Backed by a survey of more than 600 power sector stakeholders, Black & Veatch's 2020 Strategic Directions: Electric Report details an electric industry waging a sweeping transformation, much of it propelled by the rising tide of renewable and distributed energy and how to best integrate it into the grid.

Challenges — and opportunities — abound in this constantly shifting, complex ecosystem of everything from conventional power generation to energy derived from the sun and the wind, and the growing use of microgrid systems. Hydrogen is widely expected to make a star turn over the next decade with help from advances in battery storage.

The quest for sustainability, reliability and resiliency continues to drive utilities and power developers toward broader investments in decarbonization, some more quickly than others, as more states, counties and countries impose mandates that power sources become cleaner and greener. The proliferation of electric vehicles is adding to the pressure to meet added charging needs and respond to increasingly empowered, emboldened consumers.

All the while, regulation remains a focus area even as the integration of generation, transmission and distribution assets takes a stronger foothold and utilities find new ways to make their aging systems more resilient against severe weather shocks and a changing climate. The COVID-19 pandemic proved to be an unforeseen complication, in many cases shifting power loads to residential suburbs and away from commercial and industrial sites that have been forced to shut down to stem the virus' spread.

This report takes the industry's pulse on those issues and more, using survey findings and thoughtful analyses to paint a clear picture of a power sector repowering itself, modernizing with new technologies and concepts about better ways to keep the power flowing to industry, businesses and homes.

We welcome your questions and comments regarding this report and Black & Veatch services. You can reach us at MediaInfo@bv.com.
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2020 Report Background
Executive Summary: As the Power Sector Transforms, Opportunities Rest With Embrace of Renewables, Modernization

By Mario Azar
From the Atlantic Coast of the U.S. to Asia and all parts of the world, evolution of the global electric industry has been rapid, relentless and most certainly complex.

Renewable energy drawn from solar and wind, both on land and offshore, continues to accelerate, resulting in the world’s power providers needing to thoughtfully invest in ways to accommodate it on the grid. Calls for a decarbonized electric sector are rising to a crescendo from activists, shareholders, states and countries, many of them already having set ambitious green energy mandates. More than ever, there exists a need for a balanced portfolio that spans fossil fuels and cleaner, more environmentally friendly options, with an eye toward battery storage and hydrogen — a rising star in the next frontier of power generation.

All the while, regulation continues to create new dynamics, and traditional methods of simply operating a power utility with generation, transmission and distribution assets separately are giving way to a more integrated approach. Electric vehicles (EVs) and electrified fleets — everything from buses to industrial trucks and equipment and enterprise cars — are growing in numbers, pressuring power providers to meet charging needs.

After 130 years, the power industry is being repowered as sweeping changes are guiding more focus for a consistent, methodical adoption of innovative practices to ensure the sector’s relevance. And as assets become increasingly distributed across utility networks and owned and operated by third parties, management of the grid is becoming more localized, demanding rigorous attention.

Now more than ever, consumers expect their power providers to be progressive and proactive, further emphasizing the need for reliable, resilient energy supplies.

Our latest Strategic Directions: Electric Report — backed by a survey of more than 600 power utility stakeholders — offers a clear picture of the challenges and opportunities that come with such transformation.
Across the landscape, some things haven’t changed. Aging infrastructure remains the chief focus area among one-third of respondents, down 13 percentage points from a year ago. But the issue of renewables remained the secondary attention grabber, relatively unchanged from 2019 with more than one-quarter of survey-takers (Figure 1). Geographically, while aging infrastructure universally was the top challenge among three in 10 respondents in the Northeast, South and West, renewable energy was top of mind in the Midwest at 32 percent.

But while the undeniable sweep of change — much of it centered around the quest to lower the carbon footprints of power generation — is rattling the industry, utilities are finding that reducing emissions through renewables doesn’t necessarily compromise resiliency and reliability.

Power providers are developing technology transformation strategies and roadmaps, business cases and regulatory blueprints to support sustainability objectives and unlock new business models that such makeovers offer. By combining these technologies, resiliency and reliability can be delivered and perhaps bolstered beyond traditional norms.

These themes are explored in this year’s report, along with a litany of weighty topics:

- **Power Transmission:** With the push for decarbonization, the expansion of renewable energy — both at scale and local, combined with reliability concerns tied to the aging, long-term shifting utilization of the grid — is changing how investment dollars are allocated across the system. So how does that change ripple back to the multibillion-dollar buildout of renewable generation?

---

**Figure 1**

*From your perspective, what are the most challenging issues facing the electric industry in your region today? (Select the top three most challenging issues)*

<table>
<thead>
<tr>
<th>Issue</th>
<th>2019</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aging infrastructure</td>
<td>43.6%</td>
<td>33.4%</td>
</tr>
<tr>
<td>Renewables</td>
<td>27.1%</td>
<td>26.2%</td>
</tr>
<tr>
<td>Aging workforce</td>
<td>28.8%</td>
<td>24.1%</td>
</tr>
<tr>
<td>Distribution system upgrade and modernization</td>
<td>not asked</td>
<td>21.8%</td>
</tr>
<tr>
<td>Environmental regulation</td>
<td>25.8%</td>
<td>21.6%</td>
</tr>
<tr>
<td>Cybersecurity</td>
<td>27.8%</td>
<td>21.2%</td>
</tr>
<tr>
<td>Energy storage</td>
<td>20.5%</td>
<td>19.9%</td>
</tr>
<tr>
<td>Economic regulation</td>
<td>24.2%</td>
<td>16.5%</td>
</tr>
<tr>
<td>Distributed energy resources</td>
<td>17.4%</td>
<td>15.0%</td>
</tr>
<tr>
<td>Reliability</td>
<td>15.2%</td>
<td>12.3%</td>
</tr>
<tr>
<td>Market structure</td>
<td>21.3%</td>
<td>11.6%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch
**Emerging Technologies:** As the power industry responds to changing consumer behaviors, unpredictable load patterns and an increasing use of distributed energy resources (DER) and other customer-driven nuances are transforming technologies. Innovation increasingly is based on digital information and communication technology, including artificial intelligence, augmented and virtual reality, blockchain technology and robotics. However, the continued advancements in hydrogen, battery energy storage systems and small module reactors also are explored in the report.

**Rules and Ratemaking:** While one of the power industry’s great advantages should be clarity in its business activities, focus on the regulatory side is deepening as the sector’s decision-makers adapt to an increasingly competitive energy marketplace that appears to bring more unknowns by the day.

**The Road to Renewables**

The U.S. Energy Information Administration is predicting that solar and wind energy will dominate American generation in 2020, accounting for three-quarters of all new generation. Coal-fired power production, which last year plunged to its lowest level in more than four decades, is anticipated to continue its decade-long slide, dropping by an additional 13 percent in 2020.

Reflecting that surge of renewables — and their pivotal place in an evolving energy picture — nearly half of respondents to Black & Veatch’s survey say they’re committing much more or somewhat more investment in local renewables at least in the short-term. That outpaces capital spending on such things as distribution, transmission and other DER.

That expected buildout gets more telling over the next five years, with eight of 10 respondents forecasting that more of their spending in new generation capacity will be directed at solar arrays on land, followed closely by energy storage (79 percent) and eventually microgrids and other DER (65 percent). Financial commitments to coal-fired generation ranked last, with just 3 percent planning to boost their spending but 60 percent anticipating “much less” funding (*Figure 2*).

At least in the near-term, the survey shows, abundant, competitively priced natural gas is expected to remain a key part in the power generation equation — most likely as a backup, covering for the intermittency of solar and wind energy — as coal usage continues to decline.
**Figure 2**

For each of the following categories, how do you expect new generation capacity investments to change over the next five years in your region? *(Select one for each row)*

*Source: Black & Veatch*

<table>
<thead>
<tr>
<th>Category</th>
<th>Much more investment than today</th>
<th>Somewhat more investment than today</th>
<th>Same investment as today</th>
<th>Somewhat less investment than today</th>
<th>Much less investment than today</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar (on land)</td>
<td>42.7%</td>
<td>39.1%</td>
<td>13.6%</td>
<td>3.3%</td>
<td>1.3%</td>
</tr>
<tr>
<td>Solar (floating)</td>
<td>9.8%</td>
<td>31.1%</td>
<td>40.9%</td>
<td>8.8%</td>
<td>9.5%</td>
</tr>
<tr>
<td>Energy storage</td>
<td>36.6%</td>
<td>41.9%</td>
<td>17.8%</td>
<td>2.7%</td>
<td>1.0%</td>
</tr>
<tr>
<td>Microgrids and other DER</td>
<td>22.6%</td>
<td>42.2%</td>
<td>26.4%</td>
<td>5.4%</td>
<td>3.4%</td>
</tr>
<tr>
<td>Wind (on land)</td>
<td>17.9%</td>
<td>41.2%</td>
<td>31.4%</td>
<td>7.4%</td>
<td>2.0%</td>
</tr>
<tr>
<td>Wind (offshore)</td>
<td>16.9%</td>
<td>32.9%</td>
<td>35.3%</td>
<td>9.2%</td>
<td>5.8%</td>
</tr>
<tr>
<td>Gas-fired / LNG-to-power</td>
<td>8.8%</td>
<td>29.9%</td>
<td>37.1%</td>
<td>19.4%</td>
<td>4.8%</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>7.1%</td>
<td>19.3%</td>
<td>56.3%</td>
<td>9.8%</td>
<td>7.5%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>2.0%</td>
<td>14.2%</td>
<td>36.3%</td>
<td>24.4%</td>
<td>23.1%</td>
</tr>
<tr>
<td>Coal-fired</td>
<td>0.3%</td>
<td>2.4%</td>
<td>13.5%</td>
<td>23.6%</td>
<td>60.1%</td>
</tr>
</tbody>
</table>
Hydrogen, Battery Storage Essential to the Scenario

In many countries, utilities have been aggressive in melding hydrogen into their generation mixes, using electrolysis technology that culls the element from water.

But in the U.S., as Black & Veatch’s survey results show, deployment of that gas as a power source is still developing, perhaps because of its relative novelty. More than four in 10 respondents said they would consider hydrogen for fuel cell storage, nearly double those who cited its potential use for transportation fuel for fleets and as an option for peak generation. Fewer than one-fifth said they see it as a source of backup power or a component of a microgrid, with just 9 percent mulling it for baseload generation. Three in 10 respondents said they would not consider deploying it at all (Figure 3).

Battery storage appears to hold the key, given its utilitarian role as a veritable Swiss army knife capable of consuming, supplying, conditioning and storing electric energy. Such storage allows typically non-dispatchable resources like wind and solar energy to be used precisely when the systems need them most, helping balance load and generation across time and space. When it comes to hydrogen, advanced storage will enable seasonal shifting of renewable energy, stockpiling solar energy in the summer for use in generating power in the winter.

---

**Figure 3**

*What services would you consider hydrogen for? (Select all that apply)*

Source: Black & Veatch

- **43.0%** Fuel cell storage
- **24.1%** Transportation fuel
- **24.1%** Peak generation
- **18.9%** Backup power/component of microgrid
- **15.3%** To make a plant “greener”
- **9.2%** Baseload generation
- **29.7%** None of the above
As the costs of battery and other types of longer-duration storage decline over time, accelerated adoption should follow, making existing power plants — with their access to transmission and developed infrastructure — excellent candidates for hosting storage.

The bottom line: Integration is more than a buzzword, illustrated by the fact that power plant decision-makers are discussing how to best have their operations work collaboratively with renewables and, more deeply, pairing things like hydrogen and renewables with storage.

As more utilities and developers rethink their power generation mixes and adapt to the economic and environmental merits of renewables in an ever-changing power ecosystem, it’s incumbent that industry leaders with whom we work — along with regulators and other stakeholders — meet the demands of tomorrow’s energy mix with cleaner, greener options. Customers and solutions providers with deep experience in the engineering, construction and operations of energy assets must come together in a collaborative manner.

Resiliency, sustainability and reliability are riding on it.
Buildout of Renewables Drives Effort to Harden, Digitize Transmission Assets

By Kevin Ludwig and Jim Hendrickson

As the U.S. electric industry increasingly is being driven by decarbonization and its related impacts on the traditional grid, the expansion of renewable energy is changing how investment dollars are allocated across the system. With it comes a particularly challenging issue: how does this change ripple back to the multibillion-dollar buildout of renewable generation?

That's abundantly clear in Black & Veatch's 2020 Strategic Directions: Electric Report, where nearly four in 10 respondents — 39 percent — said the growth of renewable energy will be the key driver of new transmission investment over the next five years. That handily outdistanced resiliency and reliability, congestion, inter-regional coordination and the retirements of fossil fuel-powered plants.

Across the U.S., from the PJM Interconnection in the East to large utilities in the Midwest and PacifiCorp out West, transmission-owning utilities and transmission organizations continue to be deluged with transmission interconnection requests, most tied to remote utility-scale renewable generation. Such demand isn't expected to decline any time soon, and it could be further enlarged should proposed offshore wind power projects off the East Coast move ahead to construction.

Demand across the country for transmission projects linked to renewable energy remains robust, with survey respondents from the Midwest and West seeing the strongest demand for transmission investment tied to the growth of renewable energy (Figure 4).

Long transmission lines are the necessary connection to deliver renewable energy from the remote places where it is generated to load centers where it ultimately is used. As more and more utilities take a “green pledge” to decarbonize their fuel mixes — whether prodded or not by their constituents or regulators — more transmission lines will be needed to satisfy those goals. With increasing challenges to transmission access, existing lines at brownfield fossil sites, etc., will play a
vital role as interconnect points for storage, green power, reactive power and/or large-scale renewable with several notable examples occurring in the industry over the past year.

Industry leaders continue to voice concerns about integrating renewable generation into the transmission system, but that uneasiness gradually appears to be diminishing, particularly as more renewable generation comes online. Utilities and developers have found an orderly, safe and cost-effective way to add thousands of megawatts of new renewable generation to the nation’s grid.

Investment in a reconfigured transmission infrastructure to serve a changing generation portfolio is not the only, or in many cases, the prime issue. Another key challenge is managing current transmission assets to ensure resiliency and reliability — a tricky endeavor that requires much-improved asset condition monitoring, more sophisticated failure analyses and targeted predictive maintenance investment. Some utilities are investing in these requirements. Climate change also is driving investment, with severe weather incidents such as Superstorm Sandy in 2012 and Hurricane Harvey in 2017, and multiple hurricanes this year (Islais and Laura) having caused and will continue to result in many utilities investing heavily to “harden” their transmission and distribution (T&D) systems. In the West, destructive wildfires also are accounting for transmission upgrades, both to rebuild lines damaged or destroyed by flames or to find more resilient, reliable ways to keep the lights on.

Figure 4
What do you expect to be the key driver for new transmission investment over the next five years?
(Select one)

Source: Black & Veatch

A) 38.6% Renewables growth
B) 27.9% Resiliency and reliability
C) 11.7% Congestion
D) 10.7% Inter-regional coordination/integration
E) 10.4% Fossil retirements
Nearly four in 10 — 38 percent — respondents still said they have increased plans to invest in transmission projects more than last year. Approximately half said they have not changed their transmission investment plans over 2019. All the while, nearly half of those who plan to reprioritize capital spending to existing assets will direct those investments to their transmission and distribution systems. But there’s a distinct drive to digitization among those who plan to divert spending to existing infrastructure. A significant number of respondents said they would invest in some type of technology upgrade, including automating operations (35 percent), increased remote monitoring and diagnostics (23 percent) and conversion of analog systems to digital systems (20 percent) (Figure 5).

Of course, upgrading T&D systems also could have a digital dimension, as substation and transmission upgrades often include migration to microprocessor-based technology, fiber optic communication and enhanced monitoring of assets to ensure existing assets are utilized effectively. Digital substations also are being deployed with some northeastern utilities moving from pilot projects to large-scale implementation of digital substations.

Site permitting remains the biggest hurdle to new transmission investment, along with evolving incentives policies and return-on-equity determinations for new transmission construction. President Donald Trump’s July decision to streamline the National Environmental Policy Act (NEPA) to make it faster and easier to construct more energy infrastructure could address these concerns, though the new rule is widely expected to be litigated.

Respondents overwhelmingly found that FERC’s Order 841, which introduced battery energy storage systems (BESS) to the wholesale energy markets, would have a positive impact on transmission investment over the next five years. That order recently was upheld by a federal appellate court. While some market participants see BESS as a partial alternative to efforts to build new transmission, it won’t be a one-for-one replacement for resolution of all transmission constraints. However, recent acceptance by FERC of MISO’s proposed modification of their OATT for storage as a transmission only asset (SATOA) certainly opens up additional interest in BESS’s role in the transmission marketplace.

**Figure 5**

You selected re-prioritizing investments to existing assets. More specifically, where do you see this investment going? (Select up to three)

Source: Black & Veatch

<table>
<thead>
<tr>
<th>Percentage</th>
<th>Investment Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>48.6%</td>
<td>Upgrading transmission and substations</td>
</tr>
<tr>
<td>35.1%</td>
<td>Automating operations</td>
</tr>
<tr>
<td>31.1%</td>
<td>Meeting new and future environmental compliance requirements</td>
</tr>
<tr>
<td>28.4%</td>
<td>Replacement or upgrade of existing generating units</td>
</tr>
</tbody>
</table>
On the subject of bulk electric supply security, which the Trump administration sought to make more secure with a May 2020 executive order, more than one-third of respondents — 36 percent — said they were taking a wait-and-see approach until the Department of Energy issued a proposed regulation. Slightly less than one-third said they actively were auditing equipment directly purchased from vendors, while roughly one in five said they were auditing the supply chains of contractors (Figure 6).

But there remains considerable uncertainty over what equipment is included in the executive order along with what definitive action will be required once the supply chain impacts from “adversarial” countries are understood.

There also are additional potential impacts to the transmission supply chain with a Section 232 investigation to be conducted under the authority of the Trade Expansion Act of 1962. Preliminary reports said the Section 232 inquiry would focus on grain oriented electrical steel (GOES), which is a key component in transformers that have a substantial lead time. The potential outcome of this investigation may be tariffs on GOES to ensure continued viability of domestic manufacturing capability.
Finally, nearly half of respondents — 48 percent — said they were not considering and probably would not convert any of their AC transmission lines to high-voltage direct current (HVDC) ones. Such lines offer an advantage over AC counterparts in that there are fewer line losses, but making the conversion is greatly expensive. Typically, such a transition only pencils out if the owner wants to move a large amount of power across a large geographic footprint (Figure 7).

Conversions do have a place, particularly larger entities with a larger geographic footprint, as shown by the 10 percent of respondents that have considered and implemented conversions. Should offshore windfarms get built, HVDC may be the transmission option of choice, noting its implementation on projects in this market in Europe.

Figure 7

<table>
<thead>
<tr>
<th></th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yes, considered and implemented</td>
<td>10.2%</td>
</tr>
<tr>
<td>Currently considering</td>
<td>13.6%</td>
</tr>
<tr>
<td>May consider soon</td>
<td>16.1%</td>
</tr>
<tr>
<td>Considered, won't implement</td>
<td>11.9%</td>
</tr>
<tr>
<td>Not considered and probably won't</td>
<td>48.3%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

ABOUT THE AUTHORS

**Kevin Ludwig** is the global transmission technology portfolio manager for Black & Veatch’s power business. Ludwig has more than 20 years of experience in the power industry. In his present role he is responsible for monitoring technology changes, development of solutions and solution specific resource management for the transmission market.

**James Hendrickson** is a senior managing director in Black & Veatch Management Consulting. With more than 30 years of experience in power and gas consulting, Hendrickson is considered a driving force in the industry, assisting clients in assessing, develop next generation business and capability models and deploy new technologies ranging from DER to digitalization and analytics across competitive and regulated markets.
A Rapidly Evolving Energy Landscape Paints a New Scenario for Distribution Needs

By Kevin Prince, Leslie Ponder and Mark Von Weihe

The global energy landscape is changing rapidly, and the shift towards a smarter, more sustainable, reliable and resilient grid is occurring at an accelerating rate. Huge changes are needed in the nation's power distribution infrastructure to deliver a modern network that is advanced enough to meet today's rapidly changing expectations, yet flexible enough to one day enable a range of next-gen capabilities.

This balancing act will require more than just new distribution equipment — utilities will need to recalibrate how they approach new grid technologies, design, finance, management and security. Today's grid must carry, control and monitor the bi-directional flow of power while also meeting regulator and customer demands for safe, sustainable, reliable, resilient and affordable power.
Distribution a Top Challenge for Utilities

Historically, distribution was wrapped up in the traditional approach of overhead/underground, distribution automation and substation automation. But the conversation has changed, and now utilities are asking, “How can we integrate and handle distributed energy resources (DER)? How do we make the grid self-healing and more resilient? How do non-wire alternatives (NWAs) and other solutions fit into the new distribution equation? What’s their real application?”

There’s no one right answer, as the scope and scale of distribution projects vary wildly. A project can be as small as a utility-developed microgrid with a battery energy storage component on top of a middle school, or as large and complex as an entire transmission line deferral.

Distribution issues also are becoming more localized, making it difficult to deal with them in a centralized fashion. Utilities need the flexibility to match load and generation, to have distributed and NWA alternatives, and to have the ability to pull levels in specific locations versus at the system level.

With this in mind, it’s no surprise that utilities see upgrading and modernizing their distribution systems as one of the top challenges facing the industry today. According to Black & Veatch’s 2020 Strategic Directions: Electric Report survey, distribution system upgrades and modernization rank fourth behind aging infrastructure, renewables and an aging workforce, and just ahead of environmental regulation, cybersecurity and energy storage (Figure 8).

### Figure 8

**From your perspective, what are the most challenging issues facing the electric industry in your region today? (Select the top three most challenging issues)**

<table>
<thead>
<tr>
<th>Issue</th>
<th>2019</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aging infrastructure</td>
<td>43.6%</td>
<td>33.4%</td>
</tr>
<tr>
<td>Renewables</td>
<td>27.1%</td>
<td>26.2%</td>
</tr>
<tr>
<td>Aging workforce</td>
<td>28.8%</td>
<td>24.1%</td>
</tr>
<tr>
<td>Distribution system upgrade and modernization</td>
<td>not asked</td>
<td>21.8%</td>
</tr>
<tr>
<td>Environmental regulation</td>
<td>25.8%</td>
<td>21.6%</td>
</tr>
<tr>
<td>Cybersecurity</td>
<td>27.8%</td>
<td>21.2%</td>
</tr>
<tr>
<td>Energy storage</td>
<td>20.5%</td>
<td>19.9%</td>
</tr>
<tr>
<td>Economic regulation</td>
<td>24.2%</td>
<td>16.5%</td>
</tr>
<tr>
<td>Distributed energy resources</td>
<td>17.4%</td>
<td>15.0%</td>
</tr>
<tr>
<td>Reliability</td>
<td>15.2%</td>
<td>12.3%</td>
</tr>
<tr>
<td>Market structure</td>
<td>21.3%</td>
<td>11.6%</td>
</tr>
</tbody>
</table>
These responses reflect utilities narrowing their focus on distribution, especially as the bulk of responses — aged infrastructure, renewables, distribution system upgrades and modernization, DER, reliability, grid stability, resiliency and grid congestion — all roll up into the conversation around distribution.

**IT/OT Integration is Key to Success**

So how can utilities deliver this next-gen distribution system? Success will rely on putting in place the advanced communications infrastructure necessary to enable more effective asset management programs that will allow utilities to deliver at a more localized level and meet regulator and customer demands. This will require integrated planning and convergence across a utility’s information technology (IT) and operational technology (OT) systems.

The industry is seeing enough activity that may change how it views the benefits of integrated IT/OT systems. Survey data supports this, with a combined 68 percent of respondents agreeing that the integrated planning of IT/OT systems will provide their utility with meaningful benefit (Figure 9). And support for IT/OT integration was even greater among larger utilities — those that serve 2 million people or more — with 75 percent agreeing that they will see meaningful benefit from integration.

But utilities still have a lot of work to do when it comes to pulling those two pieces together. In a rather short timeframe, utilities have gone from operating a relatively static grid to biting off a massive amount of complexity (e.g., investing in next-generation AMI, replacing SCADA, and implementing ADMS).

The proliferation of DER now is driving investment in DERMS and grid-edge control capabilities. As they run these initiatives and pilots in tandem, utilities may be making technology decisions based only on concurrent projects. Utilities are recognizing that the interdependencies of the many efforts must be coordinated to translate to deliver the advanced capabilities and locational benefits of the future distribution system.

![Figure 9](image_url)

**Statement agreement: There will be meaningful benefits if we integrate the planning of all our operational and information technology systems.**

Source: Black & Veatch
Prioritizing Investment in Distribution

Utilities also will have to revise how they allocate their funding, particularly as the industry continues to deal with natural disasters — hurricanes, storms, wildfires—and global pandemics such as COVID-19. Some utilities are eyeing their investment decisions and responding accordingly, with a combined 45 percent saying they plan to reprioritize “some or most” of their investment in existing assets (27 percent) or new assets (18 percent) (Figure 10).

The remaining 48 percent said they have no plans to reprioritize investment, while 6 percent said they plan to defer investment until at least next year. Does this mean that utilities are comfortable with their current investment strategy? Or does it invite caution, if the utility is simply deferring maintenance or replacement efforts, forcing their assets to endure another hurricane, storm or fire season and, if so, could this cause some type of catastrophic failure down the road?

Of those who plan to re-prioritize investment in existing assets, nearly half of respondents (49 percent) said they plan to upgrade their transmission and substation infrastructure, which could involve substation hardening as part of grid modernization efforts or the integration of DER. This response suggests that maintaining reliable, consistent service remains the driving force behind investment plans, particularly through COVID-19 (Figure 11).

Automation ranked second, demonstrating its growing value to utilities, particularly during times of unrest — not just with COVID, but when dealing with hurricanes, storms, wildfires and other disasters. To adhere to social distancing guidelines, utilities’ field crews are smaller and spread more thinly; by allowing utilities to operate remotely, automation can remove the need to put crews in harm’s way, benefiting everyone from a public safety standpoint.

Figure 10
As COVID-19 impacts continue to play out, how will investments to new and existing assets be re-prioritized? (Select one)
Source: Black & Veatch

48.4%  
No re-prioritization

18.0%  
Some/most investment will be re-prioritized to new assets

27.2%  
Some/most investment will be re-prioritized to existing assets

6.4%  
Deferring most investment until at least next year
Automation also can be paired with data analytics to improve — and drive down the cost — of day-to-day operations. Support for some of the other responses (e.g., increased remote monitoring and diagnostics (No. 5) and conversion of analog systems to digital systems (tied for sixth), support this idea by suggesting that utilities are looking for any solution — whether its automation, remote monitoring or diagnostics — that will help move them closer to a self-healing grid, or enable them to respond more surgically to issues, and this will be a huge priority moving forward.

**Moving the Needle**

In short, utilities have a long road ahead as they work to handle distribution in a more localized fashion. Integrated systems planning will remain key to their success as they work to overcome silos and incorporate more DER and NWAs. Advanced communications infrastructure will be critical to enable utilities to run effective asset management programs, deliver at the localized level and meet demands. Meanwhile, utilities are working to balance investment as they strive to adapt to a rapidly changing world riddled with challenges, from hurricanes, storms and wildfires to COVID-19.

---

**Figure 11**

You selected re-prioritizing investments to existing assets. More specifically, where do you see this investment going? (Select up to three)

*Source: Black & Veatch*

<table>
<thead>
<tr>
<th>Percentage</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>48.6%</td>
<td>Upgrading transmission and substations</td>
</tr>
<tr>
<td>35.1%</td>
<td>Automating operations</td>
</tr>
<tr>
<td>31.1%</td>
<td>Meeting new and future environmental compliance requirements</td>
</tr>
<tr>
<td>28.4%</td>
<td>Replacement or upgrade of existing generating units</td>
</tr>
<tr>
<td>23.0%</td>
<td>Increased remote monitoring &amp; diagnostics</td>
</tr>
<tr>
<td>20.3%</td>
<td>Rehabilitation of equipment to extend plant’s life</td>
</tr>
<tr>
<td>20.3%</td>
<td>Conversion of analog systems to digital systems</td>
</tr>
<tr>
<td>18.9%</td>
<td>Reducing emission (e.g., air quality control systems)</td>
</tr>
</tbody>
</table>
So, what will move the needle on distribution? Last year, resiliency was pinned as driving decisions in distribution; this year, that mantle goes to policy and regulation. Regulation is increasingly driving decarbonization goals and customer control. Compelling events such as hurricanes, storms or wildfires will drive investment, but ultimately progress may come down to customer satisfaction.

Historically, customer expectations were considered a novel concept, viewed through the lens of usage, billing, outage management and, more recently, the ability to control one’s smart thermostat. But today’s utility customers have evolved, and their hierarchy of needs has changed. Now customers are asking: Where does my energy supply come from? Is it reliable and resilient? Is it green and sustainable? Is it cost-effective?

Change increasingly is being driven from the customer side of the meter. The utility will have to connect the dots back through the regulatory process to meet these expanding customer needs for safe, sustainable, reliable, resilient and affordable power. Alignment between the utility and the customer will drive the next-gen distribution system.

ABOUT THE AUTHORS

Kevin Prince leads Black & Veatch’s global distributed generation business overseeing the strategic direction, growth and execution of the company’s DER offerings serving both commercial and industrial customers as well as utilities. Solutions include onsite solar, energy storage, electric vehicle infrastructure, fleet electrification and CHP. He has more than 18 years of experience in the energy industry and has developed and closed more than $1 billion in projects for Fortune 500 companies and public and governmental entities.

Leslie Ponder is the technology portfolio director for global distributed energy at Black & Veatch, where she is responsible for evaluating and delivering technology solutions within distribution, asset management and distributed generation. Ponder has more than 30 years of experience and has led systems strategy and planning for communications, grid analytics, and grid control and security systems.

Mark Von Weihe is a senior managing director with Black & Veatch Management Consulting, where he is working to expand the company’s technology offering portfolio into new industry segments. With more than 20 years of experience, Von Weihe is recognized throughout the utility industry for his strategic work in technology, commercial trading, renewable energy and electric distribution operations consulting.
As the Stack Tilts Towards Distributed Energy, Utilities Boost Investment

By Kevin Prince, Leslie Ponder, Jim Hendrickson, Kevin Cornish

There is no denying the rise of distributed energy resources (DER) as policy makers, regulators, environmentalists and the public sector press for decarbonization, resiliency, energy independence and sustainability. As this distributed market grows at an accelerating pace, both behind and in front of the meter, the electric utility industry faces questions around what a distributed grid landscape will look like and the challenges it presents in terms of their role, business model, revenue, margins and asset management as the market develops and matures.

At this point, few will argue against DER playing a significant role in the future generation stack, although the exact mix of technology configurations and the pace of development still are unknown. What we do know is that the roles for solar and batteries will increase, as will the prevalence of more complex intelligent monitoring and control technologies.

What our clients tell us reinforces this perspective according to Black & Veatch’s 2020 Strategic Directions: Electric Report survey, which found that one-third of the electric industry is actively engaged in DER investment and grid modernization. Grid modernization investment trends support the expansion of DER as transmission and distribution loads shift network stress points and capabilities.

The data shows that slightly more than 39 percent of utilities are investing more money in distribution over last year (Figure 12), reflecting a significant step change in their CAPEX planning strategy. Nearly half of respondents (49 percent) said their investment remained the same, suggesting they either are focused on standard distribution upgrades, maintenance and replacements; are taking a “wait and see” approach when it comes to DER; or do not anticipate spending more money than what they were spending in the past, having already ramped up their spending over the previous year. This supports last year’s report, which
found that DER spending was less exploratory and more integrated into general rate cases. Only 11 percent of respondents said they are investing less money on distribution than last year.

The data shows one shifting trend in that utilities are increasingly looking to “go local” as they invest in distributed energy and renewables. This “additionality” is driven not just by customer demand for clean energy but the locational (marginal) value of non-wire alternatives (NWAs) to provide grid capacity and stability. With 46 percent investing more money in local renewables over last year, utilities don’t want to just build additional renewable assets somewhere out on the grid; they want these assets to be directly connected to their facilities and service territories, and to see that investment tied into local renewables that will directly impact — and benefit — their customers. A similar trend is playing out in the commercial and industrial (C&I) sector.

### Investment in Distributed Energy

When it comes to predicting how investment in new generation capacity will change over the next five years, respondents pointed to land-based solar, energy storage and microgrids as the top three categories leading the charge in investment (Figure 13).

Unsurprisingly, the survey points toward a microgrid solution involving integrated solar, storage and controls, shifting the bias to a more comprehensive, intelligent facilities management solution. The actual depth and configure mix of deployment will vary based on markets, but more importantly on customer

| Source: Black & Veatch |

<table>
<thead>
<tr>
<th></th>
<th>Much more investment than last year</th>
<th>Somewhat more investment than last year</th>
<th>Same investment as last year</th>
<th>Somewhat less investment than last year</th>
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</thead>
<tbody>
<tr>
<td>Local renewables</td>
<td>11.4%</td>
<td>34.5%</td>
<td>45.0%</td>
<td>6.6%</td>
<td>2.6%</td>
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<tr>
<td>Distribution</td>
<td>12.1%</td>
<td>27.3%</td>
<td>49.4%</td>
<td>8.2%</td>
<td>3.0%</td>
</tr>
<tr>
<td>Transmission</td>
<td>11.9%</td>
<td>26.0%</td>
<td>49.8%</td>
<td>9.3%</td>
<td>3.1%</td>
</tr>
<tr>
<td>Other distributed energy resources (DER)</td>
<td>5.9%</td>
<td>25.2%</td>
<td>58.6%</td>
<td>8.1%</td>
<td>2.3%</td>
</tr>
<tr>
<td>Generation</td>
<td>4.2%</td>
<td>15.1%</td>
<td>53.4%</td>
<td>19.3%</td>
<td>8.0%</td>
</tr>
</tbody>
</table>
For each of the following categories, how do you expect new generation capacity investments to change over the next five years in your region? (Select one for each row)

Source: Black & Veatch

<table>
<thead>
<tr>
<th>Category</th>
<th>Much more investment than today</th>
<th>Somewhat more investment than today</th>
<th>Same investment as today</th>
<th>Somewhat less investment than today</th>
<th>Much less investment than today</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar (on land)</td>
<td>42.7%</td>
<td>39.1%</td>
<td>13.6%</td>
<td>3.3%</td>
<td>1.3%</td>
</tr>
<tr>
<td>Solar (floating)</td>
<td>9.8%</td>
<td>31.1%</td>
<td>40.9%</td>
<td>8.8%</td>
<td>9.5%</td>
</tr>
<tr>
<td>Energy storage</td>
<td>36.6%</td>
<td>41.9%</td>
<td>17.8%</td>
<td>2.7%</td>
<td>1.0%</td>
</tr>
<tr>
<td>Microgrids and other DER</td>
<td>22.6%</td>
<td>42.2%</td>
<td>26.4%</td>
<td>5.4%</td>
<td>3.4%</td>
</tr>
<tr>
<td>Wind (on land)</td>
<td>17.9%</td>
<td>41.2%</td>
<td>31.4%</td>
<td>7.4%</td>
<td>2.0%</td>
</tr>
<tr>
<td>Wind (offshore)</td>
<td>16.9%</td>
<td>32.9%</td>
<td>35.3%</td>
<td>9.2%</td>
<td>5.8%</td>
</tr>
<tr>
<td>Gas-fired / LNG-to-power</td>
<td>8.8%</td>
<td>29.9%</td>
<td>37.1%</td>
<td>19.4%</td>
<td>4.8%</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>7.1%</td>
<td>19.3%</td>
<td>56.3%</td>
<td>9.8%</td>
<td>7.5%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>2.0%</td>
<td>14.2%</td>
<td>36.3%</td>
<td>24.4%</td>
<td>23.1%</td>
</tr>
<tr>
<td>Coal-fired</td>
<td>0.3%</td>
<td>2.4%</td>
<td>13.5%</td>
<td>23.6%</td>
<td>60.1%</td>
</tr>
</tbody>
</table>
buying needs (e.g., reliability, sustainability, decarbonization, cost, etc.) The market is responding with reliability solutions such as Bloom Energy’s solid oxide fuel cells that convert fuel to electricity, without combustion, to deliver reliable, resilient, clean and affordable energy.

Solar continues its meteoric rise, driven by strong regulatory policies, rapidly declining costs and increasing demand. According to the Solar Energy Industries Association (SEIA), solar made up 40 percent of all new electric capacity added last year, and the technology continues to expand rapidly across the U.S., emerging into states such as Florida and Texas, resulting in their largest market share yet. Although subsidies and investment tax credits are heavily driving solar’s ultimate pace of adoption, eventually the market will move to a point where subsidies are not the primary determining factor.

Meanwhile, the energy storage market continues to grow, with ReportLinker forecasting a compound annual growth rate of 24 percent between 2020 and 2025. By ranking energy storage second, battery storage is emerging as a top investment area, demonstrating the industry’s growing comfort with the maturing technology driven by improvement in battery technology and the ability of batteries to manage peaks and flatten the load curve.

But challenges abound, and perceived risk and safety remain top of mind, as few can forget Arizona Public Service’s battery fire in April 2019. There still are issues when it comes to scaling batteries effectively, such as physical space issues and possible shortages and cost shifts in battery input materials such as lithium. Regulatory policy also is a concern — states that have clear regulatory policies in place will have a strong advantage when it comes to attracting investors.

From a practical deployment standpoint, energy storage is not offered as a packaged solution at any scale. As a result, forcing utilities to contract with three or four entities to pull together a solution or do a top-line EPC deal that has five or six sub-providers. This piecemeal approach adds to the complexity when warranties don’t match up, there are no long-term service agreements and nothing is fully integrated. The current level of apprehension can be tied to utilities having to cobble together these solutions, and if something goes wrong, it can delay progress for years.

So what will be the differentiator in the market? Utilities need to make energy storage solutions scalable and safe by pulling together and packaging integrated energy storage solutions that involve a technology integrator, a container, control logic and an EPC. They also need the ability to get recovery from rate base. The market will shift when these fully integrated solutions come to fruition – not just from a technical standpoint but from a support standpoint as well.

The third element, microgrids, reflects the emergence of intelligent systems. We view this digitization in controls as the next phase of the DER shift following the shift in asset mix. Respondents demonstrate a growing awareness that microgrids are not “just” microgrids anymore; they can offer so much more as non-wire alternatives (NWAs) become more packaged and realistic for grid deferment. Additional spend in microgrids suggests one of two things: either the industry lacks comprehensive understanding around the complexity and market readiness of these control systems, or that the software and logic controls are maturing to the point that they will become viable to roll out at scale. That said, the maturity level and speed at which the coordination and harmonization software and telecom components can keep up with the spend will be an important driver in the next five to 10 years or, more likely, 15 years.

Diving deeper into the rankings, the increased spending on wind — both on land and offshore — reflects the technology’s role as a standard asset in the generation portfolio. But that said, wind has a natural ceiling compared to some
of the alternative solutions – due to land use and reliability, among other reasons. Gas-fired/LNG-to-power continues to hold steady in the middle, reflecting its role as a base component across fleets and its ability to improve emissions significantly while scaling down size. NWAs still must balance the premium paid for resiliency and the cost deferral of standard grid upgrades against more traditional grid centralized investments.

Perhaps more interesting is what comes next — the appearance of waste-to-energy, hydrogen, hydropower and geothermal. Three years ago, this would not have been unheard of, but these proven technologies slowly are becoming more cost-effective, driving investment.

The main takeaway? Over the past few years, utilities increasingly have recognized the role DER will play and are actively shifting their asset management and investment strategies to guide this transition, particularly in areas with favorable regulatory policy (e.g., California and New York). By delivering improved reliability, this new investment strategy also may reap OPEX benefits in the future, plus it could generate new earning paths centered around offering solutions to commercial and industrial (C&I) customers who otherwise may seek out their own off-grid solutions.

**Pushing Out the Timeline**

The past few years have been focused on determining the horizon for when DER will comprise the bulk of the resource stack. Due to a welter of issues — a recognition that this is a long journey, paired with complicated technology, policy and regulatory considerations — that timeline has stretched, and now the industry is looking past the 10-year mark to deliver DER at scale across the utility footprint.

Survey data shows that utilities are changing their perceptions. When polled on the integration of DER year-over-year, we see that support for the five-year timeline has slipped and respondents are taking a more realistic view, looking 10 to 15 years ahead to between 2030 and 2050 (Figure 14). At some point, DER will dominate the resource stack and utilities will still be able to monetize and commercialize it, but the process will take longer than originally expected, with the largest shift coming at the 10-year mark and perhaps even stretching out to 25 years.

DER remains an increasing reality. Utilities are acknowledging that there are issues from a policy perspective, but they are on a change curve. At this moment, we are witnessing the progression, though it may be methodical from an investment and resources standpoint.

---

**Figure 14**

Select how much you agree or disagree with each of the following statements relative to the future of distributed energy resources (DER). *(Select one response per row)*

Source: Black & Veatch

<table>
<thead>
<tr>
<th>Statement</th>
<th>2019</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>DER will dominate utility service offerings in the next...</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5 years</td>
<td>26.7%</td>
<td>26.7%</td>
</tr>
<tr>
<td>10 years</td>
<td>45.2%</td>
<td>46.6%</td>
</tr>
<tr>
<td>15 years</td>
<td>54.8%</td>
<td>61.2%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>% Selecting Strongly or Somewhat Agree</th>
<th>2019</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>DER will dominate utility service offerings in the next...</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5 years</td>
<td>24.3%</td>
<td>25.0%</td>
</tr>
<tr>
<td>10 years</td>
<td>46.6%</td>
<td>49.9%</td>
</tr>
<tr>
<td>15 years</td>
<td>54.8%</td>
<td>57.6%</td>
</tr>
</tbody>
</table>
The Future is Unknown

Utilities continue to deal with the complexities of investing in DER and grid modernization. DER solutions increasingly are becoming sophisticated through the advent of complex intelligent monitoring and control technologies, driving increased expansion both behind and in front of the meter.

One thing is for certain — the future is unknown. The exact blend of technologies and pace of development remain unclear, though survey data shows a shifting blend of optimism and realism as timelines push back beyond the 10-year mark, reflecting a growing awareness around the complexities of distributed energy.

DER will continue to play a significant role in the current generation stack, particularly as the market moves towards more turnkey configurable solutions. Many areas of the country will start reaching the tipping point on how they manage the distribution grid due to higher penetrations of DER. This is where the rubber will meet the road when it comes to grid-edge decision-making and how quickly it can roll out to support a truly distributed grid.

ABOUT THE AUTHORS

Kevin Prince leads Black & Veatch’s global distributed generation business overseeing the strategic direction, growth and execution of the company’s DER offerings serving both commercial and industrial customers as well as utilities. Solutions include onsite solar, energy storage, electric vehicle infrastructure, fleet electrification and CHP. He has more than 18 years of experience in the energy industry and has developed and closed more than $1 billion in projects for Fortune 500 companies and public and governmental entities.

Leslie Ponder is the technology portfolio director for global distributed energy at Black & Veatch, where she is responsible for evaluating and delivering technology solutions within distribution, asset management, and distributed generation. Ponder has more than 30 years of experience, and has led systems strategy and planning for communications, grid analytics and grid control and security systems.

Kevin Cornish is a senior managing director of the growth and performance practice with Black & Veatch Management Consulting. Cornish focuses on providing support to utilities as they perform strategic business assessments, implement enabling technologies, and revamp engineering and business processes to improve their competitiveness and evolve with the changing grid.

James Hendrickson is a senior managing director in Black & Veatch Management Consulting. With more than 30 years of experience in power and gas consulting, Hendrickson is considered a driving force in the industry, assisting clients in assessing strategy, develop next generation business and capability models and deploy new technologies ranging from DERs to digitalization and analytics across competitive and regulated markets.
Ratemaking, Capital Investments Reflect Growing Renewable Energy Trends

By Frank Jakob, Denise Nelson, Sam Scupham and Sean Tilley

he cost of solar and wind continue to fall while consumers demand more low-carbon energy, driving U.S. electric utilities to broaden their portfolio of cleaner generation. Responses to Black & Veatch’s 2020 Strategic Directions: Electric Report survey — which polled more than 600 stakeholders from across the electric industry — show that utilities actively are preparing for the increased penetration of renewable energy and distributed energy resources (DER), redesigning their rate and pricing structures and making calculated short-term capital investments as they work to meet regulator and customer demands.

Making Strides in Preparing for DER

This year’s survey shows that most utilities are not only aware of, but actively preparing for, the increased penetration of renewables and DER. According to survey data, a combined 68 percent of respondents are working to redesign their regulated rate and pricing structures to accommodate an increased penetration of DER. Fifteen percent have completed this effort, 53 percent are in the process, and 22 percent said they are considering taking such action (Figure 15).

Admittedly, the ratemaking process is lengthy and complex, starting with conceptualization discussions to determine if the utility wants to move away from a volumetric pricing structure and towards something more value-driven around how the grid is used. Utilities must observe and study the market, and actively plan for load growth, population growth and geographic expansion.

From there, the process typically would move into discussion with economists and regulators, then progress to the study and working group phase (including stakeholders) before moving to modeling, design and testing. If the utility is on the forefront of the effort, it could be completed in four to five years, while those utilities who come after may see a slightly reduced timeline. The challenge is for utilities to make these changes in a dynamic market where DER solutions like renewables are being actively deployed by commercial, industrial and governmental entities who have fewer barriers
to entry in deploying DER assets. It’s akin to planning and laying down tracks as the train is coming down the line.

Only one out of 10 respondents said they are not participating in this work, which suggests that they either haven’t started thinking about DER yet or they may be slow adopters. That grouping could include small co-ops and municipalities that prefer to wait and watch from the sidelines while the larger players go through the process first, smoothing the road ahead for them.

Even as utilities address the need to revise their rate and pricing structures, they remain challenged by certain elements of DER. According to survey results, the ability to forecast, monitor and manage utility-owned and third-party DER is the No. 1 challenge facing utilities today, according to two-thirds of respondents, followed closely by clear DER regulation and policy (59 percent) (Figure 16). The remaining challenges are industrial and commercial self-generation, electric vehicles (EVs), household self-generation, and a small amount of “other” responses.

It is unsurprising that DER management is seen as a top challenge, given both the plethora of DER and the broad expanse of their integration and management needs. It is interesting to note that concerns over electric vehicles (EVs) ranked lower than expected, given the level of ongoing discussion around their charging infrastructure needs. This may be because EVs are a known quantity, and their complexities may pale in comparison when stacked against the other concerns.

Figure 15
Are you redesigning your utility company’s regulated rate and pricing structures to accommodate an increased penetration of distributed energy resources (DER)?
Source: Black & Veatch

52.7%
Yes, we are in the process of doing this

21.5%
No, but we are considering this type of action

15.1%
Yes, we have already done this

10.8%
No, we are not considering this type of action

Figure 16
Which elements of DER are particularly challenging?
Source: Black & Veatch

65.6% Ability to forecast, monitor and manage (owned and third party) DER
59.1% Clear regulation and policy
34.4% Industrial & commercial self-generation
28.0% Electric vehicles and other inputs
25.8% Household self-generation
9.7% Other
Investing in Renewables, Other Systems

When it comes to short-term capital investments in renewables and associated technologies, local renewables saw the greatest growth in funding, with 46 percent of respondents stating that they are investing more money in local renewables compared to last year (Figure 17). Nearly half (45 percent) are making similar investments, while 9 percent are investing less.

Transmission and distribution were closely tied and showed similar results, with 39 percent of respondents investing more money than last year. Approximately half are investing a similar amount, while a little more than one in 10 respondents are investing less. Survey data shows that investor-owned utilities (49 percent) and publicly-traded corporations (48 percent) are focused on distribution, while cooperatives (43 percent) are more invested in transmission.

Investment in DER was a little flatter, with 31 percent investing more, 59 percent making a similar investment to last year, and 10 percent investing less. Publicly-traded corporations and investor-owned reported similar interest in DER, at 38 percent and 35 percent, respectively.

Generation saw the least growth in investment, with only 19 percent of respondents investing more, 53 percent making a similar investment to last year, and 27 percent investing less. More than one-third of private corporations invested in generation, more than the three other categories.

Figure 17

Compared to last year, how have your utility’s short-term capital investments changed?
(Select one per row)
Source: Black & Veatch

<table>
<thead>
<tr>
<th></th>
<th>Much more investment than last year</th>
<th>Somewhat more investment than last year</th>
<th>Same investment as last year</th>
<th>Somewhat less investment than last year</th>
<th>Much less investment than last year</th>
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<tbody>
<tr>
<td>Local renewables</td>
<td>11.4%</td>
<td>34.5%</td>
<td>45.0%</td>
<td>6.6%</td>
<td>2.6%</td>
</tr>
<tr>
<td>Distribution</td>
<td>12.1%</td>
<td>27.3%</td>
<td>49.4%</td>
<td>8.2%</td>
<td>3.0%</td>
</tr>
<tr>
<td>Transmission</td>
<td>11.9%</td>
<td>26.0%</td>
<td>49.8%</td>
<td>9.3%</td>
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</tr>
<tr>
<td>Other distributed energy resources (DER)</td>
<td>5.9%</td>
<td>25.2%</td>
<td>58.6%</td>
<td>8.1%</td>
<td>2.3%</td>
</tr>
<tr>
<td>Generation</td>
<td>4.2%</td>
<td>15.1%</td>
<td>53.4%</td>
<td>19.3%</td>
<td>8.0%</td>
</tr>
</tbody>
</table>
Of those investing in local renewables, publicly-traded corporations are leading the charge, with 56 percent of respondents stating they invested more money this year, followed by private corporations (44 percent), investor-owned utilities (39 percent) and co-ops (23 percent) (Figure 18).

**Regulators, Customers Continue to Drive Change**

Most utility respondents — a combined 85 percent — said they are working towards some type of carbon reduction, greenhouse gas emissions reduction and/or renewables goal. A little over half include goals independent of regulatory mandate, while two out of five have goals as part of state mandate.

It is no secret that government regulators and more recently corporations (e.g., data center owners) are the driving forces behind utilities’ renewable energy investments. Regulators are the primary driver, reflecting utilities’ need to adhere to renewable portfolio standard (RPS) legislative mandates, designed to increase renewable energy generation. Respondents pointed to regulators (58 percent) and customers (51 percent) as holding far more sway than the financial and investment sector (32 percent), employees (31 percent), shareholders (29 percent), the technology sector (29 percent) and interest and lobby groups (17 percent).

---

**Figure 18**

Compared to last year, how have your utility’s short-term capital investments changed? *(Select one per row, by organization type)*  *Note: IOUs may be publicly-traded but represent an important enough classification to break out separately.*

Source: Black & Veatch

<table>
<thead>
<tr>
<th>Respondents answering “much more investment” or “somewhat more investment”</th>
<th>Publicly-traded corporation</th>
<th>Investor-owned utility</th>
<th>Private corporation</th>
<th>Cooperative</th>
</tr>
</thead>
<tbody>
<tr>
<td>Local renewables</td>
<td>56.3%</td>
<td>39.4%</td>
<td>44.4%</td>
<td>23.3%</td>
</tr>
<tr>
<td>Distribution</td>
<td>48.1%</td>
<td>48.6%</td>
<td>33.3%</td>
<td>31.3%</td>
</tr>
<tr>
<td>Transmission</td>
<td>41.8%</td>
<td>40.3%</td>
<td>21.7%</td>
<td>43.3%</td>
</tr>
<tr>
<td>Other distributed energy resources (DER)</td>
<td>37.7%</td>
<td>35.3%</td>
<td>29.2%</td>
<td>16.1%</td>
</tr>
<tr>
<td>Generation</td>
<td>23.8%</td>
<td>16.7%</td>
<td>34.5%</td>
<td>12.9%</td>
</tr>
</tbody>
</table>
The factors driving renewable energy investments align with these responses, as deeper analysis shows that motivation is derived primarily from governments; government incentives and/or policy; increased shareholder pressure and sustainability goals; and increased demand from residential customers (Figure 19). Although not surprising, it is interesting to note that these top four drivers outweighed all the other things such as finances and efficiencies that make projects float. To this point, utilities continue to respond and react to demands — from governments, regulators, customers — rather than their own perceived operational benefits.

**The Future of Renewables**

So where does the electric utility industry stand when it comes to meeting their carbon, emissions or renewables goals? Thirty-seven percent of respondents said they are less than 40 percent of the way towards meeting their goals, 30 percent said they are between 40 and 59 percent, and the remaining one-third said they are more than 60 percent of the way towards achieving their goals. This is promising, if reality reflects the utilities’ estimates.

When compared to their peers, a combined 83 percent see themselves as either ahead or on pace with their peers, with 17 percent considering themselves “behind.” Again, this may be overly optimistic, but if the facts pan out, it shows the electric utility industry is taking the shift towards renewable energy seriously and making the necessary strides to get there.

Although renewable energy adoption and migration is specific to each utility, depending on where they are located, their state mandates and the technologies available to them, the industry as a whole is evolving relatively rapidly, pursuing greener, cleaner energy options in the global shift to low-carbon power generation.
ABOUT THE AUTHORS

Frank Jakob is the technology manager for energy storage within Black & Veatch’s power business. Jakob focuses on storage solutions for renewable and conventional electricity generation at distributed and utility scales. With more than 40 years of experience, Jakob advises industry, utility, developer and government clients, as well as the internal Black & Veatch engineering, procurement and construction (EPC) teams regarding the application, design, and uses of energy storage systems for stationary applications.

Denise Nelson is a principal with Black & Veatch Management Consulting’s advisory and planning group, where she is leads project teams in the power generation, electric utility and gas transmission and distribution sectors of the industry. A seasoned expert, Nelson is skilled in bridging the technical aspects of a project with its business needs, from project development through to strategy and transactions support.

Sam Scupham is the director of renewable and distributed energy for the Asia region within Black & Veatch’s power business. With more than 20 years of experience, Scupham is responsible for the growth of Black & Veatch’s engineering, procurement and construction and consulting services business across Asia.

Sean Tilley is the global technology portfolio manager for the renewable energy group within Black & Veatch’s power business. With more than 16 years of global experience across multiple renewable energy technologies, Tilley focuses on the optimization and growth of the company’s portfolio of renewable energy project solutions and expertise to meet current and future client needs globally.
Emerging Technologies Gaining Mindshare in Power Generation

By Rob Wilhite

A shift to increased distributed generation, efforts to modernize the U.S. grid, and a transition to reducing harmful emissions are posing the greatest challenges for the power sector, as the industry evolves in a market driven by demands for enhanced efficiency, reliability and cleaner power supply.

Responses to Black & Veatch’s 2020 Strategic Directions: Electric Report survey reflect these circumstances as the power sector breaks free from century-old concepts and responds to changing consumer behaviors and unpredictable load patterns. All of this is against the backdrop of an increasing use of distributed energy resources (DER) and other customer-driven, emerging technologies.

The heart of this transformation can be found in the digital realm of the information and communication technology (ICT) sector, which promotes the unification of higher-bandwidth communications technology with distributed computing, advanced analytics, machine learning and audio-visual systems to enable users to access, store, transmit and better manage information. Innovation in the power industry increasingly is based on digital ICT that
includes artificial intelligence (AI), augmented and virtual reality (AR/VR), blockchain technology and robotics.

The infrastructure that utilities rely on to deliver power has well-served its original purpose and, in many places, is in dire need of upgrading or replacement to accommodate the growth of customer-driven renewable power and interconnected DER.

According to survey respondents, the most challenging issues facing the industry include an aging infrastructure, renewable power, an aging workforce, and modernization of the distribution system. One-third of those surveyed said aging infrastructure was the top issue, while 26 percent cited renewable power. Twenty-four percent said an aging workforce was a big challenge, and nearly 22 percent identified grid modernization (Figure 20).

Many U.S. utilities and states aggressively are pursuing grid modernization and cybersecurity improvements to boost the efficiency, safety, reliability and resiliency of their systems. In fact, regulators in nearly every state are considering major proposals to upgrade systems as utilities prepare to spend billions to create a modernized grid capable of accommodating new digital technologies and increasing amounts of variable power generation, such as wind and solar.

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**Drones, Other Technologies Taking Flight**

Machine learning and AI are proving to be an effective tool in power generation to predict malfunctions, detect human error and optimize power plant scheduling. It also means power producers can eliminate unnecessary costs related to fixing an error and getting the system back online.

To that end, 30 percent of respondents said they are considering the addition of AI and/or machine learning to operations. More than 13 percent have considered adding AI or machine learning to operations, and nearly 22 percent said it’s not on their radar (Figure 21).

Along the way, more than half have considered using drones in operations, while one in five respondents said they are mulling the use of unmanned aircraft. Fourteen percent said they may consider using the technology in operations.

In addition to being relatively inexpensive, drone technology can save utilities money and reduce the physical effort — and perils posed to utility workers — to get to hard-to-reach areas on the power system.

Also, nearly one in four of those surveyed said their company is considering the use of AR in their operations, while roughly one-quarter said they may consider it. What’s more, the
Figure 21
To what extent is your organization considering the following emerging technologies as part of operations? (Select one per row)
Source: Black & Veatch

<table>
<thead>
<tr>
<th>Technology</th>
<th>Have considered</th>
<th>Currently considering</th>
<th>May consider</th>
<th>Not on our radar at all</th>
<th>Don’t know what this is</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drone Technology</td>
<td>55.5%</td>
<td>20.7%</td>
<td>14.1%</td>
<td>7.0%</td>
<td>2.6%</td>
</tr>
<tr>
<td>Phasor measurement units (PMUs) for operations</td>
<td>20.7%</td>
<td>18.0%</td>
<td>16.1%</td>
<td>12.4%</td>
<td>32.7%</td>
</tr>
<tr>
<td>Robotics</td>
<td>15.6%</td>
<td>19.3%</td>
<td>26.6%</td>
<td>29.8%</td>
<td>8.7%</td>
</tr>
<tr>
<td>Artificial intelligence and/or machine learning</td>
<td>13.6%</td>
<td>29.9%</td>
<td>26.2%</td>
<td>21.7%</td>
<td>8.6%</td>
</tr>
<tr>
<td>Augmented or virtual reality technology</td>
<td>13.0%</td>
<td>24.1%</td>
<td>24.5%</td>
<td>26.4%</td>
<td>12.0%</td>
</tr>
<tr>
<td>Virtual power plants</td>
<td>8.8%</td>
<td>15.8%</td>
<td>19.5%</td>
<td>30.7%</td>
<td>25.1%</td>
</tr>
<tr>
<td>5G</td>
<td>11.4%</td>
<td>35.2%</td>
<td>27.9%</td>
<td>18.7%</td>
<td>6.8%</td>
</tr>
<tr>
<td>Digital twins</td>
<td>3.7%</td>
<td>14.5%</td>
<td>16.4%</td>
<td>17.8%</td>
<td>47.7%</td>
</tr>
<tr>
<td>Blockchain</td>
<td>4.7%</td>
<td>14.2%</td>
<td>22.6%</td>
<td>28.8%</td>
<td>29.7%</td>
</tr>
</tbody>
</table>
deployment of AR can be a good tool for training and recruiting new personnel. These technologies also prove useful in recruiting and retaining the next generation of electrical workers.

Creating a digital twin of power plants or electric grids can be expensive, but the return on investment can be significant because it informs power system operators with understanding possible responses to certain scenarios and emergency events before they happen. Some 15 percent of respondents said they are considering the use of digital twins to enhance power plant operations, with an additional 16 percent saying they’re open to the idea of exploring such technology.

On the energy front, hydrogen rapidly is emerging as a clean fuel of choice for power generation, especially in Europe. Electric energy from a wind farm or solar plant can be stored and channeled through an electrolyzer to extract hydrogen from water, and the resulting gas can be used in a converted power plant to generate carbon-free electricity.

Some industry experts say hydrogen could be a part of the generation mix of most investor-owned electric utilities within a few years and may be more cost-effective than battery storage to deal with the variability of renewable power. Nearly one-quarter of respondents say they would consider hydrogen as a source of peak generation, while 9 percent said they would contemplate using the gas for baseload generation. Some 19 percent would consider hydrogen for backup power or as a microgrid component (Figure 22).

Some industry experts say hydrogen could be a part of the generation mix of most investor-owned electric utilities within a few years and may be more cost-effective than battery storage to deal with the variability of renewable power.

Figure 22
What services would you consider hydrogen for? (Select all that apply)
Source: Black & Veatch

<table>
<thead>
<tr>
<th>Service</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel cell storage</td>
<td>43.0%</td>
</tr>
<tr>
<td>Transportation fuel</td>
<td>24.1%</td>
</tr>
<tr>
<td>Peak generation</td>
<td>24.1%</td>
</tr>
<tr>
<td>Backup power/ component of microgrid</td>
<td>18.9%</td>
</tr>
<tr>
<td>To make a plant “greener”</td>
<td>15.3%</td>
</tr>
<tr>
<td>Baseload generation</td>
<td>9.2%</td>
</tr>
<tr>
<td>None of the above</td>
<td>29.7%</td>
</tr>
</tbody>
</table>
When asked what workforce management and remote operations solutions would be “most useful,” nearly half of respondents cited new workflow procedures, including staggered hours. Nearly half also chose “remote asset performance monitoring,” and four in 10 respondents said “on-site health screening and diagnostic facilities” (Figure 23).

Responding to COVID-19 and its impact on the industry’s workforce is perhaps the highest priority for today’s utility executives. More than half the workforce at some utilities are working remotely due to the pandemic, and executives appear ready to adopt permanent policies allowing employees to work regularly from home. Several utility executives have pleasantly discovered that call-center staff are more productive working remotely versus in a central office.

Figure 23
What workforce management and remote operations solutions would you find most useful? Include any that you’re currently using. (Select all that apply)
Source: Black & Veatch

- **New workflow procedures (including more staggered hours):** 49.3%
- **Remote asset performance monitoring:** 47.2%
- **On-site health screening and diagnostic facilities:** 40.1%
- **Remote command and control:** 36.6%
- **Remote asset condition monitoring:** 34.9%
- **Digital check-in and health monitoring of workforce on site:** 34.2%
- **Predictive health and risk indexing:** 25.0%
- **None of the above:** 11.3%
Distribution poles are becoming a growing source of revenue generation, offering utilities an opportunity to charge monthly and annual fees to use the real estate for customer-owned devices such as illuminated signs and telecommunications equipment. At a time when utilities are seeing limited load growth, distribution poles present an opportunity to add new revenue streams to their income statement.

Four out of 10 of those surveyed — 41 percent — said the value of distribution utility poles is greater today versus previous years, while more than 48 percent said their utility values those poles similarly today versus the past. Nearly one-third of those surveyed said distributed/renewable generation is among the services their company provides, and industry observers expect that number to grow significantly.

Additional, the use of distributed generators is on the rise in areas where storms are more frequent and severe. The key question: How are utilities going to tap into this source of power production and sufficiently compensate consumers for use of those assets?

**Adapting to the Growth of DER**

Centralized power generation is losing more relevance in a world with a preference for cleaner, more distributed generation. Many commercial and industrial customers are generating their own power locally, and the power they produce from DER can be an extra revenue source for them when interconnected to the grid.

Nearly one-third of those surveyed said distributed/renewable generation is among the services their company provides, and industry observers expect that number to grow significantly. Additionally, the use of distributed generators is on the rise in areas where storms are more frequent and severe. The key question: How are utilities going to tap into this source of power production and sufficiently compensate consumers for use of those assets?

**Re-prioritizing Investments**

Asked how investment in new and existing assets will be reprioritized due to COVID-19 impacts, one in four respondents said investments will be reprioritized to existing assets. Nearly half insisted their investments won’t be reprioritized.

The respondents may be underestimating the need for rethinking their business, given that a major shift in utility investment already is underway in response to the pandemic. For example, Dominion Energy sold its natural gas transmission business and is shifting its capital investments to offshore wind power and...
other forms of renewable power, recognizing that continued investment in gas transmission would result in a lower return on equity versus investments in renewable power.

At the turn of this century, more than half of the nation's power was produced with coal, and the prospects of renewable power and energy storage playing a starring role in U.S. power generation were quickly dismissed. The technologies were too expensive, unproven and difficult to integrate into a grid built around coal.

But now, the opportunities for collaboration between centralized and distributed power providers are abundant. The surge in DER is undeniable, and many utilities and states are making progress in modifying their business models to capture the increasing value of DER and cleaner, renewable energy supply. 

ABOUT THE AUTHOR

Rob Wilhite leads Black & Veatch's Global Distributed Energy business line. This includes the design, engineering, development, and monitoring/maintenance of client sustainable power solutions, including distributed generation, microgrids, battery energy storage, asset management services and utility grid services.
With or Without a Regulatory Nudge, Decarbonization Planning Must Begin Now

By Jason Rowell, Kevin Prince, Rob Wilhite and Heather Donaldson

The soaring use of renewables and DER are reshaping the electric utility industry as consumers and other stakeholders clamor for cleaner, decarbonized sources of power. Power utilities around the globe are rethinking their generation portfolio with a keener focus on ridding their operations of planet-warming emissions.

The push for decarbonization is taking a firmer hold in an ever-shifting energy landscape. Power providers are being pressed to commit today to investments needed in the future for cost-effective, low- or zero-emission energy options and more modernized, distributed grids that effectively integrate these options.

While renewables present opportunities to ensure reliable, clean and affordable power, the challenge comes with the increased penetration of those sources and in the absence of storage, replacing significant baseload power with an increasingly higher penetration of renewables.

Although renewable energy has reached cost parity with traditional energy supply options in many markets, their natural intermittency may complicate efforts to maintain grid reliability when they account for a significant portion of the energy supply stack.

Black & Veatch’s latest Strategic Directions: Electric Report brings it all into sharper focus, underscoring that utilities thoughtfully wanting to accommodate the surge of renewables must plan now and respond nimbly. Of more than 600 industry stakeholders surveyed for the report, more than three-quarters agree that they are devoting more of their capital spending to clean energy (Figure 26).

Pursuing robust decarbonization through renewables — including hydrogen, a potential game-changing energy source that’s still evolving — will be a complicated endeavor, requiring collaboration between consumers, investors, activists and regulators.
States, Enterprises Forcing the Issue

Utilities no longer have the luxury of being passive when it comes to interconnecting their grid with renewables, given growing regulatory or legislative pressure state by state to find a cleaner, greener way of doing business.

According to the U.S. Energy Information Administration, more than two-thirds of states, notably including economic heavyweights California and New York, either have enacted binding renewable energy portfolio standards or carbon-neutral goals or are considering them.

In June, for example, Massachusetts’ top law enforcer, Attorney General Maura Healy, asked the state’s utility regulators to reexamine the future of the Bay State’s gas utilities as Massachusetts transitions away from fossil fuels in hopes of achieving its legally binding statewide limit of net-zero greenhouse gas emissions by 2050.

Healy’s request recognized the state’s findings that the heating sector must make sizeable reductions in its use of fossil fuels — and that doing so “will have profound impacts on natural gas distribution companies and will require them to make significant changes to their planning processes and business model.”

On the local level in Seattle, King County Executive Dow Constantine in August announced his proposal for the local “2020 Strategic Climate Action Plan,” a five-year blueprint that includes cutting greenhouse gas emissions countywide in half by the end of this decade, a stronger focus on climate justice and preparing the region for climate impacts. That plan, which builds upon the county’s previous decarbonization efforts, integrates “climate justice” into all areas of the county’s operations.

Not to be outdone, industry leaders such as Microsoft, Jacobs and Amazon have pledged to be zero-carbon or carbon-negative in their supply chains/operations. Some of the most influential firms are not waiting on policy changes and have chosen to solidify their clean energy commitments via the “RE100,” a list of companies — among them General Motors, Hewlett-Packard, Iron Mountain, Johnson & Johnson and Kellogg’s — that have announced plans to move to entirely renewable power generation.
Compiled by the Climate Group and CDP (formerly the Carbon Disclosure Project), the lineup of more than 265 participating companies — many in the commercial and industrial (C&I) space — are intent on generating their own energy through rooftop solar or buying renewable-based power from offsite, grid-connected generators. RE100 companies will need to purchase over 220 TWhs of additional clean electricity by 2030 to meet their stated targets, which is almost as much as the entire energy consumption of Australia.

Promisingly, respondents to Black & Veatch’s survey overwhelmingly say they’re not being passive, actively blueprinting how to lower their carbon footprints or deploying more renewables. More than half say they’re doing so voluntarily, roughly 13 percentage points more than those attributing their efforts to a state regulatory mandate. Fifteen percent report taking no action (Figure 27).

Perhaps given their deeper pocketbooks to cover the cost, the biggest utilities — those serving at least 2 million residents — are most likely to voluntarily invest in emissions reduction or renewables goals, with nearly six in 10 respondents saying they’re doing so without being compelled by regulators. Some 46 percent of respondents from utilities serving 500,000 to 2 million people say their carbon-reduction goals are part of a state regulatory mandate.

As providers of roughly one-third of U.S. retail electricity sales, smaller utilities — typically municipal or co-operative enterprises in markets with fewer than 500,000 people — appear to be the laggards, with three in 10 of those respondents admitting they have no carbon-cutting game plan. Possible drivers of that could be their unfamiliarity with the technology, risks and operating characteristics — and perhaps a misperception of costs, which can be mitigated through self-financed methods or power purchase agreements (PPA). Smaller utilities also often are managed by elected boards reluctant to raise rates or who simply may be willing to wait until new technology and the business case for it is more proven. Simply put, the cost and the environment must be right.
Collaboration a Key to Decarbonization

The Electric Power Research Institute (EPRI) and the Gas Technology Institute (GTI) have unveiled a five-year global effort to hasten the development and demonstration of low-carbon energy technologies. With 19 collaborating sponsors in the electric and gas sectors, that Low-Carbon Resources Initiative (LCRI) is targeting advancements in low-carbon electric generation technologies and energy, including hydrogen, ammonia, synthetic fuels and biofuels. Rather than shun natural gas altogether, the LCRI has created a critical collaboration between the electric and gas industries to achieve broader energy and decarbonization objectives.

Among other things, the collaborative will identify and accelerate fundamental development of promising technologies, demonstrate and assess the performance of key technologies and processes, and inform key stakeholders and the public about technology options and potential pathways to a low-carbon future.

“Achieving ambitious targets will require technologies and processes beyond those widely available today,” EPRI’s president, Arshad Mansoor, said in a statement. “This global initiative will advance affordable pathways to economy-wide decarbonization.”

A Pandemic and the Power Supply

Compounding recurring concerns about aging infrastructure assets, new challenges from wildfires, hurricanes and other severe weather events increasingly are testing the resilience of electric utilities. But a new challenge has surfaced in the form of the COVID-19 pandemic, which halted the nation’s economy, left tens of millions jobless and, in large measure, forced power providers to reassess their energy portfolios.

Some seven in 10 respondents to Black & Veatch’s survey insisted that the coronavirus outbreak will have no effect on their region’s electricity generation mix. But as retirements of coal-fired power plants continue to accelerate and bankruptcies in the oil and natural gas sector become more frequent, it’s not inconceivable – as some 14 percent of respondents note – that the industry will migrate more rapidly towards integrating renewables and other clean energy options (Figure 28).

The seemingly prevailing steady-as-a-rock sentiment about COVID-19 and power generation mixes may evolve as some things continue to shake out. A key driver for change includes customer loads shifting from commercial and industrial sites to residential premises, given the dominance of remote working.
during the pandemic. The bottom line: Possible volatility and uncertainty remains in what had been a relatively predictable industry — most certainly when it comes to forecasting power demand, compounding the challenges of regulatory changes and activist investors enjoying a bigger shareholder voice and demanding swifter shifts to renewables.

For utilities accustomed to thinking in terms of 30-year planning horizons, the world has turned far more dynamic and fast-paced, creating an inflection point in that utilities must respond more frequently and faster than ever imagined. Along the way, utilities need greater certainty that when it comes to distributed energy, storage, electric vehicle charging and all of the new stakeholders coming into the market, they’re going to get reimbursed for those investments at a fair market rate.

Interestingly, non-utilities surveyed offered a far different picture, with 28 percent saying regional changes to their generation mix will be accelerated because of COVID-19, suggesting that the way in which they do business will fundamentally change. An additional 24 percent said the pandemic will simply slow alterations to energy portfolios.

Hydrogen: Tomorrow’s Answer?

Increasingly popular overseas but slower to be adopted in the United States, hydrogen-generated power, complemented by fuel cell storage, is drawing acclaim for its promise, given solar and wind energy’s intermittency that raises concerns about grid reliability.

So are we on the cusp of a “New Hydrogen Economy”? Simply put, it depends on who you ask.

Over the next decade, the survey illustrates, utilities expect solar (79 percent) and wind (67 percent) power to help them meet their clean energy goals or cut their emissions and carbon output, presumably because those options have established, matured technology and competitive costs. Those numbers drop into the 40th percentiles beyond 10 years, giving way to more deployments of hydrogen (58 percent) and battery energy storage (48 percent) amid expectations that the costs of those technologies at scale will continue to decline (Figure 29).

### Figure 29

<table>
<thead>
<tr>
<th>Technique</th>
<th>Next 10 years</th>
<th>Beyond 10 years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar</td>
<td>78.9%</td>
<td>40.1%</td>
</tr>
<tr>
<td>Wind</td>
<td>66.7%</td>
<td>41.5%</td>
</tr>
<tr>
<td>Power purchase agreements (PPAs)</td>
<td>66.7%</td>
<td>29.3%</td>
</tr>
<tr>
<td>Natural gas</td>
<td>62.2%</td>
<td>25.2%</td>
</tr>
<tr>
<td>Battery energy storage</td>
<td>60.6%</td>
<td>47.6%</td>
</tr>
<tr>
<td>Retiring traditional fossil-fueled generation sites</td>
<td>58.9%</td>
<td>34.7%</td>
</tr>
<tr>
<td>Combined cycle</td>
<td>53.3%</td>
<td>29.3%</td>
</tr>
<tr>
<td>Making traditional fossil-fueled generation more efficient</td>
<td>50.0%</td>
<td>19.7%</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>13.9%</td>
<td>57.8%</td>
</tr>
</tbody>
</table>
When asked specifically about the services for which they would consider hydrogen, more than four in 10 respondents said they would consider it for fuel cell storage, nearly double those who cited its potential use for transportation fuel for fleets and as an option for peak power generation. Fewer than one-fifth said they see it as a source of backup power or a component of a microgrid (Figure 30).

**Road-mapping Decarbonizing: The Time is Now**

While utilities are awakening to the new reality of large-scale renewable energy, stakeholders must start now in thoughtfully mapping out a decarbonized future. This is particularly true given the complicated buildout of new infrastructure that takes years beyond the early planning stages. Of particular relevance is sorting out how the utility’s carbon-reduction, renewables or sustainability goals align to its local jurisdiction(s). Smaller utilities may need incentives to get them off the sidelines, abandon their stay-the-course mindset because it’s merely more affordable and get them to the same level of commitment to renewables as their bigger counterparts.

As private investment in clean energy continues to grow globally, electric utility planners and regulators will need to adapt their forecasts and investments accordingly. This will require more rapid design and development, as well as collaboration with interested stakeholders and investors. As several studies have shown, clean energy investments create a greater number of — and often higher-paying — jobs relative to other energy investments. Just what we need for a more rapid economic recovery in a pandemic-stricken world.

### ABOUT THE AUTHORS

**Jason Rowell** is an associate vice president and global technology portfolio manager for Black & Veatch. He is responsible for developing projects and implementing industry leading solutions through technology innovation. Technology portfolio areas under Rowell’s direct leadership include carbon capture and utilization, hydrogen, supercritical CO2, waste-to-energy, biomass, and environmental and sustainability.

**Kevin Prince** leads Black & Veatch’s global distributed generation business overseeing the strategic direction, growth and execution of the company’s DER offerings serving both commercial and industrial customers as well as utilities. Solutions include onsite solar, energy storage, electric vehicle infrastructure, fleet electrification and CHP. He has more than 18 years of experience in the energy industry and has developed and closed more than $1 billion in projects for Fortune 500 companies and public and governmental entities.

**Rob Wilhite** leads Black & Veatch’s Global Distributed Energy business line. This includes the design, engineering, development, and monitoring/maintenance of client sustainable power solutions, including distributed generation, microgrids, battery energy storage, asset management services and utility grid services.

**Heather Donaldson** is director of Black & Veatch Management Consulting, where she is responsible for supporting clients through grid modernization, DER integration and other transformations. A recognized expert in the energy industry, Donaldson has served as a special advisor to the California Public Utilities Commission, as a principal with Southern California Edison, and as a director with California ISO.
Electric Industry Rethinks its Generation Portfolios With Eye Toward Renewables, Hydrogen

By Denny Yeung, Hua Fang and Jason Rowell

Illustrating how U.S. electric utilities are rethinking their power generation portfolio mixes, Florida Power & Light Co.’s corporate parent presented itself as a trailblazer in an evolving industry where once-dominant coal spirals out of favor, ceding to cleaner, greener options.

On earnings call with analysts in July, NextEra Energy’s chief financial officer affirmed plans by FPL — among the biggest rate-regulated electric utilities in the U.S. — to retire its last coal-fired plant in early 2022. Rebecca Kujawa added that mothballing the 847-megawatt site as part of the company’s coal phase-out launched in 2015 should save FPL customers hundreds of millions of dollars and prevent some 4 million tons of carbon dioxide emissions a year.

With more than 5 million customer accounts in Florida, FPL becomes one of the nation’s first utilities to purge coal entirely from its generation portfolio and stake its future to alternative fuel sources, both for the sake of the environment and resilience.
While other utilities are slower in making such an aggressive shift, there’s little question the industry is migrating from coal — and to some degree, cleaner-burning natural gas — toward more renewable power from the wind, sun and even hydrogen, a rising star. Advances in energy storage may hold the key in accelerating the makeover.

Call it a repowering of the power sector, and a recent survey of more than 600 electric industry stakeholders for Black & Veatch’s latest Strategic Directions: Electric Report brings it into tighter focus.

Nearly half of respondents say they’re investing much more or somewhat more into local renewables at least in the short-term, outpacing capital spending on such things as distribution, transmission and other DER. Looking out over the next half decade, the push for renewables is more striking. Eight of 10 respondents — 82 percent — forecast that more of their investments in new generation capacity will be directed at solar arrays on land, followed closely by energy storage (79 percent) and eventually microgrids and other DER (65 percent).

Wind energy both on land and water, along with floating solar, are seeing more popularity than power fueled by natural gas. Spending on coal-fired generation ranked dead last, with just 3 percent planning to increase their spending on it — and 60 percent expecting to devote “much less” funding (Figure 32).

Energy storage’s ranking of second only to on-land solar illustrates the mindshare that technology has grabbed and figures to continue to grow as the cost of battery and other types of longer-duration storage declines over time, accelerating adoption of renewables along the way.

At least in the near-term, the survey shows, abundant natural gas is expected to play a key role in the power generation equation — most likely as a backup, covering for the intermittency of solar and wind energy — as traditional baseload coal and nuclear generation are retired.

Forty-five percent of respondents anticipate that investment in natural gas will continue beyond 2035 as coal and nuclear units are retired. Just 10 percent see fossil fuels as important grid components over the next decade and a half (Figure 31).

**Figure 31**

Is there a future for fossil fuel generation (utility-scale coal and gas generation) in your region(s) of operation beyond 2035? Select the scenario that best applies.

Source: Black & Veatch

<table>
<thead>
<tr>
<th>Percentage</th>
<th>Scenario Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>10.1%</td>
<td>Yes, both coal and gas will remain important components of the grid beyond 2035</td>
</tr>
<tr>
<td>44.5%</td>
<td>Yes, investment in gas will remain long term however coal will be gradually phased out with little new development</td>
</tr>
<tr>
<td>15.9%</td>
<td>We will see limited investment in coal and gas investment will focus mostly on upgrading existing facilities only</td>
</tr>
<tr>
<td>7.5%</td>
<td>No, we will see limited investment in both gas and coal</td>
</tr>
<tr>
<td>15.6%</td>
<td>No, we will see limited investment in gas and we will also start seeing increased decommissioning of coal facilities</td>
</tr>
<tr>
<td>6.5%</td>
<td>No, we will see increased decommissioning of both gas and coal facilities</td>
</tr>
</tbody>
</table>
For each of the following categories, how do you expect new generation capacity investments to change over the next five years in your region? *(Select one for each row)*

Source: Black & Veatch

<table>
<thead>
<tr>
<th>Category</th>
<th>Much more investment than today</th>
<th>Somewhat more investment than today</th>
<th>Same investment as today</th>
<th>Somewhat less investment than today</th>
<th>Much less investment than today</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar (on land)</td>
<td>42.7%</td>
<td>39.1%</td>
<td>13.6%</td>
<td>3.3%</td>
<td>1.3%</td>
</tr>
<tr>
<td>Solar (floating)</td>
<td>9.8%</td>
<td>31.1%</td>
<td>40.9%</td>
<td>8.8%</td>
<td>9.5%</td>
</tr>
<tr>
<td>Energy storage</td>
<td>36.6%</td>
<td>41.9%</td>
<td>17.8%</td>
<td>2.7%</td>
<td>1.0%</td>
</tr>
<tr>
<td>Microgrids and other DER</td>
<td>22.6%</td>
<td>42.2%</td>
<td>26.4%</td>
<td>5.4%</td>
<td>3.4%</td>
</tr>
<tr>
<td>Wind (on land)</td>
<td>17.9%</td>
<td>41.2%</td>
<td>31.4%</td>
<td>7.4%</td>
<td>2.0%</td>
</tr>
<tr>
<td>Wind (offshore)</td>
<td>16.9%</td>
<td>32.9%</td>
<td>35.3%</td>
<td>9.2%</td>
<td>5.8%</td>
</tr>
<tr>
<td>Gas-fired / LNG-to-power</td>
<td>8.8%</td>
<td>29.9%</td>
<td>37.1%</td>
<td>19.4%</td>
<td>4.8%</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>7.1%</td>
<td>19.3%</td>
<td>56.3%</td>
<td>9.8%</td>
<td>7.5%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>2.0%</td>
<td>14.2%</td>
<td>36.3%</td>
<td>24.4%</td>
<td>23.1%</td>
</tr>
<tr>
<td>Coal-fired</td>
<td>0.3%</td>
<td>2.4%</td>
<td>13.5%</td>
<td>23.6%</td>
<td>60.1%</td>
</tr>
</tbody>
</table>
According to U.S. Department of Energy data, annual energy usage from renewable sources in April 2019 exceeded coal consumption for the first time since before 1885.

The March of Renewables

According to U.S. Department of Energy data, annual energy usage from renewable sources in April 2019 exceeded coal consumption for the first time since before 1885, and that trend isn’t slowing.

Earlier this year, the U.S. Energy Information Administration (EIA) predicted that solar and wind energy would dominate America’s new generation in 2020, accounting for three-quarters of new generation while adding 42 gigawatts (GW) of zero-emission capacity. As the most-used source of renewable energy for U.S. electricity generation on an annual basis, wind power last year surpassed hydropower for the first time and is forecast to represent the biggest share of new U.S. generation from renewables in 2020, at 44 percent, followed by solar (32 percent) and natural gas (22 percent). Coal-fired power production, which last year plunged to its lowest level in 42 years, is anticipated to slide by an additional 13 percent in 2020, merely adding to its disfavor over the past decade.

Striking drop-offs in prices for energy derived from the wind and sun have fanned the broader adoptions of it by utilities, putting utility-scale renewable energy prices appreciably below those for coal and gas generation, strengthening the business case for clean energy.

Over the next decade, the survey results illustrate, utilities expect solar (79 percent) and wind (67 percent) power to help them meet their clean energy goals or cut their emissions and carbon output, presumably because those renewables are readily deployable with established, matured technology and competitive costs. Those numbers drop into the 40th percentiles beyond 10 years, segueing to more deployments of hydrogen (58 percent) and battery energy storage (48) as the leading, more favored options to getting greener as those options evolve.

The Rising Promise of Hydrogen

Already used in industrial processes, “gray hydrogen” — derived from fossil fuels such as oil, natural gas and coal — slowly is giving way to “green hydrogen,” produced when electricity from clean solar or wind generation is used to power the electrolysis process that separates hydrogen and oxygen atoms in a water molecule. That hydrogen gas then can be stored in a tank or cavern before being funneled into a fuel cell, creating clean, emissions-free electricity.

To FPL and some other utilities ambitiously pursuing decarbonization, hydrogen is simply elemental.

While acknowledging its toe-in-the-water approach to deploying solar and battery storage, NextEra is devoting $65 million to a proposed FPL pilot effort to use solar energy that otherwise would have been clipped to produce completely green hydrogen through a roughly 20-megawatt (MW) electrolysis system.
Subject to approval by Florida regulators, the plan is to use the hydrogen by 2023 to replace a portion of the natural gas being consumed by one of the three Okeechobee Clean Energy Center gas turbines.

“Based on our ongoing analysis of the long-term potential of low-cost renewables, we remain as confident as ever that wind, solar and battery storage will be hugely disruptive to the country’s existing generation fleet, while reducing costs for customers and helping achieve future CO2 emissions reductions,” NextEra’s Kujawa told analysts. “However, to achieve an emissions-free future, we believe other technologies will be necessary, and we are particularly excited about the long-term potential of hydrogen.”

Thousands of miles away, Black & Veatch is helping the Intermountain Power Agency (IPA) transition to green hydrogen as it works to substantially decrease and ultimately minimize its carbon footprint across Utah, Nevada and California. As part of its intermountain “renewable project” — among the earliest installations of combustion turbine technology designed to use a high percentage of hydrogen, which emits only water — the plan is to eventually replace a coal-fired power plant with an 840-megawatt, combined-cycle natural gas facility. The new plant will be commercially guaranteed capable of blending 30 percent green hydrogen at start-up, with plans to transition to pure hydrogen by 2045.

As the Institute for Energy Economics and Financial Analysis has reported, the Los Angeles Department of Water and Power — operator of the Intermountain site and the biggest buyer of its power — plans to use the revamped plant to help meet California’s target to completely decarbonize all retail power sales in the state by 2045. Several other municipal utilities in California and Utah that now purchase power from the coal-fired plant have agreed to buy electricity from the re-powered project.

Overseas, there’s broader, more aggressive adoption of melding hydrogen into generation mixes. But domestically, as Black & Veatch’s survey results show, deployment of that gas as a power source is more plodding, perhaps because of its relative novelty. More than four in 10 respondents — 43 percent — said they would consider hydrogen for fuel cell storage, with roughly one-quarter citing the gas’ potential use for transportation fuel for fleets or as an option for peak generation. Using hydrogen for backup power or as part of a microgrid garnered slightly less than one-fifth of the responses. Three in 10 said they wouldn’t consider hydrogen at all.

The Push to Decarbonize: The Carrot or the Stick

With great fanfare, North Carolina-based Duke Energy — with 7.7 million electric customers and 1.6 million gas customers — last year committed to be entirely carbon-free by 2050 and cutting emissions in half by the end of this decade, helped a great deal by battery storage. The company expects to double its renewable energy portfolio by 2025, up 10 percent from its earlier goal.

Duke is making the move on its own, without regulatory or legislative pressure. Other utilities are being compelled to change to meet state-mandated clean energy targets increasingly demanded by environmental activists, investors, rate-payers and regulators. Dozens of states either have enacted renewable energy portfolio standards or goals or are considering them.

Some 85 percent of respondents to Black & Veatch’s survey are pursuing getting cleaner and greener with goals of cutting planet-warming emissions or turning to more renewables, albeit for different reasons. More than half — 53 percent — say they’re doing so voluntarily, roughly 13 percentage points more than those attributing their efforts to a state regulatory mandate. Fifteen percent report report having no such goals.

To no one’s surprise, bigger utilities — those serving at least 2 million people — more
commonly are chasing cleaner ways of power generation by their own volition, perhaps because they have the balance sheets to do it. Thirty percent of smaller utilities, which serve fewer than 500,000 residents, say they have no such goals, perhaps because of the cost.

Across the board, more utilities rethinking their power generation mixes are awakening to the economic and environmental merits of renewable energy amid forecasts that the prices for it will continue declining over the coming decades as the technology reaches broader scale.

As Silvio Marcacci of the nonpartisan climate policy think tank Energy Innovation pressed in a Forbes column last January, “utilities that stick with a business-as-usual approach do so at their own peril, increasing the risk of expensive stranded assets and higher consumer electricity prices.”

ABOUT THE AUTHORS

Denny Yeung is a principal consultant for Black & Veatch Management Consulting. He is an active contributor to Black & Veatch’s Energy Market Perspective (EMP), its long-term view of gas and electric markets. Yeung has managed numerous gas-electric reliability assessments and is responsible for developing the natural gas fundamental forecast.

Hua Fang is a director of advisory and planning with Black & Veatch Management Consulting LLC. She is a Ph.D. economist with 20 years of experience in integrated energy market modeling and forecasting, asset valuation and commercial strategy. Fang oversees Black & Veatch’s Energy Market Perspective, an integrated energy modeling framework that projects long-term developments of the North America energy markets.

Jason Rowell is an associate vice president and global technology portfolio manager for Black & Veatch. He is responsible for developing projects and implementing industry leading solutions through technology innovation. Technology portfolio areas under Rowell’s direct leadership include carbon capture and utilization, hydrogen, supercritical CO2, waste-to-energy, biomass, and environmental and sustainability.
From Wildfires to COVID-19 and Grid Instability, Challenges Impact Capital Planning, Plant Betterment

By Jason Rowell, Mark Dittus, Chris Klausner and Thiam Giam

COVID-19. Negative oil pricing. Wildfires. Grid instability. Rolling Blackouts. Global energy market shocks. These are just a few of the disruptive forces facing owners and operators of traditional power generation assets. For asset owners on the edge of the dispatch curve, rapidly changing regulatory requirements and consumer preferences further cloud capital planning programs as 2020 kicked off a market in transition.

Consistently low power prices driven by COVID-19 demand reductions and other macroeconomic forces placed significant pressure on owners of coal and aging natural gas assets, driving investments in transmission and distribution (Figure 33). Renewable energy, distributed energy resources (DER) and moon-shot technologies aimed at decarbonization garnered not just headlines but capital while the decline in generation likely reflects technologies on different stages of a similar curve.
Nearly 10 years ago, the Black & Veatch Energy Market Perspective predicted the ensuing decade would see the retirement of roughly 65 gigawatts (GWs) of baseload coal capacity across the United States. In fact, the decade would see more than 75 GW of coal plants removed from the bulk electric system, mostly in the form of older, smaller plants often in the PJM and New England markets. Air quality control (AQC) regulations played some part in spurring the flight from coal as costly AQC investments were weighed for return on investment (ROI), while the incentives for and embrace of renewables would shift market generation capacity. Ultimately, however, sustained low gas prices would accelerate coal plant closures due to economics and spur the boom in highly efficient gas-fired generation.

For those coal plants that continue to operate, the future is increasingly challenging with current market conditions. The desires to boost production of green energy and source it are tangible market forces, but the reality is that sustained low prices for gas at $2 to $3 (US), a price range once unheard of, is both crushing coal operators chances of dispatch, and appears to be the effective trading range for the foreseeable future. Nearly three-quarters of respondents anticipate less investment in coal asset improvement capital than in the prior five years. In a world where dispatch is king, the trend is bleak for slow-reacting base load resources (*Figure 34*).

**Figure 33**
Compared to last year, how have your utility’s short-term capital investments changed?
*(Select one per row)*

<table>
<thead>
<tr>
<th></th>
<th>Much more investment than last year</th>
<th>Somewhat more investment than last year</th>
<th>Same investment as last year</th>
<th>Somewhat less investment than last year</th>
<th>Much less investment than last year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Local renewables</td>
<td>11.4%</td>
<td>34.5%</td>
<td>45.0%</td>
<td>6.6%</td>
<td>2.6%</td>
</tr>
<tr>
<td>Distribution</td>
<td>12.1%</td>
<td>27.3%</td>
<td>49.4%</td>
<td>8.2%</td>
<td>3.0%</td>
</tr>
<tr>
<td>Transmission</td>
<td>11.9%</td>
<td>26.0%</td>
<td>49.8%</td>
<td>9.3%</td>
<td>3.1%</td>
</tr>
<tr>
<td>Other distributed energy resources (DER)</td>
<td>5.9%</td>
<td>25.2%</td>
<td>58.6%</td>
<td>8.1%</td>
<td>2.3%</td>
</tr>
<tr>
<td>Generation</td>
<td>4.2%</td>
<td>15.1%</td>
<td>53.4%</td>
<td>19.3%</td>
<td>8.0%</td>
</tr>
</tbody>
</table>
Depressed power prices are making all of the above even worse, especially in markets that don’t have capacity prices. If a plant isn’t dispatching “in the money,” there’s often no point in firing up the unit at all. Even in PJM, the nation’s largest ISO which features a capacity price, the amount of dispatch opportunities is limited for coal.

So what is an operator to do with a functioning coal plant? There are some newer units that have firm long-term contracts, but those increasingly are exceptions to the rule. Many are exploring the low hanging fruit that can help improve the odds of dispatch and demonstrate some ROI. Start-up costs are a big factor in where coal assets sit on the dispatch queue. Can investments in a natural gas start up system versus an older, more costly (at startup) oil system pay back?

**Figure 34**

Compared to the past five years, how will you allocate your next five years of plant improvement capital budget? *(Select one per row)*

Source: Black & Veatch

<table>
<thead>
<tr>
<th></th>
<th>Much more investment in next 5 years</th>
<th>Somewhat more investment in next 5 years</th>
<th>Same investment</th>
<th>Somewhat less investment in next 5 years</th>
<th>Much less investment in next 5 years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar</td>
<td>30.6%</td>
<td>43.7%</td>
<td>20.1%</td>
<td>2.6%</td>
<td>3.1%</td>
</tr>
<tr>
<td>Wind</td>
<td>18.5%</td>
<td>39.2%</td>
<td>29.7%</td>
<td>5.4%</td>
<td>7.2%</td>
</tr>
<tr>
<td>Gas</td>
<td>5.8%</td>
<td>21.1%</td>
<td>46.6%</td>
<td>17.5%</td>
<td>9.0%</td>
</tr>
<tr>
<td>Combined-cycle</td>
<td>4.1%</td>
<td>19.5%</td>
<td>50.0%</td>
<td>16.4%</td>
<td>10.0%</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2.9%</td>
<td>10.5%</td>
<td>61.0%</td>
<td>7.1%</td>
<td>18.6%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>1.9%</td>
<td>9.3%</td>
<td>49.8%</td>
<td>10.7%</td>
<td>28.4%</td>
</tr>
<tr>
<td>Coal</td>
<td>0.9%</td>
<td>2.7%</td>
<td>4.2%</td>
<td>21.8%</td>
<td>48.9%</td>
</tr>
</tbody>
</table>
Other operators are starting to make choices about accelerating start-ups to capitalize on demand spikes. This comes with a cost as coal plants were never intended to cycle, but as the 50- to 60-year life span of many coal plants built in the 1960s and 1970s now seem highly unlikely with younger units, the risk is being deemed acceptable.

The challenging market landscape is creating a rethinking of where the value play is with coal assets. Unless an operator has committed funding to upgrade a facility, they still may be holding onto an asset that gets harder and harder to extract value from. Units that cannot make the money to cover coal assets’ fixed costs and cannot make money because of gas and renewables are unlikely to see the contrary investment play of certain coal assets in the mid-2010s.

In short, many remaining coal plants are becoming teardowns in real estate parlance. The value isn’t in the equipment anymore but in its location to critical grid assets. Repurposing is the emerging thesis with the purchased asset being less about potential to produce power and more about the location. New owners can still make money in a capacity market if they buy a dispatchable coal asset or repower it, but a lot of investors now are more interested in buying the asset to repurpose the site, leveraging the supporting infrastructure. These highly integrated brownfield sites are increasingly popular sites for data centers or other emerging assets that could benefit from proximity to bulk transmission assets.

As we examined the survey data, we noted that in the past 12 months the authors haven’t had a single U.S. inquiry for a resource plan seeking new coal assets. The data and our experience centers more on whether owners should retire more of it and faster.

Given the importance of reliability, complexity of adding baseload generation in many areas and continuing uncertainty around emerging power generation technologies, many experts expect that coal generation may be around for another 20 to 30 years. But it will be in select areas such as Montana, Wyoming and the northern U.S. areas, the latter where it would be increasingly seasonal, as gas pipeline constraints makes it more challenging to get resources to the demand center.

**ABOUT THE AUTHORS**

**Jason Rowell** is an associate vice president and global technology portfolio manager for Black & Veatch. He is responsible for developing projects and implementing industry leading solutions through technology innovation. Technology portfolio areas under Rowell’s direct leadership include carbon capture and utilization, hydrogen, supercritical CO2, waste-to-energy, biomass, and environmental and sustainability.

**Mark Dittus** is the plant modernization global technology manager for Black & Veatch’s conventional generation business line, responsible for overall engineering team leadership, guidance and performance within this service area. During his 27-year career at Black & Veatch, he has managed numerous plant upgrade projects encompassing air quality control systems, turbine modifications, steam generator modifications, control and electrical system upgrades, and balance-of-plant installations.

**Chris Klausner** is a senior managing director in Black & Veatch Management Consulting, providing technical advisory services and direction for clients for planning and transaction-related engagements. He is responsible for performing independent engineering assessments for project lenders, sponsors and various investors pursuing acquisitions of generation assets. In the past few years, Klausner has led engagements representing several thousand megawatts of generation capacity and several billion in valuation and financing for clients across the power, transmission, oil and gas, and water industries.

**Thiam Giam** is a senior managing director in Black & Veatch Management Consulting. With more than 20 years of experience, Giam has completed various due diligence engagements — technical, environmental and market analysis — related to development, transaction and refinancing involving various energy and water projects and companies globally. He has advised international companies on various merger and acquisition (M&A) and financing activities, and he has more than eight years of experience in the design, development, engineering, procurement, construction, testing and commissioning phases of transmission and distribution projects.
Electric Transportation: Getting Out of First Gear
By Maryline Daviaud Lewett, Randal Kaufman, Paul Stith and Mark Von Weihe

Across the nation, the drive to electrify transportation is shifting into high gear, with further acceleration expected as market participants increasingly see electric vehicles (EVs) as a gateway to sizable business benefits.

It’s a transformation borne out in the feedback from more than 600 electric industry stakeholders surveyed for Black & Veatch’s latest Strategic Directions: Electric Report. The percentage of respondents who consider electrified transportation as a big opportunity to gain future load and revenue spiked 74 percent over 2019, to 21 percent from just 12 percent. Consistent with a year ago, an additional 38 percent said it was a good business opportunity — in many cases, a must to operate and grow business in certain states — but that they would have to invest in infrastructure to optimize the benefits (Figure 35).

The survey was fielded during a busy summer for electrifying transportation. In July, 15 states and the District of Columbia signed a memorandum of understanding (MOU) to spur greater adoption of electric options in medium- and heavy-duty fleets to improve air quality by curtailing carbon emissions, fighting global climate change. Later this year, the MOU signatory states will produce a multi-state action plan to identify barriers and propose solutions to support widespread electrification of medium- and heavy-duty vehicles.

We know from a century of utility regulation that utilities respond to regulatory direction, which should apply a little more octane on their journey to electrification.

When respondents were asked where they were on the road to electrifying transportation, survey results produced a bell-shaped curve. Those on the leading edge — roughly one in 10
— said they were in the late stage of adopting, meaning charging stations were widely available in their market. More than one in five — 21 percent — said they were in the middle to late stage, where many charging stations were deployed in their service area. Some 44 percent said they were in the middle stage, where some charging stations were deployed (Figure 36).

Perhaps not surprisingly, utilities that identified themselves as being in the late stage of EV infrastructure deployment were concentrated in the West, where state mandates and local incentives have led to aggressive EV infrastructure plans to meet emission reduction targets. Notably, 40 percent of those who said they were in a middle to advanced stage of EV infrastructure deployment were found in the Northeast. This reflects the somewhat more recent growth of EV adoption in the Northeast and increase in regulatory mandates to hasten charging infrastructure. Ownership of EV charging infrastructure continues to be a charged question, and utilities are finding regulatory proceedings on EV infrastructure ownership have become a bumper-to-bumper traffic jam, where filings from numerous intervenors have crowded regulatory dockets.

Regulators in some states are getting aggressive, imposing or mulling mandates that force broader adoption of zero-emission vehicles (ZEVs). California is leading the way, calling for full transformation in the next couple of decades. With California, at least nine other states — Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon, Rhode Island and Vermont — have signed a MOU committing to coordinated action to ensure the implementation of their state ZEV programs, explaining why such policy mandates are clustered in the West and Northeast. Collectively, these states are committed to having at least 3.3 million ZEVs operating on their roadways by 2025.
Perhaps not surprisingly, 14 percent of small utilities — defined as serving fewer than 500,000 customers — are on the sidelines of electrification. But half of their small-utility brethren report that they are in the middle stage, with some charging stations deployed. Among those in the late stage of EV infrastructure deployment, there were no statistically significant differences between small, medium and large utilities.

Despite the expressed enthusiasm for electrifying transportation and deploying EV infrastructure, there's a significant disconnect: a solid, sizable proportion of respondents to this year’s survey — between 36 percent and 41 percent — said it was of slight or no importance that vehicle charging stations be tied to renewable generation. From a public policy perspective, elected officials and utility regulators are pushing electrifying transportation as a way to clear the air and help combat global climate change. Recharging EVs with electricity generated from coal isn’t likely to pass muster with lawmakers and regulators (Figure 37).

From a public policy perspective, elected officials and utility regulators are pushing electrifying transportation as a way to clear the air and help combat global climate change.
On a year-over-year basis, there was a marked decline in the number of utilities that said they were working closely with local transit agencies to support vehicle electrification. But encouragingly, there were statistically significant increases in respondents that said they were just starting to engage with those agencies. Such was the case also with those who said they had not yet engaged but were planning to do so (Figure 38).

Once again, engagement with transit agencies appears to be partly a function of the utility’s size. Compared to mid-sized and large utilities, small utilities say they perceived less of a need to engage with local transit agencies, while more than one-quarter (27 percent) said they had not engaged with such agencies and had no plans to do so. But half of large utilities — those serving at least 2 million customers — said they were very engaged with local agencies. Half of mid-sized utilities, serving between 500,000 and 2 million customers, said they were starting to interact with those agencies.

### Figure 37
How important is it that vehicle charging stations in your area be tied to renewable generation? (Select one for each type)

<table>
<thead>
<tr>
<th>Charging stations for</th>
<th>Extremely or very important</th>
<th>Moderately important</th>
<th>Slightly or not at all important</th>
</tr>
</thead>
<tbody>
<tr>
<td>Consumer EVs</td>
<td>33.7%</td>
<td>30.4%</td>
<td>35.9%</td>
</tr>
<tr>
<td>Commercial EV fleets</td>
<td>27.2%</td>
<td>40.2%</td>
<td>32.6%</td>
</tr>
<tr>
<td>Your utility’s fleets</td>
<td>22.2%</td>
<td>36.7%</td>
<td>41.1%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch

### Figure 38
Is your utility working with the local transit agency or agencies in your territory to support electrification? (Select one)

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yes, very engaged</td>
<td>33.3%</td>
<td>52.1%</td>
</tr>
<tr>
<td>Yes, just starting to engage</td>
<td>36.0%</td>
<td>24.0%</td>
</tr>
<tr>
<td>No, but planning to</td>
<td>18.7%</td>
<td>11.6%</td>
</tr>
<tr>
<td>No, and no plans to</td>
<td>12.0%</td>
<td>12.4%</td>
</tr>
</tbody>
</table>

Source: Black & Veatch
Changing over the nation’s vehicle stock is an activity measured over the course of a decade or more, rather than a single model year. Ultimately, durability and functionality will hold sway, particularly for electric buses, trucks, cars, airport service vehicles and freight-moving vehicles. For passenger vehicles, greater battery range and increased deployment of charging stations, both in the home and in public places, would speed the attainment of the clean-air future promised by electrified transportation.

ABOUT THE AUTHORS

**Maryline Daviaud Lewett** leads sales and partnerships in distributed infrastructure and sustainable transportation for Black & Veatch’s transformative technologies business. The group has extensive experience in design and engineering, procurement and construction of electric vehicle charging infrastructure networks, fuel cell vehicle filling station networks, and behind-the-meter energy storage. Daviaud Lewett has more than 20 years of experience in the cleantech, life sciences and software industries.

**Randal Kaufman** directs sales in Black & Veatch’s transformative technologies business. He is the author of the “Fossil-Free Resilient Energy for Zero Emission Transportation and Facility Power Strategy,” devised from more than 15 years of experience in the data center and fuel cell industries, including significant responsibilities in electric vehicle charging infrastructure and complementary energy delivery systems.

**Paul Stith** is director of global transportation initiatives for Black & Veatch’s growth accelerator, where he focuses on building ecosystems needed to plan, finance, deploy and operate sustainable transportation and distributed clean energy infrastructure at scale. His projects support investors, utilities, fleets, energy and transportation providers in electrifying, decarbonizing and automating their ground, aviation and marine fleets. Stith has a decade of zero-emission vehicle infrastructure experience and serves on Forth and NACFE boards of directors.

**Mark Von Weihe** is a senior managing director with Black & Veatch Management Consulting, where he is working to expand the company’s technology offering portfolio into new industry segments. With more than 20 years of experience, Von Weihe is recognized throughout the utility industry for his strategic work in technology, commercial trading, renewable energy and electric distribution operations consulting.
Coronavirus Presents New Challenges for Energy Sector’s Cybersecurity Implementation

By Bo Poats and Joe Zhou

The COVID-19 pandemic threw a wrench into the power utility sector’s cybersecurity planning, leaving North American electric utility leaders facing the challenge of securing the grid against the growing threat of cyberattacks while meeting profound changes in energy use.

As the pandemic’s one-year anniversary nears, broader economic trends point to fundamental shifts in how America’s workforce uses energy. Those still-fluid changes, plus the increased risk of cyberattacks and mandatory cybersecurity standard compliance, have created complex new dynamics for the electric utility sector.

Results from Black & Veatch’s 2020 Strategic Directions: Electric Report survey of the power industry reveal that while utility leaders have made strides in meeting compliance requirements of the Critical Infrastructure Protection Program (CIP) of the North American Electric Reliability Corporation (NERC), there’s still plenty of work to be done. The rapidly changing landscape of coronavirus-complicated energy demands has elevated new cyber-risk vulnerabilities and the related potential of substantial service loss, asset damage and data security breaches.
Cyberattacks: A Growing Threat for North American Power Grid

Cybersecurity experts long have warned of potentially significant attacks on the North American power grid as consumers and utilities alike embrace the efficiencies of connectivity, the Internet of Things (IoT) and new digital technologies.

An increasingly unstable global political climate has heightened the sense of urgency for cybersecurity mitigation. Analysts warned the U.S. energy sector of potential phishing attacks emerging out of heightened military tensions between the U.S. and Iran, according to a January 2020 report by Industry Dive. Just days later, a cybersecurity firm reported that hacking groups were targeting critical infrastructure sectors, including the North American power grid, although no breaches occurred.

Economic downturns are well-known to heighten the frequency of cybersecurity attacks. Desperate times and idle hands favor increased online criminal activity, as security officials learned during the 2008-2009 economic recession. In the case of the coronavirus, however, the threat is exponential. Not only are there more cybercriminals and bad actors lurking, but the sudden shift in energy use — and the need for utilities to respond to those unprecedented demands while safeguarding their staff during the pandemic — have created new security gaps.

Such a confluence of events presents a unique challenge. North American utility leaders must press forward to meet cybersecurity compliance requirements, assess new risks and rapidly allocate resources to keep cybersecurity measures up to speed with America’s rapidly changing power requirements.
Utilities Make Gains in Cybersecurity Implementation

The good news is that the electrical industry, under the pressure of a looming July 2020 CIP compliance deadline, already had made inroads securing their cyber assets before the COVID-19 pandemic took hold. In April 2020, the Federal Energy Regulatory Commission (FERC) responded to coronavirus disruptions, issuing an order extending deadlines for CIP compliance’s five components. Deadlines now range between October 2020 to April 2021, depending on the component.

But many in the energy sector already were working hard on their cybersecurity compliance. In last year’s Black & Veatch Strategic Directions: Electric Report survey, respondents chose cybersecurity as their No. 3 choice as the most-challenging issue facing the industry. This year’s results show cybersecurity slipping slightly to sixth place, reflecting shifting coronavirus resource priorities and cybersecurity implementation prompted by the CIP deadlines (Figure 39).

Overall, the newest survey results reveal that electric utility leaders remain committed to cyber securing their assets for at least the next five years. Cybersecurity is second only to asset management in terms of prioritized financial investment into technological improvements, capturing 14 percent of their total technology budget (Figure 40).
Figure 41

Do you have a formal cybersecurity program or documentation? (Select one)
Source: Black & Veatch

- 68.9% Yes, it covers both IT and OT
- 19.3% Yes, it covers information technology
- 11.8% Yes, it covers operation technology

Cybersecurity Work Yet to Be Done

Despite the sector’s advances in cybersecurity implementation, survey results revealed areas where significant work has yet to be done.

Many utilities still are working to close their operational technology (OT) gap. Roughly one-fifth of respondents indicated that while they have a program covering cybersecurity for information technology (IT), they have yet to implement one for OT, despite CIP requirements. This can be accomplished, strategically, by identifying the cyber risk gaps and prioritizing a closure strategy (Figure 41).

For a recent project with Louisville Gas & Electric Company and the Kentucky Utilities Company (LKE), Black & Veatch applied a best practices methodology, identifying cybersecurity gaps for technology, hardware, software, staff, training, process and governance across all their physical assets. After internally scoring LKE on strengths and weaknesses, an external threat analysis was created for their unique operations. That was translated into a benefit-cost ratio, allowing LKE to prioritize the most bang for their cybersecurity investment buck over the next five years.

Another concern is that while utilities increasingly have leveraged new technology for operational efficiencies, many have not kept up with the subsequent cyber risks. Nearly one-quarter of utilities surveyed noted that their cybersecurity investments had not moved in lockstep with their investments into digital assets and customer engagement (Figure 42).

This is a classic cybersecurity challenge in the adoption of digital operations. Investments

Figure 42

Have your investments in cybersecurity moved in lock step with your digital operations and customer engagement investments? (Select one)
Source: Black & Veatch

- 68.3% Yes, we have similarly invested in both
- 24.4% No, our investments in digital have outpaced investments in cybersecurity
- 7.3% No, our investments in cybersecurity have outpaced investments in digital
In operational efficiencies such as connecting operating grids to dynamic real-time control or going from serial communications to IP connectivity bring tremendous benefits, but they often create new cyber risks. The lag between the operational improvements and the programs, processes and training to make them cyber secure can expose vulnerabilities that illicit individuals may capitalize on to damage equipment, cause disruptions or compromise secure data.

Smaller utilities lag behind larger ones when it comes to cyber securing their assets and meeting compliance regulations. A lack of resources and economies of scale make it more challenging to warrant significant system investments. According to the survey, more than half — 54 percent — of utilities serving 500,000 to 2 million customers have a formal cybersecurity program covering IT and OT, meaning nearly half are lacking on one side or the other. For utilities with fewer than 500,000 customers, 63 percent cover both IT and OT, meaning almost 37 percent are missing one component.

One strategy for smaller utilities is for municipalities to band their resources together for a cooperative roll-out. Ohio’s American Municipal Power cooperative, for example, owns and operates electric facilities, allowing them to provide a wide range of cooperative services on a non-profit basis.

Overall maintaining compliance with cybersecurity regulations, endpoint management (personal computers, laptops, mobile devices and the like), access control vulnerabilities, and retaining cybersecurity talent moved solidly into most utilities’ priority radar for the next five to 10 years (Figure 43).

This is a significant change over last year’s results, when security education and training, and optimizing security products and platforms claimed the top two ranks. Still, there is an ongoing need for education and training, given that human error is vulnerable to cyberattacks if not mitigated through proactive training programs. This is especially relevant at the OT level as the industry works to close the gaps with new IT adoptions and manage the increased device connectivity of both upstream (production controls) and downstream (consumer-focused) devices. Monitoring and instant response capabilities are training areas that are lagging for many utilities.

**Figure 43**

What will be your top issues or needs in regards to cybersecurity and physical security within the next five to 10 years? (Select up to three)

<table>
<thead>
<tr>
<th>Percentage</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>39.7%</td>
<td>Retaining cybersecurity talent</td>
</tr>
<tr>
<td>35.5%</td>
<td>Security education and training</td>
</tr>
<tr>
<td>43.8%</td>
<td>Endpoint management and vulnerabilities</td>
</tr>
<tr>
<td>44.6%</td>
<td>Maintenance compliance</td>
</tr>
<tr>
<td>24.0%</td>
<td>Identity and access management</td>
</tr>
</tbody>
</table>

**Source:** Black & Veatch
Cybersecurity Planning for Coronavirus-Prompted Usage Shifts

Considering the coronavirus impact on the sector, electric utility leaders should enter the winter planning period with an eye to a new, agile mid-term period resource planning impact and with a creative philosophy to technology adaptation.

As America’s workforce moved from downtown to online home offices, the energy loads followed them, creating fundamental changes in physical use and in usage times, as well as increased load needs for services such as data centers and broadband access to the cloud.

The load shift was significant and rapid. According to a Gallup Panel data report, by mid-April, nearly seven out of 10 employed adults were working from home. By late-summer, Business Insider reported, major companies — including Google, REI, Zillow, Twitter and Square — had announced that their employees could work at home indefinitely.

Many residential areas essentially have become commercial, and indicators suggest these fundamental workplace shifts may stay that way indefinitely. Utility leaders re-evaluating shifting customer needs and grid modernization requirements while reassessing new constraints and load loss probabilities also must factor in the impact of the cybersecurity exposures on their shifting customer and grid assets, as well as their increasingly automated grid and field operations along the way.

Additionally, the electric utility sector must ensure their employees' safety, looking to adopt new technology that accommodates work that traditionally was accomplished via human visits, including video, automated monitoring and controls technologies. Many companies have the same challenge and have been using video technology, remote conferencing and visualization to provide services that typically would have been achieved in person.

The energy sector never has faced such a profound disruption in both structural and cyclical energy use. Utilities must be agile and responsive to dynamic customer needs while not forgetting the associated cybersecurity risks. Now is the time to move beyond the short-term responses to coronavirus-fueled structural changes and factor these structural changes into mid-term planning that aligns cybersecurity strategies with shifting service obligations and prioritizes for the most significant potential load losses, associated attack vectors and mitigation strategies.

This will ensure that the energy sector can secure their response to customer needs, safeguard their physical and digital assets, and protect their service values and associated revenue streams against the opportunity loss of a cyber event. And, perhaps most importantly, they must be a reliable, trusted source of energy, backed by adaptive services and technologies, as North America recovers from the disruptions from the worst pandemic in a century.

ABOUT THE AUTHORS

Bo Poats is a managing director in Black & Veatch Management Consulting’s business technology and architecture (BTA) team, focusing on asset and energy portfolio reliability, resiliency and security requirements and the application of best practice risk measurement and mitigation. He has nearly four decades of energy sector leadership in enterprise risk management and investment planning support in the electric and gas utility, independent power and major end-use consumers sectors.

Joe Zhou is a senior managing director who leads the business technology and architecture offering group within Black & Veatch Management Consulting. The BTA offering group delivers innovative and integrated solutions around asset, risk and cybersecurity management. Zhou has more than 30 years of experience, focusing on providing strategic and transformative consulting and systems integration services to power, gas and water utilities around the world.
As Power Industry Evolves, Regulatory Uncertainty Abounds

By Russell Feingold and Deepa Poduval

In a perfect world, one of the power industry’s great advantages should be the degree of certainty in its business activities. This is readily acknowledged on the regulated side of the business, where a rate case — win or lose — results in greater certainty, at least in the short-term, for both electric utilities and their customers. And even in unregulated parts of the business, fixed costs are relatively stable and customer demand doesn’t materialize or disappear overnight the way it can in other industries such as retail or travel.

But these are profoundly imperfect times, and uncertainty in the power industry is growing, not diminishing. This means the industry will be looking for certainty where it can find it while adapting to an increasingly competitive energy marketplace that seems to bring more unknowns by the day.

All of this comes at a moment of declining electricity demand. The U.S. Energy Information Administration’s (EIA) August Short-Term Energy Outlook projects a 3.6-percent drop in total electricity consumption in 2020. People working from home — along with a hot summer — are driving a 2-percent increase in residential consumption, but that was more than offset by drops in commercial and industrial usage. Commercial consumption was expected to fall 7.4 percent for the year, according to the EIA.

Much of the industry is adapting to these unprecedented times by looking for new sources of revenue. For example, utilities are continuing to enhance the process for securing incremental revenue through pole attachment fees from broadband and telecom providers (among others), and they are redesigning pricing structures to accommodate the long-
term trend toward distributed energy resources (DER). While more homes and businesses are installing solar panels on rooftops, power providers are navigating a world where pricing often still is based on volume which creates financial uncertainty even though utilities have a continuing requirement to provide customers with reliable electric utility service whenever it is demanded.

**Regulatory Uncertainty**

Regulatory uncertainty loomed large for respondents to Black & Veatch’s 2020 Strategic Directions: Electric Report annual survey of the North American power industry. Recovering infrastructure investments and operating costs and predicting electricity prices all were areas cited as being impacted by regulatory uncertainty, respondents said (Figure 44).

Significantly higher regulatory murkiness over the past decade is largely driven by the transformational changes occurring in the market right now. The industry is transitioning very rapidly — with DER becoming more mainstream — and the regulatory framework in some cases has not caught up yet.

The COVID-19 pandemic is adding more unknowns. Many utilities moved proactively to halt customer disconnections for non-payment even before regulators took action, but other moves by regulators have raised eyebrows. For instance, the Indiana Utility Regulatory Commission (IURC) in June “amended” — without utility consent — provisions in previously-approved tariffs, including the collection of late fees, convenience fees, deposits and reconnection fees. In August, the IURC extended that provision for two more months “to prevent injury to residential ratepayers as the prohibition on utility disconnection expires.” Other similar regulator actions have been taken across the U.S. as the pandemic extends its economic grip on both businesses and individuals alike.

Utilities also have more on their plates now as they meet requirements for renewable energy. Billions of dollars invested in the transition of generation portfolios and modernization of transmission and distribution (T&D) infrastructure over time have created considerable risks and uncertainties over whether the utility is going to fully recover those costs on a timely basis. These financial risks are perceived to be greater than they were in the past.

[Figure 44]

**Is regulatory uncertainty at the federal or state level having an impact on your utility? (Select all statements that apply)**

<table>
<thead>
<tr>
<th>Percentage</th>
<th>Statement</th>
</tr>
</thead>
<tbody>
<tr>
<td>40.2%</td>
<td>Recover infrastructure investments to modernize the grid</td>
</tr>
<tr>
<td>39.2%</td>
<td>Recover operating costs and provide satisfactory earnings</td>
</tr>
<tr>
<td>26.8%</td>
<td>Accurately predict electricity prices</td>
</tr>
<tr>
<td>24.7%</td>
<td>Recover large one-time costs (e.g., storm restoration) in a timely fashion</td>
</tr>
<tr>
<td>2.1%</td>
<td>Other</td>
</tr>
<tr>
<td>16.5%</td>
<td>No, regulatory uncertainty does not have an impact</td>
</tr>
</tbody>
</table>
While those investments often have been encouraged by regulators, those costs eventually wind up in the utility’s rate base, and that’s where the rubber meets the road. Regulators and other interested parties increasingly are citing “rate fatigue” and rate affordability issues as concerns that drive closer regulatory scrutiny of the utility’s infrastructure proposals.

Even some states that allow large infrastructure investments to be included in rates have used revenue caps to moderate the immediate rate impacts on customers, with the utility left to seek reimbursement for the rest in future rate cases or regulatory proceedings.

While taking a closer look at what customers are getting for their money, regulators also are starting to ask fundamental questions. How do I make sure the utility is providing the customer with the most bang for the buck? And are the benefits of these investments, in fact, being realized by customers through cost efficiencies and enhanced services? To be sure, there is greater interest from regulators and intervenors in having utilities produce more rigorous cost-benefit analyses to make sure the value is demonstrable.

**Recovering Costs from COVID-19**

Two-thirds of the survey respondents said regulators had approved suspending utility service disconnection policies for non-payment (Figure 45).

Regulators will need to balance the utility’s need to recover added costs with the immediate electric bill relief sought by the utility’s customers due to the pandemic. This could mean seeking rate cases to cover some of those costs in 2021, with the rest coming later.

The pandemic doesn’t have to end for regulators to start allowing utilities to amortize the regulatory assets established this year, although utilities may wait until next year’s rate cases to press the issue. The requests could be contentious, and intervenors may

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**Figure 45**

Since the advent of the COVID-19 pandemic, what actions have been approved by your regulator to address the resulting impact on the utility and its customers? (Select all that apply)

Source: Black & Veatch

<table>
<thead>
<tr>
<th>Percentage</th>
<th>Action Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>66.3%</td>
<td>Temporarily suspend utility service disconnect policies for non-payment</td>
</tr>
<tr>
<td>40.0%</td>
<td>Provide temporary relief by relaxing the utility’s bad debt policies to account for ability-to-pay concerns</td>
</tr>
<tr>
<td>25.3%</td>
<td>Creation of a regulatory asset for future rate recovery to account for customer non-payments for future rate recovery</td>
</tr>
<tr>
<td>14.7%</td>
<td>Creation of a regulatory asset for future rate recovery of lost revenues caused by declines in electricity usage</td>
</tr>
<tr>
<td>8.4%</td>
<td>Implement an interim rate increase to enable rate recovery of COVID-19 related operating expenses</td>
</tr>
<tr>
<td>5.3%</td>
<td>None of the above</td>
</tr>
</tbody>
</table>
argue against them or propose to extend the amortization period meaning some utilities that go in with rate cases next year won’t necessarily ask for as much as they could justify.

While utilities are likely to seek reimbursement for COVID-19 expenses, there does not appear to be an immediate urgency to initiate those discussions in light of the more pressing issues created by the pandemic. A scant 7 percent of survey respondents said the financial impacts of COVID-19 would “cause your utility to accelerate its next rate case filing.”

**Looking to New Areas for Revenue**

Given all this uncertainty, looking for new revenue sources is more important than ever for utilities. The survey showed that more than half — 56 percent — of utilities said they are “probably” or “definitely” prepared to capitalize on their existing asset base for new sources of revenue. This was true across all sizes of utilities — from those serving fewer than a half-million customers to those serving at least 2 million customers.

Examples of these new sources of revenue include behind-the-meter products and services (e.g., programmable thermostats, online marketplace, enhanced data services) and, of course, the rapidly growing area of transportation electrification. Any new technology that enhances the customer experience with the use of electricity could serve as an incremental source of revenue for the utility.

Utilities are realizing they may not see the same level of load growth as they have seen in the past, as energy efficiency continues to improve and DER measures such as rooftop solar or small generation grow. Such factors lead to less sales of kilowatt hours, leaving utilities to look for ways to replace not only the top-line revenue but the bottom-line earnings that would be impacted by those changes.

**ABOUT THE AUTHORS**

**Russell Feingold** is a vice president with Black & Veatch and leads its rates and regulatory services practice. For the past 42 years, he has advised and assisted utility management, industry trade and research associations, and large energy users in matters pertaining to pricing and costing analyses, innovative ratemaking strategies, competitive market analyses, business restructuring strategies, organizational reviews, strategic planning, market power assessments, energy supply planning issues, sales and revenue forecasting, merger and acquisition analyses and regulatory reform initiatives, including performance-based regulation, and energy litigation.

**Deepa Poduval** is senior managing director and associate vice president at Black & Veatch, leading its advisory and planning practice area. Her expertise includes developing business strategies to optimize asset portfolios, valuation of energy industry assets, negotiation of commercial agreements, performance and risk assessment, and market analysis. She has advised various clients on strategic responses to key issues impacting their business.
2020 Report Background

The Black & Veatch 2020 Strategic Directions: Electric Report is a compilation of data and analysis from an industry-wide survey. This year’s online survey was conducted from 16 July through 6 August 2020 and reflects the input of 619 qualified utility, municipal, commercial and community stakeholders in North America. Because the survey was administered online, the amount of self-selection bias is unknown; therefore, no estimates of sampling error have been calculated. The following figures provide additional details on the participants in this year’s survey.
**OWNERSHIP TYPE**

Which of the following BEST describes your organization’s ownership type?  
*(Select one)*  

<table>
<thead>
<tr>
<th>Ownership Type</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Publicly-traded corporation</td>
<td>31.0%</td>
</tr>
<tr>
<td>Investor-owned utility</td>
<td>25.9%</td>
</tr>
<tr>
<td>Private corporation</td>
<td>16.9%</td>
</tr>
<tr>
<td>Cooperative</td>
<td>11.0%</td>
</tr>
<tr>
<td>Limited liability company (LLC)</td>
<td>9.9%</td>
</tr>
<tr>
<td>Other</td>
<td>14.7%</td>
</tr>
</tbody>
</table>

*Source: Black & Veatch*

**JOB ROLE**

Which of the following best describes your role within your organization?  
*(Select one choice)*  

<table>
<thead>
<tr>
<th>Role</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>CEO, COO, president or owner</td>
<td>10.0%</td>
</tr>
<tr>
<td>Vice president or executive</td>
<td>9.5%</td>
</tr>
<tr>
<td>Director, supervisor or manager</td>
<td>35.2%</td>
</tr>
<tr>
<td>Engineer, operator</td>
<td>45.2%</td>
</tr>
</tbody>
</table>

*Source: Black & Veatch*

**POPULATION**

What is the estimated population served by your organization? *(Select one choice)*  

<table>
<thead>
<tr>
<th>Population</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 500,000</td>
<td>21.9%</td>
</tr>
<tr>
<td>500,000-1,999,999</td>
<td>26.2%</td>
</tr>
<tr>
<td>2,000,000 or more</td>
<td>51.9%</td>
</tr>
</tbody>
</table>

*Source: Black & Veatch*

**BUSINESS REGION**

In which regions of the United States is your organization located and/or provide services? *(Select all that apply)*  

<table>
<thead>
<tr>
<th>Region</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>New England</td>
<td>24.1%</td>
</tr>
<tr>
<td>Mid-Atlantic</td>
<td>32.8%</td>
</tr>
<tr>
<td>North Central</td>
<td>47.1%</td>
</tr>
<tr>
<td>Great Plains</td>
<td>20.4%</td>
</tr>
<tr>
<td>Southeast</td>
<td>33.9%</td>
</tr>
<tr>
<td>South Central</td>
<td>32.3%</td>
</tr>
<tr>
<td>Southwest</td>
<td>20.9%</td>
</tr>
<tr>
<td>Rocky Mountain</td>
<td>21.5%</td>
</tr>
<tr>
<td>Northwest</td>
<td>19.9%</td>
</tr>
<tr>
<td>Other U.S. locations</td>
<td>7.5%</td>
</tr>
</tbody>
</table>
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