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Evolving Grid Services, Products, and Market Opportunities for Regulated Electric Utilities

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This policy brief focuses on the more recent changes and evolutions in grid services, products, and market opportunities regulated electric utilities are offering to their customers, both traditional end-use electric customers as well as third-party party businesses. Drawing on a database of more than 50 recent examples, the most prevalent and significant evolutions are occurring in: residential retail rate design shifts toward voluntary and default time-of-use (TOU); changes to distributed generation (DG) compensation methodologies; utilization of customer and non-utility assets as non-wires alternatives (NWAs); and utility investments in electric vehicle (EV) infrastructure.

Important and related themes emerge from this assessment of recent trends suggesting regulators and policymakers should formulate clear and consistent policy goals around the following two issues:

1. Opportunities **increasing competition** to serve the electricity needs of retail customers. Reforms that drive increases in NWAs and DG pit utility investments against customer investments and may erode the exclusivity of the utility franchise. In contrast, reforms to DG compensation, that may reduce the financial benefits of a customer's investment, may maintain or strengthen the firmness of the utility franchise boundaries.
2. Opportunities driving **greater innovation** within and outside the electric industry. Electric utilities are innovating by developing novel NWA opportunities that can provide financial support for the broader adoption of DERs. There are also electric utility efforts to enable broader innovation in other industries, where utility investment in EV charging infrastructure could promote greater EV ownership and enable utility control of these resources to provide grid services.

Introduction

The electric industry is currently undergoing substantial evolution and expansion. Recent technological advancements, as well as changing customer demands, are expanding the number and type of electric utility grid services and product offerings to end-use customers. Furthermore, these forces, as well as societal and economic shifts, are presenting regulated electric utilities with new market opportunities (Cross-Call et al., 2018). Even the definition of the regulated electric utility's customer is evolving by expanding beyond the traditional end-user of electricity into third-party businesses engaging with the utility in order to more successfully sell their own services and products.

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These evolutions[1] in regulated electric utility grid services, products, and market opportunities, however, are not uniformly pursued by all utilities. In addition, these evolutions are not unequivocally supported by all stakeholders and policymakers. A number of positions either support or oppose these evolutions and illustrate the profound effect these evolutions can have on critical issues related to competition and innovation.

This policy brief[2] highlights four of these recent evolutions in grid services, products, and market opportunities that regulated electric utilities are offering, based on an analysis of a representative database of over 50 recent regulatory filings by electric utilities and major legislation pertaining to electric utilities. They are:

1. Default Time-of-Use (TOU) Pricing for Residential Customers;
2. Distributed Generation (DG) Compensation Reforms;
3. Procurement Approaches for Non-wires Alternatives (NWAs); and
4. Utility Investments in Electric Vehicle (EV) Infrastructure.

By identifying where there is substantial commonality in the pursuit of such evolutions, as well as characterizing the viewpoints in support of and in opposition to each of these four evolutions, this policy brief can help regulators, stakeholders, and electric utilities better understand the potential implications on competition and innovation associated with these evolutions.

Major Evolutionary Trends

Default Time-of-Use Pricing for Residential Customers

Reforms in retail pricing are evolving the ways in which residential customers pay for grid services and products. A handful of states (e.g., California, Massachusetts) committed to moving all of their residential customers onto default TOU rates in the coming years, while a few other states are considering such a transition in current or future regulatory proceedings (e.g., Colorado, New York). At the same time, a number of states and utilities are pursuing innovative pricing pilots (e.g., all utilities in California, Xcel in Colorado and Minnesota) to better understand customer acceptance, retention and response to default rates.

The evolutionary trend towards residential TOU rates, especially as the default, is driven forward by two primary considerations. First, advanced metering infrastructure (AMI) business cases frequently included the substantial benefits from greater penetration of residential time-based rates (TBRs) (NETL, 2008). With over half of the existing advanced meters on U.S. households installed between 2012 and 2016 (Institute for Electric Innovation, 2017), regulators and policymakers are now encouraging utilities to capture those benefits. Second, moving customers to TOU creates opportunities for greater economic efficiency, by exposing customers to prices that better reflect the marginal cost of electricity. In turn, this should drive investment in enabling technologies that not only allow customers to more easily adapt to the TOU rate thereby better managing their overall bill,

[1] "Evolution" is defined as the development of a new or different way in which: a) customers receive and/or pay for electric utility services and products; or b) electric utilities support broader market development opportunities, which themselves may result in utility grid service or product offerings.
[2] This policy brief is based on a more in-depth technical report describing the data sources, organizational framework, supporting examples, and conclusions. The technical report and accompanying data are available at: https://emp.lbl.gov/publications/evolving-grid-services-products-and

but also to more readily participate in other programs that allow grid services to be sold to the utility (MADPU, 2014) .

In contrast, a number of stakeholder groups have raised several concerns about TOU rate reforms. Consumer advocates contend that TOU rates could be considered a regressive tax on low-income customers who they believe generally use less electricity than the average customer and are less capable of instituting behavioral changes or investing in control technology to reduce consumption during the more expensive on peak period (Cappers et al., 2016). They also raise concerns that TOU rates could increase average bills and bill volatility (Alexander, 2010). Consumer awareness about total monthly usage, peak demands, and period usage, for example, is likely very limited which may further create challenges for transitioning customers to TOU rates (Faruqui et al., 2010).

Distributed Generation Compensation Reforms

Numerous states and utilities recently made changes to compensating DG resources for exported electricity. The dominant form of compensation for DG in the U.S. has historically been net-energy metering (NEM), which essentially allows DG customers to generate credits for exported electricity and bank them for future use (typically subject to annual reconciliation) all valued at the customer's full retail rate. According to the database developed for this analysis, at least 11 states[3] currently have approved some form of compensation for exported DG output as either a reform to NEM or as a successor tariff. Another handful of states (e.g., Arkansas, Louisiana, and Texas) have pending decisions on DG compensation reforms and even more states were exploring the costs and benefits of DG to inform potential reforms. DG compensation reforms have largely focused on altering the energy (¢ per kWh) rate paid by the utility for exported customer DG output based on either an avoided-cost rate (e.g., Arizona), wholesale energy rate (e.g., Indiana), or some administratively-determined percentage of the retail energy rate (e.g., Nevada and Utah).

DG compensation reforms are primarily driven forward by the objectives of fairly and equitably incentivizing technology adoption without driving significant cross-subsidization and, to a lesser extent, interests in reflecting DG-specific value streams. As a related motivation, regulators and consumer advocates note potential cost shifting from DG owners (i.e., participants) to non-participating customers, which could be mitigated or removed entirely with DG compensation reforms (Barbose, 2017). Many utilities view the dramatic growth in distributed solar PV in some states (e.g., Nevada, California, Arizona) as evidence that incentive policies, like NEM, are no longer warranted (EEI, 2016).

Beyond these primary drivers, some utilities are reaching pre-specified caps on the amount of DG capacity enrolled in NEM, thereby forcing regulators and legislators to determine successor tariffs (NCCETC, 2017). DG providers are also supporting the determination of resource locational value (e.g., avoided marginal cost of capacity) and using that feeder-level information as the basis for new compensation schemes (Gahl et al., 2018).

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[3] States as of December 2017 include Arizona, California, Hawaii, Indiana, Maine, Mississippi, New Hampshire, Nevada, New York, Utah, and Virginia.

DG compensation reforms face several headwinds hindering reform efforts. Solar advocates and providers are concerned about inconsistent application of DG compensation methodologies across utilities and states, and the frequency of changes to compensation levels that may create uncertainty for customer investment decisions and hinder the development of a robust DG market (SEIA, 2017). Also, implicit competition among DG and other DERs may reduce existing and future value of particular resources and may depend on the integration of EE, DR, and DG savings goals. For example, distributed solar PV may be less coincident with utility system peak periods at increasing deployment levels and DG compensation may decline under TOU rates (Darghouth et al., 2015).

Furthermore, certain NEM compensation reforms (e.g., net billing arrangements) may increase bills for DG customers relative to net metering arrangements, though the magnitude depends on differences between retail and compensation rates, DG system size, and customer load profiles (Cox et al., 2015). Net billing, which compensates exported generation at a wholesale or avoided cost energy rate and DER customers purchase power at full retail rate, tends to be preferred by energy storage owners because of the ability to arbitrage, which may not ultimately address concerns about utility shareholder or customer impacts.

Procurement Approaches for Non-wires Alternatives

Utility system planning activities evolved in recent years to take into account more locational granularity with a focus at the distribution feeder level. A number of states utilizing such distribution planning activities are likewise expanding the types of resources under consideration, to include demand-side resources (e.g., New York, California) as NWAs to distribution infrastructure investments that can provide locational and temporal services necessary to support the grid (Coddington et al., 2017).[4]

Two key issues drive the development and implementation of NWAs. First, regulators have historically been supportive of utilities offering innovative pricing and programs that promote load management, load conservation, and DER adoption. Likewise, these new NWA program and procurement opportunities not only leverage existing customer relationships and technology investments, but more frequently attract third-party companies who can aggregate large numbers of resources, thereby promoting innovation and market development. Second, NWAs can provide solutions to T&D upgrade needs at lower cost and with more environmental and customer benefits (Neme and Grevatt, 2015). This creates a structure for more meaningful competition to historic utility monopoly efforts for meeting distribution-system infrastructure requirements to maintain reliability and resiliency.

The lack of movement towards greater reliance on NWAs primarily relate to utility financial incentives under rate-of-return regulatory models. The pursuit of NWA programs and procurement opportunities runs counter to a utility's preference for capital investment (Averch and Johnson, 1962). In addition, it reinforces why regulators have either ordered utilities to do so or provided them with some sort financial incentive for successfully implementing such opportunities. Finally, utilities' general lack of experience with NWAs and lack of demonstrated equivalence between NWAs and utility distribution and transmission investments may limit their proliferation in the near term (Stanton, 2015).

[4] ConEd's Brooklyn-Queens Demand Management Program is an example of a NWA that procured DERs, like energy efficiency, demand response, fuel cells, and larger-scale solar projects, to defer the need for a costly distribution substation upgrade.

Utility Investments in Electric Vehicle Infrastructure

Several states see widespread adoption of electric vehicles as imminent and are supporting the transition through a series of policy and market reforms, some of which include a role for regulated electric utilities. The most direct way for electric utilities to promote and expand the EV market is to make investments in a robust charging station infrastructure. Utilities in several states have made or proposed investments in EV infrastructure through two primary ways: directly via ownership of public charging stations and indirectly via "make-ready" infrastructure to accommodate non-utility EV charging stations.

Views on the appropriateness of utility investments made with ratepayer money to promote and expand various EV market opportunities vary significantly. Some stakeholders, including utilities themselves, see a strong role for the monopoly franchise. Where private entities have failed to sufficiently invest in enabling EV infrastructure or supply chains, monopoly electric utilities may be uniquely positioned to facilitate the development of a competitive market (CPUC, 2014; NYPSC, 2015). Utility investment and ownership of assets through demonstration partnerships with third party EV charging companies can likewise accelerate the development of sustainable business models (NYPSC, 2015).

In addition, utility investment in EV "make ready" infrastructure may create new revenue and profit generating opportunities for electric utilities that mitigate some or all of the potential financial impacts of declining load (Satchwell et al., 2014). To a somewhat lesser degree, the electric utility's ability to procure lower cost capital may further provide electric utilities with a competitive advantage over third-party EV charging station providers (Blansfield et al., 2017).

These utility EV charging infrastructure ownership opportunities also face a number of headwinds raised by regulators and stakeholders concerned about adverse impacts on competitive markets and a risk of undermining market development. Unrestricted, utilities may make investments in areas where private parties are already competing for business. Although this may increase competition in narrowly defined EV charging markets, it likely avoids addressing larger and more structural market deficiencies, like issues of underserved markets, where the utility role would be seemingly more appropriate (CPUC, 2016).

A number of stakeholders have raised concerns about adverse impacts on customers when utilities make investments to promote EV market expansion. EV charging technology is evolving rapidly. Utility investment in one type of charging technology may create a greater likelihood of stranded assets and may pursue options where benefits are overly speculative (CPUC, 2016). Furthermore, utility investments in EV charging infrastructure may not meet the legal standard for what qualifies as "electric plant" (MOPSC, 2017) under existing statutory definitions.

Last, some contend that electric utilities may not even be the right entity to support market growth. In some cases, it may be problematic to assume that the utility can successfully expand into new and existing market opportunities, given its limited successful experience with innovation vis-à-vis private enterprise which must survive in a competitive market by being innovative (NYPSC, 2015).

Implications for Regulators and Policymakers

Important and related themes emerge from this assessment of recent trends suggesting regulators and policymakers should formulate clear and consistent policy goals around the following two issues:

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- Opportunities driving **greater innovation** within and outside the electric industry. Electric utilities are innovating by developing novel NWA opportunities that can provide financial support for the broader adoption of DERs. There are also electric utility efforts to enable broader innovation in other industries, where utility investment in EV charging infrastructure could promote greater EV ownership and enable utility control of these resources to provide grid services.

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