVESTMENTS IN UTILITY RATE CASES.

IMPROVING ASSET MANAGEMENT

Based on survey participant inputs, it appears that asset management will be an area of focus for the industry during the next three years. Nearly half of participants (49.5 percent) stated that in three years they expect their organization to have fully integrated asset management principles and/or demonstrate excellence in asset management. This suggests commitment to implementing leading practices and improving asset management (Figure 23).

While it is encouraging to see the level of commitment from the industry regarding asset management improvement, there is still a significant percentage of respondents who did not quantify their current maturity or where they expect to see their organization in three years. This could suggest a lack of awareness or understanding of asset management programs and principles, in general.

When asked to rate the primary challenge for improving asset management at their utility, industry respondents by far rated, “Developing the required systems and processes needed to improve asset management” as the top issue (45 percent). This is a common challenge for all industries implementing asset management programs. In Black & Veatch’s 2012 Strategic Directions in the U.S. Water Industry Report, 61 percent of utility respondents stated this was the main challenge for their organizations, as well (Figure 24).

The challenge of improving asset management practices should not be underestimated. Concerted effort is required to change organizational culture, paradigms, practices and in some cases the structure of the organization. Many utilities have benefited from the use of third-party consultants to provide independent and objective advice related to embedding asset management into day-to-day business and operational tasks. This is especially true for organizations that have limited knowledge on asset management programs. In such instances it is recommended that leaders reach out to other organizations that have successfully implemented programs and gain insights on the challenges and benefits of such programs.
In the process of developing an understanding of asset management
Utility has good understanding of asset management and is deciding how elements will be applied. Work is progressing on implementation
Asset management is integrated and applied throughout the organization. Utility demonstrates competence in asset management and follows good practice
Utility demonstrates excellence in asset management and is pushing the boundaries of asset management to develop new concepts and ideas
I don’t know

Utility respondents were asked to select the response that best represents the level of asset management maturity within their organizations today and what they expect it to be in the future. Responses indicate that this will be a focus area for the industry.

Developing the required systems and processes needed to improve asset management
Defining what asset management is and communicating it to the workforce
Obtaining senior management buy-in to improving asset management
Lack of asset management capabilities in the workforce
I don’t know

Respondents were asked to select the response that represents the greatest challenge for their organization to improving asset management.

Source: Black & Veatch

Sound asset management programs provide utility leaders the information and processes needed to reduce operational and life cycle costs.
ENVIRONMENTAL REGULATIONS

BY ANDY BYERS

Uncertainty regarding environmental regulations and their eventual impacts to the power generation industry has continued to grow since the 2012 survey. This year, environmental regulations represent one of the greatest concerns for utilities, second only to reliability at a national level. Much of this uncertainty is a result of the slowly evolving regulatory landscape. Currently, the U.S. Environmental Protection Agency (EPA) has a multitude of new, proposed or pending regulations concerning air emissions, waste management, surface water withdrawal and wastewater discharges that affect nearly every type of thermal generation technology.

AIR QUALITY

By the beginning of 2013, several of the EPA’s major air quality rulemaking initiatives had been finalized and moved into the litigation phase. The Cross-State Air Pollution Rule had been struck down by the courts in August 2012, reverting eastern electric utilities back to the Clean Air Interstate Rule (CAIR) cap-and-trade program for sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions for at least the next few years. Litigation over the Mercury & Air Toxics Standards (MATS) split into two separate actions over the requirements for new and existing units, with the EPA reconsidering and issuing revised proposed standards for new units. Meanwhile, legal challenges to new, one-hour National Ambient Air Quality Standards (NAAQS) for SO2 and NOx proved unsuccessful, while other legal efforts forced the EPA to finalize more stringent fine particulate matter NAAQS. Regional haze plans targeting older plants in western states for similar emissions reductions were also finalized.

While these events provided a bit more clarity on emissions control requirements, utilities still face significant risks with regard to near-term and long-term compliance planning. The MATS 2015-2017 deadline looms near, but ongoing litigation may still delay or even invalidate its mandates for coal-fired generation units. The EPA is still obligated to develop a future replacement program to the CAIR, which itself has a cap reduction scheduled to take effect in 2015. And the specter of the EPA regulation of greenhouse gas emissions casts additional doubts into long-range planning for all fossil-fuel generation development.

This year’s annual survey reflects the use of a diverse combination of technologies that will be used in utilities’ compliance planning approaches. Predominately coal-dependent regions, such as the Midwest, Southeast and Southwest (including Texas) have a significant number of utilities planning early plant retirements, as well as upgrades to air quality control systems such as electrostatic precipitators (ESP) or fabric filter baghouse upgrades and sorbent injection systems to address the impending MATS requirements. A significant number of respondents from utilities in the Midwest (42.9 percent) and the Southeast (33 percent) indicated some type of flue gas desulfurization system would be retrofitted, while approximately 30 to 50 percent of respondents from all regions reported either selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR) systems were being installed for NOx control purposes. More than 40 percent of utilities in the Midwest, Southeast and Northeast will be implementing fuel-switching projects (Figure 25; see the Appendix to view regional data). The variety of these emissions control projects brings to light the multitude of regulatory requirements to be met, and that there is no single “silver bullet” solution for all utilities’ compliance challenges. It is also worth noting that more than one-third of respondents selected “I don’t know,” reflecting the large number of utilities that may be awaiting the outcome of litigation before making final decisions on compliance investments. Those utilities taking a “wait and see” approach risk being caught with very little time to come into compliance if the rules are upheld, while those utilities moving ahead with retrofits risk incurring costs for compliance deadlines that may ultimately be delayed or invalidated by the courts.

FIGURE 25
PREPARING FOR EPA AIR QUALITY REGULATIONS

| 41.4% | 39.0% | 30.0% | 27.2% | 25.6% | 25.1% | 34.6% |
| Early plant retirement(s) | SCR or SNCR (for NOx control) | Fuel switching | Flue gas desulfurization (scrubber) | ESP upgrade or fabric filter baghouse | Sorbent injection system (e.g., DSI or PAC) | I don’t know |

Source: Black & Veatch
Utility respondents were asked to select all of the listed types of air quality programs their organization is planning to take in order to address new and pending EPA air quality regulations.

UTILITIES STILL FACE SIGNIFICANT RISKS WITH REGARD TO NEAR-TERM AND LONG-TERM COMPLIANCE PLANNING.
CARBON EMISSIONS REGULATION

For the past five years, carbon emissions legislation has been, by far, the top environmental concern for the electric utility industry. Nearly three-fourths of all utility respondents believe they will be subject to federal or state regulations that either cap or require reductions of greenhouse gas emissions (Figure 26).

In the absence of Congressional legislation, the EPA has moved forward to regulate reductions in greenhouse gas emissions. Last year, the federal court of appeals upheld the EPA’s authority to regulate greenhouse gas emissions. The EPA proposed a numeric emissions standard for greenhouse emissions for mobile and stationary sources. The EPA will begin to require reduction of greenhouse gas (carbon) emissions from existing facilities.

The EPA first proposed potentially reclassifying coal fly ash ash as either a solid waste or hazardous waste following the 2008 TVA Kingston Fossil Plant ash pond failure that released more than 1 billion gallons of coal ash slurry into surrounding lands and waterways. Although the comment period on the EPA’s original rule closed in November 2010, the agency has yet to draft a final rule and has indicated it is unlikely to do so in the near future.

Regardless of whether the final rule designates CCR as hazardous or solid waste, as proposed, the EPA rulemaking would force many utilities to undertake costly reconfigurations of the entire back end ash handling systems and disposal operations of their coal-fired units. Approximately 30 percent of survey respondents from utilities in the Midwest, Southeast and Rocky Mountain regions, where coal plants are prevalent, stated that the impact of CCR rules as proposed would be significant (see the Appendix to view regional data).

THE EPA PROPOSED A NUMERIC EMISSIONS STANDARD FOR GREENHOUSE GAS EMISSIONS FROM ALL NEW FOSSIL FUELFIRED STEAM ELECTRIC GENERATING FACILITIES WHICH, IF FINALIZED, WILL EFFECTIVELY END DEVELOPMENT OF NEW COAL-FIRED GENERATION IN THE UNITED STATES.

COAL ASH MANAGEMENT

In coal country, or the Southeast, Midwest and Rocky Mountain regions, environmental regulations are the top concern for utilities (see the Appendix to view regional data). One of the biggest lingering regulatory uncertainties for coal generators is the EPA’s proposed coal combustion residuals (CCR) rulemaking.

The potential classification of coal ash as a hazardous waste is of extreme concern for utilities. More than 70 percent of utility respondents stated such a regulation would have a moderate to significant impact on their utility operations (Figure 27). Although the EPA proposed to exempt beneficial reuse from regulation under the CCR rule, just the association of coal ash with “hazardous waste” has been blamed for diminished sales of ash and beneficial reuse products. This, in turn, has prompted ash recyclers to file lawsuits seeking court orders to force the EPA to finalize the CCR rulemaking.

FIGURE 26
ANTICIPATED TIMING OF GREENHOUSE GAS EMISSIONS REGULATIONS

Source: Black & Veatch

FIGURE 27
IMPACT OF COAL COMBUSTION RESIDUALS RULES

Source: Black & Veatch

Anticipated impact on utility operations if proposed coal combustion residuals rules are enacted.
POWER GENERATION

SURFACE WATER REGULATION

Regulation of surface water withdrawals and wastewater discharges is the next big dilemma for the utility industry. The EPA is scheduled to finalize a proposed new rule for cooling water intakes at existing facilities, and propose new guidelines for wastewater discharges in the second quarter of 2013. Given that the industry had limited knowledge of final requirements of these pending rulemakings at the time of the industry survey (January 30 through February 18, 2013), approximately one-third of utility respondents selected “I don’t know” to questions related to the impact of each potential rule.

The final rulemaking on cooling water intake design and operations under Clean Water Act Section 316(b) will be of particular interest to utilities. The EPA’s original proposal would establish fish mortality standards that would require costly impingement monitoring and compliance demonstrations. However, last year, the EPA released a regulatory notice that it was considering declaring specific technologies (i.e., fine mesh traveling screens with fish return or closed-cycle cooling tower systems) to meet 316(b) requirements. Overall, approximately 25 percent of survey respondents anticipate the final rule will have a moderate-to-significant impact on their utility (Figure 28).

Unfortunately, Black & Veatch does not anticipate quick relief for power plant owners or operators in regard to regulatory uncertainty. However, many leading organizations are working to alleviate this pressure by engaging in scenario planning. Scenario planning provides utility leaders with a clear picture of all possible future operating environments and regulations. This, in turn, provides them with a playbook for meeting future electric needs, while maintaining compliance, in the most cost-effective manner.

The EPA’s upcoming Steam Electric Power Generating Effluent Guidelines are expected to focus on effluents from flue gas desulfurization blowdown, ash transport waters, landfill leachate, coal pile runoff and metal cleaning wastewaters. The proposed new standards will determine whether, and to what extent, power plant cleaning wastewaters. The proposed new standards will determine whether, and to what extent, power plant cleaning wastewaters. The proposed new guidelines will likely require greater levels of investment for larger facilities that utilize once-through cooling systems, a significantly higher number of respondents representing utilities in the Southeast (37.5 percent) and Midwest (41.5 percent) expected a moderate to significant impact (see the Appendix to view regional data).

More than one-third of utility respondents state they did not know what level of impact the proposed 316(b) Cooling Water Intake regulation will have on their utility’s operations. More than one-third of utility respondents state they did not know what level of impact the proposed 316(b) Cooling Water Intake regulation will have on their utility’s operations.

REGULATION OF SURFACE WATER WITHDRAWALS AND WASTEWATER DISCHARGES IS THE NEXT BIG DILEMMA FOR THE UTILITY INDUSTRY.
In Black & Veatch’s Midyear 2013 Energy Market Perspective, a long-range outlook on the integrated power, emissions and natural gas markets, the company projects that natural gas-fueled generation will more than double in the next 25 years. This projection is validated by survey results that show nearly one-third of utilities are expecting to increase natural gas demand by more than 25 percent by 2020 (Figure 30). To ensure that today’s high levels of electric service reliability and price stability continue into a natural gas-fueled future, utilities must begin planning now to shore up critical natural gas supplies, pipeline and storage capacity.

This is the first year Black & Veatch has surveyed electric utility leaders on specific issues associated with natural gas supply and transportation. This is also the first year that survey participants were asked to rate the overall level of concern they have for natural gas prices and fuel supply reliability. While survey respondents ranked natural gas prices seventh on our Top Ten Industry Issues list, fuel supply reliability came in just under the cut in 11th place. Notwithstanding this comparatively low prioritization, an examination of the regional data provides profound insight.

In the Northeast, natural gas prices were second only to reliability as the region’s top issue. Given the timing of the survey (January 30 through February 18, 2013), participants in the Northeast were coming off a cold snap that caused the spot price of physical gas delivered to New York via Transco Inc. to rocket to more than $37/ million British thermal units (MBtu) on January 24 and 25. Boston’s spot pricing, similarly impacted by the cold spell, spiked in excess of $34/MBtu. Survey results, particularly results from the regions’ respondents show the electric industry is naturally sensitive to these price swings.

It is important to note that gas prices at the Henry Hub in Louisiana for those days remained below $4/MBtu leading to questions about the causes of price spikes for the region. The answer relates to fuel supply reliability and is perhaps why the issue should be of much greater significance to energy consumers than the issue of natural gas prices alone.

While fuel supply reliability is often evaluated as a single issue by the markets, Black & Veatch believes it is composed of two important components. First, there must be sufficient gas supply attached to the pipelines serving a power region (or a given generation facility). Second, there must be sufficient gas pipeline capacity available to deliver the gas when and where it is needed.

The Northeast and New England illustrate the relationship between the two components of supply. With the Marcellus Shale famously creating a supply glut in Appalachia, the region’s recent cold weather snaps registered as only a minor fluctuation in local gas prices; clearly neither supply nor deliverability were at issue. Yet, only a few hundred miles to east, New York, and the Northeast region in general, saw prices spike.

The primary difference accounting for this variance is the availability of pipeline capacity in peak demand periods. New York, the broader Northeast in general and New England are largely pipeline constrained under certain demand circumstances. This means that regardless of how much gas is available in nearby production basins, only so much can reach residential, commercial or industrial burner tips or power generation busbars. Surges in local gas prices help reveal the location – and sometimes underlying details – of a constraint scenario.

Most gas utilities, which are responsible for serving residential and commercial customers, hold firm winter pipeline capacity under a portfolio of maximum and discounted rate contracts. This is a comparatively expensive reservation fee that merchant generators who lack utility cost recovery advantages typically prefer to avoid. Instead, they seek to generate significant savings and profits by building their supply portfolios with a combination of seasonal firm and interruptible service pipeline capacity contracts. This works as long as adequate pipeline capacity is available. Both firm and interruptible pipeline/supply options can provide satisfactory financial results for merchant generators, but interruptible gas supply portfolios can be troublesome for regional electric grid reliability when pipeline capacity is constrained and those generators cannot obtain gas.

The brief period of extremely cold weather in January created a confluence of many gas buyers, few gas sellers and scarce pipeline capacity for the Northeast. As a result, the laws of supply and demand prevailed, and gas prices rose sharply, causing power prices to spike in tandem. This costly scenario emphasizes the need for thorough planning and diverse fuel portfolios – including diverse supply and transportation capacity portfolios for natural gas.

<table>
<thead>
<tr>
<th>FIGURE 30</th>
<th>ANTICIPATED NATURAL GAS DEMAND INCREASES BY 2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Source: Black &amp; Veatch</td>
<td></td>
</tr>
<tr>
<td>Nearly one-third of utility respondents believe their organizations will have significantly greater (more than 25 percent) demand for natural gas to fuel power generation facilities by 2020.</td>
<td></td>
</tr>
</tbody>
</table>
Utility respondents were asked the extent to which their organizations have begun planning for potentially large natural gas demand increases on their regional pipeline systems. Less than 7 percent have plans that are fully ready. In contrast, more than a third of utility organizations have not started or are just now in the initial planning stages (Figure 31).

Fuel supply planning can be extremely beneficial for utilities and merchant generators alike because it promotes intelligent resource decisions, such as siting of new generation to access competitively priced supply and delivery pipeline capacity. Given the efficiency of new drilling technologies, supply is expected to support domestic use and potentially liquefied natural gas (LNG) export opportunities for the foreseeable future. Gas storage, which can address gas price volatility in peak demand periods including winter heat or summer cooling, is another planning component that should be addressed long-term. For utilities or merchants building gas portfolios, managing the long-term cost and risks inherent in those portfolios will ultimately be a major determinant of business profitability.

The management and development of pipeline capacity represent an opportunity and challenge for the electric industry. When asked how confident they were in medium- to long-term adequacy of intra/interstate pipeline within their utility’s regional grid, 28 percent answered “I don’t know”; 20 percent answered “Neither confident nor unconfident”; and 19 percent are either “unconfident” or “very unconfident.” The responses are revealing because they suggest that more than two-thirds (68 percent) of the industry respondents either do not know what to think of their regional pipelines or are not confident of their adequacy (Figure 32).

This knowledge/confidence gap can be traced, in part, to the scarcity of formal studies of regional pipeline delivery capacity and to the overall complexity of simultaneously analyzing multiple interconnected pipeline systems. It also reflects the steep learning curve associated with mapping regional pipeline studies to regional electric grids. It is critical to remember that only a few short years ago, utility planning, which often takes a decades-long outlook, did not envision low-cost natural gas as the primary fuel source.

Decisions made regarding a utility’s portfolio should not and do not need to be made in a vacuum. To prepare for the future, utilities must be keenly aware of what others are doing within their regional pipeline systems. The benefit of a regional study, such as the one Black & Veatch began in 2012 for the New England States Committee on Electricity, is that it provides a forum for regulators, utilities, RTOs/ISOs and stakeholders to consider what the collective best practices are for a region. As compared to individual studies and decisions, this more holistic approach to planning should yield benefits to consumers.

As compared to individual studies and decisions, this more holistic approach to planning should yield benefits to consumers.

It should also be noted that challenges associated with fuel supply reliability are not unique to the Northeast. In 2011, a cold snap in Texas froze natural gas compressors and made residential and commercial demand escalate. The loss of supply sources prevented electric generators from starting up natural gas-fueled plants, resulting in widespread service outages and soaring spot market prices for power.

In addition to Texas and the Northeast, Black & Veatch finds that many locations, such as Florida, the Upper Midwest and Southern California, may ultimately face issues associated with pipeline capacity as a result of growing demand from the power generation industry. This issue may become more significant in the next two to four years when planned coal-fired generator retirements are enacted, existing natural gas generator capacity factors increase and new gas generators are brought online. Rapidly increasing gas use underscores the need for sound fuel supply planning in the short-term and additional pipeline and storage capacity in the long-term.

There is a growing interest in how the Federal Energy Regulatory Commission (FERC) proceedings on the coordination between Natural Gas and Electricity Markets (Convergence) may play out. Though intended to identify rules, regulations and other policies that will close the gap between these two industries on issues regarding reliability, costs and risks, among other areas, it will likely be years before any final decisions or policies are implemented. Until then, the only certainty is uncertainty, and companies will have to work with what they can reasonably foresee, assess and manage.
RENERABLE ENERGY

BY RYAN PLETKA AND WILLIAM ROUSH

Over the course of the next 25 years, Black & Veatch projects that renewable energy generation will increase by approximately 150 percent, accounting for nearly 10 percent of all energy consumed in the United States. Much of this growth will occur in the next seven to 10 years as utilities strive to meet Renewable Portfolio Standard (RPS) requirements.

This year, the Black & Veatch survey asked participants if RPS targets within their operating areas were achievable and, if so, what type of rate impact would meeting those objectives have on consumers. Of those with an opinion, about 80 percent of respondents stated they believe targets are achievable with varying degrees of rate increases, compared to only 3 percent who believe targets are not achievable due to technical considerations (Figure 33).

The 3 percent figure represents a maturation of the renewables industry within the United States as well as a growing level of acceptance of renewable energy as a generation resource by utilities. However, when it comes to renewable energy cost, technical feasibility and technology preference, regional views can vary widely.

Overall, more than 40 percent of all respondents who expressed an opinion believe renewable portfolio targets can be met with a customer rate increase of less than or equal to 5 percent. A few regions notably depart from the national trends. In the Midwest, which is rich with relatively low-cost wind resources, over half the respondents feel RPS targets can be met with rate increases of 5 percent or less. There are already many large wind projects that have been developed across the region, and states are well on their way to meeting RPS targets.

On the other hand, in the Southeast, more than 70 percent of respondents with an opinion feel that RPS targets cannot be met because the cost is too great (30 percent) or that RPS targets can be met, but rate increases would be higher than 5 percent (40 percent). Only 17 percent of respondents in the Southeast believe RPS targets can be met without raising rates above 5 percent. This is an interesting result that could be interpreted many ways. Currently, the only state within the region with a renewable energy requirement is North Carolina. This likely accounts for the number of respondents from the region (30.9 percent) who selected the “I don’t know” option. For those who did provide an opinion, responses are likely from the point of view of what it would cost if utilities in the Southeast region were required to meet similar standards (see the Appendix to view regional data).

The skepticism in the Southeast could be attributed to a general lack of low-cost wind resources within the region. In addition, the Southeast, outside of the sizable Martin Next Generation Solar Energy Center which supplements a conventional power plant in Florida, has not been the focus of utility-scale solar implementations. Uncertainty in Federal tax policy and emissions regulations and few state incentives have also hampered development of an abundant biomass resource. More than half of respondents from the region (55.7 percent) believe intermittent resources such as wind and solar will make up less than 5 percent of overall generation capacity by 2015.

Respondents from the Southwest also widely believe that renewable energy implementation will come at a greater cost (on a percentage basis) to customers. Only 29 percent of respondents from this region believe renewable requirements can be met with a 5 percent or less rate increase to customers. Black & Veatch attributes this to the historical high cost of solar and widespread perception of the technology as expensive. However, the cost of solar generation has come down significantly, and currently several of the largest solar projects in the world are under way in the desert Southwest. Because of the overall size and complexity, however, the price tag for many of these projects tops the $1 billion mark.

Large projects currently under construction in the Southwest include the Copper Mountain Solar 2 project (150 megawatts (MW)), the Mesquite Solar Ranch One (150 MW), the Imperial Solar Energy Center South (130 MW), the Topaz Solar Farm (550 MW), California Valley Solar Ranch (250 MW) and the Desert Sunlight Solar Farm (550 MW). Combined, these solar photovoltaic (PV) plants represent more than 1,700 MW of new renewable resources, which point to why utilities in the region are generally bullish on the overall amount of intermittent capacity their region will have in the next few years. Nearly half (48.9 percent) believe intermittent generation capacity will be greater than 10 percent by 2015.

FIGURE 33
MEETING RENEWABLE PORTFOLIO TARGETS

<table>
<thead>
<tr>
<th>50%</th>
<th>40%</th>
<th>30%</th>
<th>20%</th>
<th>10%</th>
<th>0%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yes, 1-5% rate increase</td>
<td>Yes, greater than 5% rate increase</td>
<td>No, technically feasible but cost too great for customers</td>
<td>No, not achievable due to technical considerations</td>
<td></td>
<td></td>
</tr>
<tr>
<td>13.2%</td>
<td>32.1%</td>
<td>36.8%</td>
<td>14.5%</td>
<td>3.4%</td>
<td></td>
</tr>
</tbody>
</table>

Source: Black & Veatch

Utility respondents were asked if renewable portfolio targets within their operating areas are achievable and what cost to consumers. More than one-third believe targets are achievable with a 5 percent or less rate increase to customers. NOTE: Figures do not include participants who answered “I don’t know.”

WHEN IT COMES TO RENEWABLE ENERGY COST, TECHNICAL FEASIBILITY AND TECHNOLOGY PREFERENCE, REGIONAL VIEWS CAN VARY WIDELY.
DISTRIBUTED GENERATION

Utility respondents believe distributed generation — or power assets with a capacity less than 20 MW — will likely grow from today’s current levels of approximately 5 percent of the total U.S. power generation. Driving this growth will likely be the continued decline in solar PV technology costs as well as the relatively low cost of natural gas (Figure 34).

The breakthrough in solar PV manufacturing that is driving utility-scale projects in the Southwest is also helping to move distributed generation forward nationally. As little as five years ago, individuals or businesses that implemented solar PV applications did so not necessarily to save money, but simply to have rooftop solar. Rooftop solar essentially was a status symbol for the ultimate environmentalist. Today, the reduced cost of PV technology, combined with, in some areas, state and/or local incentives, enables businesses and residential customers to implement solar energy with the expectation of ultimately saving money.

Overall distributed generation in California has grown so much in recent years that it now accounts for a similar capacity as the now offline San Onofre Nuclear Generating Station, or about 2,000 MW. Another example of the increasing use of solar PV technology is the overall leap in solar incentive program applications submitted to the Los Angeles Department of Water & Power (LADWP). LADWP manages the largest municipal solar incentive program in the United States. Since 2009, the utility has experienced a 400 percent increase in applications. From 2011 to 2012, LADWP provided incentives for 1,900 solar projects totaling 21.8 MW of generation — 42 percent of total incentivized generation since the program’s inception in 1999.

For large industrial organizations, the cost of natural gas in comparison to rising electric rates is prompting some to investigate on-site generation for their electric power needs. Black & Veatch is currently working with several organizations in examining existing combined heat and power (CHP) equipment within factories and manufacturing centers to determine if this equipment — or the implementation of new equipment — can provide businesses with a lower cost energy solution.

FIGURE 34
AMOUNT OF DISTRIBUTED GENERATION BY 2020

<table>
<thead>
<tr>
<th>Percentage</th>
<th>2013</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 5%</td>
<td>20.6%</td>
<td>13.4%</td>
</tr>
<tr>
<td>Approximately 5%</td>
<td>42.8%</td>
<td>42.8%</td>
</tr>
<tr>
<td>10-20%</td>
<td>12.6%</td>
<td>12.6%</td>
</tr>
<tr>
<td>More than 20%</td>
<td>2.9%</td>
<td>7.8%</td>
</tr>
<tr>
<td>I don’t know</td>
<td>7.8%</td>
<td>7.8%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch
Utility respondents were asked what percentage of all U.S. power generation they believe will come from distributed resources (capacity less than 20 MW) by 2020.

CHALLENGES

Injecting massive amounts of renewable energy, particularly intermittent solar and wind, onto the nation’s electric grid in an efficient and reliable manner will be a significant challenge. As noted in the Transmission section of this report, the Federal Energy Regulatory Commission (FERC) has implemented new rules and regulations to potentially help move critical transmission infrastructure development forward, but major investment will be required to effectively harness this capacity.

Outside of the transmission issue, survey participants were asked to rate the top three technologies or policies needed for facilitating the integration of intermittent energy into the grid in a reliable and cost-effective manner. More than half (54 percent) selected energy storage. This is somewhat surprising, in that storage has often been viewed as a relatively expensive option to integrate renewables compared to using existing generating stations. While storage comes in many forms, historically, most energy storage has been in the form of pumped hydropower. Increasingly there is consideration of Compressed Air Energy Storage, flywheels and a plethora of battery technologies, configurations and chemistries. Policymakers, such as FERC, are promulgating rules that would reward the speed and accuracy of new storage technologies. If fully implemented, that compensation could improve the business case for battery storage. Despite the absence of a ubiquitous storage solution, perhaps the industry is hopeful that this technology will advance in a manner similar to how solar PV technology has in the past few years (Figure 35).

The overall ranking of existing conventional power plants as the third most important technology for facilitating intermittent technology is puzzling. If anything, new, flexible conventional plants featuring advanced gas-fueled combustion turbine technology would likely be more useful in integrating renewables into the grid. Given current capabilities, some feel it is not an efficient use of resources to cycle down a coal or nuclear facility to make way for wind or solar energy on the grid. Black & Veatch notes that improved forecasting nearly tied with existing conventional plants in terms of most important items. This could mean that by better identifying when wind and solar will be “on,” grid and plant operators could better facilitate the use of all generation resources in an efficient and reliable manner.

The renewable energy industry has made important strides in the last decade to become part of the mainstream power sector. As the industry has grown, it has sought to further reduce costs so it can be an economically viable option independent from subsidies. With forecasted continued growth in renewable energy, especially solar and wind, utilities will be faced with integrating larger and larger quantities of variable energy generation into their mix. Policies and procedures are being developed to enable utilities to achieve high levels of renewable integration in a safe and reliable manner, but they are still in a nascent form. Black & Veatch’s best advice for dealing with such issues is strategic placement of renewables over a wide geographic setting and on sections of transmission and distribution networks where impact will be limited, the use of control techniques for large renewable generators akin to those seen with conventional power plants, and balancing renewables with conventional generation sources using integrated resource planning and power forecasting techniques.
Utility respondents were asked to identify the three most important technologies or policies needed for facilitating the integration of intermittent energy into the grid in a reliable and cost-effective manner.

Source: Black & Veatch

Utility respondents were asked to identify the three most important technologies or policies needed for facilitating the integration of intermittent energy into the grid in a reliable and cost-effective manner.
NEXUS OF ENERGY AND WATER

BY TED PINTCKE, MICHAEL PRESTON AND MICHAEL EDINGTON

America’s power depends on water. Approximately 85 percent of the current generation mix in the United States is produced by thermal generation facilities such as coal, nuclear and natural gas – facilities that generally require massive amounts of freshwater supplies for cooling and steam production. Even though the country’s overall generation mix is expected to evolve over the next 25 years, with a significant amount of nuclear and coal unit retirements, Black & Veatch projections indicate that approximately 85 percent of the country’s energy mix will still be from thermal generation technologies.

Water supply has long been on the minds of utility leaders. For the seventh straight year – since this report’s inception – the issue of water supply has been second only to carbon emissions legislation among the top environmental concerns for utility leaders at a national level. With growing populations and increasing competition for freshwater resources, utilities will face increasing scrutiny with regard to freshwater use when siting and permitting new facilities.

For this year’s report, Black & Veatch sought to gain additional insights on how the issue of water supply has affected the operations of power generation units and what utility owners are doing to prepare for future water scenarios. For the past five years, drought conditions and/or extreme heat in various parts of the country have given way to headlines of power plant curtailment or shutdowns due to either a lack of water supply or high water temperatures from surface supplies. This includes the shutdown of plants in the Southeast in 2008 and 2009, particularly in Georgia when water levels in Lake Lanier hit historic lows, through the summer of 2012 when one of the two units at the Millstone Nuclear Power Plant was brought offline due to high water temperatures.

IMPACT ON OPERATIONS

At a national level, the industry is evenly split regarding overall concern for water supply risks. Approximately 45 percent of utility respondents have no or minimal concerns regarding the vulnerability of their operations to water supply risks and/or severe drought. Another 45 percent have moderate to significant concerns, while nearly 9 percent do not know (Figure 36).

The regional results of this question were also fairly predictable: Water-scarce regions such as the Southwest and Northwest (east of the Cascade Mountains) had a significantly higher percentage of respondents who selected moderate or significant levels of concern, 57.8 percent and 47 percent, respectively. Regions that have recently experienced or are currently experiencing drought also indicated higher levels of concern such as the Midwest (48.8 percent) (see the Appendix to view regional data).

The surprise within these results is that the level of concern is not higher. With severe drought in the Midwest, Rocky Mountain and Southwest regions throughout 2012, it was expected that the overall level of concern would be higher. Just last year, utilities operating in the Electric Reliability Council of Texas (ERCOT) rated water supply as the greatest environmental concern – even more so than carbon legislation – as a result of devastating drought that has gripped the region since 2010.

When asked what effects constrained generation had on utilities during the past year as a result of high water temperatures and/or water shortages, nearly two-thirds of all respondents selected “No impact,” a result that was fairly consistent across all regions. When taking into account overall water availability, this is a surprising statistic considering the record droughts and temperatures experienced across much of the country in 2012, as well as headlines pointing to the shutdown of major baseload power plants, most notably nuclear units (Figure 37).

From an industry and regional point of view, the overall level of impact resulting from the curtailment of power plants in 2012 likely was inconsequential as a result of excess reserve generation capacity. By rule, RTOs and ISOs are required to maintain a minimum of 15 percent reserve margins within their operating areas. Today, most regions are operating with reserve margins approaching or surpassing 20 percent as a result of the 2008 recession and the slow recovery of overall energy demand. However, as the economy recovers, much of this reserve capacity will diminish. Black & Veatch projects that the ERCOT region will be the first to achieve the reserve margin capacity balance in the near future, with the remaining RTOs/ISOs coming into balance within the next three to four years. This means that water constraints could have far greater impacts to the industry and customers in the not-so-distant future. The use of more water-efficient generation technologies (based on gallons per megawatt-hour), such as photovoltaic, wind and combined cycle facilities, may mitigate impacts to water supply.

FIGURE 36
CONCERN FOR WATER SUPPLY VULNERABILITY

<table>
<thead>
<tr>
<th>Concern or Risk</th>
<th>Minimal concern or risk due to alternatives</th>
<th>Moderate concern or risk with limited alternatives</th>
<th>Significant concern or risk to continued operations</th>
<th>I don’t know</th>
</tr>
</thead>
<tbody>
<tr>
<td>60° – 80°</td>
<td>16.9%</td>
<td>29.0%</td>
<td>33.5%</td>
<td>11.8%</td>
</tr>
<tr>
<td>80° – 100°</td>
<td></td>
<td></td>
<td>33.5%</td>
<td>11.8%</td>
</tr>
<tr>
<td>100° – 120°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
<tr>
<td>120° – 140°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
<tr>
<td>140° – 160°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
<tr>
<td>160° – 180°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
<tr>
<td>180° – 200°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
<tr>
<td>200° – 220°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
<tr>
<td>220° – 240°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
<tr>
<td>240° – 260°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
<tr>
<td>260° – 280°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
<tr>
<td>280° – 300°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
<tr>
<td>300° – 320°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
<tr>
<td>320° – 340°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
<tr>
<td>340° – 360°</td>
<td></td>
<td></td>
<td></td>
<td>11.8%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch
Utility respondents were asked to indicate their level of concern regarding the vulnerability of their organization’s operations to water supply risks and/or severe drought conditions.
As time goes by, competition for precious freshwater resources will continue to increase as will the population and demand for critical electric supply. With nearly 85 percent of the nation’s electric infrastructure highly dependent upon water, utility leaders will be wise to consider alternative options for planned and existing facilities—even within regions that are historically “water rich.” As recent history has shown, severe drought can quickly diminish water levels in lakes, rivers and reservoirs existing power plants depend upon for safe, efficient and reliable operations. The good news is that proven technologies and alternatives do exist that can enable the industry to become less water-intensive and, therefore, more reliable despite evolving and more extreme weather patterns.

PLANNING FOR FUTURE NEEDS

A significantly greater number of utility respondents are aware of their organization’s water supply risks (8.8 percent selected “I don’t know” according to Figure 36) than what they are planning to do in order to secure water supplies (31.9 percent selected “I don’t know”) (Figure 38). This is particularly acute in the Northwest, where 12.2 percent of respondents didn’t know about water supply issues, and nearly 40 percent didn’t know how their organization would secure future needs.

Among respondents who are knowledgeable of their organization’s water supply planning activities, responses to this question indicate a portfolio-type approach to meeting future needs. Plans for alternative/backup supplies, the use of reclaimed wastewater and alternative cooling designs are receiving a relatively equal amount of consideration nationally.

When looking at plans for cooling technologies, again a significant portion (45.7 percent) selected “I don’t know,” and a quarter of respondents selected traditional wet systems supplied by local freshwater (Figure 39). At a regional level, the Southwest is leading the way for a less freshwater-intensive industry with the most dry cooling, hybrid wet/dry technology and the use of gray water for cooling (see the Appendix for regional data). This likely reflects that in general, when plant designers have water available, they are typically going to try to use it. Likewise, where water supplies are not widely available, designers and utility owners look to other solutions.

Economics is a primary driver in selecting cooling technologies for power plants. However, in some regions of the country, the ability to obtain water permits and/or site a new facility at a specific location is becoming increasingly more challenging. If the consumptive use is significantly reduced by using hybrid or dry cooling, it may potentially reduce the time required to obtain necessary permits.

Source: Black & Veatch

Utility respondents were asked to select which of the listed options their organization is considering to ensure a more reliable water supply.

My organization’s primary freshwater supplies are adequate

Source: Black & Veatch

Utility respondents were asked to select which of the listed options their organization is considering to ensure a more reliable water supply.
TRANSMISSION

BY ALLEN SNEATH AND ROBERT MECHLER

With reliability ranking as the perennial top issue for the industry, it is not surprising to see survey respondents identify generation, transmission and distribution to ensure reliability as the areas where their capital spending is most concentrated. This is especially true when considering that the North American Electric Reliability Corporation (NERC) now has authority to levy fines on organizations that do not maintain compliance with strict reliability standards.

The scope of NERC’s new authority is forcing transmission operators to ensure that their power delivery grids meet standards that were previously considered industry guidelines. This change removed the flexibility in maintenance to mandatory repair of the network. System reliability has always been an industry focus; but now, that focus has been sharpened by the force of law.

While regulation, such as NERC’s reliability standards, is driving significant investment in maintaining or replacing current assets, expansion of the nation’s electric grid is, like all other areas of the industry, greatly hampered by regulatory uncertainty. Ironically, two areas providing perhaps the greatest amount of uncertainty are policies developed to encourage transmission development.

RETURN ON EQUITY

The Energy Policy Act of 2005 directed FERC to implement incentive-based rate treatments for transmission of electric energy. Since 2006, FERC has granted return on equity (ROE) incentives for several transmission projects across the United States, many of which will help bring renewable energy to market.

Today, the market is seeing pressure to reduce these incentives and limit transmission utilities’ regulated rate of return on transmission investments, particularly in the Northeast and West Coast markets. In some cases, FERC-granted incentives are being challenged in the courts. In the Northeast, for example, the New England ISO tariff formula rate of 11.14 percent base return on equity currently approved by FERC is now being challenged by FERC staff as “unjust and unreasonable.” The premise of the challenge by FERC for a lower rate is based on comparable risk assessment of like investments.

A final ruling could have broad implications across the industry. Without a favorable ROE, utilities will be hesitant to take on the risks and costs associated with new transmission development. Perhaps this is the reason there is such a fair even split among survey participants when asked if FERC ROE incentives will be sufficient to stimulate an appropriate level of transmission investment across the national electric grid (Figure 40).

Utility respondents were asked if they believed ROE incentives granted by FERC for new transmission investment are sufficient to stimulate additional investment nationwide.

One way for utilities and/or transmission developers to better balance risks and costs is through the use of joint ventures. Demonstrating a growing trend in this area, the majority of utility industry respondents stated their organization is either currently involved in a joint venture or is open to the opportunity of creating a joint venture (Figure 41). Joint ventures enable utilities to look beyond traditional service territories for new investment opportunities, as well as share the risk of these projects. In many cases, projects that are being contemplated by joint ventures are substantially large, crossing multiple regions and requiring a long-term view of the electric grid landscape.

FIGURE 40
ROE INCENTIVES FOR ENCOURAGING TRANSMISSION INVESTMENT

Source: Black & Veatch

Utility respondents were asked if they believed ROE incentives granted by FERC for new transmission investment are sufficient to stimulate additional investment nationwide.

FIGURE 41
VIEWPOINT ON TRANSMISSION JOINT-VENTURE OPPORTUNITIES

Source: Black & Veatch

Survey respondents were asked if their organization is either currently involved in a joint venture or is open to the opportunity of creating a joint venture.

Survey respondents were asked if their organization is either currently involved in a joint venture or is open to the opportunity of creating a joint venture.
ORDER NO. 1000

FERC’s landmark Order No. 1000 ruling seeks to remove transmission development barriers by increasing competition and regional coordination, while better distributing cost obligations to stakeholders benefiting from the infrastructure. Transmission owners met a fall 2012 filing date for submitting regional plans and FERC has set July 10, 2013, as the deadline for transmission owners to file inter-regional plans. On February 21, 2013, FERC issued its first two orders regarding compliance with regional plan requirements (for a Duke Energy subsidiary and for Central Maine Power). Further action on the outstanding filings is expected to take place in the coming months. Appeals have been filed by various parties to the U.S. Federal Court of Appeals, and some remain open. The full Order No. 1000 compliance cycle (i.e., regional and inter-regional submissions and approvals) is anticipated to span several more months, at a minimum.

FIGURE 42

ANTICIPATED IMPACT OF FERC ORDER NO. 1000

<table>
<thead>
<tr>
<th>60%</th>
<th>50%</th>
<th>40%</th>
<th>30%</th>
<th>20%</th>
<th>10%</th>
<th>5%</th>
</tr>
</thead>
<tbody>
<tr>
<td>It will create concern that other entities will enter utility’s territory and build critical transmission infrastructure</td>
<td>It will not be beneficial to the utility system</td>
<td>It will generate new, joint-ownership projects across the seams</td>
<td>It will generate new, internal projects that result in more power transfer and higher capacity across the seams</td>
<td>I don’t know</td>
<td>13.1%</td>
<td>12.0%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

Black & Veatch asked utility survey respondents to rate the overall impact FERC Order No. 1000 will have on utilities. The majority of utility respondents (57.3 percent) selected “I don’t know,” even though every utility has had to file an Order No. 1000 compliance plan. This could be attributed to the broad base of respondents who may or may not be directly involved in developing these compliance programs. Or, it could be attributed to the overall complexity of the requirements that the industry is still working through (Figure 42).

Perhaps the most controversial issue and area of greatest concern for utilities is the “non-incumbent developer requirements” within Order No. 1000. Under the rule, independent transmission developers and new joint ventures will be able to propose, design, build, and own transmission facilities that operate in and across a utility’s service territory. Historically, local utilities have enjoyed the right of first refusal; that is, the right to build and own all the transmission in their service territory. Order No. 1000 would curb this right. However, some states, concerned over potential changes in the competitive landscape, have taken legal action to block access of out-of-market entities, while others are open to competition.

Since the economic downturn in 2008, overall electric demand has fallen and has yet to return to pre-recession levels. Current reserve margins within each RTO/ISO region range between 20-30 percent. Despite these figures, significant renewable generation development continues because of hard renewable portfolio requirements at the state level, the majority of which must be made by 2020. NERC projects that 60 percent of all new power sources added to the bulk power system by 2019 will come from wind and solar. And, with significant renewable development comes significant transmission needs.

“The nation’s existing transmission system was not built to accommodate this shifting transmission fleet,” said former FERC Chairman Jon Wellinghoff in a statement issued with Order No. 1000. “It is critical that transmission planners seek the most efficient and cost-effective ways to meet the needs of their region.”

Though final adoption may not be for quite some time, Order No. 1000 will change the way the electricity market looks at transmission. Similarly, the dramatic shift in generation fuel costs due to the U.S. shale gas revolution, coupled with federal and state support of renewable generation, is forcing the development of new transmission to link facilities to the grid. However, integration points are just one of the challenges to be addressed in determining when and where to inject renewable power. A key area to watch will be the delicate balance that FERC must achieve in regard to the need for open access to the transmission grid and the rights of local governments to define their generation mix, transmission ownership and competitive electric wholesale and retail markets.

LARGE INTERSTATE TRANSMISSION PROJECTS ARE NEEDED TO BRING RENEWABLE ENERGY TO DEMAND CENTERS.
UTILITY TELECOM & DISTRIBUTION SYSTEMS

BY PAUL MILLER, CHARLES HILL, JENNIFER JAMES AND KEVIN CORNISH

As the U.S. electric grid gets “smarter,” a robust communications network that serves as a foundation and supports the increased functionality of the grid becomes increasingly important (Figure 43). The addition of new technologies to the underlying infrastructure requires a communications backbone that ensures the reliable exchange of information between smart devices on the network and intelligent systems used by the utility operator. These smart technologies are providing unprecedented levels of information on the status of the network, energy consumption and performance of network infrastructure enabling new efficiencies and optimization across a broad range of metrics.

To support the rapidly expanding flow of data, the majority of utility telecom networks feature a blend of private and public network infrastructure developed through a series of historical choices and available-at-the-time solutions. Respondents indicated that this hybrid model will continue to be the dominant arrangement for the foreseeable future (Figure 44) as new approaches to smart integrated infrastructure are considered for deployment. This forward view reflects a blend of cost-effectiveness, interest from the public carriers in playing a larger role in smart grid networks and the need to balance the right network with the vastly disparate quality of service requirements for the varied smart grid solutions.

Harnessing the capacity of their telecom networks, 47 percent of utilities indicated they are going to start or expand advanced metering infrastructure (AMI) programs. Public power organizations and IOUs are still more focused on AMI than any other initiatives with roughly 50 percent looking at expanding AMI programs versus adopting programs further along the technology development cycle such as Volt-VAR (VVO), demand response and Fault Location, Isolation and Service Restoration (FLISR) (Figure 45).

Figure 43

IMPORTANCE OF TELECOM NETWORKS TO FUTURE UTILITY OPERATIONS

<table>
<thead>
<tr>
<th>Importance</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Very important</td>
<td>26.3%</td>
</tr>
<tr>
<td>Important</td>
<td>41.4%</td>
</tr>
<tr>
<td>Neutral</td>
<td>5.9%</td>
</tr>
<tr>
<td>Unimportant</td>
<td>16.9%</td>
</tr>
<tr>
<td>I don’t know</td>
<td>8.6%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

More than two-thirds of utility participants believe telecommunications networks will be important or very important to future operations.

Figure 44

MEETING FUTURE TELECOMMUNICATION NEEDS

<table>
<thead>
<tr>
<th>Need</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maintain use of a combination of private and public networks</td>
<td>46.5%</td>
</tr>
<tr>
<td>Maintain utility-owned private network</td>
<td>31.4%</td>
</tr>
<tr>
<td>Will increase dependence upon private network to support utility operations</td>
<td>9.2%</td>
</tr>
<tr>
<td>Will increase dependence upon a public carrier network to support utility operations</td>
<td>8.9%</td>
</tr>
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Source: Black & Veatch

SMART TECHNOLOGIES ARE PROVIDING UNPRECEDENTED LEVELS OF INFORMATION ON THE STATUS OF THE NETWORK, ENERGY CONSUMPTION AND PERFORMANCE OF NETWORK INFRASTRUCTURE ENABLING NEW EFFICIENCIES AND OPTIMIZATION ACROSS A BROAD RANGE OF METRICS.
This chart reflects the status of Smart Grid programs based on the size of utilities as determined by total number of employees. Nearly half of large utilities are deploying physical infrastructure upgrades.

As previously noted, this reflects that many utilities remain focused on AMI initiatives due to their large-scale, multiyear implementation cycles. Some are in the final stages of deployment, others are beginning system implementation and some are just now beginning to plan and fund their AMI programs. The more recently started programs will likely benefit from the work of the initial wave of projects and the programs supported by Smart Grid Investment Grant funding from the U.S. Department of Energy. As AMI technologies have matured, and utilities’ results have been published, insights have evolved for industry best practices that can facilitate greater success for future deployments. Note: Nearly 50 percent of respondents representing utilities with more than 10,000 employees are in the deployment phase (Figures 46 and 47).

While initially focused on network and meter deployment, significant numbers of utilities are now beginning to see the tangible value in enhanced operational performance, expanded customer service and improved efficiency. AMI programs are receiving increased benefits with expanded use of integrated disconnect devices for residential meters and the increased integration of AMI into outage management systems and other operational systems. Demand Response, the number two option for future automation deployment (35.2 percent), and Time of Use (TOU) rates often build upon the core AMI solution infrastructure. In fact, TOU rates are not possible without some type of advanced metering solution. The capability of AMI solutions to support more detailed measurement and verification as well as providing an enabling communications network greatly improves the reach and economics of Demand Response programs.
Also among the programs under heavy consideration for development are those targeting FLISR (32.1 percent), and VVO or Conservation Voltage Reduction (CVR) (29.3 percent). FLISR is significantly attractive, particularly in light of the prolonged outages following Superstorm Sandy.

Unlike major telecom and cable service providers that have adopted self-sensing and self-healing IP-based networks over the past decade, traditional electric networks cannot automatically pinpoint where outages have occurred, and utilities often determine predicted outage locations based on customer phone calls and models maintained manually in their outage management systems. The interest in FLISR solutions is to improve reliability and improve customer satisfaction by reducing outage times, and it parallels the increased use of AMI information to feed enhanced, internally focused outage management solutions and customer-focused outage communication solutions.

Another particularly exciting advanced distribution program that can find synergy in AMI investment is VVO. VVO programs allow a utility to more closely manage the voltage profile and reactive power requirements of its distribution networks – from the substation to the most remote customers. VVO can be used to minimize technical losses, reduce reactive power draw from the transmission system, and reduce demand to conserve energy and minimize costly peak power purchases. By having real-time information on conditions at the edges of the distribution system, a utility can ensure that the voltage is within mandated service standards while optimizing distribution system efficiency and identifying undersized or failing distribution equipment.

For example, FLISR schemes optimally receive outage information in the system protection time frame, on the order of milliseconds. VVO schemes may only require meter voltage data on the order of minutes, but must be immediately responsive to voltage excursions. Distributed generation, while still an emerging application in most locations, can also be significantly more demanding of higher volume, more timely communications than traditional meter reading and DR signaling.

Given the often conservative approach of electric utilities and their focus on reliability, smart grid investments that lack a proven industry track record are often difficult to justify. Even though many of the enabling technologies considered beneficial to implementing smart grid programs have been around for some time, many utilities are still in the earliest stages of rolling out these programs or combining them into a cohesive integrated solution.

Just 10 percent of utility survey respondents stated that their organization has not started implementing smart grid projects, but it is likely that many of the utilities in this group have implemented or are implementing various smart grid solutions such as advanced metering, distribution automation, or substation SCADA. Perhaps exemplifying the challenges of categorizing certain initiatives, survey participants are looking at these projects as independent programs and not as part of a broader set of smart grid initiatives. An additional 25 percent of respondents are in the early planning/strategy development stage, and 30 percent are in deployment of physical infrastructure upgrades related to their various smart grid initiatives.

Further, a significantly greater percentage of respondents from public power organizations stated that their organization is moving forward with deployment of physical infrastructure upgrades (36.7 percent), compared to only 23 percent of respondents from IOUs. This could be a result of the easier path that many public power utilities have in making decisions on transformational projects such as smart technology, based in part on the uncertainty many IOUs face in presenting their smart grid programs to their regulators for rate recovery.

Increasing the capacity, reach, and reliability of utility telecom networks is important in facilitating smart infrastructure or enabling infrastructure functions such as meter reading, fault locating and real-time system optimization to become automated. Because different smart grid functions have varying needs in terms of data volume and timeliness, it becomes increasingly important to develop long-term roadmaps that ensure infrastructure is adequate and investments are allocated wisely.

While balancing the cost-benefit analysis of program deployments, the evidence continues to mount that implementing smart grid programs will have significant benefits to utilities and their customers.
Driving this transition is the complex nature of utilities’ role in their communities, which creates significant pressure for efficiency and sustainability. Yet, at the same time, consumer expectations of improved reliability and nominal price increases can conflict with the accompanying capital expenditures. These costs, necessitated by regulatory mandates concerning reliability, safety and the implementation of new technologies, are significant. Fortunately, the data concerning these competing interests are encouraging; survey respondents show an awareness of many of their current and future issues. They are also testing and refining strategic approaches to managing large-scale changes in the sector.

Arguably, the most dramatic changes in the industry are being driven by the abundance and low cost of domestic natural gas. Virtually all analysts, including Black & Veatch, agree that domestic supplies will be able to satisfy traditional heating markets and the growing demand from power generation, industrial and LNG exports. Yet, the challenge for individual electric generation buyers will be determining how to plan ahead in order to construct the most cost-effective portfolios of pipeline and storage capacity to aggregate and deliver gas in response to varied load profiles.

Building upon 2012’s historic coal-to-gas switching, low natural gas prices will require many North American regions to develop additional pipeline and storage capacity in order to meet growing demand from the power generation industry. Six months ago, the Black & Veatch Strategic Directions in the U.S. Natural Gas Industry Report reflected gas pipeline operator concerns about their ability to recover operating costs and provide satisfactory earnings to their shareholders. This concern for pipeline constraint was demonstrated by episodic, weather-driven price spikes witnessed in the Northeast during a relatively mild winter. Because it is unlikely that pipeline capacity will develop as rapidly as demand for gas from the power generation market, online, this could potentially lead to operators having to plan for more frequent price fluctuations.

Pipeline constraint is just one element of the larger issue of transmission. As the electricity portfolio shifts to accommodate a larger percentage of natural gas and renewable fuels, aging infrastructure and capacity issues will require significant investment. FERC Order No. 1000 has the potential to transform electricity transmission by bringing new levels of competition and regional planning to often static markets.

The task of addressing utility challenges by identifying and extracting value from new tools will increasingly fall to operations, and innovation will help. Similar to the telecom industry, which previously deployed technologies that increase consumer interaction and operational visibility, the electric utility industry will benefit from advances in access to actionable data. Advances like the Smart Grid give electric utilities the information they need to make better informed decisions to manage large-scale industry change.

Further, these advances are important as utilities strive for a flexible electricity grid system that more readily adapts to changes in source generation and consumer demand. Communications technology that increasingly supports a modern, flexible grid can open up new possibilities for distributed generation, greater resiliency and improved system response times, as well new market dynamics brought on by competition and other factors.

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In order to capitalize on established Smart Grid programs like AMI or less widely deployed but potentially effective efficiency measures such as Volt-VAR optimization, Demand Response and FLISR, a robust, reliable communications network must be in place. Further, these innovations also create vulnerabilities that utilities must address. It is quite striking that in the span of one year, cyber security concerns have gone from a lower tier concern to a major issue according to respondents.

From a regulatory perspective, the economics of compliance mean that the whole organization must prepare to invest in people, tools, and processes to meet efficiency and environmental requirements. Many times, this must occur with minimal impact on rates. FERC Order No. 1000 is an example of the regulatory environment driving change. Of the three reforms for transmission planning enumerated by the rule, the idea of coordination between neighboring regions to determine efficient or cost-effective solutions for transmission may highlight the best approach to managing an environment of increased competition and decreased funding.

Similarly, action at the Environmental Protection Agency, long-focused on air quality standards, may in turn shift to a focus on freshwater and effluent standards. Although there is great awareness of the nexus of water and energy, the same cannot be said of the potential impact that new water regulations could have on operations. Excess capacity likely saved many regions from potential crisis situations as a result of curtailment of large-scale generating stations due to record heat, water shortages or high water temperatures during the summer of 2012. Working with regulators to ensure system resiliency will be critical in the coming years.

Despite the potential for new technology, domestic gas and renewable access to create a smarter, more robust electric grid, cost concerns and the boundaries of the Regulatory Compact continue to be the most significant barriers to change. It can be argued that each of the top ten issues identified in this report has a cost component for remediation. From reliability to aging infrastructure, to physical security, adapting to new requirements and demands requires investment, yet concern over the capital that can be recouped via rates slows investment.
Accordingly, electric utility stakeholders are equally concerned about capital availability, rising interest rates and decreasing debt/equity ratios. It is telling, however, that generation, transmission and distribution investments to ensure reliability remain the priority for survey respondents. It is perhaps a reflection of the difficulty in securing and deploying financing in the current climate that this percentage is slightly lower than one year ago.

Given the complex array of challenges facing utilities, developing a comprehensive, forward-looking list of priorities is essential. Today, utilities must know how every regulatory issue, new technology and operational decision will impact their business. For some, this will mean weighing the opportunity costs of compliance and innovation against the practical considerations of reliability and capital and limiting the potential for unintended consequences.

For example, during the February 2013 meeting of the California Independent System Operator, regulators discussed the impact rapid growth in renewable capacity will have on regional reliability. This growth, combined with retirement of conventional baseload units, is creating a risk to grid stability. Utilities and regulators must find the proper technology balance. Elsewhere, electric utilities are grappling with the cybersecurity challenges that come with smart grid adoption. Similarly, each of the smart meters that provides operational data to a system operator enabling greater performance and reliability, could potentially be exploited by nefarious parties if not hardened by knowledgeable experts.

The changes facing the electric utility industry demand a situational awareness that, to a degree, can border on omniscience. Utilities seeking to shape their future rather than be shaped by changing events will be forced to adopt new ways of looking at their business. For nearly a century, Black & Veatch has helped steer our clients through periods of expansion and change, always with an eye toward the future.

For more information on how Black & Veatch can help, please visit www.bv.com.
The following charts provide additional information on specific subject matter covered within this report, including differences among geographic regions and utility type.

**FINANCIAL ISSUES**

**TOP FINANCIAL CONCERNS**

- **Capital availability**: 3.30
- **Rising interest rates**: 3.27
- **Decreasing debt/equity ratios**: 3.23

Source: Black & Veatch

Utility respondents were asked to rate on a scale of 1 to 5, where 1 indicated “Least Concerned” and 5 indicated “Most Concerned,” the level of concern they have for each of the financial issues for their organization.

**TOP FINANCIAL ISSUES – BY UTILITY TYPE**

**FINANCING NEW GENERATION ASSETS**

- **25.7%**: No new generation to finance
- **23.3%**: Bond financing
- **16.0%**: Balance sheet financing
- **12.3%**: Project financing
- **5.1%**: Financed by others (independent power generator)
- **3.5%**: Other
- **14.2%**: I don’t know

Source: Black & Veatch

**FINANCING GENERATION ASSETS – BY UTILITY TYPE**

- **Public**
- **IPP**
- **IOU**

Source: Black & Veatch
TOP INDUSTRY ISSUES BY REGIONS SERVED

NORTHEAST

| 4.63 | Reliability |
| 4.43 | Natural gas prices |
| 4.41 | Environmental regulation |
| 4.34 | Aging infrastructure |
| 4.32 | Economic regulation |

Source: Black & Veatch

MIDWEST

| 4.63 | Environmental regulation |
| 4.59 | Reliability |
| 4.41 | Economic regulation |
| 4.32 | Long-term investment |
| 4.30 | Aging infrastructure |

Source: Black & Veatch

NORTHWEST

| 4.58 | Reliability |
| 4.54 | Environmental regulation |
| 4.38 | Cyber security |
| 4.30 | Economic regulation |
| 4.26 | Long-term investment |

Source: Black & Veatch

ALASKA/HAWAII

| 4.81 | Reliability |
| 4.44 | Environmental regulation |
| 4.31 | Aging infrastructure |
| 4.31 | Cyber security |
| 4.31 | Fuel policy |
| 4.31 | Technology |

Source: Black & Veatch

SOUTHEAST

| 4.69 | Environmental regulation |
| 4.66 | Reliability |
| 4.43 | Natural gas prices |
| 4.31 | Aging infrastructure |
| 4.31 | Economic regulation |

Source: Black & Veatch

ROCKY MOUNTAIN

| 4.63 | Environmental regulation |
| 4.63 | Reliability |
| 4.46 | Economic regulation |
| 4.21 | Natural gas prices |
| 4.19 | Long-term investment |

Source: Black & Veatch

SOUTHWEST

| 4.62 | Reliability |
| 4.59 | Environmental regulation |
| 4.41 | Natural gas prices |
| 4.37 | Economic regulation |
| 4.30 | Aging infrastructure |

Source: Black & Veatch

Source: Black & Veatch

Source: Black & Veatch

Source: Black & Veatch
### Top Environmental Concerns

#### Top Environmental Concerns – Historic Trends

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Source: Black & Veatch

#### NORTHEAST

- **4.03** Carbon emissions legislation
- **3.71** Nuclear fuel disposal/storage
- **3.65** Physical carbon emissions
- **3.62** Water supply
- **3.53** Nuclear safety

Source: Black & Veatch

#### MIDWEST

- **4.31** Carbon emissions legislation
- **3.74** Nuclear fuel disposal/storage
- **3.71** Physical carbon emissions
- **3.58** Water supply
- **3.57** NO<sub>x</sub>
- **3.49** Coal handling & ash disposal

Source: Black & Veatch

#### SOUTHEAST

- **4.20** Carbon emissions legislation
- **3.86** Water supply
- **3.82** Physical carbon emissions
- **3.63** Nuclear fuel disposal/storage
- **3.60** Wastewater discharge

Source: Black & Veatch

#### ROCKY MOUNTAIN

- **4.13** Carbon emissions legislation
- **4.13** Water supply
- **3.54** Physical carbon emissions
- **3.46** Water supply
- **3.40** NO<sub>x</sub>
- **3.33** Particulates

Source: Black & Veatch
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Source: Black & Veatch

### PREFERRED “ENVIRONMENTALLY FRIENDLY” TECHNOLOGIES

- **Carbon emissions legislation**
- **Particulates**
- **NOx**
- **SO2**
- **Water supply**

Source: Black & Veatch
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<th>Natural gas</th>
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<th>Wind power</th>
<th>Biomass</th>
<th>Tidal generation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear energy</td>
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<td>3.83</td>
<td>3.83</td>
<td>3.88</td>
<td>3.63</td>
<td>3.63</td>
</tr>
<tr>
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<td>3.91</td>
<td>3.91</td>
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<td>3.63</td>
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</tr>
<tr>
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<td>3.91</td>
<td>3.81</td>
<td>3.81</td>
<td>3.63</td>
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<td>Wind power</td>
<td>3.91</td>
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</table>

Source: Black & Veatch

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</tr>
</tbody>
</table>

Source: Black & Veatch
## Preferred Regulatory Practices

### Value of Regulatory Practices

<table>
<thead>
<tr>
<th>Practice</th>
<th>Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-approval of a utility’s planned capital investments</td>
<td>4.43</td>
</tr>
<tr>
<td>Formula rates (where the utility can adjust rates annually to reflect</td>
<td>4.39</td>
</tr>
<tr>
<td>changes in its revenue requirement)</td>
<td></td>
</tr>
<tr>
<td>Greater flexibility to recover large one-time costs (e.g., natural</td>
<td>4.38</td>
</tr>
<tr>
<td>disasters, integrity programs)</td>
<td></td>
</tr>
<tr>
<td>More flexibility to construct facilities without an extensive</td>
<td>4.34</td>
</tr>
<tr>
<td>regulatory approval process</td>
<td></td>
</tr>
<tr>
<td>A statutory time frame within which a regulatory commission must</td>
<td>4.31</td>
</tr>
<tr>
<td>decide a utility’s rate case and proposed revenue increase request</td>
<td></td>
</tr>
<tr>
<td>Reducing the financial risk of stranded cost recovery</td>
<td>4.31</td>
</tr>
<tr>
<td>A forward-looking test year for setting a utility’s rates</td>
<td>4.10</td>
</tr>
<tr>
<td>Establishment of utility performance metrics against which a utility’s</td>
<td>3.82</td>
</tr>
<tr>
<td>operational performance is measured on an ongoing basis</td>
<td></td>
</tr>
</tbody>
</table>

Source: Black & Veatch

Utility respondents were asked to rate the value of each of the listed regulatory practices in terms of how helpful each would be to improving the quality and efficiency of utility regulation. Participants rated each practice using a scale of 1 to 5, where 1 indicates “Very Little Help,” and 5 indicates “Great Help.” Responses reflect the opinions of participants from IOUs.

## Preparations for Air Quality Regulations

### Northeast

<table>
<thead>
<tr>
<th>Practice</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Early plant retirement(s)</td>
<td>35.4%</td>
</tr>
<tr>
<td>Fuel switching</td>
<td>32.3%</td>
</tr>
<tr>
<td>SCR or SNCR (for NOx control)</td>
<td>27.7%</td>
</tr>
<tr>
<td>Flue gas desulfurization (scrubber)</td>
<td>21.5%</td>
</tr>
<tr>
<td>ESP upgrade or fabric filter baghouse</td>
<td>21.5%</td>
</tr>
<tr>
<td>Sorbent injection system (e.g., DSI or PAC)</td>
<td>13.8%</td>
</tr>
<tr>
<td>I don’t know</td>
<td>49.2%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

### Southeast

<table>
<thead>
<tr>
<th>Practice</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCR or SNCR (for NOx control)</td>
<td>42.6%</td>
</tr>
<tr>
<td>Early plant retirement(s)</td>
<td>42.6%</td>
</tr>
<tr>
<td>Fuel switching</td>
<td>38.3%</td>
</tr>
<tr>
<td>Flue gas desulfurization (scrubber)</td>
<td>33.0%</td>
</tr>
<tr>
<td>ESP upgrade or fabric filter baghouse</td>
<td>28.7%</td>
</tr>
<tr>
<td>Sorbent injection system (e.g., DSI or PAC)</td>
<td>25.5%</td>
</tr>
<tr>
<td>I don’t know</td>
<td>30.9%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch
IMPACT OF COAL COMBUSTION RESIDUALS RULES

NORTHEAST

- Large impact: 30.9%
- Moderate impact: 17.6%
- Very little impact: 13.2%
- Significant impact: 10.3%
- No impact at all: 19.1%
- I don't know: 8.8%

Source: Black & Veatch

MIDWEST

- Large impact: 21.5%
- Moderate impact: 25.2%
- Very little impact: 6.7%
- Significant impact: 12.9%
- No impact at all: 30.1%
- I don't know: 3.7%

Source: Black & Veatch

NORTHWEST

- Large impact: 12%
- Moderate impact: 22%
- Very little impact: 5.5%
- Significant impact: 10%
- No impact at all: 30.1%
- I don't know: 12.5%

Source: Black & Veatch

ALASKA/HAWAII

- Large impact: 18.8%
- Moderate impact: 25%
- Very little impact: 18.8%
- Significant impact: 24.2%
- No impact at all: 25%
- I don’t know: 12.5%

Source: Black & Veatch

SOUTHEAST

- Large impact: 25.5%
- Moderate impact: 22.4%
- Very little impact: 8.2%
- Significant impact: 30.6%
- No impact at all: 5.1%
- I don’t know: 5.1%

Source: Black & Veatch

ROCKY MOUNTAIN

- Large impact: 12.5%
- Moderate impact: 31.3%
- Very little impact: 10.4%
- Significant impact: 4.2%
- No impact at all: 30.6%
- I don’t know: 12.5%

Source: Black & Veatch

SOUTHWEST

- Large impact: 34.1%
- Moderate impact: 6.6%
- Very little impact: 24.2%
- Significant impact: 7.7%
- No impact at all: 5.5%
- I don’t know: 12.5%

Source: Black & Veatch
### Impact of Wastewater Effluent Limitation Discharge Standards

#### Northeast

- **Minimal Impact**: 26.5%
- **Moderate Impact**: 32.4%
- **Large Impact**: 16.2%
- **Minimal Impact**: 16.2%
- **Moderate Impact**: 32.4%
- **Large Impact**: 16.2%

#### Midwest

- **No Impact**: 29.9%
- **Minimal Impact**: 7.9%
- **Large Impact**: 14.0%
- **No Impact**: 29.9%
- **Minimal Impact**: 7.9%
- **Large Impact**: 14.0%

#### Northwest

- **No Impact**: 34%
- **Minimal Impact**: 16%
- **Large Impact**: 6%
- **No Impact**: 34%
- **Minimal Impact**: 16%
- **Large Impact**: 6%

#### Alaska/Hawaii

- **No Impact**: 37.5%
- **Minimal Impact**: 6.3%
- **Large Impact**: 6.3%
- **No Impact**: 37.5%
- **Minimal Impact**: 6.3%
- **Large Impact**: 6.3%

---

Source: Black & Veatch
**ACHIEVING RENEWABLE PORTFOLIO TARGETS**

### NORTHEAST

- Yes, 1-5% rate increase: 33%
- Yes, greater than 5% rate increase: 15%
- No, technically feasible but cost too great for customers: 2%
- No, not achievable due to technical considerations: 13%

Source: Black & Veatch

### MIDWEST

- Yes, 1-5% rate increase: 40%
- Yes, greater than 5% rate increase: 10%
- No, technically feasible but cost too great for customers: 1%
- No, not achievable due to technical considerations: 13%

Source: Black & Veatch

### SOUTHEAST

- Yes, less than a 1% rate increase: 40%
- Yes, 1-5% rate increase: 12%
- Yes, greater than 5% rate increase: 15%
- No, technically feasible but cost too great for customers: 3%
- No, not achievable due to technical considerations: 15%

Source: Black & Veatch

### ROCKY MOUNTAIN

- Yes, less than a 1% rate increase: 25%
- Yes, 1-5% rate increase: 45%
- Yes, greater than 5% rate increase: 13%
- No, technically feasible but cost too great for customers: 5%
- No, not achievable due to technical considerations: 13%

Source: Black & Veatch
## 2013 Strategic Directions in the U.S. Electric Utility Industry

### NORTHWEST

- **Yes, greater than 5% rate increase**: 50%
- **Yes, 1-5% rate increase**: 15%
- **No, technically feasible but cost too great for customers**: 15%
- **No, not achievable due to technical considerations**: 0%

Source: Black & Veatch

### SOUTHWEST

- **Yes, greater than 5% rate increase**: 60%
- **Yes, 1-5% rate increase**: 11%
- **No, technically feasible but cost too great for customers**: 0%
- **No, not achievable due to technical considerations**: 8%

Source: Black & Veatch

### ALASKA/HAWAII

- **Yes, greater than 5% rate increase**: 8%
- **Yes, 1-5% rate increase**: 31%
- **No, technically feasible but cost too great for customers**: 38%
- **No, not achievable due to technical considerations**: 15%

Source: Black & Veatch
CONCERN FOR WATER SUPPLY VULNERABILITY

NORTHEAST

- Minimal concern or risk due to alternatives: 30.9%
- Moderate concern or risk with limited alternatives: 20.6%
- Significant concern or risk to continued operations: 5.9%
- I don’t know: 19.1%

Source: Black & Veatch

MIDWEST

- Minimal concern or risk due to alternatives: 29.0%
- Moderate concern or risk with limited alternatives: 34.0%
- Significant concern or risk to continued operations: 14.8%
- I don’t know: 6.8%

Source: Black & Veatch

NORTHWEST

- Minimal concern or risk due to alternatives: 30.6%
- Moderate concern or risk with limited alternatives: 38.8%
- Significant concern or risk to continued operations: 12.2%
- I don’t know: 10.2%

Source: Black & Veatch

ALASKA/HAWAII

- Minimal concern or risk due to alternatives: 31.3%
- Moderate concern or risk with limited alternatives: 25.0%
- Significant concern or risk to continued operations: 18.8%
- I don’t know: 6.3%

Source: Black & Veatch

SOUTHEAST

- Minimal concern or risk due to alternatives: 37.1%
- Moderate concern or risk with limited alternatives: 32.0%
- Significant concern or risk to continued operations: 12.4%
- I don’t know: 10.3%

Source: Black & Veatch

ROCKY MOUNTAIN

- Minimal concern or risk due to alternatives: 35.4%
- Moderate concern or risk with limited alternatives: 33.3%
- Significant concern or risk to continued operations: 8.3%
- I don’t know: 10.4%

Source: Black & Veatch

SOUTHWEST

- Minimal concern or risk due to alternatives: 23.3%
- Moderate concern or risk with limited alternatives: 45.6%
- Significant concern or risk to continued operations: 10.0%
- I don’t know: 8.9%

Source: Black & Veatch
### Future Cooling Technology Considerations

#### Northeast

<table>
<thead>
<tr>
<th>Technology Type</th>
<th>Northeast</th>
<th>Midwest</th>
<th>Southeast</th>
<th>Rocky Mountain</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dry Cooling Systems</td>
<td>20.9%</td>
<td>16.0%</td>
<td>12.5%</td>
<td>25.0%</td>
</tr>
<tr>
<td>Hybrid - a combination of dry and wet technologies</td>
<td>22.4%</td>
<td>17.3%</td>
<td>14.6%</td>
<td>25.0%</td>
</tr>
<tr>
<td>Traditional wet cooling systems supplied by local freshwater resources</td>
<td>29.9%</td>
<td>29.0%</td>
<td>34.4%</td>
<td>22.9%</td>
</tr>
<tr>
<td>Other</td>
<td>7.5%</td>
<td>17.9%</td>
<td>4.2%</td>
<td>18.8%</td>
</tr>
<tr>
<td>I don't know</td>
<td>46.3%</td>
<td>4.9%</td>
<td>37.5%</td>
<td>35.4%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

#### South East

<table>
<thead>
<tr>
<th>Technology Type</th>
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<th>Southeast</th>
<th>Rocky Mountain</th>
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<tr>
<td>Dry Cooling Systems</td>
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<td>25.0%</td>
<td>25.0%</td>
<td>10.4%</td>
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<tr>
<td>Hybrid - a combination of dry and wet technologies</td>
<td>14.6%</td>
<td>25.0%</td>
<td>22.9%</td>
<td>35.4%</td>
</tr>
<tr>
<td>Traditional wet cooling systems supplied by used water</td>
<td>34.4%</td>
<td>22.9%</td>
<td>18.8%</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>4.2%</td>
<td>Other</td>
<td>Other</td>
<td>Other</td>
</tr>
<tr>
<td>I don't know</td>
<td>37.5%</td>
<td>I don't know</td>
<td>I don't know</td>
<td>I don't know</td>
</tr>
</tbody>
</table>

Source: Black & Veatch
### Survey Participants by Job Title

<table>
<thead>
<tr>
<th>Job Title</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Director/Supervisor/Manager</td>
<td>39.9%</td>
</tr>
<tr>
<td>Chief Executive Officer/President</td>
<td>19.0%</td>
</tr>
<tr>
<td>Vice President/Senior Executive</td>
<td>18.0%</td>
</tr>
<tr>
<td>Engineer/Operator</td>
<td>12.8%</td>
</tr>
<tr>
<td>Supporting Staff</td>
<td>6.2%</td>
</tr>
<tr>
<td>Others</td>
<td>4.2%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

This figure includes utility and non-utility respondents.

### Survey Participants by Organization Size

<table>
<thead>
<tr>
<th>Size</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;100</td>
<td>31.1%</td>
</tr>
<tr>
<td>1,000-9,999</td>
<td>28.8%</td>
</tr>
<tr>
<td>100-999</td>
<td>24.2%</td>
</tr>
<tr>
<td>&gt;=10,000</td>
<td>15.9%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

This figure includes utility and non-utility respondents.

### Survey Participants by Years of Experience

<table>
<thead>
<tr>
<th>Years</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;10 years</td>
<td>45.9%</td>
</tr>
<tr>
<td>10-30 years</td>
<td>37.3%</td>
</tr>
<tr>
<td>Over 30 years</td>
<td>16.8%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

This figure includes utility and non-utility respondents.

### Survey Participants by Age

<table>
<thead>
<tr>
<th>Age</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;=44</td>
<td>50.2%</td>
</tr>
<tr>
<td>45-54</td>
<td>34.1%</td>
</tr>
<tr>
<td>&gt;=55</td>
<td>13.1%</td>
</tr>
<tr>
<td>Prefer not to answer</td>
<td>2.5%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

This figure includes utility and non-utility respondents.
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