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Welcome to Black & Veatch’s 2014 Strategic Directions: U.S. Electric Industry report. Now in its eighth year, the report has historically represented the electric utility industry’s sentiment about current events and trends affecting the way it does business. This year, in addition to capturing data about top of mind issues, the report looks ahead. The 2014 Strategic Directions: U.S. Electric Industry report tracks an industry in the midst of rapid transformation and explores the market, technology and regulatory drivers its stakeholders must manage in order to thrive.

The view is of an industry at a crossroads. U.S. electric utilities are weighing operational needs against regulatory imperatives in an economy that is still recovering. New and improving technologies present an opportunity to meet business objectives, but at what cost?

Finding opportunities for growth in the midst of change will be a key component of survival in these transformative times. This report highlights emerging issues and delivers expert analysis and insights for electric utilities faced with managing disruption brought about by accelerated change.

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

Sincerely,

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

JOHN CHEVRETTE | PRESIDENT
Black & Veatch’s management consulting business
A utility's ability to maintain its power delivery infrastructure may require changes to the existing revenue structure.
THE BLACK & VEATCH ANALYSIS TEAM

EXECUTIVE SUMMARY
John Chevrette is President of Black & Veatch’s management consulting business 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.

MARKET FORCES
Ann Donnelly, Ph.D. has more than 35 years of experience in the energy industry as a consultant, project manager, executive, and a resource explorationist, including more 25 years of experience in the natural gas and power industries of North America. She has served as a project manager for strategic studies in energy analysis and forecasting of natural gas, LNG, coalbed methane, coal, oil, pet coke, nuclear fuel, and renewable resources. She is a contributor to Black & Veatch’s long-term Energy Market Perspective. She has provided fuel planning service to the power development industry since the inception of independent power in the early 1990s, designing and implementing gas procurement and risk management plans for gas-fired generation throughout North America.

Robert Patrylak (Energy Market Perspective, Power Generation) is Managing Director in Black & Veatch’s management consulting business. Patrylak leads Black & Veatch’s Energy Markets and Resource Planning Service Line, which encompasses such services as Market Assessment, Economic Transmission Planning, and Integrated Resource Planning and is responsible for the Energy Market Perspective Product Line. The Energy Market Perspective Product is developed every six months and forms the Black & Veatch underlying baseline view of the North American Energy Markets and its impact on the power industry. Mr. Patrylak has more than 23 years of energy industry experience with more than half of that time working directly for energy industry companies and the remainder as a consultant to energy industry companies.

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

Alap Shah is Turbine Technologies Manager and Turbine Business Line Director in Black & Veatch’s energy business. Shah has more than 16 years of experience at Black & Veatch, serving in roles of Rotating Equipment Engineer and Thermal Performance Section Head. He has been working closely with major turbine OEMs such as GE, Siemens, Alstom and MHI in gas and steam turbine technologies assessment and several “First-of-a-Kind” turbine technology launches on Black & Veatch EPC and Services projects.

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

**Will Williams** *(Asset Management and Capital Planning)* is a Director in Black & Veatch management consulting, where he leads and provides a full range of strategic and tactical asset management services for global water and power clients. Williams has more than 24 years of experience in asset management planning, including capital investment planning, asset failure analysis, risk assessment, performance benchmarking, maintenance optimization and business change management, among other areas.

**TECHNOLOGICAL DRIVERS**

**Kevin Cornish** *(Consumer Technology)* is an Executive Consultant in Black & Veatch management consulting. With more than 25 years of experience in the industry, Cornish specializes in the integration of intelligent infrastructure systems into utility enterprise, such as geographic information system (GIS), advanced metering infrastructure (AMI), meter data management system (MDMS), and OMS, among other areas.

**Greg Henry** *(AMI and Analytics)* is the Grid Analytics Solution Lead within the company’s Smart Integrated Infrastructure practice. Henry leads the development of data-intensive and math-heavy analytic solutions for electric transmission and distribution clients, aiding development with his background in large-volume data processing, numerical analysis and statistics.

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

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

**REGULATORY SHIFTS**

**Peter Abt** *(LNG Exports)* is a Managing Director and leads Black & Veatch’s Oil & Gas consulting practice. Abt has more than 30 years of experience in the energy industry, focused primarily on natural gas and electric power generation business development, marketing and trading.

**Andy Byers** *(Environmental Regulation)* is an Associate Vice President in Black & Veatch’s 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.

**Russell Feingold** is a Vice President with Black & Veatch management consulting 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.
Deepa Poduval (LNG Exports) is a Principal Consultant with Black & Veatch management consulting and is responsible for business strategy and project management. Poduval’s client engagements focus on strategic analytical services supporting portfolio optimization, asset acquisition, risk management and business strategy development. Her expertise includes the valuation of energy industry assets, analysis of oil and gas marketing strategies and commercial agreements, performance and risk measurement, and analysis and utilization of natural gas industry structural models.

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

Forrest Terrell (Physical and Cyber Security) is Director of Total Energy Solutions in the Black & Veatch Special Projects Corp. After completing an Army Engineer Officer career, Terrell had 18 years of professional consulting experience, serving in diverse roles including Vice-President Federal Programs, VP Army Programs, and regional/local operations manager. Since joining Black & Veatch, he has led the BVSPC Total Energy Solutions initiative positioning the company to win DOD and other federal energy contracts to design renewable energy and smart infrastructure solutions and to provide professional energy consultant services.

CLOSING COMMENTARY

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

2014 REPORT BACKGROUND

The eighth annual Black & Veatch Strategic Directions: U.S. Electric Industry report is a compilation of data and analysis from an industry wide survey. This year’s survey was conducted from 7 May through 27 May 2014. The online questionnaire was completed by 576 qualified electric industry participants.

Statistical significance testing was completed on the final survey results. Represented data within this report have a 95 percent confidence level. The following figures provide additional detail on the participants in this year’s survey.

Unless otherwise noted, survey data presented within this report reflect the opinions of respondents who represent a utility organization.

INDUSTRY RESPONDENTS BY SERVICE REGION

Source: Black & Veatch
**Survey Participants by Type of Utility**

- Public-owned utility: 35.4%
- Investor-owned utility: 33.1%
- Cooperative: 16.7%
- Independent/industrial power producer: 11.1%
- Other: 3.7%

**Survey Participants by Utility Services Provided**

- Electric distribution: 51.9%
- Regulated generation: 35.4%
- Vertically integrated electric utility: 33.1%
- Bundled transmission & distribution: 21.2%
- Merchant generation: 16.9%
- Combined electric and water services provider: 15.1%
- Bundled generation and transmission: 14.6%
- Merchant distribution: 2.4%
- Other: 9.5%

**Industry Type**

- Utilities: 65.6%
- Non-Utilities: 34.4%

*Source: Black & Veatch*
EXECUTIVE SUMMARY

ACCELERATION AND DISRUPTION

BY JOHN CHEVRETTE

The Black & Veatch 2014 Strategic Directions: U.S. Electric Industry report tracks how electric utilities are managing the accelerated pace of change and transformation of many traditional elements of their business. Black & Veatch predicts that this disruption, propelled by a confluence of market dynamics and shifting technologies, will result in a leaner, more nimble electric utility industry that will be able to better deliver on its primary mandate: reliability.

Survey respondents are feeling pressure in several areas. Many are closely watching to see if state and federal regulators will fully place air and water challenges in the midst of the broader climate change discussion, while carefully balancing the cost of requiring new environmental technology on a recovering U.S. economy. Outside the regulatory sphere, the industry presses on with a host of challenges and opportunities: consolidation to grow scale; the need to reduce operating costs and improve efficiencies; exploration of adjacent/new markets to further growth; determining how to leverage low-cost natural gas; and improving overall disaster response to protect the nation’s vital power infrastructure.

This theme of asset protection found a new level of focus as cybersecurity surged in the ranking of the Top 10 industry issues (Figure 1), leapfrogging two spots to number four – just below reliability, environmental regulation and economic regulation. The industry is paying attention and actively seeking ways to bolster security practices to limit power system vulnerability. To highlight its rapid advance, in 2012, cybersecurity was not ranked as a top 10 issue by industry leaders. At the time, Black & Veatch suggested the industry be aware of the need to plan and revisit the issue. Today, we are seeing an industry that is actively moving forward with the deployment of comprehensive asset protection plans following several high profile cyber and physical threat events.

For 2014, this report is divided into three sections that reflect the agents of change thematically. The Market Forces section focuses on the impact of current economic trends. The Technological Drivers section examines how innovation in operational and consumer technologies is disrupting traditional electric utility industry operations and services. In Regulatory Shifts, Black & Veatch captures and analyzes the effect of new issues and policies.

It is also important to look at where utilities are making the investments necessary to take advantage of growing segments, such as liquefied natural gas (LNG) and renewables. The 2014 Strategic Directions: U.S. Electric Industry report also features dispatches from the Gulf Cooperation Council (GCC), Indonesia and India. For each region, local subject matter experts share data and anecdotes from economies in transition that grapple with change daily.

CYBERSECURITY SURGED IN THE RANKING OF THE TOP 10 INDUSTRY ISSUES, LEAPFROGGING TWO SPOTS TO NUMBER FOUR.
Respondents were 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.

Source: Black & Veatch

FIGURE 1
TOP 10 INDUSTRY ISSUES

- Reliability: 4.64
- Environmental regulation: 4.50
- Economic regulation: 4.31
- Cybersecurity: 4.27
- Natural gas prices: 4.20
- Long-term investment: 4.17
- Aging infrastructure: 4.16
- Physical security: 4.09
- Natural gas fuel supply reliability: 4.06
- Fuel policy: 3.99
MARKETS
As the U.S. economy recovers, so too does the electric utility industry. Forty-three percent of survey respondents characterize their utilities’ status as recovering/growing slowly but not yet back to historical growth rates (Figure 2). This state of affairs presents a challenge for those already struggling to meet mandates and make capital expenditure decisions around capacity replacement because of pending coal and nuclear retirements. The June 2014 executive order on climate change has added a sense of urgency. How does an industry facing uncertain financial and economic markets, an aging workforce and aging infrastructure grow? The answer is through informed decision-making guided by reflection and a willingness to be nimble.

New to the report this year is the inclusion of insights from Black & Veatch’s Energy Market Perspective. Our professionals examine the marketplace and, based on client interactions and data, produce forecasts that are used to inform long-term decision planning. The Energy Market Perspective breakout will provide electric utility-specific information to supplement our forward-looking agenda. Key trends include:
- Electric power pricing will increasingly be tied to natural gas prices as natural gas evolves into the predominant fuel for generation.
- Coal will continue its significant role in resource mix, even with the anticipated 59.5 gigawatt retirement of smaller, older plants.

FIGURE 2
CURRENT GROWTH RATE FOR UTILITY

<table>
<thead>
<tr>
<th>Percentage</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.6%</td>
<td>Declining</td>
</tr>
<tr>
<td>26.5%</td>
<td>Flat</td>
</tr>
<tr>
<td>42.6%</td>
<td>Recovering/growing slowly, but not back to historical growth rate</td>
</tr>
<tr>
<td>14.3%</td>
<td>Returning to historical growth rates</td>
</tr>
<tr>
<td>5.8%</td>
<td>Growing significantly, have surpassed historical growth rate</td>
</tr>
<tr>
<td>5.3%</td>
<td>I don’t know</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

Utility respondents were asked to describe the current load growth rate for their utilities.
MODERNIZATION

From an innovation perspective, there is a gap between recognition of emerging technology as a priority issue and the value of technology to the industry’s future. This report dedicates a significant portion of analysis to technological forces that are changing the way electric utilities are doing business. However, emerging technology ranks last among the top industry issues (Figure 1). Our subject matter experts make the case for viewing the importance of innovation in two ways: how technologies can help solve business challenges, and the business impact of specific technology advances, such as energy storage (Figure 3).

In terms of further integration of renewables into the fuel mix, improvements to the electric grid and the implementation of advanced metering infrastructure reflect both challenges and opportunities.

FIGURE 3
IMPORTANCE OF FACILITATING INTEGRATION OF VARIABLE ENERGY RESOURCES

<table>
<thead>
<tr>
<th>%</th>
<th>Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>65.8%</td>
<td>Energy storage</td>
</tr>
<tr>
<td>41.9%</td>
<td>Transmission system upgrades</td>
</tr>
<tr>
<td>32.9%</td>
<td>New, flexible conventional power plants</td>
</tr>
<tr>
<td>27.6%</td>
<td>Improved grid system operations policies</td>
</tr>
<tr>
<td>26.8%</td>
<td>Smart grid</td>
</tr>
<tr>
<td>23.6%</td>
<td>Demand-side management</td>
</tr>
<tr>
<td>23.6%</td>
<td>Improved forecasting</td>
</tr>
<tr>
<td>20.2%</td>
<td>Improved curtailment policies in times of excess generation</td>
</tr>
<tr>
<td>2.5%</td>
<td>Other</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

Utility respondents were asked to identify the most important factors for facilitating the integration of variable energy resources (e.g., solar and wind) into utility operations in a reliable and cost-effective manner.
Environmental regulation ranks second among the list of top industry issues. Here, electric utilities must balance the costs of compliance against the environmental benefits of meeting Renewable Portfolio Standard (RPS) requirements. A third of survey respondents rank regulatory compliance among the top drivers of rate increases. In addition, utilities cited regulatory compliance as a primary driver for rate increases in the next five years (Figure 4).

Cyber and physical security requirements also come with a cost. Prioritization will be key to meeting regulatory mandates hardening goals. However, utilities may well be on their way to compliance as incentives remain available.

A modern utility recognizes that change is constant and fast-moving. We often hear words like “disruption” cast in a negative light. This report concludes with an exploration of the idea that disruption can be the catalyst for embracing change. Utilities that embrace what seemed impossible just a few years ago may find the key to thriving. The 2014 Strategic Directions: U.S. Electric Industry report offers insight for utilities to help make those choices and move forward.
A modern utility recognizes that change is constant and fast-moving.
POWER GENERATION: NATURAL GAS AND RENEWABLES ARE A PERFECT PAIR

BY ROBERT PATRYLAK

The movement to natural gas-fired and renewable energy solutions for U.S. power generators is continuing its rapid march. Utilities are aligning their generation portfolio assets to address increased federal regulations concerning cross-state air emissions, proposed carbon emissions rules and surface water regulations, as well as renewable portfolio standards. In addition, utilities are facing the challenge of determining the amount of generation capacity that will be needed in the future for customers as economic conditions evolve.

Today, utilities are focused to an even greater extent on making generation investment decisions. In past decades, utilities would add capacity by often building the same size generating plant because of a steady trend in increasing load. However, future load growth rates are now more uncertain because of stressed economic conditions, energy efficiency, distributed generation and demand-side management. This is reflected in this year’s utility survey with 43 percent of respondents reporting that load growth rates have not returned to historical levels. In addition, nearly one-third of respondents say that their load growth rate is flat or declining (refer to Executive Summary).

In this challenging environment, many utilities are holding off on making larger investments in power generation until there is more certainty around emerging environmental Protection Agency (EPA) regulations including recently proposed CO₂ rules for existing plants and economic trends. It is critical that power generators approach their integrated resource planning using many different possible future conditions. These include utility modeling around various regulatory and economic scenarios, stronger future renewable requirements and higher carbon taxes to ensure that their generation decision will perform effectively in different future conditions.

As this year’s survey reflects, the trend toward natural gas will remain strong during the next five years, with 50 percent of survey participants planning to replace retiring coal and nuclear plant capacity with gas generation, as well as provide backup power for intermittent renewable generation (Figure 5). Black & Veatch’s Energy Market Perspective projects that approximately 60 gigawatts of coal plant capacity will be retired by 2020 and 35.4 gigawatts of nuclear resources will be retired by 2038, with the electric sector’s demand for natural gas nearly doubling in the next 20 years.

The main driver in coal retirements is environmental regulation. Coal retirements are having the biggest impact in the Midwest where coal-fired capacity is most predominant. Nuclear generation is being challenged by increasing regulatory and safety compliance costs that escalated after Fukushima. In addition, there is increasing interest in retiring smaller and single-unit nuclear facilities because of declining capacity and energy payments. This is especially affecting nuclear plants in the Independent System Operator (ISO) New England, Midcontinent, and PJM regions.

In this year’s survey, nearly 43 percent of utility respondents believe that 6 to 10 percent of U.S. power generation will come from distributed generation facilities with capacities of 20 megawatts or less in the next five years (Figure 6). Factors moving this growth include the current low cost of natural gas, coupled with declining
costs for solar photovoltaic (PV) technology. The cost of solar PV technology has plummeted during the last five years, resulting in additional utility-scale projects in the Southwest. In addition, many states and municipalities have developed incentive plans for commercial and residential solar installations that provide customers with a financial benefit. Rising electric rates and sustained low-cost natural gas have fueled interest among large industrial customers in developing on-site power generation to meet their electric needs. Black & Veatch is working with several organizations in examining existing combined heat and power within factories and manufacturing centers to determine if the current equipment or new equipment can provide a lower cost energy approach.

**FIGURE 5**
PLAN FOR NATURAL GAS-FUELED GENERATION IN THE NEXT FIVE YEARS

<table>
<thead>
<tr>
<th>Percentage</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>50.0%</td>
<td>Capacity replacement due to pending coal/nuclear retirements</td>
</tr>
<tr>
<td>19.3%</td>
<td>New baseload to meet demand growth</td>
</tr>
<tr>
<td>11.4%</td>
<td>Fast response to backup intermittent renewables</td>
</tr>
</tbody>
</table>

**FIGURE 6**
PERCENTAGE OF POWER GENERATION FROM DISTRIBUTED GENERATION

<table>
<thead>
<tr>
<th>Percentage</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>15.3%</td>
<td>Less than 5%</td>
</tr>
<tr>
<td>11.6%</td>
<td>Approximately 5% (current market share)</td>
</tr>
<tr>
<td>42.9%</td>
<td>6-10%</td>
</tr>
<tr>
<td>14.1%</td>
<td>11-20%</td>
</tr>
<tr>
<td>5.2%</td>
<td>More than 20%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

Utility respondents were asked to describe the primary drivers for planned natural gas-fueled generation.

Respondents were asked to select the percentage (on a megawatt basis) of all U.S. power generation that they believe will come from distributed generation (power assets with a capacity less than 20 megawatts) by 2020.
As electric utilities continue their evolution from vertically integrated entities toward becoming system integrators that align and manage disparate subsystems, technology will emerge as the primary catalyst for change. This shift, which can be characterized as a move toward “Utility 2.0,” will also be precipitated by rising costs, performance challenges and increasing customer expectations.

Investment in and implementation of asset management programs that leverage technology as an enabler present both an opportunity and challenge for utilities in the future. From an investment perspective, new data collection and performance monitoring technologies will assist utility operators in better understanding potential points for failure and managing risk by improving visibility into asset condition and performance.

A key consideration is the ability of existing and planned assets to interact with new technologies in concert with the asset’s capability to function from an infrastructure perspective. This focus on technological readiness comes into play as utilities seek to gauge asset health. Online monitoring of critical assets can assist organizations in deciding where and how to prioritize capital expenditure. This is currently costly and limited to the most critical assets in the system, but as technology advances and prices are reduced the uptake of advanced monitoring and control technologies is set to be rapid and widespread.

Incorporating technology will require electric utilities to view issues like aging infrastructure in new ways. For example, utilities will need to consider technological obsolescence in addition to the more traditional assessment of remaining useful life or the examination of asset health. This expanded view challenges the historical short-term focus on financing aging infrastructure with an eye toward preserving the utility’s ability to access capital for new build.

With reliability maintaining its position as the issue of greatest concern to electric utilities, it is telling that other issues in the top ten – long-term investment and aging infrastructure – are variables that affect the reliable delivery of services. Effective asset management enables utilities to optimize expenditures required in an “always-on,” rapidly changing environment.

In an effort to assist utilities in implementing or enhancing their approach to asset management and to capture industry knowledge and experience of best practices, asset management frameworks such as Publicly Available Specification 55 (PAS 55) and International Organization for Standardization (ISO) 55001 have been developed. PAS 55 was developed by the UK Institute of Asset Management in conjunction with the British Standards Institution in 2004. PAS 55 defines good practice asset management and specifies what elements need to be included in a successful asset management program.

PAS 55 has been used by electricity utilities in the UK and overseas, but its uptake by the U.S. electricity industry has been limited. This is confirmed in the responses to the question where respondents were asked if their utility used a formal asset management program (Figure 7). Less than 10 percent of respondent are using PAS 55 or have some elements in place, and only 3.7 percent are considering using PAS 55.
The need for an international asset management standard that would be applicable to a wider range of organizations was addressed by the development of ISO 55001 by the International Organization for Standardization. The standard was only recently published in early 2014, so it is understandable that only 1.6 percent of respondents are currently using it. However, considering that the responses to last year’s survey indicated that many utilities were implementing asset management programs and looking to increase their overall asset management maturity, the high number of respondents who chose “no” or “don’t know” is surprising. The ISO 55001 standard provides utilities with a significant opportunity to measure their current level of maturity and “fast track” their asset management programs.

Approximately 30 percent of respondents are using or are considering the use of risk-based approaches to capital planning. The risk assessment process involves assessing the likelihood of failure, based on the condition and performance of the assets as well as assessing the consequence of failure or “criticality” of the asset or asset system. Risk-based planning and risk management are key components of effective asset management and are used by leading utilities globally.

Regulatory requirements can also incentivize electric utilities to incorporate risk-based approaches in their planning. In this environment, successful rate cases incorporate a risk-based asset management framework. As noted in the executive summary, survey respondents recognize that several factors will drive rate increases over the next 5 years. Investments in aging infrastructure and grid readiness account for 27 percent of responses, just behind regulatory compliance.

In many states, legislators have recognized the need to put in place mechanisms to enable much needed repair and replacement (R&R) investments, particularly for transmission and distribution infrastructure. Increasingly, “infrastructure replacement riders” have been established that focus on more timely recovery of costs related to aging infrastructure. Typically, these regulatory mechanisms allow for investment to improve safety, replacement, reliability and modernization. In assessing the case for funding, regulators are increasingly looking for well-argued, risk-based business cases that are anchored in sound asset management practice and which quantify and articulate the clear costs and benefits of investment.

Incorporating technology will require electric utilities to view issues like aging infrastructure in new ways.
Another key driver that has been the focus of investment planning is increasing system resilience to extreme weather events (Figure 8). Here, a risk-based planning approach has also been adopted, with utilities assessing the criticality of their assets and focusing investment in system hardening where it will make the most difference, coupled with implementing strategies for ensuring they have sufficient critical spares. Emergency response plans are being updated in-line with lessons learned and embedded in the organization, often as part of an asset management improvement program.

Risk-based asset management strategy enabled by technology and integrated in the operations and financial decision-making process creates opportunities for utilities to survive in this transformative time. Pressure to reduce costs, ensure reliability and shore up aging infrastructure can be daunting. Organizations that recognize these challenges and respond with well-argued and substantiated cases that prioritize the need to invest while minimizing the impact on customers will thrive. Getting there will require sound asset management programs where the needs of the utility and its stakeholders reflect a balanced approach to risk optimization, investment and technology integration.

**FIGURE 8**
**PLAN TO IMPROVE RESILIENCY OVER WEATHER AND UNANTICIPATED EVENTS**

<table>
<thead>
<tr>
<th>Percentage</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>56.9%</td>
<td>Updating emergency response plans</td>
</tr>
<tr>
<td>44.2%</td>
<td>Identifying critical assets</td>
</tr>
<tr>
<td>38.1%</td>
<td>Hardening of assets</td>
</tr>
<tr>
<td>26.7%</td>
<td>Implementing a critical spares strategy</td>
</tr>
<tr>
<td>21.7%</td>
<td>Collaborative procurement arrangements with suppliers</td>
</tr>
<tr>
<td>17.5%</td>
<td>Maintaining current programs such as fuel oil backup</td>
</tr>
<tr>
<td>2.1%</td>
<td>Exploring LNG peak shaving facilities</td>
</tr>
<tr>
<td>7.9%</td>
<td>Not applicable</td>
</tr>
<tr>
<td>14.6%</td>
<td>I don’t know</td>
</tr>
</tbody>
</table>

*Source: Black & Veatch*

Respondents were asked to describe their utility’s plan for improving resiliency in the face of extreme weather and other unanticipated events.
Risk-based asset management strategy enabled by technology and integrated in the operations and financial decision-making process creates opportunities for utilities to survive in this transformative time.
U.S. electric industry leaders once were gravely worried about their aging workforce. In Black & Veatch’s 2007 Strategic Directions in the Electric Utility Industry report, aging workforce was second only to service reliability in the ranking of Top 10 industry issues by survey participants. Unlike the stock market and many 401k plans, aging workforce concerns have not rebounded to pre-2008 levels. In fact, aging workforce did not make this year’s Top 10 industry issues list among all utility respondents (refer to Figure 1 in the Executive Summary).

It should be noted, however, that while aging workforce did not make the list of top concerns, nearly 70 percent of utility leaders believe their organization will have workforce challenges because of employee retirements during the next five years (Figure 9). There are many reasons why utility leaders do not have aging workforce at the top of their concerns lists. Foremost, it represents a slow-developing challenge. Not all workers over the age of 62 will retire at once. A more immediate and pressing concern for utility leaders is new and pending environmental regulations and cybersecurity requirements that come with hard deadlines and hard costs. However, one could also argue that aging workforce is not as big of a concern today because utility workforce needs have changed significantly since 2007.

**FIGURE 9**
**ORGANIZATIONS IMPACTED BY WORKFORCE RETIREMENTS DURING THE NEXT FIVE YEARS**

<table>
<thead>
<tr>
<th>Option</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yes</td>
<td>68.5%</td>
</tr>
<tr>
<td>No</td>
<td>23.8%</td>
</tr>
<tr>
<td>I don’t know</td>
<td>7.7%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch
Utility participants were asked if their organization forecast any workforce challenges due to employee retirements during the next five years.
CHANGES IN GENERATION TECHNOLOGY

Since the start of the Great Recession, three major occurrences have reshaped the future U.S. power portfolio: the Fukushima tsunami, the Environmental Protection Agency’s Utility MACT (Maximum Achievable Control Technology) rule, among other environmental regulations such as CAIR/CSAPR (Clean Air Interstate/Cross State Air Pollution) rules, and the discovery and exploitation of domestic natural gas resources.

For utilities that own nuclear and/or coal generating units, changes to the generation portfolio affect the number of staff needed to keep a facility running. Nuclear plants, for example, could require more than 400 personnel to keep the facility continuously operational. The labor force for a large coal-fired plant can be more than 200. Natural gas facilities, which will largely replace retiring baseload units, only require a couple of dozen operations and maintenance (O&M) personnel. Renewable generation technologies generally do not require significant numbers of O&M personnel at the plant site.

Prior to the recession, utilities were gearing up for the nuclear renaissance to meet growing demand as the industry recognized the increasing difficulty in permitting new coal-fired generation, and natural gas prices were increasing, with prices above $10/MBtu (million British thermal unit), and were extremely volatile. As such, a much larger workforce was anticipated for simply running the nation’s power generation facilities.

CHANGES IN UTILITY ECONOMICS AND OPERATIONS

Many electric utilities are challenged with difficult financial situations, particularly investor-owned utilities. The revenue base is decreasing as customers continue to conserve and implement on-site generation (e.g., solar panels) while fixed costs continue to rise. Stagnant demand for power means there is less demand for major capital programs to add large-scale generation assets in the near term.

Rapid utility consolidation is under way as utilities seek to either cut costs, such as the selling of generation assets, or grow existing customer bases. Exelon and Constellation Energy announced their companies’ plans to merge in 2011. In 2014 alone, Berkshire Hathaway Energy has closed transactions to acquire TransAlta’s interests in CE Generation LLC and CalEnergy LLC and has reached an acquisition agreement with AltaLink. The company already owns PacifiCorp and NVEnergy, among other utility and power generation assets. These are just a few examples of closed or announced mergers and acquisitions within the industry during the last five years.

Operational technologies are also helping to alleviate the workforce issue. Smart metering infrastructure, automation technologies and remote monitoring and control technologies have all advanced significantly from early adopter/experimental stages prior to 2008, to industry best practice. These technologies enable utilities to manage, control and monitor exponentially more areas with the same amount or fewer people.
PAIN POINTS FOR UTILITIES
While the power portfolio, market dynamics and technology advances have helped utilities reduce the overall need, there are specific areas of concern for their workforce. Of the nearly 70 percent of utility participants that stated they expect workforce-related challenges during the next five years, nearly 75 percent selected power engineers and more than half selected management and administrative functions (Figure 10) as the groups most affected by retirements.

Within the identified personnel groups, utilities are often feeling what industry is now referring to as the “double squeeze” — retirement of existing staff and lack of qualified candidates to take their place. Not specifically polled here, but of significant importance, is the dearth of skilled physical laborers. While larger scale new builds are no longer the norm, the lack of skilled personnel is placing added pressures on utility staffing.

For some utilities, outsourcing design, operations and maintenance and other areas can alleviate the loss of power engineers. Other organizations are targeting military veterans who have experience in control system engineering, leadership and other essential qualities. Still others are working directly with local technical, trade schools and community colleges to develop programs specifically designed to fill looming gaps in the utility workforce.

MARKET FORCES
A GLOBAL SHORTAGE OF SKILLED LABORERS IS PLACING ADDED PRESSURES ON UTILITY STAFFING.
FIGURE 10
UTILITY PERSONNEL GROUPS MOST AFFECTED BY RETIREMENTS AND ABILITY TO RECRUIT NEW STAFF

73.4% Power engineers
52.7% Management/administrative
42.2% Control center operations
32.8% Transmission network teams
9.4% IT
7.8% Customer service

Source: Black & Veatch
Respondents were asked to identify the personnel groups they believed would be most affected by retirements and their organization’s ability to recruit new staff.
Twice each year, Black & Veatch issues its Energy Market Perspective (EMP). Using an integrated market model to prepare a 25 year view on energy markets, the report is a leading information and planning source for the energy industry and a key resource for executive decision-making.

In order to arrive at this market view, Black & Veatch draws on a number of commercial data sources and supplements them with its own view on a number of key market drivers, for example, power plant capital costs, environmental and regulatory policy, fuel basin exploration and development costs, and gas pipeline expansion.

The midyear 2014 EMP focuses on several trends, observed and discussed throughout the 2014 Strategic Directions: U.S. Electric Industry report, that shape the landscape for electric utilities across the United States including:

- Electric power pricing will increasingly be tied to natural gas prices as natural gas evolves into the predominant fuel for generation.
- Reliability, environmental regulation and economic regulation are the top issues facing the industry.
- Coal will continue its significant role in the resource mix, even with the anticipated 59.5 gigawatt retirement of smaller, older plants.
- Natural gas units will replace these retired coal units and meet load growth and reserve requirements.
- Economic challenges will continue for smaller and single-unit nuclear plants.
- Renewable Portfolio Standards will drive growth in renewable capacity.

**POWER MARKET OUTLOOK**

Despite some projections for flat or declining demand, Black & Veatch believes U.S. power demand will grow by roughly 1 percent each year over the next 25 years. This growth comes despite the retirement of 59.5 gigawatts of coal-fired capacity by 2020, which is being driven primarily by Mercury Air Toxics Standards (MATS) compliance.

With much of the focus on the rise of natural gas within the electric sector due to economic and regulatory drivers, Black & Veatch anticipates that increased production capacity will keep natural gas prices steady through 2020. This price stability will encourage operators to move ahead with new natural gas capacity additions to support baseload generation and greater renewable integration. This latter point is particularly important as simple cycle natural gas turbines and aeroderivative technology will play an essential role in ensuring reliable power supplies in states with high levels of deployed renewable capacity and/or high renewable portfolio standards.

In the short to medium term, there is clear evidence that the majority of new capacity additions will use natural gas fueled technology. Further, recent actions by the U.S. Supreme Court upheld the Environmental Protection Agency’s ability to regulate 83 percent of all carbon emissions. This decision supported our forecast for steady growth in gas-power generation that could increase dramatically in 2020 with the implementation of a carbon price.
TOTAL COINCIDENT PEAK DEMAND (GW)

Source: Black & Veatch

COAL RETIREMENTS OF 59.5 GW (20% OF FLEET) PROJECTED BY 2020

Source: Black & Veatch

During this period, average coal unit age at retirement is 56.5 years.
**PROJECTED NORTH AMERICAN NATURAL GAS SUPPLY**

North American natural gas production will grow by 50 Bcf/d (billion cubic feet per day) over the next two decades. 

**INCREMENTAL LOWER 48 GAS DEMAND FOR POWER GENERATION FROM 2014**

U.S. natural gas demand for power generation is expected to grow by 5 Bcf/d by 2020 and nearly 15 Bcf/d by 2035.
NATURAL GAS-FUELED COMBINED CYCLE FACILITIES WILL LARGELY TAKE THE PLACE OF RETIRING COAL-FIRED GENERATION CAPACITY.
The Gulf Co-operation Council (GCC) states – Bahrain, Kuwait, Oman, Qatar, Saudi Arabia and the United Arab Emirates (UAE) – represent Black & Veatch’s current focus in the Middle East. This is a fast growing region. The demographic changes the GCC is going through – population growth, industrialisation and urban migration – are all stimulating demand for power. In Saudi Arabia, for example, it is forecast that generation capacity needs to expand by an average of 9 percent until 2015.

It is important to recognise that the region is not homogenous, different states within the GCC have different needs. Some general trends exist, however. A major challenge is meeting businesses’ and peoples’ need for power in a manner that will not impede the generation of revenues through oil and gas exports. The need to reduce consumption of domestically sourced oil and gas has led to what Saeed Khorry, CEO of Emirates National Oil Company described as, “an era of responsibility.” A number of measures are being used to try and achieve this.

One such measure is the move to diversify feedstock portfolios for power generation. While oil and gas will be the primary feedstock for the foreseeable future the role of others is growing significantly. Nuclear power is one of the options. Of the GCC states, UAE and Saudi Arabia have the most developed nuclear programmes. The UAE hopes to generate up to 25 percent of its electricity needs, 5.6GW, using nuclear power by 2020. Saudi Arabia has plans to build 16 nuclear power plants that will generate 17.6GW of power progressively to 2032.

There is also a substantial move toward renewable energy. The total value of renewables projects and master plans, either completed or under execution, in the GCC states is US$4.5 billion, split between $1bn for hydro projects (all of which are in Saudi Arabia) and $3.5bn for solar, according to figures from Meed Projects. Dubai forecasts that solar voltaic or luminescent solar concentrator generation will account for 12 percent of its generation by 2030; Saudi Arabia has expressed a desire to achieve 30 percent of its energy needs through solar generation by 2032. Wind energy is also starting to receive serious attention. Masdar, Abu Dhabi’s leading renewable energy company, has completed wind-mapping of the emirate and is now looking for suitable wind array locations.

Dubai, which currently relies on imported liquid natural gas (LNG) as a feedstock, is also looking to coal. The emirate recently announced its first coal Independent Power Producer project. Dubai’s Integrated Energy Strategy 2030 envisages coal accounting for 12 per cent of feedstock.

As well as diversifying feedstock, increasing generation efficiency is another way in which GCC states are looking to conserve oil reserves for export. Across the GCC there is increased interest in more efficient generation technology. For example Saudi Arabia’s average thermal efficiency in generation is around 30 – 35 percent. Converting the kingdom’s single-cycle plants to combined-cycle is estimated to increase thermal efficiency to 40 – 45 percent.
With energy demand in the GCC among the highest in the world reducing consumption, while meeting consumers’ expectations and not affecting growth, is another way in which pressures upon fossil fuel reserves can be managed. We are seeing many initiatives aimed at cutting energy consumption. Air conditioning (AC), which accounts for circa half of the GCC’s summer energy consumption, provides a good example of the approaches being taken to reduce energy use. Measures include legislation to improve buildings’ heat insulation, asking people to set the thermostat a degree lower, and a greater focus on AC units’ energy efficiency ratios are all measures receiving great attention.

In a further step to manage demand January 2014 saw the GCC’s Electricity Cooperation Committee announced it was beginning to explore the possibility of implementing joint legal and legislative rules to strengthen rationalising the consumption of water and electricity.

In an arid region such as the GCC, recognising that power and water are inextricably linked is crucial for reducing demands for both. Energy generation is water intensive and water services are energy intensive; cutting consumer demand for one will reduce consumption of the other. This is important when customers in the GCC have some of the world’s highest per-capita demands for water as well as energy.

This interdependency, or nexus, of energy and water is another driver for the use of more efficient generation technology. Combined cycle plants generate nearly 66 percent more energy per unit of water used compared to traditional gas fired plants. So, by understanding the technology and the nexus of water and energy, you begin to see a virtuous circle with more efficient generation coupled to a reduction in demand for water.

To ensure the sustainable provision of both precious resources the integrated planning and delivery of energy and water infrastructure provides among the most efficient means to meet and manage demand. As a result, meeting governments’ objectives will increasingly require companies that have expertise in delivering both water and energy projects, and successfully combining insights from both.

In terms of infrastructure delivery, the independent sector is playing an increasing role in meeting many GCC states’ energy needs. The participation of IPPs and IWPPs is ushering in more alternative delivery approaches for infrastructure projects - various engineering, procurement, construction (EPC) models; and build, operate, transfer (BOT) and build-own-operate-transfer (BOOT) schemes – for example. Varying perspectives regarding lump sum, shared risk, cost reimbursable contract structures will also continue to evolve.

On projects in the GCC we have served in multiple roles: from technology and contracting strategy selection to Owner’s Engineer and Lender’s Engineer to detailed design and project integrator to EPC. The main trend we see is the need for flexibility to help clients develop and deliver projects using the execution method best suited to meet their overall goals.

Across all client types and delivery models we are seeing an increasing recognition in the GCC that the ability to meet demand in a sustainable manner requires technological innovation. As greater efficiency is sought in the delivery and operation of energy infrastructure, factors other than the least cost solution should be considered. To reliably meet the region’s goals utilities, IPPs and IWPPs need partners with a world-class understanding of the energy technologies available. Such partners should be evaluated on their ability to deliver value – a combination of their expertise and solutions delivered at the most competitive price possible. To be effective this expertise has to be coupled with the ability to identify the solution most suited to meeting local needs.

GCC states have made major investments in energy infrastructure during the last decade, and high levels of spending are forecast in order to meet growing demand. Asset creation, however, is only half the story. To deliver the levels of customer service and environmental performance end-users and governments seek, GCC states’ infrastructure asset base needs to be managed effectively. We see this as a growth area.

PAS 55 is recognised around the world as the benchmark for asset management quality. Use of the specification in the GCC is growing; Abu Dhabi Distribution Company
announced last year, the appointment of Black & Veatch to help it achieve PAS 55 certification.

In a recent advance in the discipline of asset management the International Organisation for Standardisation – commonly called the ISO – published ISO 5500X, the world’s first international suite of standards for asset management. We have commenced work on an asset management project to support ISO 55001 certification for Abu Dhabi Transmission & Despatch Company TRANSCO, and anticipate a growing demand for services which deliver effective asset management regimes, so utilities can ensure their investments deliver the performance desired in the long-term.

In addition to developing infrastructure, the GCC needs to develop people. Reliance on expatriate expertise to deliver and manage utility infrastructure is unsustainable. Knowledge transfer is now essential to a project’s success. For example, Black & Veatch’s PAS 55 work with ADDC includes the development of training and structures for the adoption of industry best practices. Knowledge transfer is an essential component of the overall programme.
In an arid region such as the GCC, recognising that power and water are inextricably linked is crucial for reducing demands for both. Energy generation is water intensive and water services are energy intensive; cutting consumer demand for one will reduce consumption of the other. This is important when customers in the GCC have some of the world’s highest per-capita demands for water as well as energy.
Electric utilities are grappling with the broader adoption of renewable generation against a backdrop of stymied rate recovery and otherwise flat demand. The added conflict between government-mandated reliability goals and rate constraints, along with competition from non-utility actors leveraging emerging technologies, is illustrative of a sector under pressure. As noted elsewhere in this report, the best chance for growth might be to view emerging technology, particularly innovation in storage and distributed generation, as a potential new source of revenue and as part of a broader initiative to facilitate renewables integration.

The U.S. Federal Energy Regulatory Commission (FERC) aims to increase the amount of electricity being produced from renewable energy sources. FERC said that it, “… will continue to pursue market reforms to allow… renewable energy resources, to compete in jurisdictional markets on a level playing field. These efforts could include amendments to market rules, the modification or creation of ancillary services and related policies, or the implementation of operational tools that support the reliable integration of renewable resources.”

It would appear that an endorsement from the country’s energy governing body would be enough to continue acceleration of the mainstreaming of renewable energy sources such as wind and solar. Instead, further integration may be spurred by other reasons: incentives creating a profitable opportunity for third-party players and early investors as they seek to fill the gaps from coal and nuclear plant retirements. Taken collectively, when asked how their organization planned to manage demand growth or lost capacity due to plant retirements, 64 percent of survey respondents with an opinion cited natural gas and/or renewable generation as an energy source (Figure 11).

When it comes to diversifying the energy mix, distributed generation represents a conundrum for electric utilities. At replacement levels of less than 20 percent, renewables and distributed generation (photovoltaic [PV] comprises the majority of distributed generation currently being deployed) are the first choice energy source (Figure 12 ). At replacement levels of over 20 percent, utility respondents indicated natural gas as a preferred option. The anticipated adoption of distributed generation and renewables does not come without costs since electric utilities are still responsible for providing transmission and distribution services to their customers. The inclusion of additional complexity to the system from distributed generation along with reduced demand may require electric utilities to reimagine their traditional vertically integrated model and role as the primary provider of power. The asset and capital management section of this report alludes to this potential transformation – the emerging paradigm will be the electric utility as systems integrator.
Utility respondents were asked to select the option that best described their utility’s plans to manage demand growth and/or lost capacity due to planned coal/nuclear plant retirements.

**FIGURE 11**
PLAN TO MANAGE DEMAND GROWTH OR LOST CAPACITY DUE TO PLANT RETIREMENTS

- **21.2%** Replacing the retiring capacity with the same size new build natural gas baseload facility and/or renewable generation
- **13.0%** Wait-and-see approach
- **10.1%** Replacing the retiring capacity with larger size new build natural gas baseload facility and/or renewable generation after partnering with other utilities
- **7.1%** Acquiring shares in existing plants as opposed to building new facilities
- **4.8%** Leveraging third-party renewable generation
- **33.6%** Not applicable
- **10.3%** I don’t know

Source: Black & Veatch

**FIGURE 12**
ANTICIPATED COAL/NUCLEAR RETIREMENTS (PERCENT OF OVERALL CAPACITY)

<table>
<thead>
<tr>
<th>Level of Replacing Coal or Nuclear Capacity</th>
<th>Natural Gas</th>
<th>Distributed Generation</th>
<th>Energy Efficiency</th>
<th>Renewables</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 – 5%</td>
<td>3.4%</td>
<td>31.2%</td>
<td>28.6%</td>
<td>22.5%</td>
</tr>
<tr>
<td>6 – 10%</td>
<td>5.8%</td>
<td>10.8%</td>
<td>14.8%</td>
<td>14.3%</td>
</tr>
<tr>
<td>11 – 15%</td>
<td>6.1%</td>
<td>4.0%</td>
<td>71%</td>
<td>8.5%</td>
</tr>
<tr>
<td>16 – 20%</td>
<td>6.6%</td>
<td>3.4%</td>
<td>6.3%</td>
<td>5.3%</td>
</tr>
<tr>
<td>More than 20%</td>
<td>41.5%</td>
<td>5.6%</td>
<td>5.8%</td>
<td>14.6%</td>
</tr>
<tr>
<td>Not applicable</td>
<td>23.4%</td>
<td>26.5%</td>
<td>23.5%</td>
<td>23.8%</td>
</tr>
<tr>
<td>I don’t know</td>
<td>12.2%</td>
<td>18.5%</td>
<td>13.8%</td>
<td>11.1%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

Respondents were asked to estimate on a percentage basis the level each of the listed items will have in replacing retiring coal or nuclear capacity for their organization.
While the aforementioned transformation is under way, electric utilities are seeking near-term solutions. They are reviewing policies (Figure 13) and examining billing changes to properly account for the net costs and/or benefits of net metering. This will allow for policies that provide an equitable treatment of distributed solar as part of the generation mix. This will also mean that distributed solar may be seen as more valuable in some places on the grid than others, and this value may actually change as PV penetration increases.

Over the long term, innovation in storage could be the answer to the variable distributed generation and reliability challenges facing electric utilities. It should be noted that energy storage being regarded as a necessary technology or process for integrating renewables into the grid is not a new notion. In fact, it has been the number one technology identified by an increasing margin for the past three years. What has changed is the sense of urgency. While 38 percent of utility respondents are not currently involved in energy storage programs, a third are conducting energy storage pilots programs requiring storage for variable generation projects, or are currently involved in an energy storage incentive for developers or customers (Figure 14).

**FIGURE 13**

**REVIEWING POLICIES DUE TO DISTRIBUTED SOLAR GENERATION**

- **33.6%** Currently reviewing net metering policies internally
- **20.1%** Actively working to change net metering tariffs to properly account for net costs and/or benefits
- **6.6%** Allowing “virtual net metering”
- **5.8%** Using a “value of solar” rate structure
- **3.7%** Other
- **17.2%** None of the above
- **26.7%** I don’t know

*Source: Black & Veatch*

Respondents were asked to select the items that applied, “In response to rapid growth of distributed solar generation, some utilities are reviewing policies regarding net metering.”
In addition, the most valuable storage functions as identified by survey respondents hew closely to the number one priority enumerated in the top ten issues; reliability. When asked which energy storage functions were most valuable to their organizations, a majority cited bulk energy storage to meet peak capacity requirements and renewables integration including smoothing/ramp rate control/time shifting to manage electric vehicle charging to avoid peaks (Figure 15).

Another long-term solution will be to create synergies with non-utility stakeholders such as electric vehicle manufacturers and charging equipment suppliers that innovate on the shoulder of the grid. The rise of electric vehicles to high penetration levels will require upgrades to distribution infrastructure, but could also provide opportunities for grid management.

With government-mandated reliability and Renewable Portfolio Standard (RPS) requirements, public and private participation is sure to increase. Further, as investment firms and, more recently, internet companies increase their investments in advanced grid technologies and clean energy, opportunities to leverage their participation in support of renewables integration are emerging.
The increasing penetration of distributed generation and renewable energy will require creative solutions. Part of that creativity may be to utilize the power of utility-generated data to move away from meaningless incentives toward something better. Current incentives, which were developed in the 1970s, were originally meant to encourage people to put solar hot water on their rooftops. They were essentially just blanket statements that supported the sentiment that “renewables are good, and we want more of them.”

As renewables move into the mainstream, we expect to see smart utility-based incentives that are targeted to where solar and other distributed generation can be interconnected for the lowest cost and do the most good on the utility system. This will take analysis of each utility’s situation including its generation mix, load management programs and its distribution system. It may take utility ownership, management of, or at least engagement with, new technologies such as PV inverters, electric vehicle charging stations and energy storage. Fortunately, as the grid gets smarter, we are acquiring the tools to do more of this kind of analysis and engagement. Energy storage, smart PV inverters and incentives that are designed to encourage distributed PV in the places where it can help and not cause problems on the grid will help us structure a reliable, clean and efficient utility grid for years to come.

**FIGURE 15**

**MOST VALUABLE ENERGY STORAGE FUNCTIONS**

- **70.3%** Bulk energy storage to meet peak capacity requirements
- **50.5%** Renewables integration including smoothing/ramp rate control/time shifting to manage electric vehicle charging to avoid peaks
- **40.6%** Fast-responding energy storage for frequency regulation
- **17.9%** Bulk energy storage to capitalize on rate arbitrage
- **17.7%** Bulk energy storage to defer distribution system investment
- **15.8%** Bulk energy storage to defer transmission system investment

*Source: Black & Veatch*

Utility respondents were asked to select the energy storage functions they believed were most valuable to the electric grid.
The U.S. electric utility industry today stands at the beginning of a long-term transition to a grid in which distributed generation (DG) plays a much larger role. In particular, solar photovoltaic (PV) technology has seen spectacular growth in cumulative installed capacity – from about 1,200 MW at the end of 2009 to over 12,000 MW at the end of 2013. This figure could reach nearly 40,000 MW by the end of 2017, according to Greentech Media Research.

Well over half of those 40,000 MW are expected to be installed on the distribution system, most of it behind the customer meter. In a report for the California Public Utilities Commission, Black & Veatch estimated that DG already reduced the state’s peak demand 1 – 2 percent in 2011. Further, even at relatively low penetration the report found that utilities were becoming concerned about adverse grid impacts, rate implications, and lack of monitoring and control infrastructure.

Electric utilities are reacting to DG in different ways. Some see it as a threat to their current business model, because it can reduce energy sales and revenues if customers purchase less and less electricity from the incumbent utility. Some believe that simply allowing customers a “choice” about their electricity source is dangerous, because it is the first step toward customers getting “off the grid” entirely. They see that third-party vendors are incentivizing the switch to DG through use of innovative financing structures such as solar leases, which require no money down from the customer and promise monthly utility bill savings, but they observe that these vendors do not have the same regulatory constraints on rates as traditional utilities. Many utilities also argue that net energy metering tariffs – which most DG customers use – result in a cross-subsidy, because DG customers do not pay their fair share of fixed utility costs like transmission and distribution infrastructure.

Other utilities are seizing on DG as an opportunity. Moreover, if they adopt a proactive approach toward DG, utilities can leverage it to increase customer engagement; they can participate in development, financing, construction, and maintenance of DG facilities; and they can build the operational capabilities to accommodate DG on their grid before negative impacts are felt.

For instance, utilities can own and control solar PV inverters as another distribution asset, offer community solar programs to customers who are unable to install DG, allow on-bill financing of customer DG, or use existing field crews to provide operations and maintenance services to customers with DG. When utilities move from a reactive to a proactive stance on DG, Black & Veatch calls this “flipping the DG equation.”

Perhaps the best example of this proactive approach is “Smart DG Deployment,” a multi-step process that allows utilities to take control of DG and reverse the so-called “utility death spiral” of higher rates, which ultimately result in greater DG adoption:

1. Assess technical and economic DG potential within the service territory
2. Analyze customer load profiles and rate structures to determine who can benefit most from DG
3. Identify locations on the distribution system where DG provides net benefits to the grid
4. Restructure customer rates to remove cross-subsidies and compensate DG customers fairly for benefits to the grid
5. Implement location-based incentives to encourage DG adoption in the right places
6. Develop proactive transmission and distribution plans to accommodate DG growth

Though no utility has yet put this entire concept into practice, Black & Veatch is already working on the first four steps of this process with leading utility clients. These clients understand that when customers can adopt DG and receive fair compensation while avoiding negative impacts on non-DG customers, everyone wins. However, given regulatory limits on investments outside core services, utilities must be careful to gain regulatory support to recover DG investments in rates. But by taking steps to embrace DG, they can avoid being blind-sided by its growth and successfully prepare for the DG-enabled grid of the future.
EMERGING TECHNOLOGIES OFFER MORE OPPORTUNITIES THAN CHALLENGES

By Kevin Cornish and Greg Henry

Despite countless headlines, forums and industry strategy sessions, the 2014 Strategic Directions: U.S. Electric Industry report found that emerging technologies did not rate among the Top 10 industry issues. It is without question that implementation risks, integration complexities and ongoing support concerns (e.g., cybersecurity and lack of in-house experience) are real challenges. However, new and emerging technologies such as demand-response and advanced applications can provide utilities with the tools needed to modernize the distribution grid, gain efficiencies and enhance the customer experience.

The electric industry continues to advance in the saturation and maturity of the deployment of advanced metering infrastructure (AMI) (Figure 16). Nearly 58 percent of respondents indicate that an AMI program is in place or in progress while one-quarter are assessing or have not yet embarked on a program. However, the fundamental challenge for many utilities remains understanding the full range of capabilities of the new technology, how to integrate the solutions into the utility enterprise and how to successfully transform business processes in order to improve operations, enhance reliability, address environmental regulations, deliver improved customer service and more.

Data analytics is an area of tremendous opportunity for utilities, particularly when considering that the data from most AMI programs today are primarily used for meter-to-billing applications. There is much value to be gained from AMI data, such as:

■ Using consumption data to update load profile classes and revisit cost of service and rate structures;
■ Focusing marketing programs on those customers that can best take advantage of the program based on their usage profiles;
■ Providing an opportunity to fully integrate AMI data to the utility outage management, voltage optimization, grid management and other initiatives;
■ Leveraging the AMI solution to support increased penetration of renewable generation; and
■ Supporting the new focus on smart communities via initiatives such as street light monitoring, connected transportation, integrated energy and water management programs.

DATA ANALYTICS: IN SEARCH OF A DEFINITION

Of the respondents indicating AMI networks in place at their utility, only 40 percent noted the existence of an active data analytics program (Figure 17). Among these respondents, however, the definition of what comprises an analytics program is very broad. Some view analytics programs as highly complex Big Math applications, while others consider them to be more basic data visualization, performance tracking and reporting as analytics.
FIGURE 16
ADVANCED METERING AT UTILITY

38.1% Yes
19.0% No
19.6% In progress
8.2% Assessing
15.1% I don’t know

Source: Black & Veatch
Respondent were asked, “Does your utility have advanced metering infrastructure (AMI) in place?”

FIGURE 17
DATA ANALYTICS PROGRAM IN PLACE

40.3% Yes, in place
17.4% No
34.0% Assessing/in development
8.3% I don’t know

Source: Black & Veatch
Respondents were asked if their utility had a data analytics program in place.
TECHNOLOGICAL DRIVERS

Industry leaders are also beginning to see the value potential analytics programs could provide related to improving reliability and outage management across traditional generation/transmission and distribution (T&D) functions. In addition, there is an increasing sense that data will inform customer engagement/service and regulatory compliance planning (Figure 18).

Without question, new and enabling technology will reshape many aspects of the electric utility industry. The key will be for service providers to harness the diverse sources and volumes of data available through their smart networks to create more flexible and adaptive solutions to address the current and emerging issues. From generation and T&D to customer service and renewable integration, as data that demonstrate the value of emerging technology come in, we can expect to see more utilities transition from the challenge stage of adoption to the opportunity stage.

**FIGURE 18**

**IMPORTANCE OF AMI AND DATA ANALYTICS PROGRAMS**

<table>
<thead>
<tr>
<th>Score</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.02</td>
<td>Improved reliability/availability</td>
</tr>
<tr>
<td>4.00</td>
<td>Improved outage management</td>
</tr>
<tr>
<td>3.93</td>
<td>Improved efficiency/cost reductions</td>
</tr>
<tr>
<td>3.83</td>
<td>Improved operational flexibility</td>
</tr>
<tr>
<td>3.81</td>
<td>Improved customer service/customer segmentation</td>
</tr>
<tr>
<td>3.72</td>
<td>Better load management</td>
</tr>
<tr>
<td>3.52</td>
<td>Regulatory compliance</td>
</tr>
<tr>
<td>3.51</td>
<td>Improved rate/tariff design</td>
</tr>
<tr>
<td>3.41</td>
<td>Price stabilization/dynamic pricing</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

Respondents were asked to rate a selection of potential outcomes of AMI and data analytics programs by level of importance to their utility.
Without question, new and enabling technologies will reshape many aspects of the electric utility industry.
CONSUMER TECHNOLOGY

BY KEVIN CORNISH

For the last several years, a consistent theme of the Black & Veatch Strategic Directions report series is the increasing role of technology in improving efficiency across utilities. For electric utilities, much of their recent focus was on the deployment of intelligent advanced metering infrastructure (AMI) projects to improve meter to billing applications and core customer service functions. This reflected the initial rate recovery justifications that were given to regulators versus higher level, data-driven functions focused on system efficiency that are now possible, though not yet widely in practice. Black & Veatch’s 2014 Strategic Directions: Utility Automation & Integration report, published in January, addresses this idea in detail.

Recently, the multibillion dollar acquisition of Nest Labs, along with high profile activity in single-family rooftop solar has focused attention on the potential for in-home technology to impact electric utility operations. With projected sales of $1.4 billion in 2020 (Navigant), Wi-Fi enabled learning thermostats are also establishing a position as the leading consumer home energy management solution. While some view the increased role of the home consumer as an exciting opportunity to enhance utility demand-response programs, others see the widespread adoption of home energy management technology as a threat to traditional operating models.

Given utilities’ interest in providing a more robust customer experience and expanding demand-response programs beyond corporate accounts, some service providers have actively embraced the deployment of smart thermostats as a means to address these goals. Smart thermostats from providers such as Honeywell, Ecobee, Venstar ranked number one among the home area network solutions in use by utilities to manage demand-response programs (Figure 19).

Despite expectations for broader adoption of smart thermostats, widespread support for these programs remains elusive since only 24.9 percent indicated their utility is actively working to increase penetration of smart thermostats (Figure 20). Although an additional 14.3 percent of participants indicated they are supporting deployments, but not actively informing customers, more than 35 percent indicated no support effort for the technology. This is likely because many utilities themselves are not yet particularly focused on emerging customer technologies and because some previous program rollouts did not go particularly well.

While the user experience of smart thermostats is a big draw and advances in design have spurred demand, utilities looking to launch or expand consumer demand-response programs must consider whether the technology has the capacity to change behavior, ideally, to achieve their goals. Although easily accessible mobile apps facilitate customer engagement, once the initial “cool factor” wears off, it is likely that the primary driver of consumer behavior remains the ability to save money.
FIGURE 19
HOME AREA NETWORK SOLUTIONS USED

27.8% Programmable, controllable thermostats
26.5% Direct load control
15.9% In-home displays
10.6% Pricing signals to connected devices
33.3% None of these
23.3% Other / I don’t know

Source: Black & Veatch
Respondents were asked to select the home area network solutions being used by their utility to support demand-response programs.

FIGURE 20
RESPONSE TO CONSUMER PARTICIPATION IN DEMAND-SIDE MANAGEMENT

24.9% Actively working with customers/vendors to increase penetration of smart thermostats via subsidies/incentives via customer communications and marketing
14.3% Supporting deployment of smart thermostats, but not actively informing customers
35.7% None of these
25.2% Other / I don’t know

Source: Black & Veatch
Respondents were asked how their utility was responding to greater consumer participation in demand-side management through technologies such as smart thermostats.
DISRUPTIVE SOLAR

In areas where utility bills are historically low or small in relation to rents/housing costs, customer engagement can be a challenge. The natural tendency for households to try and save money declines when the stakes drop. However, in many high energy cost areas, the desire to save is propelling the rapid expansion of third-party solar leasing companies that are capitalizing on strong customer trends and a favorable regulatory environment. Unlike direct purchase-and-install providers, rooftop solar leasing companies own the system installed on the customer roof and effectively replace part or all of the customer’s utility bill.

This loss of revenue, coupled with the prevalence of net metering regulations that allow customers whose systems “overproduce” electricity to feed it back into the grid at a set price, has raised concerns about the long-term prospects among some industry analysts and issues of subsidization and rate equity (Figure 21).

FIGURE 2
NET METERING FOR SOLAR GENERATION

45.5% A subsidy to the customer generator impacting utility financial results

18.1% A net benefit to the utility

8.3% Not a subsidy to the customer generator

3.8% Other

24.3% I don’t know / I haven’t studied the issue

Source: Black & Veatch
Respondents were asked to select the phrase that best described their sentiments about net metering for customer-installed solar generation.
In this environment, many industry observers call for greater engagement of customers, including the extension of the relationship beyond the meter or the segmentation of customers based on usage into differing service-level tiers. While conceivable for unregulated market participants, these calls overlook clear regulatory mandates that preclude the launch of services supported by regulated revenue or customer information.

With that in mind, to strengthen their relationships with customers, utilities need to make the economics of engagement worthwhile. This will vary by region and by the energy use and leverage technology that is increasingly in place. Some steps include:

- Actively focus on developing incentives and programs that will drive consumers to use enabling smart technologies. This may require utilities to seek help or collaborate in designing programs.

- Look at enabling technologies and determine the goals – What are they enabling customers to do? Do they enable consumers to actively manage their use patterns? If so, why? Are they targeting consumer behavior because the customer is environmentally focused or are they responding to a message from the provider? For utilities with a critical peak problem that have to buy expensive power to meet peak demand, credits to shave peak usage could drive participation. If the challenges are baseload, credits could be issued to promote energy efficiency.

- Get proactive on renewables – To this point, many utilities have been in a reactionary mode to renewable deployments. The rooftop solar market has expanded rapidly around them. Given the likelihood of greater renewable penetration, what is the utilities’ plan to embrace renewables? Can they support distributed generation versus simply making the approval process easier? Are there opportunities to use distributed generation as a means of adding capacity in high growth areas in lieu of running new distribution lines? With little downside for consumers and advances in storage technology looming, there is a need to work with regulators on a host of issues including differing energy rates in high density areas.

As consumers take a greater role in managing their home energy usage and transition to consumers/producers, utilities must understand that they do not necessarily need to focus on consumer-enabling technology, they need to encourage what the technology empowers the customer to do.

**TO STRENGTHEN THEIR RELATIONSHIP WITH CUSTOMERS, UTILITIES NEED TO MAKE THE ECONOMICS OF ENGAGEMENT WORTHWHILE.**
Perspective:
Rising Public Expectations in Indonesia Set Tone for Evolving Electric Utility Service

BY JIM SCHNIEDERS, VICE PRESIDENT & PRESIDENT-DIRECTOR BLACK & VEATCH, INDONESIA

Indonesia is at an exciting moment in its development. As I write, people throughout the world’s third largest democracy are casting votes to determine the nation’s next president.

Among many challenges facing the new president is a significant infrastructure gap. Across the vast and complex archipelago, electrification rates, for example, are well below ideal levels and have suffered from historic under-investment. Remote areas face the biggest catch-up challenge. Pressure is mounting in Indonesia to close this gap. With half of its 250 million people under 30 years of age, alongside a growing and more affluent society, expectations for greater levels of public and utility services are rising.

In recent days, for example, a major consumer advocacy group* spoke out in national newspapers about the social impact of electricity shortages in North Sumatra and Aceh. The chronic power outages during the fasting month of Ramadhan have disrupted Muslims’ fasting as current blackouts were affecting Buka Puasa (breaking of the fast), Tarawih evening prayer and the pre-dawn meal.

Regardless of who wins the elections, the presidency must tackle the electricity power supply issue. Historic fuel and electricity subsidies continue to burden current-account balances. In 2013, IDR 199.9 trillion (US$ 18.0 billion) was allocated from the Government budget to petroleum product subsidies and IDR 100.0 trillion (US$ 9.0 billion) to electricity subsidies. The total expenditure budget set for 2014 is IDR 282.1 trillion (US$ 25.4 billion). Taken together with high international crude prices and a weak exchange rate for the Indonesian rupiah, there is a growing appetite for subsidy reform to help steer the economy, invest in more infrastructure and advance Indonesia’s next phase of growth.**

We are already seeing some examples of progressive reform. New electricity tariff regulations were signed in April, which will see more costs for developing needed power infrastructure passed onto large industrial electricity consumers. For example, the government has decided to raise the tariff for exchange-listed companies in medium-scale industries — classified as “Tier 3” consumers — by nearly 40 percent, while the tariff for large-scale industries — classified as “Tier 4” consumers — will rise by more than 60 percent. From June, these changes are due to be implemented in stages every two to four months until December 2014 and will be determined based on inflation rates, currency exchange rates, and oil prices.

From a utility perspective, as well as improving its top line, these changes could also have positive effect on managing the growth in electricity demand on an already maxed-out electricity grid. Robust economic growth in recent years, particularly from industrial belts in developed areas of Java and Sumatra, has put additional demands on the grid. The significant tariff adjustments

* The Consumer Advocacy and Protection Institute (LAPK) were quoted in Jakarta Post on July 8th
could encourage more independent power producer developments as well as large-scale electricity consumers to develop their own small-scale, captive power solutions to serve their own needs as well as potential sales power to the grid.

The thriving mining industry in Indonesia, for example, is also facing other regulation changes under the 2009 Mining Law which could see how it sources and provides for electricity needs evolve. The Law is intended to curb exports of unprocessed mineral ore over time, requiring processing to be conducted onshore. This means that mining companies must develop onshore smelting facilities, increasing the mining companies’ electricity demands, and together with the recent electricity tariff increase, create a strong case for developing their own captive power facilities.

Indonesia’s electricity landscape will also see other developments in the near future, which will help reduce the country’s use expensive diesel-fired power facilities and further diversify its power generation fuel mix. One of Indonesia’s inherent strengths is that the country can point to vast and yet-to-be-tapped natural resources. Indonesia is estimated to be sitting on 40 percent of the entire world’s geothermal resources. With its crude production in decline, the importance of developing Indonesia’s natural gas resources for export and domestic use is also rising, and more than 1,000 potential renewable hydropower sites have also been identified. Recent legislation (i.e. Presidential Decree no. 28/2011 and revision to Geothermal Law no. 27/2003) is making headway to support easier approvals and access to untapped geothermal resources.

How fast we see these developments pull through and play out in full effect is a different question that must be answered by the new administration. What is more certain is that the challenge of delivering the new infrastructure to catch-up on Indonesia’s current power supply deficit and meet its anticipated future demand remains steadfast. The new administration will need to navigate a more demanding civic society, an industrial base which must remain competitive, an investment community who will favor regulatory stability as well as other well-documented issues such as those surrounding land acquisition.
Technology has changed the nature of our critical power and data infrastructure. Transformative technologies such as automated metering and advanced smart grid tools, as well as new or expanded connections between existing transformers, utility automation, and supervisory control and data acquisition (SCADA) systems require utilities to harden complex and increasingly vulnerable networks. For proof, one need look no further than the rapid rise of cybersecurity to number four among the Top 10 industry issues from a number six ranking in 2013.

This rise comes on the heels of headline-grabbing cyber incidents, planned facility assaults and a decision by the Federal Energy Regulatory Commission (FERC) to adopt the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Version 5 standard for cybersecurity in April 2014. This decision was followed by a late-May 2014 action to adopt NERC CIP-014 to develop reliability standards to address heightened risks due to physical security threats and vulnerabilities.

While the concept of asset security is not new, investments in generation, transmission and distribution to ensure reliability are typically the primary focus of capital spends. One year ago, cybersecurity was identified as an area of concentration for major investments by only 1.7 percent of survey respondents. Physical security was not even polled.

The new standards aimed at improving the resiliency of critical network operations in electric generation and transmission systems from cyber and physical security threats appear well timed. Respondents indicated that nearly half (Figure 22 and Figure 22.1) do not have integrated security systems with greater progress among investor-owned utilities (IOUs) compared to small-to mid-sized public, cooperative and independent providers.
Respondents were asked if the expanded definition of “infrastructure protection” to include cyber, physical, corporate and control system environments and the increasingly integrated nature of infrastructure protection systems would cause additional operational security risks.

Source: Black & Veatch

FIGURE 22.1 INFRASTRUCTURE PROTECTION

<table>
<thead>
<tr>
<th>Infrastructure Protection</th>
<th>Total</th>
<th>Publicly Owned</th>
<th>Investor Owned</th>
<th>Cooperative</th>
<th>Independent</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yes, our security systems currently do not integrate across the environments and doing so will be costly and cause additional operational security</td>
<td>48.1%</td>
<td>55.2%</td>
<td>37.6%</td>
<td>50.8%</td>
<td>52.4%</td>
<td>50.0%</td>
</tr>
<tr>
<td>No, our security systems are already somewhat integrated and well managed across all environments with proper segmentation, monitoring and redundancies</td>
<td>31.7%</td>
<td>28.4%</td>
<td>38.4%</td>
<td>27.0%</td>
<td>31.0%</td>
<td>28.6%</td>
</tr>
<tr>
<td>I don’t know</td>
<td>20.1%</td>
<td>16.4%</td>
<td>24.0%</td>
<td>22.2%</td>
<td>16.7%</td>
<td>21.4%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch
PROTECTING INFRASTRUCTURE FROM PHYSICAL ATTACKS IS ALSO A KEY AREA OF CONCERN FOR UTILITIES.
This lack of adequate physical security funding is driven by several factors. First, utilities are mandated to deliver reliable service and comply with environmental regulations. Second, previous versions of CIP have called for reliability but have not mandated some level of physical security protection and compliance. In addition, the outlook of nearly 50 percent of respondents is that physical asset attacks will either stay the same or decrease (Figure 23). Without a regulatory mandate to increase investment in security or a clear-cut mechanism for obtaining rate relief from local public utilities commissions (PUCs), limited load growth and rate flexibility have hampered “non-core” investments.

As awareness and publication of cyber threats have grown, several PUCs have taken steps to require the expanded adoption of cybersecurity controls addressing all assets that are able to “communicate” and talk across networks. These include essential functions such as enterprise asset management (EAM) systems, document and media data management systems, outage management systems and customer management systems, often running on the same logical network without logical segmentation or physical separation. To comply with these standards, cybersecurity plans will likely not just be limited to what impacts the bulk electric system but the corporation as a whole.

While well intentioned, in some cases, the problem with these limited actions falling to state PUCs creates a chaotic environment for the many multistate entities providing electric service. For instance, on the transmission side, many utilities, particularly small- to mid-sized operators, have yet to deploy robust NERC CIP programs and, therefore, will struggle to meet the guidelines of Version 5. One such example involves the many small transformers and devices that often are not top of mind in terms of threat assessments.

**FIGURE 23**

**PHYSICAL ASSET SECURITY**

- **42.3%** Increasing. I feel there will be more attacks, and security investments and requirements should be substantially increased
- **46.0%** Remain the same, do not see increases to physical risks or attacks and spending should remain stable
- **6.6%** Decreasing, facilities were built with security features and attacks to the physical environments remain the same, there is no more publicity of the stacks
- **5.0%** I don’t know

Source: Black & Veatch

Respondents were asked to select the statement that best described their opinion about whether the risks of physical attacks are increasing and whether there should be greater emphasis on the protection of critical assets.
Under the new standard, once overlooked assets will require additional funds and technical solutions to protect. The scale of the task is compounded by the lack of expertise and rigorous compliance and management programs within many organizations. Only 37 percent of respondents stated a belief that their cybersecurity plans were above average (Figure 24). Further, a great deal of industry experience is at or near retirement age, and new staff may not have the skill set to address these evolving challenges.

Given these hurdles, there will be a lot of infrastructure deployed to address the specific systems like the network communications, software applications, network and patch management that are drawn out in more detail in Version 5. For example, what is a protected cyber asset? Version 5 identifies distinctions between a “critical” cyber asset and a “protected” cyber asset in the electronic security perimeter of a bulk electric system. Everything connected to the network now needs to be protected, at minimum, by a firewall.

Considerations such as employee safety, customer data privacy and protection, and network resiliency are garnering new levels of regulator and insurance industry scrutiny. However, the physical disposition of the asset base also creates significant issues for launching security programs.

Unfortunately, given the myriad of evolving challenges facing many utilities, including aging infrastructure, disruptive changes in generating fuel and elements of regulatory uncertainty impacting cost recovery, many utilities will struggle to implement compliance programs that at the moment have financial teeth.

So what are the alternatives? Shut down assets that would be costly to protect? Unfortunately, those assets are often critical to delivering reliable service. In 2009, industry estimates called for upwards of $50 billion in spending on cyber assets with $15 billion to 18 billion for utilities. This figure has not changed, but many utilities do not have the financial wherewithal to make this expenditure, plus there are challenges associated with PUCs for rate recovery.
In a sense, foresight is forearmed. In an environment where threats are both real and virtual and physical damage can be triggered by natural forces or nefarious intent, the best approach is preparedness. Since CIP-014 was adopted, Black & Veatch has seen the number of requests for security assessments increase. Once conducted, organizations can prioritize investments using risk-based standards such as the published National Defense Industrial Association (NDIA) Responsibility Assignment Matrix (RAM) processes and National Institute of Standards and Technology (NIST) frameworks, which, as an added benefit, provide justification information that may help utilities in making a rate case with their local PUC.

There is not a single solution, but with an approach that addresses the physical elements of cybersecurity and the cyber elements of physical asset security, organizations will be better equipped and educated to manage the full spectrum of dangers.
Significant federal environmental regulations for the power generation industry are still being formulated as of this year’s survey and will have significant impacts on producers. Once again, environmental regulation ranked second only to service reliability on a national level. In addition, after the survey closed, the release of a proposed Environmental Protection Agency (EPA) rule on cutting carbon dioxide emissions from existing fossil fuel plants is creating integrated resource planning challenges for power generators. Overall, a large percentage of survey participants expressed the view that increasing regulatory compliance is the main force behind rate increases during the next 5 years (refer to Executive Summary).

**CARBON EMISSIONS**

In June, the EPA proposed a regulation that would reduce carbon emissions from existing fossil fuel plants by up to 30 percent by 2030 compared with 2005 levels. This regulation is having a major impact on electric utilities’ planning and generation approaches. The rule would establish state-specific carbon dioxide reduction goals while allowing states or regions to develop customized compliance methods. These include mixing four options: dispatching gas plant generation ahead of coal generation; energy efficiency; increasing low-carbon renewable and nuclear energy generation; and heat rate improvements to coal-fired generation plants.

Although this survey was completed before the EPA announcement, there was and will remain uncertainty among respondents on the final effects of carbon dioxide rulemaking. The rule in its current form has the potential to create a major paradigm shift for utility generation resource modeling. Under the rule, the states have until 2016 to submit their plans to the EPA for review. Compliance to the new rule will begin in 2020.

There are significant regional differences on the carbon dioxide rule’s impact on power generators. The Midwest, Southeast and Southwest would be most affected based on their significant amount of coal-fired generation. The Northeast and Northwest are primarily relying on gas-fired and hydro generation, respectively. The Northeast is taking advantage of the boom in shale gas production and has already instituted a carbon dioxide cap and trade program. Also in the Northwest, there is currently a collaborative agreement with California and British Columbia on reducing carbon dioxide emissions. The survey responses strongly reflect overall environmental regulations concern by region ranging from 53.2 percent in the Midwest to 13.2 percent in the Northeast (Figure 25).
AIR QUALITY

In May 2014, the U.S. Supreme Court reversed a lower court decision and upheld the Cross-State Air Pollution Rule (CSAPR). The Supreme Court’s CSAPR ruling gives substantial leeway to the EPA in its emissions enforcement powers. As a result, future legal challenges against the administration’s proposals to regulate carbon emissions from new and existing fossil fuel-fired power plants may have a more difficult time being successful in the federal courts. The ruling came as a surprise to many in the industry, and its concern regarding compliance is reflected in the survey results.

CSAPR allows the EPA to regulate power plant air emissions crossing state lines by using cap and trade programs. Specifically, CSAPR requires 28 states in the East, Midwest and South regions to reduce the emissions of nitrogen oxide and sulfur dioxide. Under the ruling, the EPA maintains authority to regulate nitrogen and sulfur emissions from coal plants.

Prior to the Supreme Court’s ruling on CSAPR, the U.S. Court of Appeals for the D.C. Circuit upheld EPA’s Mercury and Air Toxics Standards (MATS). MATS require coal-fired power plants to install technology to cut emissions of mercury and other hazardous air pollutants. This rule, combined with low natural gas prices, is a major factor in the number of planned coal plant retirements that will occur during the next two years.

Under the MATS ruling, many power plants have until March 2015 to meet the requirements, with possible one or two year extensions. The rule was originally proposed by the EPA to be effective in 2012. The extension to 2015 provided utilities with a window of opportunity to formulate compliance plans and begin implementation, which is lessening the overall impact going forward. Approximately 70 percent of coal-fired power plants are currently in compliance with MATS.
SURFACE WATER REGULATION
In May, the EPA finalized a new rule concerning cooling water intake for any power or industrial plant withdrawing 2 million gallons or more daily. The rule applies to more than 500 power plants. The EPA had originally proposed stringent fish mortality standards that would have required costly monitoring and compliance demonstrations. However, the final rule provides flexibility for site-specific analysis with state permitting requirements tailored to individual facilities.

New EPA wastewater regulations for steam electric generation plants are expected to be finalized in 2015. The rule establishes wastewater standards designed to reduce pollutant discharges from power plants associated with coal ash waste and flue gas desulfurization air quality controls. The ruling will provide clarity on what level of reconfiguration is necessary on the back-end operations of power plants and the resulting costs of compliance. As such, it is vital that utilities conduct in-depth planning around the various possible final rule scenarios.

COAL ASH
The EPA announced in January 2014 that it will take final action on coal combustion products standards by the end of the year. This ruling will have a major effect on the Southeast, Midwest and Southwest service regions where wet ash handling is more prevalent. The ruling will clarify whether coal ash is designated as either a hazardous or solid waste. This classification will determine the extent of making expensive investments in reworking the ash handling systems and disposal operations of utilities’ coal-fired units. The utilities’ concern over the outcome of the EPA decision increased following a February spill of 39,000 tons of coal ash into the Dan River in North Carolina.
The anticipated build out of new natural gas-fueled generation has electric industry leaders worried about the proverbial too many eggs in one basket approach. This is evident in growing concern for natural gas prices, which has jumped from seventh to fifth in Black & Veatch’s annual Top 10 industry issues ranking (refer to the Executive Summary) among utility respondents.

Electric industry leaders do not soon forget. Memories of the early 2000s, when natural gas prices surpassed $10/MBtu and even $15/MBtu (million British thermal units), still linger even though the circumstances leading up to those events are largely moot in 2014.

Most of the sharp price escalations in the early 2000s were directly attributed to weather and available supply, most notably in 2005. During this time, growing demand for natural gas to support electric generation demand and declining production from conventional supply basins combined to create a high price environment. The Gulf of Mexico was the dominant gas supply basin in the United States. Hurricanes Ivan, Katrina and Rita damaged these facilities significantly impacting supply and resulting in dramatic price increases across the nation.

Today, electric power generators still experience weather-related price spikes. However, these spikes are not attributed to lack of gas resources but constrained pipeline capacity. North America currently has more than enough natural gas supply to meet peak demands. The challenge is in available capacity to transport enough of this supply to demand centers to meet peak demand. Price spikes associated with pipeline capacity constraints are typically isolated to a specific region, such as the spot natural gas price spikes experienced in New England during the past two winters.

NATURAL GAS PRICE DRIVERS

Nearly half of electric utility industry leaders believe that liquefied natural gas (LNG) exports will raise domestic natural gas prices and utility costs (Figure 26). This is true to some extent because LNG exports are but one of the factors that will contribute to the growth in gas demand over the course of the next 25 years. Demand growth in the industrial sector and the power generation sector will also contribute to an increase in the natural gas price above current levels. Black & Veatch’s 2014 midyear Energy Market Perspective forecasts that LNG exports could reach 16 Bcf/d (billion cubic feet per day) by 2025, raising domestic natural gas prices by approximately $1/MBtu.

Black & Veatch’s most recent natural gas price forecast shows price acceleration occurring after 2020 when natural gas demand for power generation, LNG exports and industrial applications accelerates. Natural gas demand for power generation is currently approximately 23 Bcf/d and could grow to approximately 30 Bcf/d by 2020. Total power generation demand could reach 40 Bcf/d by 2035. Recently proposed federal carbon dioxide regulations, if enacted, could generate an additional 2 to 4 Bcf/d of demand.
FIGURE 26
EFFECTS OF LNG EXPORTS ON ELECTRIC INDUSTRY

48.8%  LNG exports will raise domestic natural gas prices and utility costs

31.1%  LNG exports will have a limited impact on domestic natural gas prices and utility costs

3.6%  Not applicable

16.5%  I don’t know

Source: Black & Veatch
Respondents were asked to select the statement that best represents their view on the potential impacts LNG could have to their utility.

FIGURE 27
BLACK & VEATCH NATURAL GAS PRICE FORECAST

Source: Black & Veatch
As noted within Black & Veatch’s 2013 Strategic Directions in the U.S. Electric Industry report, “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.”

Fuel supply planning involves assessing the long-term natural gas supply sufficiency within a service territory. Such an assessment typically includes analysis of supply availability and the reliability and cost of natural gas infrastructure. Gas storage, another component of fuel supply planning, can help address seasonal volatility.

In addition to assessing natural gas assets, utilities and merchant generators should also evaluate current and future competition for natural gas within their service territory. Growth in demand from industrial users, LNG exports, other power generators and increasing residential or commercial demand could all influence the long-term costs and risks of their power generation assets. Forums related to the gas-electric interdependency issues can provide additional resources for utilities and merchant generators in determining optimal solutions for firm natural gas pipeline capacity for their portfolios.
There is an interdependency between India’s economic development and the development of its energy infrastructure. For economic development to continue, infrastructure investment must continue.

Time and cost overruns, however, have become synonymous with project execution, including energy schemes, in India. Reserve Bank of India data reveal that in the last two years, more than 1,900 mega-infrastructure projects have been delayed registering an average cost overrun of 19.2 percent.

The main reasons attributed to delays in implementation are delay in land acquisition, rehabilitation and resettlement problems, delay in forest and environment clearances, impediments in supply of feedstock, inflation-fueled higher costs of inputs, and funding constraints. To ensure energy security, India’s new government needs to be aware of these problems and streamline the project approval processes to facilitate quick single-window clearances. Indications are that this is the case. Initiatives by the Project Monitoring Group to digitize the procedure of issuing clearances for megaprojects need to be encouraged as this will help in improving their timeliness in completion.

As another signal of intent, the new government is set to give a big push to India’s power capacity addition programme by putting four 4,000 megawatt (MW) ultra-megaprojects up for bidding in its first year in office.

According to the Ernst & Young India Attractiveness Survey 2014, the country was the fourth largest recipient of foreign direct investment (FDI) in terms of projects started in 2012, and in terms of value, it accounted for 5.5 percent of global FDI. Ever since, there has been a marked decline. The trillion-dollar investment target in the infrastructure sector of India, set by the Planning Commission during the 12th Plan period (2012 – 2017), 50 percent of which was expected to come from private players, looks distant as the country failed to attract new investments. Therefore, to help ensure energy security, it is essential for bidding norms for infrastructure projects in India to be transparent to infuse confidence and create a level playing field for not just domestic players but also for foreign players who can play a major role in building India’s energy infrastructure.

Power tariffs should be rationalised to capture the cost of generation and transmission. The new government cannot continue to subsidise power and needs to take a practical viewpoint on the power tariff issue. On the transmission and distribution side, the challenges of poor operational efficiency and high aggregate technical and commercial (AT&C) losses need to be addressed with urgency through the usage of smart metering, which would ensure better financial health of the distribution companies.

India’s feedstock portfolio is another area in which we anticipate change in the short to medium term. India is the fourth largest energy consumer in the world and, due to limited domestic feedstock production, is heavily dependent upon imports. The country’s feedstock portfolio is dominated by coal and oil, which in 2012 jointly accounted for 84 percent of generators’ needs. The remaining feedstock is a mix of gas, nuclear, hydro and renewables.

While coal will continue as a viable feedstock, the need for the greater efficiency offered by supercritical plants will continue to grow. In addition, we see the importance of renovation and modernisation (R&M) to increase
efficiency of existing coal and oil units, recover lost
capacity and efficiency, and promote better operations and
maintenance practices. R&M presents a significant market
opportunity in India.

Use of liquefied natural gas (LNG) as a feedstock is likely
to see the most significant change in both the short and
medium term. Although it is a relatively low proportion
(9 percent in 2012) of the feedstock portfolio, gas is likely
to grow in importance. Current gas requirements of 197
million cubic metres per day are forecast to reach 467
million cubic metres per day by 2030.

It is estimated that India holds less than 1 percent of
the world’s natural gas reserves, and tapping them has
not progressed as desired. Although importing gas via
pipelines from energy rich countries would result in an
uninterrupted supply of gas, it is not a viable option in
the short term because of implementation challenges
stemming from prevailing geopolitical scenarios.

This makes importing LNG the most attractive short- to
medium-term option. India is the world’s fifth largest
LNG importer behind Japan, South Korea, Spain and
China. Levels of imports are likely to grow such that some
forecasts place India as the world’s second largest LNG
importer by 2017.

With India’s energy demand expected to more than
double by 2035, from less than 700 million tonnes of oil
equivalent (MTOE) today, a focus on renewable energy to
help bolster India’s energy security is likely under the new
government.

In addition to solar generation, it is likely the BJP-led
government will create an environment that will foster
investment in other renewable technologies such as
offshore wind. Hydel, which in some countries falls under
the renewable portfolio, is well established in India and
as such treated separately from more recently adopted
technologies such as solar and wind. In 2012, renewables
accounted for 2 percent of India’s energy consumption,
with hydro providing an additional 4 percent.

Nuclear power plants generated 1 percent of India’s
energy consumption in 2012, at 7.5 MTOE. In an
interesting illustration of how the country’s energy
demand has grown, nuclear generation’s percentage of
consumption in 2005 was the same in 2012. In terms
of energy generated, however, the figure has virtually
doubled to 7.5 MTOE during that period. We expect the
amount of energy generated by India’s nuclear sector to
continue to grow.

This is a period of great potential growth for India’s energy
sector and a period of change. Whether the changes are
good, and enable the sector to deliver upon this potential,
depends to a great extent on the new government. Initial
signals are that the government is willing to address
the challenges the country faces as we commence
the premiership of what The Economic Times recently
described as India’s “first energy literate Prime Minister.”

In part, this belief is based upon Prime Minister Narendra
Modi’s tenure as Chief Minister for Gujarat. During this
time, he oversaw the creation of more than 900 MW
of solar capacity in the state. In addition, his party, the
Bharatiya Janata Party (BJP), has had a Non-Conventional
Energy Cell for a number of years. The cell is currently
active in just a few states: Maharashtra, Gujarat and
Odisha. It is expected, however, to be expanded across the
country, with district level units. These units will provide
inputs to the Minister for New and Renewable Energy.
One year ago, the Black & Veatch Strategic Directions in the U.S. Electric Industry report reflected an industry in transition. Just 12 short months later, we find an industry at a crossroads because of the accelerating impact of new technologies, regulation and external market forces. To provide a deeper understanding of how the industry views these developments, this report strives to address each subject with a focus on how it relates to the traditional areas of utility operations, power generation and power delivery.

With more than a century of consistent, reliable service, even slight shifts in the Top 10 industry issues represent a major happening. Year in and year out, electric utilities’ mandate to deliver “always there” service kept reliability as the industry’s top concern. It remains so in 2014. Meeting this goal in the face of changes in environmental and economic regulation closely followed. But, this year we saw significant shifts in concerns over cybersecurity and natural gas prices, two areas that are relatively recent entrants to the list. This is likely due to extended coverage of high profile incidents and the expanded role of gas in the generation mix.

These shifts, along with rising challenges to the traditional utility/customer delivery model are forcing decision-makers to explore alternative ways to plan for their short-, medium- and long-term futures. Now more than ever, new technologies with the capability to impact customer usage are available and being leveraged to achieve operational objectives. Similarly, utilities are realizing tangible benefits from their own embrace of technology.

From a markets perspective, the interconnection between fuel sources and supply, regulation and finance are coming to a head. Given high levels of regulatory uncertainty, many capital projects were delayed over the past several years pending resolution in the courts. At the time of this writing, the Environmental Protection Agency (EPA) had announced its state by state targets for an overall 30 percent reduction in carbon emissions, and the Supreme Court recently upheld the EPA’s ability to regulate 83 percent of greenhouse gases emitted by stationary sources, like power plants. The likely impact of these decisions will be greater adoption of natural gas, renewables, hydro and nuclear power as the available resources and economics of each technology are weighed.

Even this seemingly straightforward conclusion is wrought with complexities. As dozens of older, coal-fired plants come off-line in the years ahead, questions remain about how to replace lost capacity. Natural gas plants, powered by low-cost domestic resources, built faster and more economically than other traditional technologies, and with the ability to cut greenhouse gas emissions, are increasingly the primary option for new builds and conversions for many utilities.

With this in mind, some in the industry anticipated 1 megawatt for 1 megawatt replacement levels, but a look at the infrastructure required to support a natural gas plant, accelerating renewables integration and the rise of distributed generation can help to explain the challenges faced on both sides of the regulatory compact. Regulators, examining reserve margins, pipeline constraints, demand-response programs and energy efficiency measures may not be inclined to approve ratepayer funded projects at that level.
On a regional basis, the industry is already facing challenges to its model from the rapid deployment of rooftop solar and wind resources. Coal retirements have little impact on much of the West Coast, yet vast renewable resources, including rooftop solar are creating bifurcated consumer markets. Increasingly, those consumers with the resources to adopt rooftop solar are doing so, those without are not.

This is creating a scenario in which the costs to maintain and upgrade an aging electric grid trend upward while potential revenue as measured by anticipated demand decreases. As storage technology improves and costs drop, many homes will conceivably go off-grid. To remain not just financially viable, but to address growing concerns, many utilities may need the regulatory flexibility to transition to a model of service integration where they manage the grid and provide a mix of power and services using dynamic pricing tied to market fluctuation.

The driver for all of these changes is technology. The Black & Veatch Strategic Directions: Utility Automation & Integration report covered how utilities are managing intelligent technologies. Advanced metering infrastructure (AMI) and analytics, however, are but one piece of this new reality, especially considering how technology is affecting the industry in other ways. For utilities managing environmental regulations, this could mean leveraging more advanced real-time air quality monitoring. With regard to natural gas, advances in liquefaction and extraction are creating potential new markets for U.S. exports. This creates a dynamic new earning paradigm, but may also raise domestic natural gas prices. In the long term, increases in gas prices will encourage efficiency and renewables integration and investment in domestic infrastructure.

Technology is also enabling utilities to more fully embrace asset management programs. This requires a fundamental shift from viewing asset health to a risk-based model that includes technology readiness. Risk-based calculations might account for an increased pace of innovation and more rapid technology cycles. Formal risk-based planning, backed by data, also affords greater opportunity to support capital planning before regulators. With resiliency planning a growing area of concern, technology can help identify and remediate key areas of weakness.

Consumer expectations and engagement remain evergreen. However, today’s utility consumer expects a more “high touch” experience with hallmarks that include customization of services and multiple points of contact with providers. This new interest, in what was before rightly characterized as more passive engagement, if used correctly, can assist electric utilities in meeting efficiency and conservation goals.

As the business transforms so too does its workforce. Black & Veatch does not normally include demographic information in our analysis. However, it is worth mentioning that a full 70 percent of utility respondents have been working in the industry for 20 years or more. Retirements aside, creating opportunities within utilities to attract technology savvy, nontraditional candidates to the field will be immensely important. Likewise, the ability to leverage massive computing power will not eliminate the need for skilled labor and technical workers to manage physical assets.

With such a large percentage of the industry at or nearing retirement age and technology deployments occurring at such a rapid pace, planning for skills training and knowledge transfer is imperative. Just as customers seek to embrace innovative technologies, there must be room for the expansion of recruitment in the trades and focusing on the builders who will do the physical work to upgrade the day-two grid. Given the significance of these results, we expect to more fully explore this challenge, including a focus on gender, in future reports.

It is difficult to address change without making a nod to cycles. The precursor to the current U.S. electric grid was Pearl Street Station in New York City. Established in the late 1800s, its model was replicated across the country until market forces came into play. Consolidation, regulation and competition followed. One cannot help but make comparisons to today’s environment: smaller, localized generation; collaboration and consolidation; regulation; and competition from non-utility actors. Preparedness will require agility, awareness and a willingness to learn the lesson from past cycles. With the benefit of technology, utilities are better able to understand their environment and act accordingly.

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