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Cover graph: Electric bills as percent of consumer expenditures, January through November 2015, 2016 and 2017. By PUF Staff.
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Grid Investing

Why We Invest

BY STEVE MITNICK

We invest our dollars, our time, our attention, our creativity. We invest in something. We invest sometimes in someone.

People constantly invest. Constantly, though they receive nothing of value in return. Not then and there. Aside from promise, some satisfaction perhaps. The value from investing comes later. It might not come until much later.

When it does come, the value that is, it might disappoint. Due to adverse events. Due to bad luck. Due to both possibly. The value might come diminished as well as delayed. If value comes at all.

Then, why? Why do people invest? This question is rarely asked. And, more rarely answered. Indeed, there are ample and prominent reasons not to invest. So, why don’t we start with the opposing question? It’s a simpler question to answer. Why don’t people invest?

Here’s one obvious reason. Investment siphons off monies. Monies that can help satisfy immediate needs and wants. Of which there are always many.

Here’s another reason. Investment commits monies to a particular course of action, while different courses beckon. Investment is a bet the chosen course is the correct course. Critics aplenty disagree, inevitably. They charge the choice is incorrect. That alternative courses of action are superior because of this or that. Even doing nothing – the course of inaction – might be represented as superior.

And still another reason. Investment is a journey of patience, discipline, dogged persistence. Ask any developer of energy infrastructure. Instant gratification? Ha. Plans are detained, diverted, deferred. A hostage to an investment’s ultimate resolution.

We invest nonetheless. For investment pays homage to the future. Though the future – when an investment finally bears fruit – extends beyond the investor’s lifetime.

Investing is noble. It is a sacrifice of the present for the future. Investing defies financial analysis in which the principle of discounting pronounces the present to be more important than the future. The investor denies herself or himself today so that days far off shall be enriched.

It’s what earlier generations did. They built the Hoover Dam – at great cost to themselves – so that we may have a better life decades later. They built a hundred nuclear power plants, a dense network of electric lines spanning the continent. And connected every structure in the nation to it.

So, let me say thank you. Thank you to the men and women of the thirties, of the forties, of the fifties, of the sixties, and so on. Thanks for allowing grid investing then. My society, in the first quarter of the twenty-first century, is realizing that promise that you paid for back then.

These days, a single investment in the grid can cost tens of millions, hundreds of millions, even billions. Stunning amounts, except when one realizes investment costs are spread thinly over decades and thus always barely budge today’s electric bills.

The proof is in the pudding. Though grid investing nationally now exceeds a hundred billion per annum – by a lot – electric bills are at all-time low levels as a percent of consumer expenditures. Yet individual projects cost tens of millions, hundreds of millions, even billions. Somehow, utility regulation and utility finance manage to spend all that cash on tomorrow’s grid, for our children and grandchildren, without running up the tab on us.
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Grid Impact from High-Altitude Nuclear Attack

PUF’s Steve Mitnick, with Rob Manning,
Vice President, Transmission and Distribution, EPRI

PUF’s Steve Mitnick: Rob, you just conducted an intensive and important study. What did you do and what did you find?

Rob Manning: This is the second study of the detonation of a high-altitude nuclear weapon that generates an electromagnetic pulse – an EMP – on the face of the Earth. The first study we did was on the effects of an E3 blast with the Earth’s magnetic field, on transformers, and on the power grid. E3 is the third wave of electromagnetic pulse.

We advanced that study to look beyond transformers, to look at what the other impacts might be on the power grid. The conclusion of the study was that we would certainly expect to see some impact from a high-altitude nuclear blast from an EMP E3 wave.

We would expect that would likely create some regional disruptions, what we call voltage collapse. It’s the inability of the system to sustain a normal level voltage, so it collapses; the system will automatically fail-safe to protect the equipment.

Our study would indicate that type of scenario is likely to occur on a regional basis. It appears that the effect would not result in a nationwide voltage collapse. That does put us in a position to be able to recover much more quickly.

PUF: If there is a catastrophic attack from this bomb, are there different kinds of electromagnetic effects? There’s E1, E2, and E3. What exactly is E3 and what are the other two?

Rob Manning: That’s exactly right. A high-altitude nuclear burst will generate three energy waves that move towards the Earth’s surface. That is, if it’s a sufficient-sized weapon and at a sufficient altitude.

E1 is very fast, in nanoseconds, and it’s characterized as a very high electric field. We measure that in volts per kilometer. It looks like a very high pulse of energy that moves towards the Earth at the speed of light. It’s followed in milliseconds by E2, which looks a lot like lightning. The grid already has a lot of protection against that.

The third, E3, is the interaction of the blast with the Earth’s magnetic field. It generates currents that appear like direct currents on our alternating current system. This creates a lot of challenges for an alternating current system. It’s an effect similar to a solar storm. It’s a much shorter duration than a solar storm, but with much higher field levels than solar events.

PUF: Then E3 is the biggest threat to worry about?

Rob Manning: E3 has the potential for creating significant equipment damage.

It’s the inability of the system to sustain a normal level voltage, so it collapses; the system will automatically fail-safe to protect the equipment.

That’s why we started with that. The effect of EMP is really a very complicated puzzle. We’re working our way through that puzzle.

We started with E3 because of the potential for equipment damage. We’re moving towards E1. We’ve been working on E1 for some time now. E1 would be more targeted towards electronics and challenges with control systems and electronics.

I would not say that one was more
threatening than the other. I think they occur together, and together they are a formidable threat.

**PUF:** Tell us a little about how you conducted the study.

**Rob Manning:** It’s old-fashioned mathematics, along with some testing. We were able to secure public information about a nuclear weapons test that was done in the 1960’s, called Starfish Prime.

They used a very large weapon, which when detonated over in the Pacific, created some challenges on the grid in Hawaii. That began the analysis of EMP back in the 60’s.

The telemetry and information about that weapon is now publicly available. We could study that weapon and convert that into mathematical impacts on the electric grid, then plug those impacts into the power systems analysis tools that we used to analyze the grid.

From that, we were able to make pretty accurate predictions about what would occur as a result of a weapon that size at the altitude of the Starfish Prime test.

**PUF:** This data’s more public?

**Rob Manning:** That’s correct. We were very interested in keeping this away from being classified so that we could use it in open discussion with the industry. And, not just with the industry, but also with regulators and the government, to deal with the challenge of EMP.

We were trying hard to make sure that all our work was done in a way that it could be shared openly. That’s why we selected the test that was public–it could be shared openly. That’s why all our work was done in a way that it could be shared openly.

**PUF:** If I’m a regulator or at the utilities or elsewhere in our industry, what do I want to take away from this study? What have I learned?

**Rob Manning:** There are a couple of things to take away. One, the scope of the study is on E3 impacts alone. It does not include the effects of E1, which will occur before the E3 wave. It has to be taken in context.

We have to take the study in the context for which it was intended. This is a single piece of a very complex puzzle. We released it early because we want to provide information as soon as we have it available.

It’s difficult to make a general conclusion about the performance of the system on a single report. However, this report tells you that you would expect to see regional impacts from a high-altitude burst. Because of that, we should be prepared for how we recover from this sort of event.

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**If it does occur, how do you recover more rapidly? How do you protect systems that need protecting, to ensure that recovery is easier?**

**PUF:** This might lead to certain measures or equipment that the industry can take or use to make us more resilient?

**Rob Manning:** Absolutely. We are looking at choices for how you might mitigate this threat. We’re also evaluating recovery plans. If it does occur, how do you recover more rapidly? How do you protect systems that need protecting, to ensure that recovery is easier?

**PUF:** This was the second big study in this series. The first was on the transformers. Where do we go from here?

**Rob Manning:** We do have a couple more to go. We are shifting gears away from the E3 wave and beginning to focus on in the E1 effect. We’ve already begun testing and modeling the effects of E1. We’ve got the mathematical model for E1, so we’re moving along rapidly on E1.

We have a planned report for April of 2019 that would put all of this together. It’s detailing the holistic effect of EMP and how we might mitigate against that. We’ll release the E1 report when we have that, which will probably be later this year. Then in early 2019 our plan would be to do the holistic report, which wraps up the project.

**PUF:** Would we then be in a position as an industry to say, “Now that we have a whole picture, what kinds of equipment or processes should we put in place to bring down the threat?”

**Rob Manning:** Yes. That is the intention of our project, to equip utilities with the technical information they need to do their own risk-based analysis. They can look at where the systems are that they would be interested in protecting, and where would they focus instead on recovery.

This study will give them the information they need, not just to do their own analysis, but to share that analysis with the regulatory authorities. To make sure that we’re all on the same page on what the appropriate response might be.

**PUF:** It seems like it’s not a likely event but it’s something that were it to occur in certain conditions, it would have big impacts.

**Rob Manning:** This is serious. With any risk, you’re trying to balance the consequences of an event and the likelihood that an event occurs. The likelihood of this event is very low.

But the consequences are significantly high enough that it’s worthy of discussion and trying to understand how we could reduce those consequences and therefore reduce the risks.

I think that’s where utilities will focus, on how we might reduce the consequences.

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Hear more from Rob Manning on EPRI’s EMP research in the EPRI Unplugged podcast EMP and the Electric Grid, available on iTunes and archive.org.
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FERC Gets It Right on DOE NOPR

Now What?

BY JOHN DI STASIO AND JONATHAN SCHNEIDER

With its order on January 8, 2018, the Federal Energy Regulatory Commission quieted the firestorm sparked by the Notice of Proposed Rulemaking initiated by the Department of Energy in Docket No. RM18-1. We believe that FERC got it exactly right. The Commissioners were right in concluding that the NOPR presumed a remedy for a problem that had yet to be fully defined, and right to terminate the NOPR, given the time frame imposed by DOE.

The DOE NOPR attempted to address a complex and only vaguely-defined challenge by promoting a narrow set of resources. There is, we believe, a legitimate concern regarding grid resilience in the face of the nation’s changing generation resource mix. But there are many potential measures that would enhance resilience, and FERC was right to focus first on defining the issue on a regional basis, and only then to move toward solutions.

FERC’s approach reflects the position taken by the Large Public Power Council (LPPC) in comments we filed with FERC on the NOPR. We were heartened by the Commission’s consensus in the matter.

LPPC comprises twenty-six of the nation’s largest municipal electric utilities committed to achieving the optimal balance of reliability, affordability and environmental stewardship. LPPC members operate in thirteen states and all regions of the country other than the upper-Midwest. They focus on regional or local solutions with a full appreciation of fuel and resource availability, and local governance preferences regarding economic development and the environment, and strongly support the regional approach taken in FERC’s approach.

What’s Next at FERC?

Without presuming a remedy, FERC directed RTOs/ISOs within sixty days to address a series of questions, with these aims: (1) to develop a common understanding among the Commission, industry, and others of what resilience of the bulk power system means and requires; (2) to understand how each RTO and ISO assesses resilience in its geographic footprint; and (3) to use this information to evaluate whether additional Commission action regarding resilience is appropriate at this time. This is all for the good.

Helping focus the coming discussion, FERC appropriately took the further step of offering a broad definition of resilience, following the lead of the National Infrastructure Advisory Council: “The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.” FERC invites initial comments on this proposal from the RTOs/ISOs, and responsive comments from interested parties.

This broad definition makes sense. But

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Jonathan Schneider is a partner and energy regulatory practice group leader with Stinson Leonard Street.
it also leaves room for debate on a variety of important topics, including the nature and magnitude of the risks against which the grid can reasonably guard and from which plans can be made to recover; the criteria against which resilience of the grid can be measured; and the list of system and resource attributes useful in contributing to a more resilient grid.

From a national perspective, it’s fair to say that the nation’s changing generation mix poses a challenge with respect to the provision of essential reliability services. And while FERC was right in concluding the problem is not imminent, the statistics show that it’s not insignificant either. This was pretty clearly established by NERC’s May 2017 Reliability Assessment and the DOE Staff Report of August 2017, upon which the DOE NOPR relied, making the point that the retirements of large centrally-located facilities pose a challenge to the grid.

Likewise, resilience is a regional matter, among other things: varied generation portfolios around the nation, including substantial difference in the prevalence of intermittent resources; differences in the availability of transmission, firm natural gas transportation and fuel resource options; and varied projections of the availability of fuel-secure generating stations.

For all of these reasons, FERC’s regional focus is appropriate. The focus is also consistent with the experience of LPPC’s varied membership, operating in some states with an abundance of hydroelectric or renewable resources, and some with an abundance of coal or natural gas. These fuel and resource realities drive investment, portfolio designs and ultimately, the aforementioned balance. Likewise, resilience is a regional matter, since the risks from varied weather conditions, infrastructure, supply flexibility and geography all contribute to very different options to address resilience.

The upcoming discussion will no doubt include a debate over the appropriate roles exercised by FERC, state and municipal authorities, and NERC. As to FERC, while there may be an academic question regarding the scope of its authority, it seems pretty clear as a practical matter that the Commission must consider the implications for grid resilience of its rate and regulatory decisions. The Federal Power Act calls for FERC to ensure that transmission and wholesale sales rates are just and reasonable, and while the scope of FERC’s authority to regulate practices affecting such rates is not unlimited, the direct effect that economic regulation has on the reliability and resilience of the grid seems pretty well within FERC’s wheelhouse.

That said, state and municipal authorities also have an important role to play. FERC does not have authority over generation siting, and states that have not unbundled generation, or moved to retail access, maintain authority over generation resource adequacy. Even where FERC’s authority is clearest (unbundled states), it is appropriate and wise for FERC to defer to state and locally-based resource choices, as we discuss below. State-based Renewable Portfolio Standards, and other incentives offered to certain generating resources, though under attack in certain quarters, also reflect legitimate state and local choices to which FERC should defer as it reviews individual RTO/ISO responses to the inquiries framed in the new docket.

The Commission has a history of working hand-in-hand with state and municipal authorities when the jurisdictional line cannot be so clearly drawn, and we believe its decision-making is most durable when it does so. The approach taken in Order No. 1000 is very much on point. There, the Commission recognized that transmission planning subject to its oversight must reflect state and local policy choices regarding the nature and location of generating resources.

What role NERC should play in all of this is a little less clear. The Commission notes that most commenters on the NOPR distinguished between reliability and resilience. Under section 215 of the Federal Power Act, NERC’s authority extends only to the former. NERC may have a role here, but we urge both NERC and FERC to proceed carefully. Mandatory standards in this area can become quite expensive very quickly, especially without a consensus regarding resilience metrics.

What Should FERC Do?
Based on DOE Staff’s and NERC’s 2017 Assessments reflecting medium to long-term resource issues that should be addressed, it’s safe to assume that FERC’s inquiry will not soon be at an end. In the coming discussion, we hope FERC will be open to suggestions for restructuring capacity markets (remuneration for fixed cost investment in generation) with an eye to ensuring: (1) that they
elicit needed investment; and (2) that they provide room for state and local governments to accomplish legitimate policy objectives.

Over the past several years, FERC has been criticized (and as recently as the December 2017 General Accounting Office Report on Electricity Markets), for sending money to the generation sector without being sure that it elicited needed investment. In regions where states have had utilities divest generation and moved to a retail access environment, we don’t doubt that finding a way to assure fixed cost recovery and secure new investment in generation is important.

But the efficacy of existing capacity markets is not clear. Shorter-term (one to three-year) capacity markets may provide an additional revenue source for existing generators, but they appear not to drive new investment decisions, nor investment in infrastructure (long-term firm pipeline transportation capacity for natural gas supplies comes to mind). And to the extent these markets exclude capacity that is self-supplied and funded, a valuable source of long-term investment is discouraged.

Where regional analyses show legitimate concern regarding the adequacy of resources needed to support grid resilience, it will benefit FERC and the industry to be specific regarding the resilience attributes that are in short supply, and to develop pricing mechanisms (markets or sub-markets) geared to eliciting the generation-related resilience attributes. In comments on the DOE NOPR, EPRI provided a useful, if broadly framed, template for how this might work. EPRI identified these broad components of resilience: resilience – adequacy, resilience – operating reliability, and resilience – recovery.

As to each of these components, EPRI suggests the development of supply resilience metrics reflecting desired performance characteristics. Where it is determined that specific resilience attributes are not being met or adequately incentivized, new market or cost-based mechanisms may be considered.

As the Commission sifts through these available tools, we strongly urge it to provide room for state-supported resource choices and incentives that it can build upon, rather than curtail, as some have advocated. In an environment in which the federal government has substantially backed away from environmental regulation, and certainly any form of carbon control, the importance of state-supported resources looms particularly large for many states. There is no good reason to shut these programs down.

The importance of state-supported resources looms particularly large for many states. There is no good reason to shut these programs down.

The authority over generating resources is clearly a shared responsibility. While FERC’s authority over wholesale markets is clear, it lacks any authority over generation siting, and it has no role in the development of legitimate state-based policy choices that drive many investment decisions.

DOE reports that twenty-nine states have adopted Renewable Portfolio Standards, and a number of regions have adopted carbon control and trading measures, as part of which the provision of renewable energy credits and zero emission credits, such as those adopted in New York and Illinois.

In adopting these policies, state policymakers are responding to the interests of their electorate and, in many cases, furthering other state objectives regarding economic development or the environment. LPPC has supported local and regional autonomy on resource decisions on the basis that resource mandates and incentives often create economic distortion and undermine the benefits of a well-constructed resource portfolio. There is nonetheless clearly a role for the federal government to support emerging technologies though research and development work helping to commercialize new and promising technologies.

To date, state-based programs have withstood legal challenges, rested on the arguments that federal law – the Federal Power Act – and the United States Constitution call for preemption and invalidation.


Nonetheless, challenges are being advanced at FERC asking the Commission to act affirmatively to offset the impact of any state-based support for specific generating resources. We urge FERC to reject these challenges, except in cases where state-based programs are expressly designed to alter wholesale market prices.

This distinction is supported by the Supreme Court’s recent decision in Hughes v. Talen Energy Marketing, 136 S.Ct. 1288 (2016). There, the Court invalidated a state-based program “tethered” to generation participation in the FERC regulated wholesale market, and designed to drive prices down. But the Court specifically stated that it was not acting to invalidate other measures states “might employ to encourage development of new or clean generation, including tax incentives, land grants, direct subsidies and construction of state-owned generation facilities.” This
Where Energy Storage is Headed

PUF’s Steve Mitnick, with Kelly Speakes-Backman, CEO, Energy Storage Association

**PUF’s Steve Mitnick:** What are your top goals for 2018 as the CEO of the Energy Storage Association?

**Kelly Speakes-Backman:** The energy storage industry is experiencing unprecedented growth, and with it, ESA will expand its support of the market. 2018 will be a year of continued growth for ESA and the storage industry, but also one of reflection on what the future will hold and how ESA can be a catalyst for this growth.

Since I joined six months ago, I have begun the process of establishing ESA’s long term goals. Early in 2018, I expanded our executive team to support our strategic efforts and develop our organization’s long term plans, which should follow the expected growth of thirty-five gigawatts of new energy storage by 2025.

Throughout the year, we will do everything we can to open markets in states through participation in regulatory processes and support of legislation that sets a policy direction toward the deployment of cost-effective energy storage.

**PUF:** What are the most interesting trends you’re seeing in energy storage?

**Kelly Speakes-Backman:** The cost of storage has dropped so much faster than most predictions. The installed cost of battery grid storage has dropped fifty percent in the last four years, and that rate is likely to continue for the next several years.

The result is that storage project economics are increasingly competitive. We’ve just seen from the Xcel Colorado all-source solicitation, median bids reported for combined wind & storage PPAs were twenty-one dollars per megawatt-hour, and solar plus storage PPAs were at thirty-six dollars per megawatt-hour for delivery before 2023.

Also, as costs have come down, new megawatt-scale battery storage projects are being delivered with longer durations. Aliso Canyon made big news in 2017 with over ninety megawatts of four-hour batteries deployed to make up capacity shortfalls. There are already two eight-hour grid battery projects under development in New York and Massachusetts in 2018.

The comprehensive trend we’re seeing is that as costs come down, durations will grow and storage will be a more competitive resource for new capacity.

That ties into the second big trend: utilities are increasingly including storage in their planning and procurement. Since the first utility integrated resource plan meaningfully included battery energy storage in 2016, we’ve now seen a dozen utilities across eight states earnestly consider energy storage for future capacity, more often selecting it as an economic resource than not.

At the same time, more state regulators are directing their utilities to look at storage in long-term planning. Commissions in Washington, New Mexico, and Michigan have explicitly directed their utilities to do so, and Washington, in particular, made it an explicit part of their prudence determinations.

Frankly, if a utility in 2018 doesn’t include storage in its integrated resource plan, there’s a good chance they have an
out-of-date view of storage economics over the next two decades, or are not doing the work to model the flexibility needs of their systems.

At the same time, more utilities are making storage a part of their distribution infrastructure. Not just in California and New York, but also in states like Arizona, Massachusetts, North Carolina, and Texas.

This trend will only continue and grow as utilities get more familiar with the operations and performance of storage, and realize how cost-effective it is to defer or avoid costlier infrastructure upgrades.

Finally, it’s clear that states are getting more educated and active on energy storage matters, particularly in legislatures. In 2016, there were perhaps a handful of states where storage-focused legislation was introduced, and only a few bills were passed into law.

In 2017, we saw a dozen states introduce bills on energy storage, and a decent number passed into law. We’re going to do our best to make 2018 a very busy year on this front. More states are deciding to jumpstart development of their state’s regulatory framework around storage through deployment targets. First, California in 2013, then Oregon in 2015, then Massachusetts in 2017, now New York in 2018, and potentially Nevada this year as well.

On the regulatory side, there’s a growing awareness of the need to remove barriers to grid access for storage, with storage-specific interconnection conversations proceeding in nine different states.

And initial discussions of a competitive framework for storage ownership, prompted by the broader conversation around grid modernization and distribution planning. Considering all these regulatory activities, I think it’s safe to say that there will also be a trend for more PUF articles on energy storage!

**PUF:** What are the greatest challenges facing storage and its rapid growth?

**Kelly Speakes-Backman:** Policy takes time to catch up with technology. Our industry is now entering market frameworks that never contemplated cost-effective, widespread, highly flexible storage. Even when we get a final order from FERC on the treatment of energy storage at the federal level, there will still be a time-lag for RTOs and ISOs to make needed changes.

More utilities are making storage part of their distribution infrastructure. Not just in California and New York, but also in Arizona, Massachusetts, North Carolina, and Texas.

So, it’s not surprising that state regulators and policymakers in states are beginning to lead on storage. ESA is addressing that growing interest by working to break down the barriers to energy storage at the state level, which happens to be like the work required at the RTO and ISO level.

These barriers aren’t related to cost anymore, but rather to how storage is valued, open and fair competition, and access to markets. Accordingly, ESA is working at the state level to create mechanisms to value and compensate the flexibility of storage; allow storage to compete in all planning and procurement processes; and ensure access to the grid and the ability to operate flexibly.

**PUF:** How will the annual Energy Storage Policy Forum on February 14 address these issues?

**Kelly Speakes-Backman:** We’re very excited about the topics and the caliber of speakers lined up for the annual Energy Storage Policy Forum this year. ESA will host a range of policymakers, utility executives and market participants to discuss their perspectives on these major topics of the day.

From FERC, Commissioner Powelson will provide his perspective on storage in the new Commission’s agenda. Alicia Barton from NYSERDA will update us on the most recent actions from New York state, including the recent announcement by Governor Cuomo of a 1.5 gigawatt target and two hundred fifty million dollars in support by 2025.

Also, for state perspectives, we’ll hear from regulators from Washington, Arizona, Hawaii and Maryland, discussing how storage fits into their planning processes. From the legislative side, we will hear both Republican and Democratic policy perspectives from the federal government, including Senate Energy and Natural Resources Majority Staff Counsel Patrick McCormick.

Later that day, industry participants will engage in discussions on topics such as what a competitive framework for storage looks like in a world where utilities, customers, and third parties all may own it. We also look forward to hosting allied stakeholders from across the U.S. to share their perspective on local advocacy for storage.

It’s going to be an incredibly interesting day, and we’re honored to bring so many influential participants together to share their perspectives.
Will Demand Charges Accelerate Adoption of Behind-the-Meter Storage?

Part One of Two

BY JIM PYKE AND NIC WHITE-PETTERUTI

Utilities have been considering alternative rate designs to better align customer behavior with their cost structures in order to increase overall system efficiency. One common approach has been the consideration of demand charges. However, demand charges have significant potential to accelerate the adoption of behind-the-meter storage, even at seemingly low demand charges and low overall electricity prices.

Under current rate designs, fixed charges don’t come close to covering utilities’ fixed costs, so volumetric charges have to be much higher than a utility’s true variable costs to cover the rest of the fixed costs.

While all costs are covered, it is in a pattern that does not resemble the way costs are incurred. Utilities have tried sporadically over the years to fix this misalignment, but it has proven difficult. Regulators are hesitant to approve rate designs that would significantly impact small customers or create equal cost burdens for customers in a given rate class regardless of their consumption.

The combination of net metering, widely available in most states, and rooftop solar has turned this theoretical problem into a real and serious one for utilities. Through net metering, solar customers avoid the volumetric charge for any solar energy they produce and consume. They also typically receive credit for the full volumetric charge of any excess electricity they export to the grid.

This substantially reduces their total volumetric charges paid to the utility, a portion of which would cover some fixed costs of maintaining a safe, resilient grid. However, these customers still benefit from access to that grid. This disparity produces the much-remarked-on cross-subsidization from non-solar to solar customers. It also creates a significant revenue gap for utilities.

As a result, utilities have redoubled their search for a way to manage the mismatch between revenue collection and cost structure. It has often been addressed in the industrial and large commercial segments by a demand charge. While demand charges seem reasonable, they have not been frequently applied to residential and small commercial customers.

Many utilities have begun to view demand charges as a silver bullet to resolve the issues posed by net metering. For example, in June 2016, Arizona Public Service submitted a rate case that included mandatory demand charges for residential customers. After pushback from customer and solar advocates, the Arizona Corporation Commission chose not to allow mandatory demand charges, instead opting for time-of-use rates. APS

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Nic White-Petteruti is an Associate in Houlihan Lokey’s Strategic Consulting business. He is a licensed Professional Engineer with nearly a decade of consulting experience in the energy and power industries.
was allowed to keep its voluntary demand rate and was advised by the ACC to pilot some new demand rate designs.

In February 2017, the ACC approved two voluntary demand rates for Tucson Electric Power, a Peak Demand rate and a Demand TOU (time-of-use) rate. These rates lowered the basic service charge from $13 to $10.04 per month.

In June 2017, Eversource filed a petition with the Massachusetts Department of Public Utilities for NSTAR Electric and Western Massachusetts Electric Company that proposed mandatory demand charges for residential customers owning distributed energy resources. However, that proposal is facing strong opposition from the solar industry and ratepayer advocates.

While these examples highlight the industry’s steps toward the implementation of demand charges, utilities are also now recognizing that demand charges can pose potentially serious unintended consequences.

Even if a demand charge gives customers more accurate price signals, it may also drive customers to invest in the next big DER technology: behind-the-meter storage. With behind-the-meter storage, customers can potentially manage their peak demand, offsetting the impact of the demand charge and possibly leading to eventual grid defection.

**Demand Charge Analysis**

The goal for the utility is identifying rate designs with appropriately sized demand charges. But what size is just right? The answer will be different from company to company.

To help companies better understand what rate designs they should aim for, we have developed a proprietary model. It factors in the projected cost of storage, the utility’s average price of electricity, the customer’s consumption profile, and demand charges to quantify the potential savings that a customer could experience with behind-the-meter storage.

Figure One shows two customers’ economic indifference curves toward behind-the-meter storage. We define economic indifference as the point at which investing in storage makes sense today, based on the average electricity price the customer is exposed to and the percentage of their total bill stemming from a demand charge.

By analyzing economic indifference points at a range of average electricity prices and demand charge percentages, we are able to develop detailed economic indifference curves for each customer.

With an indifference curve further down and right, we can see that Customer #1 is much more likely to own storage than Customer #2. For Customer #1, owning storage makes sense at 2017 storage costs, if they have an average electricity cost of at least fifteen cents per kilowatt-hour and the demand charge accounts for more than forty percent of their bill. In contrast, storage would only make sense for Customer #2 with a very high average electricity cost and high demand charge situation.

See Figure One.

Further exacerbating the challenge is the declining price of storage driven by
technical innovation, learning curves, and manufacturing process improvements. Over time, the potential for rising electricity prices and declining battery prices will drastically improve the economics of behind-the-meter storage, in much the same way that rooftop solar has spread to all fifty states.

Figure Two shows the case study’s economic indifference curve for Customer #1 over time, based on the expected drop in storage costs. In 2021, if Customer #1’s average total electricity price is at least fifteen cents per kilowatt-hour, we estimate that owning storage will make sense if a demand charge makes up twenty-five percent or more of their bill, as opposed to roughly forty percent in 2017.

The change over the five-year period is even more pronounced for an average total electricity price of ten cents per kilowatt-hour, where the indifference percentage to a demand charge drops from more than sixty percent in 2017 to less than forty percent in 2021.

See Figure Two.

The role of the cost of storage is obvious: the lower the cost, the better the economics for installing it. The role of the utility’s average electricity price is also obvious: the higher the price, the more vulnerable the utility is. Not only to storage, but to other DER technologies as well.

The implementation of meaningful demand charges may accelerate the adoption of behind-the-meter storage. For utilities considering a transition to alternative rate designs, especially those looking to add or increase an existing demand charge, the decision is not a simple one.

The potential to incentivize customers into adopting behind-the-meter storage may lead to revenue shortfalls? The second article in this series, in March’s PUF 2.0, will cover the following key topics: A high-level assessment of the largest utilities’ exposure levels and the importance of the development of a thorough understanding and segmentation of customers. It will also address how any proposed rate changes will impact customers’ bills. Who are the winners and who are the losers? How will those changes potentially lead to revenue shortfalls? The second article will also address the importance of examining rate design holistically, while looking outside the electric utility segment for inspiration on potential alternative revenue collection methods.

NIC WHITE-PETTERUTI

Innovation in rate design may suggest additional revenue structures beyond demand charges. One can look to other industries, including telecommunications, for ideas.

FERC Gets It Right

(Cont. from p. 12)

approach is consistent with cooperative federalism and need not conflict with FERC’s oversight of wholesale markets.

Conclusion

FERC’s unanimous approach to the DOE NOPR builds upon a history of bipartisan decision-making. This is an excellent precedent for the newly-formed Commission. There are clearly challenges ahead, but we believe the Commission will be well-guided by shouldering its responsibility to ensure that markets support a resilient and reliable grid, while accommodating state-based policy and regional differences and other markets that exist outside of their full authority.

The diversity of the national electric sector is a source of strength, since it provides competitive benchmarks that would be lost in a one-size-fits-all market structure. It also reduces reliability risks as a result of regional infrastructure, fuel and connectivity differences.

We look forward to participating in this important conversation going forward and commend FERC for creating a forum for careful consideration of the input to be provided by market operators and the industry as a whole. Any resulting actions can only benefit from a thorough investigation and understanding of the problem.
Taking Reliability and Resilience to Next Level

Achieving True Power Security through CRISP

BY ELLIOT ROSEMAN

Business as usual will not do. Recent major storms that cut power supplies for weeks or months, such as Hurricanes Harvey, Irma and Maria; significant power outages such as the one at the Atlanta airport that stranded thousands of travelers; and the Department of Energy’s proposed Grid Rule have rekindled the debate about what constitutes a reliable and resilient supply of power, and what it will cost. This is a propitious time for such a debate.

“Reliability” is generally defined as the ability to keep the lights on under normal system operation. “Resilience” is regarded as the ability to recover from unanticipated or extreme events, whether due to natural disasters or caused by humans.

While both are critical and require careful attention, these two concepts are insufficient to cover the future significant risks to power supplies. In fact, the paradigm shifts taking place in power markets today are creating a much broader need, one that requires new metrics, policy guidance and a clear, integrated process to ensure the secure power system that customers need for tomorrow’s economy, and on which daily life depends.

What shifts are giving rise to these new needs? First, the shift taking place to distributed resources such as rooftop solar, EVs/local storage and demand response constitutes a risk to the continued secure local supply of power, such as the hosting capacity of lines, feeders and substations.

Second, the rapid price reductions and growth of both intermittent and firm sources of power such as solar, wind and storage on the wholesale grid, along with the low price of natural gas, are pushing several traditional baseload sources into lower utilization and early retirement. That is causing greater ramping – the so-called duck curve – and peak time issues.

The coal-fired St. Johns River Park, San Juan Generating Station, J.M. Stuart, and Navajo Generating Station all announced early retirements in the first half of 2017, even though all are MATS-compliant, and some are relatively young power plants. Add nuclear plants such as Indian Point, Three Mile Island and Diablo Canyon to this list, and it’s clear that we are facing a major transition in our base-load generation mix.

Elliot Roseman is a strategic energy advisor with decades of power sector experience, specializing in helping executives make decisions relating to resilience, sustainability, technologies and markets in times of significant change. He has worked extensively with utilities, IPPs, trade associations and regulators, in the US and internationally.

The shift taking place to distributed resources constitutes a risk to the continued secure local supply of power, such as the hosting capacity of lines, feeders and substations.

Third, our future power supply must factor in the policy requirements in many states and cities to reduce emissions and mitigate climate impacts. On top of these initiatives, many customers share such concerns, and some are signing their own renewable or system power supply contracts, making market-based deals, or forming new geographic aggregations (for example, Community Choice Aggregation in California) to meet them.

These factors are directly related.
The retirement of nuclear plants makes it harder to achieve emissions objectives, as it removes the largest source of non-emitting capacity from the generation mix. The proliferation of distributed resources lowers or eliminates growth in kilowatt-hour sales, and puts greater pressure on traditional sources to compete for the end-use customer’s needs.

These three factors – more distributed resources, rapid price reductions, and increasing policy and market drivers – are neither “normal”, invoking reliability, nor “unanticipated”, invoking resilience. Business as usual will not maintain secure power supplies.

Utilities, regulators, regional entities, and power providers must still prepare and invest properly to accommodate these sea-changes to assure a future near-uninterrupted supply of power. If we maintain the status quo, the risk to secure power supplies will rise.

Moreover, these changes are taking place at the same time as the value of electric power to customers is rapidly rising, leading to less tolerance for insecure supplies. We continue to own more devices, conduct more cyber-transactions that require more data centers, convert our transportation fleet to electricity, and convert commercial and industrial processes to electricity.

The loss of power today and in coming decades would have profound economic costs and cause major societal disruptions. Lack of power puts us quickly back into the nineteenth century.

As a society, we would be willing to spend a good deal more to achieve a secure supply of power. As the risks to such supply rise, it’s worth spending more to ensure them.

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That on average, every kilowatt-hour is worth at least two dollars and fifty cents to the U.S. GNP, and much more than that in some regions and industries. Yet, the average amount we pay nationwide is twelve cents. That’s a factor of twenty to one in terms of value over cost.

As a society, we would be willing to spend a good deal more to achieve a secure supply of power. As the risks to such supply rise, it’s worth spending more to ensure them.

Planning for a secure power supply should explicitly take the economic impact of outages, known as the value of potentially lost load (VOLL), into account. I prefer to rephrase this in positive terms, and call it the value of electric power (VOEP).

Rather than just meeting today’s challenges, taking individual measures, or providing one-time fixes, what’s the best approach to prepare for the future?

What we need is a holistic commitment to power security. In particular, we need a process that covers reliability issues related to normal operations; takes all factors relating to resilience, such as security of fuel supply, transformer supply, hurricanes, and cyber-attacks, into account; and explicitly takes the fundamental paradigm changes directly into account, reflecting VOEP in the process.

This holistic process should retain traditional metrics of reliability (such as SAIDI and SAIFI) and add new measures required for resilience. For example, hardened substations; days of secure fuel supply; adequate equipment inventories. It should also include performance standards that embrace planning risks and regulatory policies at the distributed and grid levels. Those standards should reflect best practices and market opportunities.

Customers expect comprehensive power supply security. But now more than ever, delivering on this expectation is increasingly complex, and will involve multiple actors. The responsible entities
would include utilities, state regulatory agencies, wholesale and retail power suppliers, RTOs and FERC at different times, in an interactive process designed to minimize power supply risks over time.

We have a limited window of time in which to get ahead of this curve before the security of power supplies deteriorates or weakens in response to changes. In some states and localities, the window is closing or almost closed; in others, it is a couple of years away, but it will be soon, just about everywhere. And because of all the market, regulatory and technology changes taking place at the same time, we need to walk and chew gum at the same time, and do it while in mid-air!

I propose that stakeholders adopt a more comprehensive and multi-faceted approach. Achieving a future secure power supply for customers means that we either put in place a ten-point planning and implementation process, or modify existing approaches to do so.

Here are the elements of this approach. To start, we will need to understand customer needs for a secure supply of power. Some customers have greater needs for secure power, and perhaps should pay for it. We should articulate the events that could give rise to a lack of secure power, and forecast how severe the outages could be if they occur.

So-called hundred-year storms seem to occur about every five years. We must also determine how to measure our preparedness for such threats and implement needed upgrades, including an assessment of the value of lost load.

For example, VOEP analysis could justify moving substations or putting selected transmission lines underground. Specifically, the ones that serve customers with the highest value on power and the greatest economic impact, albeit at higher costs.

We also need to identify the desired attributes of all potential sources of power supply, including technical, cost and environmental attributes. We must forecast how they will perform under stressful conditions, over time, to maintain reliability, resiliency and meet policy and market needs.

It will be important to decide on and apply the standards of power security to the appropriate geography, whether to an entire RTO, state, community, or individual customer. Part of that process will involve determining what mix of supplies can best assure the supply of power, under adverse conditions, at a reasonable cost.

We will need to understand customer needs for a secure supply of power. Some customers have greater needs for secure power, and perhaps should pay for it.

We need to plan holistically for both utility-scale and distributed resources, and be prepared to invest in accordance with those plans. We also need a performance measurement approach so that we can track how the new system meets customer needs and reflects market opportunities, and modify those measures over time.

It is vital for this process to play out in the regulatory arena, with coordination among economic, environmental and security regulators. Such coordination is far from trivial. As part of this process, regulators should consider and implement new rates and rate structures to reflect these priorities, including subsets of the rate classes that exist today.

What is this new process? I recommend that we call it Comprehensive Resource and Increased Security Planning (CRISP). Utilities, in particular, have the opportunity now to communicate and push forward their vision of future assured power supplies, to regulators, customers and others, taking all the CRISP factors into account, and to win approval to make this vision happen.

In states that have them, integrated resource planning (IRP and DRP) and special restructuring proceedings may provide a good vehicle for such communication and to put CRISP in place. In addition to the marquee states of California and New York, Ohio, Maryland and Minnesota are examples of states with power industry review processes in place.

The figure above displays several elements of the CRISP process, which would need to be tailored to each situation.

Does doing all this mean that the cost of power could rise from where it is today? For some, perhaps. However, in many if not most cases, the added future security of power supplies would be well worth it to customers. Every insurance policy has a premium!

Secure fuel supplies are a key part of this equation; that is the so-called inter-dependence issue. Moreover, due to the shale gas revolution, fuel and power prices in many parts of the country are a good deal lower now than they were a decade ago.

Ralph LaRossa, the CEO of PSEG Power, pointed out recently at a PJM forum that in his area, gas prices are just half of what they were in 2008, and power prices are just seventy percent of those levels. He describes this as headroom that can be used to invest in needed infrastructure, conduct system hardening, and raise the overall security of fuel and power supplies.

But do customers and regulators grant that this is headroom: a “free” increase in power costs? Perhaps not, unless utilities and others can convince them that the

(Cont. on page 22)
Welcome to Our New Integrated Smart Operations Center

PUF’s Steve Mitnick, with Gil Quiniones, CEO – New York Power Authority

PUF’s Steve Mitnick: Gil, can you tell me what makes the Integrated Smart Operations Center extraordinary?

Gil Quiniones: The iSOC, as we call it, is unique because it’s very comprehensive. There are five things that are noteworthy. There’s an aspect that monitors the health of our assets: our power plants, substations, and transmission lines, all the time.

It helps us in our operations. It also helps us in planning for operations and maintenance and capital expenditures. We can optimize instead of doing upgrades or maintenance based on time in our number of cycles.

Now, it’s really based on the health of the equipment, the systems or components of the equipment or the system. That’s where we’re headed. It’s condition-based or health-based maintenance and capital upgrades.

It’s also the place where we monitor our cybersecurity, our physical security and our communications network. We have a communications network that ties all of our assets together. We’re upgrading that.

We’re building a dedicated high-speed, high-bandwidth, fiber optic system that’s going to be connecting all our core generation and transmission facilities across the state.

Here, we also monitor our communications network and our strategic software. There’s a mirror of the New York Energy Manager, which is in Albany, where we monitor state buildings.

Now, we have eleven thousand buildings. We estimate that in 2020 we’ll have twenty thousand public buildings where we have completely digitized or created digital twins or digital replicas of the energy systems of those buildings.

The iSOC is unique because it’s end to end. You have monitoring our assets, monitoring our customers, monitoring cyber, monitoring physical security, monitoring our communications network and strategic software. Plus, if there is an emergency, automatically it becomes our emergency operations center.

PUF: What is a digital twin?

Gil Quiniones: A digital twin is basically a digital replica or representation of the actual asset and the way it performs. We take information from existing control systems and data acquisition devices, then add sensors, add more meters. All that information then creates the digital replica or representation of that asset and how it operates.

PUF: The protection, the cybersecurity, this dedicated fiber communication network, it sounds like it’s a lot more secure.

Gil Quiniones: It is. In some cases, right now we’re leasing and sharing communication lines from Verizon, AT&T and others. We just think that we should have our own. For our assets, it should be dedicated just for us.

It helps in terms of cyber, but the benefits of the iSOC are reliability, availability, increasing efficiency and more optimized investments, both O&M and capital. All of that translates to benefits for our customers because they are part of the rates.

In terms of the customer buildings, if
we’re able to really monitor, and if we’re able to analyze how buildings use energy in a very granular way, it creates all kinds of opportunities.

That helps with energy efficiency, energy productivity and demand response for incorporation of distributed energy resources, whether they’re solar or batteries, and whole building optimization in terms of how they use energy. That’s on the customer’s side.

Cyber and physical are important emerging issues. They’re top of mind, not only for utilities, but the Board of Utilities as well. We just created a Cyber and Physical Security Committee within our Board because this is such a big issue. In New York, naturally we’re a target. These are the kind of things that we’ll benefit from.

PUF: Is there anything left to do?

Gil Quiniones: We’re still increasing the amount of information brought back to the iSOC. We need to still have advanced systems or equipment data fully integrated. There are islands, meaning that they’re not connected to our network.

We’ve got to connect those networks. We have to add more sensors and smart data acquisition devices, and bring all that information back to the iSOC so we can do data analytics and monitoring.

Then we need to really apply the power of the data analytics by using machine learning and artificial intelligence. Right now, it’s about getting all the information that we can get in a clean, continuous way. We need to be able to warehouse all that information properly.

Also, we need to be able to curate the data appropriately so we can then perform the correct analytics, and get actionable insights from that information.

**We’re a little different, in that we could make the platform accessible to trusted third parties and have them slice and dice our data.**

Our facilities are spread all over the state. We have sixteen power plants, twenty-four or so substations, and fourteen hundred miles of transmission lines from Niagara to Long Island. It’s a very expansive network and we still have a lot to do.

When we can get all the information and warehouse the data, curate the information, and have a platform for this data, we then intend to open it up to our trusted partners. We want them to be able to do their own data analytics and innovation using our data, to create new apps and new products and services for all kinds of customers.

Think of it as we’re building the iPhone and the iPhone platform. We are building our own apps. GE is our partner with the PREDIX software platform. We also want to open our platform and our data to other trusted third-party partners, whether they’re technology companies, original equipment manufacturers, utility, grid operators, research institutions, Ph.D. students or universities.

We want them to come to White Plains. It’s home to our innovation zone, where others can come and access the data to create new apps, to create new products and services for our customers, for their customers, for all kinds of customers. We think it will create a really great innovation ecosystem for using the platform and using our data.

PUF: I guess that makes you a Steve Jobs of the power industry.

Gil Quiniones: No, but we’re unique, because we’re a public benefit corporation. We’re a little different, in that we could make the platform accessible to trusted third parties and have them slice and dice our data. If they innovate in New York, that benefits New York from a technology and economic development point of view.

**Reliability and Resilience**

(Cont. from p. 20)

additional costs of power security are justified and cost-effective; that is, that they protect much greater value than any increase from current rates.

Is CRISP all or nothing, and does it need to be done all at once? No. However, does adopting a process like CRISP matter? Big time. Unless we deal with rising risks and threats, we cannot ensure the continuous supply of increasingly valuable electricity to our vibrant economy. The security of future power supplies is one of the most important challenges and opportunities facing the power industry and our economy today.

And there’s a threat to utilities and power generators embedded here as well, since if they don’t meet the power security challenge in a cost-effective way, customers may increasingly find ways to bypass their service. Another way of putting it: if you’re not at the table, you may be on the menu.

But if we’re proactive and smart about it, this is an opportunity for the power industry to collaborate with customers and regulators as never before. To modernize the network, thrive in an increasingly competitive and complex world, and meet shareholders’ expectations to boot.
In November, 1.33 percent of consumer expenditures – 1 of every 75 dollars – paid electric bills. The remaining 98.67 percent – 74 of every 75 dollars – was available to the American consumer to purchase other goods and services. According to the latest Commerce Department data.

November’s 1.33 percent was tied for the seventh lowest month in history, going all the way back to January 1959. The lowest month in history was earlier this year. Actually, this was a tie too.

Six of the eight lowest months in history have been this year.

Just 1.24 percent of consumer expenditures in January and in February – 1 of every 81 dollars – paid electric bills. The remaining 98.76 percent – 80 of every 81 dollars – was available to the American consumer to purchase other goods and services. The next lowest month in history was also earlier this year.

Just 1.26 percent of consumer expenditures in August – 1 of every 79 dollars – paid electric bills. The remaining 98.74 percent – 78 of every 79 dollars – was available to the American consumer to purchase other goods and services.

Indeed, six of the eight lowest months in history have been this year, 2017.

The U.S. Department of Commerce calculates the Gross Domestic Product. Since consumer expenditures are around seventy percent of the GDP, the Commerce Department tracks consumer expenditures in extraordinary detail.

These percentages are easy to understand. 2% means that one-fiftieth of consumer expenditures goes to pay electric bills. 1% means that one-hundredth of consumer expenditures goes to pay electric bills.

The lower these percentages are, the smaller is electricity’s share of consumers’ budgets. And the larger is the share of consumers’ budgets for all other goods and services.

Source: Bureau of Economic Analysis. U.S. Department of Commerce. Public Utilities Fortnightly maintains a comprehensive historical and updated data base of consumer expenditures, and our own analyses of the data. Fifty-eight years of monthly data.
Electricity Lags CPI Increases

Electric Rates vs. Consumer Price Index

The Labor Department recently reported November’s Consumer Price Index, the CPI. The detail—which we closely follow—shows the trends in prices for everything from pork chops to postage to pet services. Including the electric rates that consumers pay.

In December, the CPI was 2.1 percent higher than it was a year earlier, in December 2016. And electric rates on average were 2.6 percent higher than they were a year earlier. So, inflation-adjusted, electric rates slightly increased over the last twelve months.

Inflation-adjusted, electric rates decreased significantly over the last twenty-four months and the last thirty-six months.

Over the last twenty-four months, the CPI was 4.2 percent higher than in December 2015. Electric rates on average were just 3.3 percent higher. Over the last thirty-six months, the CPI was 5.0 percent higher than in December 2014. Electric rates on average were just 2.0 percent higher. So, inflation-adjusted, electric rates decreased significantly over the last twenty-four months and the last thirty-six months.

Long-term, electric rates have risen only 84.5 percent as much as the CPI.

To track the average price of the goods and service that American consumers buy, the U.S. Department of Labor calculates the Consumer Price Index. There’s a CPI for all the goods and services that consumers buy. And there’s a CPI for categories of goods and services, including residential electric rates.

Compare the CPI for electric rates with the CPI for all goods and services. Doing so shows if electric rates are increasing faster or slower than the price of other things. And, therefore, it shows if electricity is becoming costlier or less costly to consumers.

In the long term, 100% means the CPI for electric rates and the CPI for all goods and services increased at the same pace since the Labor Department’s base period (the years 1982 through 1984). At 100%, electric rates aren’t becoming costlier, and they aren’t becoming less costly.

The lower that these percentages are, the slower the CPI for electric rates has risen as compared to the CPI for all goods and services. So, the lower these percentages are, the less costly electricity has become.

Source: Bureau of Labor Statistics, U.S. Department of Labor. Public Utilities Fortnightly maintains a comprehensive historical and updated data base of the CPI for electric rates, the CPI for all goods and services, and our own analyses of these indices.

Sixty-five years of monthly U.S. data. Forty years of monthly regional data.
In October 2017, the latest month of data published by the Energy Department, zero carbon generation was 37.3 percent of grid generation and low carbon was another 33.5 percent. Summing the two, 70.8 percent of grid generation was zero and low carbon. This was the seventh highest month historically in terms of clean power production. The record remains March 2016 when 75.1 percent was clean power production.

One could project that in a month not too distant in the future, high carbon will fall to below 20 percent of grid generation.

In those months when clean power production exceeds 70 percent, high carbon falls to below 30% of grid generation. One could project that in a month not too distant in the future, high carbon will fall to below 20 percent of grid generation. Below a fifth of the grid’s power.

The U.S. Department of Energy tracks in extraordinary detail the origin of the grid’s electricity. Each month, it publishes total electric generation and the breakdown by manufacturing method.


This Scorecard adds the amount of the grid’s electricity produced by the zero-carbon methods, and by low-carbon methods (natural gas). And then calculates their share of all grid electricity.

These percentages are easy to understand. 25.0% would mean that a quarter of the grid’s electricity is zero-carbon. The U.S. grid hit and surpassed 40.0% zero-carbon for the first time in March 2016. At 40.0%, four of every ten kilowatt-hours produced by the grid didn’t emit carbon dioxide.
In these short videos, Ricardo da Silva, Emilie Bolduc and Kenneth Carnes speak about the technology and applications of the state-of-the-art NYPA Integrated Smart Operations Center at the iSOC opening on December 11 in White Plains.

**Ricardo da Silva**

My name is Ricardo da Silva. I’m the Vice President of Strategic Operations. It’s a pleasure for me to be here with you today, and to show you how the information displayed on this video wall is the embodiment of what you have heard described throughout this afternoon.

By leveraging technology through these applications, NYPA’s taking a role in managing our assets on the generation side, on the transmission side, more effectively. What that does in turn, is it allows us to reduce our operating costs, which ultimately, we pass on as energy savings to our customers.

I’ll just walk you through a couple of different examples of how we’re doing that.

Right here in the left-hand corner of the screen is an application called UltraMap. [It’s] monitoring a vital transmission circuit that connects Westchester County to Long Island. It’s monitoring vessel traffic in real-time, and alerting ships of their proximity to the submarine cable to avoid damage from anchor drops that have occurred in the past. The reason we do that is to avoid millions of dollars in repair costs, that could otherwise result from such damage.

Another example, different application, is mPrest on the top section of the screen. [It] is an application that we are using to monitor the health of large power transformers across our fleet statewide.

As I walk my way towards the center of the room, I’ll just point out a couple of different screens that are based on GE software applications, and the GE Predix App Engine. That coupled with OSI PI, we’re gaining some very valuable insights into the operation and into the health of our hydro and fossil facilities across the state.

Through data analytics, through greater data transparency, we’re improving reliability, improving plant performance, and managing our assets more effectively. In a relatively short amount of time, what we’ve observed is approximately three million dollars in cost avoidance. And we expect that value to increase over time.

Even with our newest set of assets, the New York State Canal System, we’re also beginning to apply data analytics as you can see from this display that’s monitoring water levels across that system.

**Emilie Bolduc**

Hello, I’m Emilie Bolduc. I am the Vice President of the New York Energy Manager, which you see on the center screens here. The New York Energy Manager is a digital service for our customers. We are empowering our customers to use their energy data and analytics, to manage their energy in a whole new way.

We have, as Gil mentioned, over eleven thousand buildings online. Which means we are tracking, gathering, and monitoring the energy data for eleven thousand of our customer’s facilities. That includes at the building level.

As well as we’re rolling out a new deep sub-metering initiative. Which means we’re gathering energy data from the most energy consuming equipment within our customer’s facilities.

One other point is that both this room, as well as the rooms immediately behind you, are equipped to serve as a Power Authority’s Emergency Operation Center when the need arises.

Between the information along this video wall, it’s providing data transparency, data analytics, and enhancing the situation awareness that our executive teams can use to make the best decisions.

Three Young NYPA Leaders at iSOC Opening
We use this energy data to start identifying trends. And then opportunities to help our customers reduce their energy and costs. We’re not just helping optimize and advance our customer’s energy efficiency, but most importantly their productivity.

Kenneth Carnes
Hello, my name is KC Carnes, Chief Information Security Officer. We have combined cyber, physical and network monitoring in the iSOC. What we’re doing different is tightly coupling that with the operations and the customer perspectives. That allows us broad situational awareness and capability to respond quickly. With the Emergency Operations Center behind us, we can bring these teams together and make sure that we quickly combine for any threats, events or anything happening to NYPA’s asset systems or our customer’s infrastructure.

Outside of that you can assume that much of our data is sanitized today for security reasons. But I can assure you that during normal operations this facility will be the hub of intelligence gathering and information sharing for NYPA across all of our assets.

And to further push the vision of our future, and to bring more and more critical information into this facility, we will be leveraging the Network Communications Backbone Project. Where we will bring more and more critical information from smart generation and transmission resources into this facility for more and more security protection, to protect those critical energy resources that NYPA provides to all of New York.

Excerpt from Today from PUF Column entitled Picture Energy Poverty (Jan 8, 2018)

Liberian doctors doing night rounds by the light of their cell phones. Teenaged boys in overcrowded cells when power outages in Sierra Leone cast a juvenile prison into pitch dark. A pensioner in Ukraine struggling to cope with a two hundred and eighty percent increase in gas prices.

Over the past few months, stories and images from The Energy Action Project, EnAct, have shown PUF readers the harsh reality of how energy poverty affects individuals and societies. This close-up reporting makes it staggering to consider that almost half the global population still lacks access to modern energy.

But EnAct has also featured exciting initiatives such as the revival of water mills in Nepal’s remote hillsides, low-cost water purification through solar power in India, and aggressive action to curb load-shedding in Kathmandu.

So, we’re asking you all to get behind EnAct work in a very tangible way. By providing them a little support. The EnAct crowdfunding campaign is both personal and corporate contributions.

With some great rewards offered in return. Cool! Hanging EnAct outstanding photos in your office, lobby, or boardroom can show your commitment to ending energy poverty. A customized webinar can help you learn how to tell your own story more effectively. Corporate support can even include the chance to have your logo attached to an EnAct article in PUF.

To get the ball rolling, I’ve personally donated. If you’ve enjoyed EnAct reporting as much as I have, I hope you’ll meet or beat these launch contributions! Check out:

https://www.indiegogo.com/projects/reporting-that-seeks-to-empower-energy

– Steve Mitnick, Editor-in-Chief
In this short video, Scott Gibson of Snohomish County Public Utility District and Eric Walters of Gainesville Regional Utilities speak at the APPA Public Power Forward Summit on December 11-12 in San Francisco about the technology and applications of their cutting edge microgrid projects.

Scott Gibson: The purpose of the microgrid is to be able to power up a building so that in the event of a disaster we can keep this building powered, keep crews going through the time of the disaster, and allow the grid to be put back together.

Eric Walters: [University of Florida – Gainesville] has a microgrid that’s in partnership with our local healthcare provider. It is located on their campus, in between their healthcare facilities, and it serves the entire block of the master planning community. That area is just south of the University of Florida campus, and in between our downtown and I guess, western parts of town.

It allows for us to be able to operate in our core competency, to operate utilities, to do the maintenance to the operation and those things. And also, frees up our customer to be able to focus on what they do best. We’re able to separate from the grid if we need to, and supply them without them even knowing.

Scott Gibson: The main components of the microgrid are a lithium ion battery, that’ll be the backbone of the system. And we’ll have a five hundred-kilowatt solar array, that’ll be the main power source for the microgrid. Then we’ll have a recip. generator, a natural gas fired generator. And then we’re also going to have a vehicle-to-grid system.

We’re going to experiment with using our fleet vehicles to also be another chunk of battery. This battery storage system, lithium ion, the solar ray, the recip. generator, the vehicle-to-grid system, all of that will work in conjunction with a microgrid controller to keep a really critical facility powered up in the event of a disaster.

Eric Walters: We have two prime movers, our independent generators that produce the power. We’ll use heat from those generators to produce steam that also serves the hospital. And we have the ability to either serve chilled water through steam production or chilled water through electric chillers.

All of that is self-contained within the building. So, if we have to separate from the grid, we can also operate that equipment.

Scott Gibson: The challenge is for cost. Costs of batteries are still expensive. The costs are coming down. Fortunately, the electric vehicle market is driving improvements in efficiency and cost reductions in batteries. But they are still expensive. So, being able to afford a battery big enough to do what we need to do is one of our biggest challenges.

I think another challenge is just going to be creating the microgrid control system, to make sure that everything works in unison. So that when the grid goes away, we can seamlessly disconnect from the grid and connect up to the microgrid system with no loss of power to the building.

Eric Walters: Key challenge is really integration within the existing grid and also with the customer. They’re on the cutting edge of healthcare technology, and being able to support them consistently, in a way that they need, has presented some growing pains. But I believe that we’ve overcome that.

Also, just some of the things that were in the design that we thought, hey this will be a great idea, when we get into it, it doesn’t work out as far as we thought it was going to work out. Being able to work with those things, to improve them, to either change settings or designing a program to make them more applicable for what we’re doing and make them more reliable, and resilient.
Peek at 2018
Great Year for Energy and Environment

BY BARRY WORTHINGTON

There’s a premium on predictions, but the exception could be energy priorities in 2018.

The Trump administration has revealed plenty in 2017 about what we can expect for our industry in 2018, and how it plans to shape energy policy.

The administration moved at record speed in 2017 to lay the groundwork for infrastructure expansion and job growth. It began rolling back redundant regulations and proffered a plan to optimize electricity markets.

And President Trump signed into a law the largest tax overhaul in thirty-one years, which opens oil and gas exploration in the Arctic National Wildlife Refuge. It also encourages the renewable energy sector to thrive.

We see that momentum continuing in 2018.

We expect public policy goals for the United States in 2018 will be infrastructure, infrastructure and more infrastructure in the same manner that jobs, jobs, and more jobs was the mantra in 2017.

Our energy industry has various ownership structures and business models. But a common denominator is that infrastructure investments are essentially financed using private, not taxpayer money.

Another common denominator is the major goal of our sector: to ensure energy production and delivery is increasingly safe, affordable, reliable, and clean.

The U.S. oil and natural gas industry deserves enormous credit for tapping a domestic resource base that is clearly abundant and affordable. New records for oil and gas production in the U.S. are expected in 2018.

And record exports of crude oil, refined products, and liquefied natural gas are predicted. And record exports of crude oil, refined products, and liquefied natural gas are predicted. Exports support U.S. jobs and help reduce the trade deficit. We will learn more this year about how U.S. energy resources fit into the global geopolitical puzzle.

Contributing to this export boom are refined products. In 2018, the United States will have the largest and most technologically advanced petrochemical complexes in the world. Additional regulatory relief in 2018 will allow our products to continue to be abundant and affordable.

Our domestic natural gas industry will be in the world spotlight when the World Gas Congress comes to town in June 2018. We will learn that all around the world, the pipeline industry shares our concern that those who protest new pipelines can constrain our energy supplies and delivery.

The electric power sector is certainly in the spotlight. On Thursday, January 18, as USEA kicks off its 2018 annual State of the Energy Industry Forum, the Federal Energy Regulatory Commission will hold its first meeting of the year, and with a full commission; FERC went without a full commission from October 2015 to its last meeting of 2017.

It should be an eventful year at FERC, if its decision on DOE’s Notice of Proposed Rulemaking to compensate coal and nuclear plants in electric markets is any indication. 

(Cont. on page 31)
Top Three Tax Reform Changes Impacting Utilities

Widespread Impacts

BY ROBIN MILLER

With the most significant overhaul of the U.S. tax code in more than thirty years now signed into law, power and utility companies will move toward implementing the changes and evaluating the impacts it will have on their business, cash flow and capital investments.

Certain provisions of the Tax Cuts and Jobs Act are expected to have widespread impacts on the industry. One of the most notable changes is the reduction of the corporate tax rate as well as the elimination of the corporate alternative minimum tax.

The new law contains rules that may impact deductibility of interest and the accelerated cost recovery of capital assets. In the meantime, no changes were made to the dividend and capital gains rates. That means these rates remain in parity, which is also important to industry investors.

Leading up to reform, industry leaders had several key priorities that they were watching very closely. Here’s a look at three of the top issues, and what the changes could mean for the industry.

Reductions to corporate tax rate:
Effective January 1, 2018, the corporate rate dropped from 35 percent to 21 percent. Considering that income taxes are a significant component of cost of service and, therefore, utility rates, this reduction will have a meaningful near-term and positive impact on customer rates.

The tax rate reduction also reduces the amount of accumulated deferred tax, that is, the amounts companies anticipated paying in taxes in the future for timing difference deductions taken in the past. That creates excess deferred income taxes for regulated utilities that will be shared with their customers.

The new tax law generally provides for the normalization of regulated utilities’ property-related excess deferred income taxes. That is, the difference between the utility’s property deferred taxes at today’s thirty-five percent rate versus the new twenty-one percent rate.

Normalization of excess deferred income taxes generally provides regulated utilities the opportunity to reduce rates charged to customers over the book life of the property, thus avoiding sharp fluctuations in rates charged to customers as a result of the tax rate change. Utilities also have excess deferred taxes associated with nonproperty-related differences.

The normalization rules in the new law do not cover the nonproperty-related excess deferred income taxes. That means the regulatory commissions have discretion to determine the period over which the nonproperty excess deferred income taxes may flow back to customers.

Limits to interest deductibility:
The new rules generally limit the deduction for interest to the sum of interest income plus thirty percent of the ‘adjusted taxable income’ (similar to taxable EBITDA) of the taxpayer, while allowing unused deductions to be carried forward indefinitely.

PwC Partner Robin Miller leads the firm’s U.S. Power & Utilities tax practice. With more than 25 years of experience, she helps utilities optimize tax outcomes and manage risk by addressing specific company issues and the wider business and regulatory environments.
For tax years after December 31, 2017 and before January 1, 2022, the limitation becomes stricter, as companies will be required to include depreciation or amortization, similar to taxable EBIT.

Regulated utilities are specifically excluded from the limitations on the deductibility of interest. Thus far, however, guidance has not been provided on the methodology to be used in allocating interest among members of consolidated groups that include regulated utilities.

Changes to the capital recovery rules:
Given the capital-intensive nature of the power and utility industry, changes to the capital recovery rules are also of great interest. The new rules generally allow non-regulated businesses to immediately write off the cost of qualified property acquired and placed in service after September 27, 2017, for five years. Then, the rules phase down full expensing by twenty percent each year for the next five years.

Energy tax credits such as wind production tax credits and solar investment tax credits were largely unchanged by the tax reform changes.

The tax reform act also allows the additional first-year depreciation deduction for new and used property. Similar to the interest limitation rules, certain regulated utilities are excluded from the full expensing rules. Thus, public utility property will generally be depreciated using existing or non-bonus accelerated depreciation methods, such as the Modified Accelerated Cost Recovery System.

Final thoughts:
Energy tax credits such as wind production tax credits and solar investment tax credits were largely unchanged by the tax reform changes. After initial concerns in the renewable industry about the base erosion anti-abuse tax (BEAT) provisions of the proposed bills, Congress modified them so that the renewable energy credits can be used to offset up to eighty percent of BEAT liability.

While this change does not fully alleviate the concerns of the renewable investors, it certainly landed in a better place than where it started.

The Tax Cuts and Jobs Act is the most historic tax reform enacted since the Tax Reform Act of 1986. It represents years of effort to enact a reform of U.S. tax law providing a more competitive tax system for business taxpayers and improved economic opportunities for individuals and families.

It also provides opportunities for the power and utilities industries, with companies expected to continue evaluating the effects of the new law for years to come.

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Energy Secretary Rick Perry had sought financial support for coal and nuclear units to recognize the security and reliability attributes of their on-site fuel supply. Money reinvested in those plants would have meant infrastructure investments for all components of the U.S. power business.

But on January 8, FERC terminated the proceeding on the NOPR and instead asked operators in organized markets for more information, to determine whether any action on the matter of resilience was even needed.

2018 should be a boon for all areas of the energy sector and the environment.

The renewable industry will see 2018 as a year in which to benefit from last year’s tax package. Tax credits were unchanged in the final bill, but it was widely expected that they could be modified.

Less certain is the trade issue, with the potential for tariffs to be levied on solar panels, particularly from China. Fortune 500 energy companies are the largest investors in renewable energy, and this is unlikely to change in 2018.

And we see our industry continuing to reduce greenhouse gas emissions.

We are motivated by the entire variety of stakeholder pressures. We need neither the Clean Power Plan nor the Paris Accord.

Power sector emissions will be down more than twenty-five percent in 2018; the Paris Accord goal was to reduce emissions twenty-six to twenty-eight percent.

We are motivated by our shareholders. Every corporate shareholder resolution on climate change will get more favorable votes in 2018 than the same resolution would have received in 2017.

Our public and government officials at all levels want us to reduce emissions. Our customers want us to reduce emissions. All other stakeholders want us to reduce emissions, and our employees want us to reduce emissions.

We are retiring sixty-five-year-olds and replacing them with twenty-five-year-olds. The twenty-five-year-olds have a different perspective on climate change. They want to work for a company that is clean, green and cool. If we are not clean, green and cool, they will go to work for someone that is.
In the wake of the Department of Energy releasing its Staff Report on Electricity Markets and Reliability, followed by its Notice of Proposed Rulemaking directed at FERC, more than a few observers have questioned the motives driving DOE's agenda. Are the motives resiliency and security? Maybe they include propping up the nuclear and coal industries? Or maybe they are just a perverse fascination with keeping the energy Twitterverse fully engaged?

Many of us seem to agree that some sort of market reform is necessary. But, in many ways, we are confronted with a market identity crisis concerning what exactly we are trying to achieve.

Leave it to the great electricity market philosopher Jon Bon Jovi to succinctly describe where we are with energy policy – the more things change, the more they stay the same.

History tells us that electricity, one of the most omnipresent commodities in the U.S., is and will continue to be inherently susceptible to political and social intervention. Let’s recap some of that history.

In the midst of the Great Depression, electricity production was controlled for the most part by private utility companies. At the time, however, it was not uncommon for urban areas to be fully electrified, but for adjacent rural areas to be without power.

In response, President Franklin Roosevelt and the New Deal Democrats proposed large public works projects to employ millions of jobless Americans while simultaneously creating and modernizing critical infrastructure. FDR promoted the concept of large, federally funded hydroelectric developments in several of the nation’s river basins throughout the south and west to create jobs and mitigate the electricity divide between urban and rural communities. It also happened to be a popular idea among those in FDR’s core political base.

U.S. energy policy in the 1970s and 1980s was the result of a number of cultural and political upheavals. The Three Mile Island nuclear incident, foreign oil embargoes, and growing support for environmental conservation reshaped the way electricity was produced and regulated. And in 1978, Congress opened the door to small, non-utility power producers with the passage of the Public Utilities Regulatory Policy Act.

Later, issues like the stagnant demand for electricity, cost overruns at merchant generation facilities, excess capacity, rising fuel costs, and new federal and state regulations for air and water quality presented stark challenges to regulators.

State and federal regulators sought to achieve a balance, providing affordable electricity to consumers while remaining sensitive to utility companies’ bottom lines. This convergence of issues paved the way for a renaissance in utility integrated resource planning.

Integrated resource planning was, and remains, a viable way to reconcile the concerns of ratepayers,
environmental groups, and industry stakeholders by allowing utility companies to develop a resource portfolio with their preferred mix of least-cost and sustainable resources.

The 1990s brought a fundamental restructuring of the energy industry, intended to deliver more efficiently priced electricity by paving the way for regional wholesale power markets.

While most low-cost states made the inherently political decision to retain vertically integrated utilities, political imperatives in higher cost states sought to place resource decisions in the hands of merchant generators, shifting risk from captive ratepayers to shareholders.

All of this created a marketplace for electricity that had been largely non-existent throughout the 1970s and 1980s.

While open markets were the objective of the 1990s, the pendulum is swinging again, unsure of which direction to go.

An honest conversation that involves confronting the reality that the electric markets of the 1990s are hardly – and never will be – the “open markets” we set out to create.

Electric markets are confronting the political realities of low gas prices, decreasing costs for utility-scale renewables, a fervent desire to create jobs and preserve a tax base with market subsidies for renewable and zero-emission power, and the effects of aggressive environmental regulations.

In that context, while it might seem we have come a long way since the New Deal and the Arab oil embargoes, current events are merely reinforcing the fact that social and political imperatives inherently animate the electric industry.

It appears we are now standing at another fork in the road. As we contemplate which way to go, perhaps we would benefit from deeper discussions about where we are heading, all the while not forgetting where we have been. Undoubtedly, politics have and will continue to have a profound influence on electricity policy.

Indeed, as FDR sagely noted, “In politics, nothing happens by accident; if it happens, you can bet it was planned that way.” While accepting this fact, we should be clear that the country would do well to better define what it is we are trying to accomplish, and that the conversation cannot be “markets” versus “non-markets.”

Rather, we need to have an honest conversation that involves confronting the reality that the electric markets of the 1990s are hardly – and never will be – the “open markets” we set out to create.
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This past year three hurricanes affected an area which encompassed about eight percent of the U.S. population. According to an article by Joel Achenbach in The Washington Post, dated November 19, 2017, “Disaster claims soar in year of calamities: Federal resources stretched as applications for aid rise tenfold,” these three storms contributed to a year of “record setting disasters.”

4.7 million Americans registered for FEMA aid compared to four hundred eighty thousand in 2016, and an average of a hundred and eighty thousand for the previous three years.

This means that U.S. electric utilities also experienced significant storm-related costs.

These costs are significant and are increasing. This is because the economy continues its decades-long trend of increasing electrification.

Whether there has been an increase due to “climate change” in the frequency of storms or whether storm intensity costs increased as more asset investment is subject to damage, there is no question that disaster restoration costs are increasing.

The U.S. electric utility industry and its regulators use a number of ratemaking techniques to lessen the financial impact of these increasing disaster restoration costs. Cost minimization is not the first goal, however.

Importantly, the electric utility’s first goal after a storm is rapid service restoration. The lack of electric service impedes restoration of all other segments of infrastructure.

These include direct life support services such as water service, communications, medical service, public safety, and so forth. As well as all the services that support the whole economy. Electric utilities incur additional costs in quickly restoring electric service. These costs, while incurred by the utility, reduce economic losses in other sectors of the economy created by electric service interruption.

Generally, regulators apply a regulatory policy which states that prudently incurred restoration costs are recoverable in rates either before or after the event. This is done in a storm reserve account established before the event or in the form of a special surcharge on rates after the event.

While financial impacts of storm damage can be mitigated through the use of storm reserves or deferral of storm costs, neither technique provides cash during the storm restoration period.

That last observation recommends the introduction of greater reliance on insurance for storm cost recovery. Many utilities have already joined in mutual self-insurance mechanisms for some costs, but not all.

Regulators should encourage this trend with approval of the inclusion of reasonable premiums in the utility’s revenue requirement for ratemaking. The reasonableness test should also recognize the secondary economic benefits to the entire economy from the more rapid restoration of service, beyond the direct restoration benefit to the utility.

Obtaining more insurance coverage may indeed prove to make sense now, climate change or no climate change.
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