How Reshaping Regulation Will Reshape the Grid

As technology advances, customers' use of electricity evolves, and threats to electricity delivery mount, significant changes are needed in the electric utility sector. Electric utilities will need to make significant shifts in their priorities and in how their performance is evaluated. The electric utility industry needs new regulatory models so utilities can be profitable while they oversee a transformation to the grid of the future. This transition will require considerable investment, but it will also create efficiencies and deliver a much broader suite of services to customers.

The S&C regulatory team has laid out what we believe to be the most likely road regulatory bodies will follow to enact these changes. Countries and localities will differ in the specific makeup and pace of change, but we believe most will start with adaptive rate-making, the inclusion of non-wires alternatives, adoption of performance-based regulation and, eventually, transition to a distribution system operator role for electric utilities.

Introduction

Countries and states/provinces all over the world are dealing with a changing energy landscape. On one hand, the consensus among scientists that human activities are causing climate change is leading policymakers to monetize and regulate those externalities—the beginning of the end for fossil fuels. At the same time, aging infrastructure coupled with increasingly severe weather and natural disasters is putting more stress than ever on power grids. Finally, technological and manufacturing innovations in the areas of renewable energy, energy storage, information technology (IT), and self-healing grids can help address the first two problems and considerably increase the capabilities and services the grid delivers. New solutions have the potential to give energy users more choice about the services they want and enable them to not just consume from the grid, but provide energy and services to the grid.

Sounds good, right? There's a catch. Two, actually. The first is this transition won't be free; it will cost a vast amount of money. These transitions involve major investments. It will cost money to modernize the grid with sensors, switches, protection, and controls to allow for a more resilient system with two-way power flow. It will cost money to deploy the energy storage and inverters necessary to leverage large-scale renewables to handle base-load power duties. It will cost money to adopt the IT infrastructure necessary for system optimization and protection from cyberthreats. After all this is done, rates will need to reflect these investments. With a considerable number of energy customers below the poverty line, issues of energy welfare will be of increasing concern.

The second catch is most regulatory systems aren't designed to engender these kinds of investments right now. The present regulatory environment in many countries typically involves some minimum standards of service, but it primarily focuses on cost-of-service (COS) regulation, where utilities make their profit based on their investment in grid infrastructure. You may think, “That’s fine, we need new infrastructure!” Unfortunately, traditional COS regulation doesn’t easily allow for transformational investments, nor does it reward solutions that are not hardware-based. It rewards utilities for building the same thing they’ve always built, the way they have always built it. It does not reward innovative activities that fall outside those parameters. Regulators are often focused on short-term efficiency and limiting rate increases rather than the future needs of customers. This means developing the grid of the future is a hard-sell in most of these environments.

So, what is needed? Utilities are going to need three things to address the changing energy landscape:

- An excellent understanding of new energy solutions;
- Access to money to pay for those solutions;
- A regulatory framework that makes modernizing the grid the most economically attractive pathway.

Regulators understand this, which is why many are looking to (slowly) transform electricity regulation.

The more progressive regulatory agencies are supporting a transition from traditional utility operations to a “distribution system operator” (DSO) model. The DSO model uses performance-based regulation instead of a pure cost-of-service approach. It levels the playing field between both wires investments and non-wires alternatives, and it allows utilities to earn returns on both, giving them the flexibility to adopt solutions that give the best combination of performance and cost. Ideally, it creates a situation where utilities are empowered and encouraged to invest in a grid that delivers better outcomes because that is how they can best make money.

This paper will talk about how the regulatory landscape is changing, why those changes are trending toward a DSO model, and what to expect in terms of costs and benefits from that change. It will then walk through the steps along that pathway. Finally, it will discuss how this change is likely to affect services and rates over time.

The Changing Regulatory Landscape

The regulatory landscape is changing, but in different directions and at different speeds depending on the country and locality. The late 1980s saw privatization of electric utilities in the United Kingdom and elsewhere. In the 1990s, electric utility deregulation created the first major schism in how energy was regulated in the United States and in several other countries. Certain governments decided to create open competition in the energy generation sector, forcing utilities to divest their generation holdings or in energy retail. The goal was to spur competition and innovation. Different governments pursued this in different ways (to varying degrees of success). The result was energy generation, delivery, and retail were now operating under noticeably different rules, even in a single country.

Further divergence in energy regulation followed with the myriad of approaches to renewable generation targets and net-metering laws. As countries/provinces/states became more proactive in encouraging specific behaviors and technologies, the question of which energy solutions made the most sense became truly a localized issue.

The next layer of complexity is coming from multiple angles. Regulators are responding to new technology and increased demands for energy reliability. While all these drivers are being discussed broadly at national energy conferences, there are specific actions being taken as well. Regulators and lawmakers are pushing to:

- Create incentives and mandates around specific technology solutions, such as advanced metering infrastructure (AMI), utility-scale microgrids, and other new technology out in the field to advance and strengthen the electrical grid, leading to greater reliability and resilience
- Create market mechanisms and consumer incentives that will enable the market to push utilities toward desired outcomes
- Support or require the use of non-wires alternatives in infrastructure investment

- Provide more clarity around definitions and rules of engagement – particularly around solutions such as microgrids
- Implement performance-based regulation to encourage utility focus on more than just capital infrastructure projects

Countries and states will continue to evolve and diverge in their areas of focus. This local-solutions approach will enable lots of new ideas, but it will slow the implementation of large, sweeping changes. In each case, those taking action are being watched by others to see how these policy experiments play out. The success of a particular approach may bring a cascade of others who follow suit.

In all these jurisdictions, however, there is a common thread: the need to update the regulatory environment to encourage or empower the transition. And while the actions they are taking may vary, they all seem to be heading away from traditional COS regulation and toward a situation where these three things are true:

- There is an understanding that fundamental change is needed in the way the grid works and, possibly, the roles being played in the delivery of electricity.
- There is a greater measurement of key performance indicators in areas such as cost, efficiency, carbon footprint, reliability, resilience, cybersecurity, and safety.
- Suppliers are being enabled and encouraged to bring new products and solutions to market.

S&C's regulatory team believes, despite the different areas of focus within specific countries, the future of electricity regulation is going to follow a largely similar course.

The Path to a New Regulatory Future

S&C's regulatory team believes most nations will eventually adopt regulatory policies that shift from electric utilities only making money based on infrastructure investment to a distribution system operator model. This will be a model where utilities earn new sources of income from coordinating a marketplace of solutions and providing a platform through which customers can provide services on a peer-to-peer basis and back to the grid. Increasingly, utilities will make their profit based on how well they provide a reliable, resilient, low carbon, and efficient grid to deliver those solutions. This change can be made in both vertically integrated and restructured regulatory models. There are four primary steps along this pathway.

Step 1: Cost-of-Service Regulation

Traditional COS regulation is designed to ensure utilities can recover their costs and make a profit on their investments while keeping this in balance with customer interests. It allows utilities to recover their annual operation and maintenance (O&M) expenses. Capital investment flows into the "rate base," and utilities recover these costs over time through a depreciation allowance and a percentage return on the rate base. Regulatory commissions work with utilities to agree on the allowed level of O&M, depreciation, and the percentage rate of return. These costs together become the "allowed revenue" for the utility, which determines how much it can charge its customers for service over a particular period. Typically, this is done using a historical test year (usually the previous 12 months, adjusted for foreseeable changes) to project the expenses for the coming period. This is combined with long-term integrated resource plans (IRPs) to scope out investments that will take more than a year. All of this is done to protect customers by setting fair rates in a market that, by its nature, must be a monopoly. This trade-off, where utilities allow regulators to set their rates and standards in return for guaranteed returns on their investment and monopoly power, is referred to as the regulatory compact.

The COS approach has two big problems. First, it focuses utilities on making infrastructure investments because that's what they make money on rather than improving performance outcomes for customers. While regulators keep their eye on performance issues such as customer satisfaction and reliability, utilities in pure COS states can't really make more money by doing an excellent job in these areas or by extending the services they provide to customers. The second problem is the COS regulatory approach tends to undervalue new technologies, such as advanced controls or distributed energy resources (DERs). Utilities know they can get a rate-of-return approval on traditional technologies, but proving the long-term value of new technologies is more difficult, so these solutions are not leveraged to the extent they probably should be. And remember, because utilities operate in a monopoly environment, there is no invisible hand of the market to introduce these solutions through open competition. So, if the goal is to have a system optimized to deliver the best possible service while taking advantage of new and innovative solutions, COS regulation isn't designed to get us there.

Step 2: Adaptive Rate-Making and Non-Wires Alternatives

While regulatory commissions are looking for ways to empower utilities to make investments in the grid of the future while also driving them to improve performance, most are not ready for a wholesale change in regulatory approach (as will be described in Steps 3 and 4). As an initial step, regulators are using targeted regulatory changes to engender grid transformation. The most common techniques are described below and could be done individually or in concert.

Greater sharing of data with regulators and the industry. By requiring utilities to collect and share more data than in the past, regulators can achieve a more granular understanding of where the utilities are performing best or are falling behind. Having utilities make some of this data available to the public creates greater transparency with customers and allows the market to better target non-traditional energy solutions.

More aggressive integrated resource plans (IRPs). Traditional IRPs guide long-term investment but are usually created based on a traditional view of what should be built. By working with the utilities to forecast future needs and sending clear signals about how and which new solutions will be approved in a rate case, regulators can dramatically improve the alignment of IRPs with future system needs.

Non-wires alternatives (NWAs). NWAs are measures aimed at deferring, mitigating, or eliminating the need for traditional "wires" investments in utility transmission and distribution grids. NWA projects involve modifying generation and/or load at the point of the end-users. These could be energy-efficiency projects funded because they reduce peak or average demand on specific feeders. They also could be demand-response or energy storage projects that can respond to grid demands in real time, or they could be microgrids that can do all those things but also provide enhanced local energy resilience. NWAs are a way to allow the utility to engage and leverage market solutions without undercutting the utility's ability to profit from new investments. The ideal way to do this is with a shared-savings incentive, where utilities and customers share in the avoided costs of using an NWA over a traditional wires-based solution.

Early trials of performance-based regulation (PBR) concepts. Regulators that want to dip their toes into PBR have identified one or two areas of performance and have created specific incentives or penalties associated with performance in that particular area. The most common areas for focus are in system reliability, customer satisfaction, or the rollout of a specific technology (such as AMI meters). If this type of incentive works well, regulators can use it as the basis for a more robust performance-based regulation scheme.

Step 3: Performance-Based Regulation

The switch to PBR alters the profit incentive for utilities away from capital investment and toward meeting performance objectives and improved efficiency. The metrics used could cover anything but typically include things such as reliability, customer satisfaction, safety, environmental measures that include reducing carbon footprint or incorporating renewables, cybersecurity, deployment of advanced grid controls, demand-side management capability, and fostering transportation electrification.

PBR is tricky because it can run afoul of the traditional utility/regulator compact that exists in some form in regulated and restructured regulatory models alike. PBR also requires regulators to start picking winners and losers when it comes to certain outcomes and goals. Does society prioritize a clean grid or a reliable one? Does it want low rates or an evolution to a more advanced grid? These questions are being discussed by legislators and regulators while utilities and interest groups lobby for the answers they want. The keys to successful PBR, as has been seen in countries such as the UK, Australia, and Canada, are:

- Engage the utilities and market players early so they can have input into the targeted outcomes, which metrics to measure, and what is feasible in each.
- Make performance metrics and incentives crystal clear to avoid confusion.
- Avoid having too many metrics because they will dilute the impact of each.
- Understand PBR is iterative and requires feedback and changes in future periods.

Step 4: Distribution System Operator

The success of utility restructuring in some states and the rise of third-party-owned distributed energy resources (such as renewables and energy storage) are creating a tension with the traditional role of the utility as the top-to-bottom supplier of all energy solutions. At the same time, there are mounting challenges for operating the distribution grid. Coordinating increasingly dense loads with increasingly distributed and variable energy sources (through forecasting and controls); leveraging the Internet of things, big data, and artificial intelligence to optimize the grid; enabling a marketplace for a myriad of new energy solutions; and managing the transition to an electrified transportation industry are just some of the critical roles that will be played by the future utility: the distribution system operator (DSO).

Leveraging PBR and NWAs, the DSO will coordinate and maintain the grid of the future with a significant portion of its revenue coming from incentives, providing ancillary services, and serving as a market platform. DSOs will still play a critical role in asset-planning, but now this will be less about building power plants and more about retaining services from the market. The DSO will manage a system with better information and low market barriers, enabling energy solutions to meet customer needs while the utility profits from meeting its performance metrics.

There are many challenges in transitioning to a DSO system. The first and most obvious is carefully altering the regulatory compact so utilities can continue to be healthy and profitable as they shift their focus. PBR can be a healthy way to shift that focus over time and smooth the transition. The second challenge is ensuring utilities have the infrastructure and technical capability to play this role. Forward-looking integrated resource plans in adaptive rate-making should help lay the ground for this. Finally, the DSO scenario requires a robust market of third-party solution providers to bring generation, energy storage, and demand response to the table, and the utilities will play a key

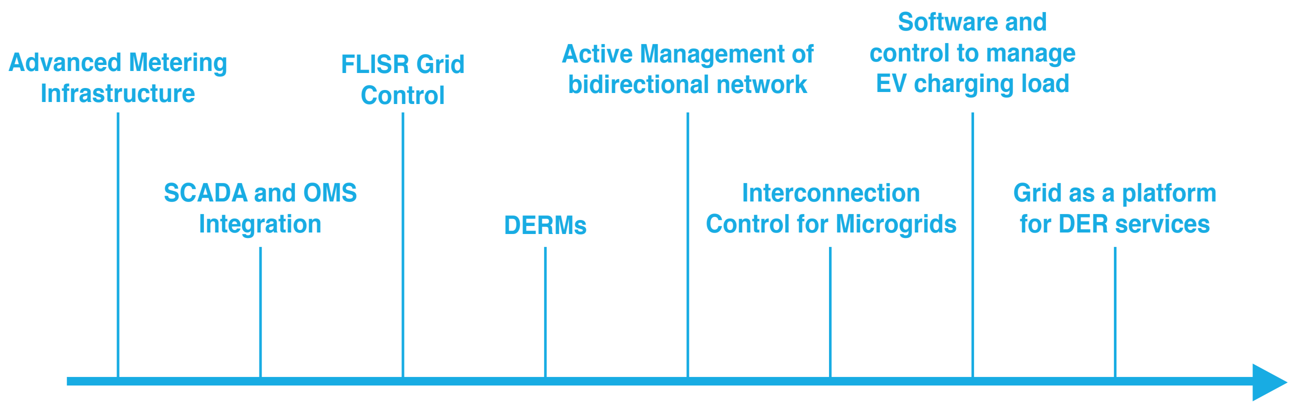

Figure 1: Technology timeline.

role in facilitating the development of such markets. An established non-wires alternative program will help that market grow to the point it can scale up to meet a DSO's needs.

As stated in the Introduction, utilities will need three things to address the changing energy landscape. They need an excellent understanding of new energy solutions, access to money to pay for those solutions, and a regulatory scheme that makes modernizing the grid the most economically attractive pathway. Each of these steps, culminating in the utility's role as a DSO, will pave the way for the transition to the grid of the future.

Impacts of This Change

So, what can utilities and regulators expect as regulations pivot from a cost-of-service model to a distribution system operator model? First, the benefits, costs, and timing are entirely dependent on the way the new regulations are written. That said, there are some changes that can be expected given the priorities regulators espouse at conferences such as NARUC and CAMPUT. Experience shows technology will develop faster in a DSO environment, and additional services will come online more easily. These changes will cost real money but PBR can create major cost savings that can be shared with customers.

Changes in Technology and Service

Based on the trends in technology development and the stated desires of regulators, certain solutions and services will be introduced or expanded upon. The exact timing and order of these technologies are impossible to predict, but Figure 1 shows a likely scenario.

Advanced metering infrastructure or smart metering refers to integrated systems of smart meters, communication networks, and data management systems. They are used to automatically gather granular data on energy use from customers and can also enable a two-way flow of information between the utilities and their customers.

Utilities are increasingly moving toward integrated Supervisory Control and Data Acquisition (SCADA) and Outage Management Systems (OMS) to achieve improved reliability, operational efficiency, and system security. SCADA is a widely accepted means of real-time monitoring and control of electric power systems, including power generation, transmission, and, increasingly, distribution. Modern OMS solutions include the geographical network model and covers analysis of outages, service call handling, management of field crews, and reliability reporting.

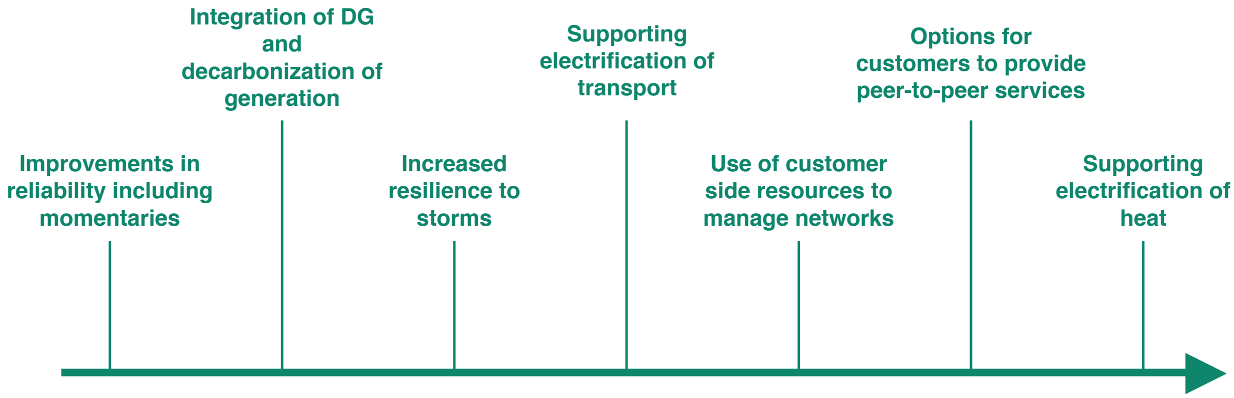

Figure 2: Growth in customer benefits.

Fault Location, Isolation, and Restoration (FLISR) systems include both SCADA-related centrally controlled distribution automation as well as distributed automation and switching to locate faults. They limit the scope of faults and restore customers as quickly as possible.

Distributed Energy Resource Management Systems (DERMS) are hardware and software platforms to monitor and control DERs in a way that improves the reliability, efficiency, and performance of the distribution system. They present operational and forecast information on individual DERs or on an aggregated basis and automate and manage individual or aggregated DERs.

Active Network Management (ANM) of a bidirectional system refers to the control of load and generation within part or all of a distributor's network to keep the system within predefined parameters, such as available capacity or voltage limits. For example, this may involve turning up or down load, distributed generation, or energy storage to meet a capacity constraint. This control may be achieved directly or through commercial arrangements with customers.

Interconnection control for microgrids will allow utilities to integrate and leverage the capabilities of microgrids and other non-wires alternatives, including islanding, demand response, load shifting, frequency regulation, and voltage control. Some of these systems will be owned by the utility while others will be owned by customers or third parties.

Software and control to manage electric-vehicle charging include solutions that enable smart charging in response to time-of-use or dynamic tariffs or other signals from utilities to safely manage charging within available capacity limits.

A Distributed Services Platform sees the grid as an intelligent network that provides safety, reliability, and efficiency by making use of diverse connected resources to meet customers' and society's needs. They allow DERs to provide valuable services to support the grid and on a peer-to-peer basis to support other customers.

These new technologies and services will create benefits for the grid and its customers. The likely order of these may look like what is shown in Figure 2.

Improvements to reliability will help utilities tackle not just the large outages but also shorter momentary outages. These much more common momentary outages are extremely costly for data centers and manufacturing customers. What's more, these momentaries are an increasing problem for residential users, who rely on uninterrupted connectivity more than ever. Importantly, these shorter-duration outages also result in the distribution generation being disconnected because, without access to the grid, they go offline and then need to be restarted, with their electricity frequency realigned with the grid. This is an increasingly serious problem as DERs start to make up a larger portion of our generation.

The integration of distributed generation will support more clean energy sources, such as distributed solar power. Even fossil fuels such as natural gas will have a lower carbon footprint when sited close to loads where it can avoid line losses from transmission and potentially take advantage of waste heat for buildings and manufacturing processes.

Resilience in the face of major weather events is going to be increasingly important. Hardening infrastructure and undergrounding lines will be coupled with advanced controls for a self-healing grid and more microgrids for local resilience.

The electrification of transportation will require considerable effort in systems planning, controls, and big-data forecasting. This transition will help utilities dramatically reduce the carbon impact of transportation. The S&C regulatory team cannot overstate how impactful and daunting this transfer of one-third of our energy use from fossil fuels over to the grid will be. The result, however, will be a huge public benefit and an opportunity for electric utilities.

Customer-side resources, such as DERs, energy storage, and demand response, are difficult to incorporate now because of imperfect market signals and limited visibility into what the grid can take advantage of. Technology improvements and increased communications will open this market.

As the distribution system as a platform market develops, customers will find opportunities to provide services directly to each other. This will not require end users to all become energy experts because software and artificial intelligence will handle these transactions. Technologies supporting sale of energy between end-users and communication protocols, such as blockchain, will facilitate more direct energy activity.

Just as with the electrification of transportation, the electrification of heat will have a huge impact on the distribution system. This will come decidedly later because the lifespan of heating systems is much longer than that of most cars and trucks, and changing these systems over to electricity will be costlier. Still, improvements in efficiency and carbon impact make incremental changes very likely.

Changes in Customer Costs

So, what will all this mean for rates? If the industry needs to reinvent the energy system and add all kinds of new features, won't that cost a lot? It will. There is no avoiding the fact the U.S. built an energy system in the 1960s and 1970s based on engineering concepts from the early 1900s, and utilities have been mostly maintaining that system with small improvements ever since. However, present (mostly) low electricity rates hide various expenses, including:

- The costs of power outages from aging equipment and storm events–costs utilities and customers are often not tracking
- The costs of climate change fueled, in part, by carbon emissions from energy generation
- The opportunity costs of leveraging renewable energy and demand response that could allow society to meet its energy goals in a much more cost-effective manner
- The global economic opportunity in perfecting and exporting the energy solutions of the future

So, while there are hidden, difficult-to-estimate costs to the present energy system, there is a clear need to modernize the grid, and doing so will require rate increases to pay for these investments. Is there any good news? There is! Experiences with NWAs and PBR have shown both have the potential to drive down costs for customers. NWAs enable utilities to

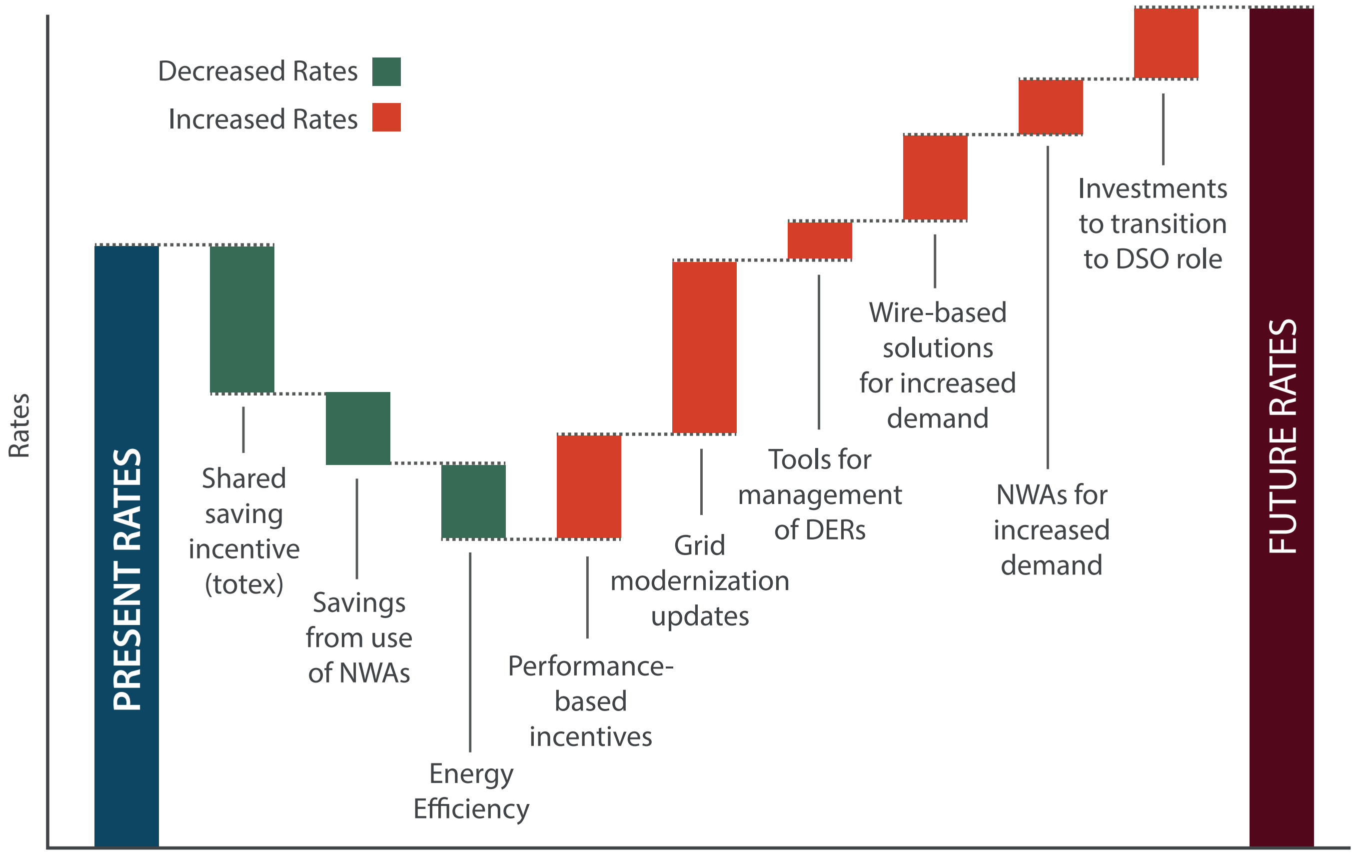

Figure 3: Potential pressures on rates.

meet increasing energy needs with solutions that can cost considerably less than traditional wireline investments. PBR has shown to spur innovation and efficiencies that simply aren't leveraged in traditional COS schemes. These savings can create downward pressure on system costs and customer rates. Fees and taxes on externalities, such as carbon taxes already being applied by some governments, could be used to reduce rates, particularly for those below the poverty line.

Will these efficiencies fully counterbalance the major investments needed in the system? No, almost certainly not. But they should do a good job of mitigating costs, particularly early on while existing inefficiencies are identified and resolved and before new requirements such as large volumes of electric vehicles create significant additional demands for grid capacity. They will also help to reduce those difficult-to-calculate externalities listed earlier.

Finally, the implementation of new technologies has the potential to unlock even greater system improvements that can create additional downward pressure on rates. For example, big-data analytics should improve the utility's ability to predict equipment maintenance needs and system planning, allowing for more efficient use of time and materials. Likewise, the electrification of transportation and heat will create even larger economies of scale to leverage advanced electricity distribution solutions.

Figure 3 provides a notional concept about how rates are expected to be affected as utilities modernize the grid and transition to a DSO role under a PBR framework. The new regulatory scheme present in

PBR is expected to bring inherent efficiencies and cost savings to the system. At the same time, realizing these efficiencies and modernizing the grid will require considerable investment. It should be noted that, beyond the performance-based incentives and transitioning to DSO role portions of the increase, all the other increases would be necessary if regulators wanted to modernize the grid while staying in a COS scheme. The primary difference would be that making those investments would be more difficult and the savings from decreased rates would be considerably less (if realized at all).

Conclusion

Technology is advancing to meet the increasing demands on our electricity system. The speed brake on innovation here are the regulatory schemes designed for a different time and environment. Regulators are working hard to keep up, but they face a constant challenge of having to understand new solutions and develop regulations that will enable their adoption, all while working with an industry that, by its very nature, takes years to implement new priorities. Every country, province, and state is going to have to find a regulatory scheme and pace of change that handles these competing challenges in the best way possible. The S&C regulatory team believes, slowly or quickly, piecemeal or all at once, most regulatory commissions will end up adopting adaptive rate-making, non-wires alternatives, performance-based regulation and, eventually, a fully DSO business model for electric utilities. This is the path that meets the goals heard from regulators and utilities alike, while realistically incorporating the technology trends seen in the market today.

S&C Support for Clients on Policy and Regulation Issues

While S&C Electric Company is primarily known for its equipment and engineering work, the company also has a regulatory team tracking and analyzing trends in electricity policy. This team has worked with utilities on performance-based regulation, advised regulatory commissions, and spoken at international conferences on the coming changes in electricity regulation. If your team is looking to model how regulatory changes could affect your planning, S&C's regulatory team is available to work with you on that front.

About the Author

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