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Building New York's Future Electricity Markets: Identifying Policy Prerequisites & Market Relationships

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Introduction

New York State's "Reforming the Energy Vision" (REV) proceeding[1] aims to improve the efficiency of the State's electricity system by animating markets for distributed energy resources (DERs).[2] Thus far, the New York State Public Service Commission (Commission) has laid out several aspirational features of its DER market vision. The Commission has determined that distribution utilities will serve as distributed system platform (DSP)[3] providers and will administer competitive DER markets.[4] Moreover, the Commission has identified six long-term objectives[5] that new distribution-level energy markets should advance.

However, the Commission has not yet established a detailed vision of how various actors will interact in the end-state DER markets. This report seeks to flesh out that vision and to identify the policy foundations – particularly in terms of data access and network pricing – that will be required to bring about robust DER markets. The report also considers whether ongoing legal cases that examine the boundaries of state versus federal jurisdiction over electricity markets may hinder the Commission's authority to shape DER markets as it would like.[6]

Part I of this report distills key takeaways from a pair of roundtable discussions that the Guarini Center convened to elucidate features of REV's DER marketplace that the Commission has thus far left undefined, as well as certain policy innovations that will be needed to realize this end-state. Part II maps out the actors, roles, and relationships in New York's electric distribution systems – both under the *status quo* and as envisioned in mature REV-enabled markets – and presents the transactions that will characterize those relationships at the REV end-state.

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[1] *See* Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (N.Y. Pub. Serv. Comm'n, Apr. 24, 2014).

[2] DERs are the class of resources that includes energy efficiency, demand response, distributed generation, and energy storage. *See* Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues at 3 (N.Y. Pub. Serv. Comm'n, Aug. 22, 2014).

[3] The Commission characterizes a DSP as an "intelligent network platform" that valuates power system and societal attributes, engages customers and third parties, and integrates DERs. *See* id at 12.

[4] *See* Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan at 48 (N.Y. Pub. Serv. Comm'n, Feb. 26, 2015).

[5] The long-term REV policy objectives are: enhanced customer knowledge and tools that will support effective management of their total energy bill; market animation and leverage of ratepayer contributions; system-wide efficiency; fuel and resource diversity; system reliability and resiliency; and reduction of greenhouse gas emissions. *See* DPS Staff Straw Proposal on Track One Issues at 1-2.

[6] Notably, the Market Design and Platform Technology Working Groups met in March of 2015 to reach consensus on an end-state vision for REV, including the identification of market actors, roles, and products and transactions that comprise their interactions. However, their efforts have largely focused on identifying near-term business and technological steps that can facilitate the transition to DSP markets. *See* http://newyorkrevworkinggroups.com.

I. Defining an End-State for REV and the Policy Innovations Needed to Get There

In spring of 2015, the Guarini Center at NYU School of Law convened two expert roundtable meetings to articulate details of the end-state that REV strives to achieve, as well as the policy adjustments that will be needed to attain it. These meetings, conducted under Chatham House Rule, drew upon the opinions and impressions of experts from industry, advocacy, consulting, and academic perspectives.

The meetings fleshed out how participants felt that features of the REV end-state should look, including the roles and interactions of market participants and the policy foundations of robust DER markets. The overarching themes of the discussions were as follows:

- The future role of regulated utilities in distribution systems as the boundaries of their natural monopoly recede;
- The need for expanded access to electricity data on the consumer and/or system level to allow DER providers to readily determine profit opportunities;
- The inadequacy of current network pricing techniques to reflect the complete and dynamic values of DER for distribution systems; and
- The ongoing legal cases that may have a bearing on the Commission's authority to shape the DER markets it seeks to create through REV.

This report conveys the major points of consensus from these meetings with respect to each of these themes.

A. What Will Be the Role of Utilities in REV Electricity Markets?

The boundaries of the natural monopoly in electricity are receding

States have traditionally granted distribution utilities exclusive franchise over regional service territories in tacit recognition that their expensive infrastructure constitutes a natural monopoly. Economic theory deems a natural monopoly to exist where "the technology of certain industries or the character of the service is such that the customer can be served at least cost or greatest net benefit only by a single firm" rather than multiple competing parties.[7] In exchange for geographic exclusivity, the rates utilities charge for natural monopoly services are subject to regulation by state authorities.[8]

Historically, the scope of this natural monopoly has extended to the products and services that distribution utilities have been allowed to provide to their customers, such as those that support demand management. Utility control over crucial information and infrastructure access, coupled with regulated rate designs that often do not sufficiently monetize the value of these products and services, has caused the development of markets for these solutions to proceed unevenly.

However, improvements in distributed generation, communication, information technologies, and regulatory practices are enabling new classes of actors to participate in distribution-level electricity markets. This expanded universe of market actors calls into question the future role of regulated utilities, which should only be granted monopoly franchise for services that competitive markets cannot viably provide.

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[7] *See* Alfred Kahn, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS at 2 (Vol. II) (Wiley. 1971).
[8] *See, e.g.,* Robert L. Bradley Jr., *Origins of political electricity: Market failure or political opportunism?*, 17 ENERGY L.J. 59, at 62 (1996).

In a departure from years past, competitive markets are now viable for distributed solutions, which allow customers to provide resources like generation and demand response on premises or close to load. As DER markets mature, competition will become increasingly viable for other distribution grid services, such as voltage regulation and distributed energy storage. As such, "the transport function is pretty much all that's left" of what one expert called the "residual monopoly." Several participants cited economic theory credited to Ronald Coase to cast the trend toward a shrinking monopoly as a product of decreasing transaction costs.[9] As one participant noted, "10 or 20 years ago you could have argued that customer energy management fit into [the natural monopoly], but technology has evolved to the point where that no longer holds."

Looking ahead, the natural monopoly should continue to contract until only provider-of-last-resort responsibilities remain. That is, even in the presence of mature DER markets, backup service will still be required and regulated network utilities should provide that service. But beyond that, all grid services should be subject to competitive entry: "Elon Musk will see to it that all homes can handle their own reliability issues." Third-party DER innovators will be able to provide competitive solutions that obviate historical utility functions, which should reduce the scope of the natural monopoly going forward.

System planning should not be a monopoly function going forward

The Commission has acknowledged that the viability of competitive DER services will cause the extent of the natural monopoly to recede.[10] However, in designating incumbent utilities as DSPs[11] and enumerating DSPs' core responsibilities as integrated system planning, grid operations, and market operations,[12] the Commission has effectively extended the natural monopoly to encompass these planning and operations functions.

While operations of the grid and markets seem to be reasonable natural monopoly responsibilities going forward, it is less clear that system planning should reside under the monopoly umbrella at the REV end-state. Until now, with virtually all distribution system assets under the regulated control of utilities, system planning responsibilities have been "reasonable extensions of regulatory oversight" as a way to mimic competitive outcomes. However, with a greater diversity of competitive actors and technologies in the REV end-state, system planning must evolve from prevailing conventions. The need to "do more sophisticated planning at the grid edge" by integrating more DERs extends beyond traditional utility planning, which does not encompass siting and deployment of distributed generation resources. As a result, one expert remarked, "There's a bit of a mix between what we're asking the regulated entity to plan for and what we want the market to respond to."

Consistent with this sentiment, REV working groups have endorsed the Commission's decision to assign distribution system planning to DSPs at this juncture, calling the management and optimization of such planning a "foundational responsibility of the DSP."[13] However, the competitive DER marketplace

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[9] This concept and its applications to distribution networks are discussed in a forthcoming paper sent by a meeting participant subsequent to the meetings. *See* Lynne Kiesling, *Implications of Smart Grid Innovation for Organizational Models in Electricity Distribution*, forthcoming, WILEY HANDBOOK OF SMART GRID (2015).

[10] "The viability of intermodal competition provided by DER means that the monopoly function of power delivery is more tied to ensuring reliability than it is to building delivery infrastructure." *See* Order Adopting Regulatory Policy Framework and Implementation Plan at 20.

[11] "Because the DSP core functions would be highly integrated with utility planning and system operations, assigning them to an independent party would be redundant, inefficient and unnecessarily costly." *See* id at 45.

[12] *See* id at 31.

[13] *See* Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Draft Report of the Market Design and Platform Technology Working Groups (Public Feedback Draft) at 7 (N.Y. Pub. Serv. Comm'n, July 15, 2015).

envisioned for REV calls into question the need for an assigned planning function in New York in the longer term. As utilities cede more territory to customers and DER providers, the DER marketplace should be increasingly responsible for diagnosing and addressing system needs, eventually supplanting a planning function assigned to the monopoly. Rather than prescribing a planning role for an indefinite term, the Commission should take steps to ensure that DSPs publish system data (see section B) that will enable competitive actors to address system demands responsively and without regulatory prodding.

Utilities should shrink in asset size but not necessarily profitability
Another outshoot of a receding natural monopoly boundary is that utilities' asset bases will shrink as other market participants assume a portion of the grid services role that utilities have historically controlled. With smaller asset bases, utilities' rate base-driven profits should diminish. However, reducing the size of utility assets should not necessarily compromise the ability of utilities (or DSPs) to attract capital – one expert stressed that it is possible to keep utilities' rate of return on assets more or less constant regardless of asset size.

Interestingly, however, lower asset-driven profits can catalyze the transition to a DSP model. Specifically, as utilities' revenues from sales of electricity under regulated tariffs decline, utilities should seek to augment revenues by providing fee-based DER services. For instance, the "integrated utility services" model being piloted by Fort Collins Utilities[14] exemplifies a hybrid utility business model that includes both tariff-derived and system operator-derived revenues.

Competitive markets will still require regulation to ensure a level playing field
From one perspective, a reduced scope of utilities' natural monopoly can be viewed as a logical continuation of electric liberalization efforts that New York State initiated in the late-1990s. This "restructuring 2.0" approach reflects the belief that "the distribution utility was the next big target for unbundling services." Accordingly, REV should induce competition to displace at least some of the regulated activities associated with electric distribution.

However, expanding the scope of competitive services does not necessarily entail a diminished role for regulators; one expert pointed out that "markets can introduce more regulation." For instance, one might think of the active role the Securities and Exchange Commission plays in policing anticompetitive behavior in financial markets. In the electricity context, the role of the regulator should change from simulating competitive outcomes in a monopoly setting to ensuring a level playing field among competitive actors.[15]

B. Who Controls the Data?

A shrinking natural monopoly should expand access to data
The emergence of DER technologies that can leverage information to provide grid services has made electricity data a valuable commodity. As one participant explained, "This information used to be of no particular use to anyone […] But now we acknowledge that the collection of that data confers a big social benefit." While this untapped social benefit holds the key to the development of robust DER markets,

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[14] *See* Rocky Mountain Institute, *Integrated Utility Services: A New Business Model for Fort Collins Utilities* (2014). Available at: http://www.rmi.org/Knowledge-Center/Library/2014-36_eLabFortCollinsIUS+Report-FINAL-20141219.

[15] This is analogous to the increasing need for federal oversight of regional markets following state restructuring reforms in the 1990s and early 2000s. *See* Jeffery S. Dennis, *Twenty-five years of electricity law, policy, and regulation: A look back*, 25 NAT. RESOURCES & ENV'T 33 (2010).

utilities currently guard access to data closely: "There's a lot of evidence to suggest that utilities view [data] as a gateway resource to keep control over."

As the boundaries of the natural monopoly recede, utilities should no longer have exclusive control over electricity data. In fact, as customer options for DER products and services expand, customer access to data should become a component of basic service. One expert contended that "if the data is there, it should be made accessible for download and sharing with third parties of customers' choosing." Several participants made note of national efforts to democratize energy data access, namely Green Button Connect[16] and Mission:data,[17] as an appropriate starting point to provide customers with access to their data in a form that enables them to engage with DER providers.

The Commission must identify a clearer pathway toward advanced metering

Despite the benefits of greater data access, the Commission has not adequately specified how it will promote such access in REV. Meeting participants were skeptical that REV could take root without advanced metering to generate the requisite volume of and access to data. However, even in states that have already rolled out advanced metering infrastructure (AMI), "regulators have abdicated on the subject of data." New York's delay has thus provided an opportunity to "embed customer access to data in whatever technological solution is chosen," which could make it "one of the last great frontiers of advanced metering."

Notably, "competitive providers would be perfectly capable" of rolling out advanced metering, so there is no reason for ratepayers to bear the financial burden. In fact, third parties can supply meters for little or no cost if they view AMI as establishing a foundation from which they can profit going forward: "Third parties may provide AMI in hopes of leveraging two-way communication down the road."

Feeder-level data may be as useful as customer-level data but avoids privacy concerns

While customer-level data can provide valuable information that can accelerate the formation of DER markets, it also invites privacy and security concerns. Nevertheless, the Commission can reap the benefits of expanded data access without confronting the issues that customer data access presents; higher-level data (e.g., for distribution feeders) could suit third-parties' needs equally as well as customer-level data. As one expert explained, "What we really want is for third parties to go prospecting where they think their products will turn a profit. Higher-level data could be sufficient for this prospecting without needing granular, customer-level data." Feeder-level information would enable third parties to assess "hot spots and feeder needs" throughout distribution networks to better understand system costs and profit opportunities.

Still, utilities are unlikely to buy into the notion that feeder-level data should be a public good under current regulatory norms. If utilities are the only participants with knowledge of grid needs, they can maintain exclusive responsibility for system maintenance and upgrades and increase profits by adding network investments to their rate bases. Releasing this data empowers third parties to unseat utilities in the provision of grid services and system solutions. Additionally, while there is a case to be made for democratization of customer-level data, "utilities have a stronger argument that feeder-level data is theirs" on the basis of ensuring cyber-security.

[16] *See* http://www.greenbuttonconnect.com/.
[17] *See* http://www.missiondata.org/.

The Commission has not yet made clear how DER providers will get the necessary data to create robust markets
Recognizing that "animated markets require enhanced, standard format, time-stamped distribution system data in real time to develop detailed business cases," the Commission has proposed to create an independently operated data exchange to provide DER providers with such data.[18] REV working groups have also recognized that "[d]istribution system data will assist DER providers to align investments with distribution system needs."[19]

However, citing parties' concerns over the expense and complication of such an exchange, the Commission has opted not to implement the data exchange at this time, instead instructing utilities to publish "system planning information" in the initial filings and annual updates of multi-year distributed system implementation plans (DSIPs).[20] The Commission has also tasked REV working groups with fleshing out the nature and frequency of system data that is needed for robust DER markets to develop.[21]

This vague and agnostic treatment of system data fails to inspire confidence that DER markets will mature as desired. In the absence of a transparent, real-time data exchange, the Commission should encourage utilities to publicize electricity data with sufficient geographic and temporal resolution to reflect the dynamic nature of distribution networks. Notably, however, the Commission must also take care to establish a cyber-security protocol for all DER market participants. To do so, regulators should look to experiences with liberalization in other industries that have largely overcome similar concerns; as one discussant noted, "We worked out a lot of these issues in [telecommunications], in terms of access and privacy for value-added services. I'm surprised we're not hearing much about that experience."

C. How Should Networks Price DER Products and Services?

Market-based pricing is needed to animate DER services
REV is working toward an end-state in which heretofore nonexistent markets will provide grid solutions, rather than the utility-dominated *status quo* arrangement. As one expert explained, "The idea now is to get more of a market response to fill a need." But markets don't emerge in a vacuum and proper incentives must be in place in order for DER to emerge as a viable alternative to utility-provided power. In order to set out appropriate incentives, the Commission needs to "fix" distribution pricing so that "customers and DER providers are seeing the right price signals" rather than rigid average-cost pricing.

To sufficiently incentivize DERs, distribution networks must monetize their multifaceted and dynamic benefits. However, these attributes are incompatible with existing regulatory tariffs and require a transition to market-based rates to reflect the dynamic nature of distribution systems. One participant expounded upon this vision, explaining that new technologies enable new classes of tariffs and market offerings that are based on geographically and temporally specific features of the distribution grid. Critically, this pricing approach would affect rates for services provided *by* customers in addition to those provided *for* customers.[22]

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[18] *See* Order Adopting Regulatory Policy Framework and Implementation Plan at 54.
[19] *See* Draft Report of the Market Design and Platform Technology Working Groups (Public Feedback Draft) at 67.
[20] *See* Order Adopting Regulatory Policy Framework and Implementation Plan at 58-59.
[21] The MDPT groups have since suggested that "[h]ourly [DER] reservations and 15-minute interval dispatch signals […] should be sufficient to get the market and the DSP platform set up and operational. *See* Draft Report of the Market Design and Platform Technology Working Groups (Public Feedback Draft) at 67.
[22] This portion of the discussion was aided by a concept paper drafted by Cameron Brooks, titled "Animating the Market in New York and Beyond."

Pricing that accounts for heterogeneous fixed costs can unlock value for DER markets
Current network pricing conventions assess a uniform fixed price to all customers within a broad class: "Utilities are making decisions based on a proxy 'average customer' and we don't have the information to assess the validity of that proxy." Experts cited the "utility argument" that "the cost to serve you is no different than the cost to serve anyone else" as the reason that utilities have pushed for fixed charges in an attempt to "avoid the problem of customers not paying average levels."

However, the cost to serve customers is inherently heterogeneous, and the changing nature of customers' interactions with electricity networks will exacerbate these differences. As an expert pointed out, "Now we have technology to profile users into different classes that can inform various types of charges. More than just being usage-based, [payments] can also reflect production. This transforms network consumers into network 'users.'" As customers add behind-the-meter resources and engage in more relationships with DER providers, the cost to serve them will become increasingly disparate.

Network pricing must better reflect the heterogeneity in customer-specific fixed costs. One participant suggested that utilities should "segment customers into classes or, in the ideal, uniquely" as a more refined way to allocate fixed costs across customers. Another, perhaps more feasible, possibility is demand charges that are proportional to the maximum instantaneous power demand over a given period, and therefore serve as a proxy for the cost to serve a customer. Demand charges would also encourage customers to reduce their individual peak demand, which in turn could shave system peaks and improve system efficiency. This incentive can encourage customers to leverage DERs to reduce their peak billable demand, which can provide "a toehold for behind-the-meter solutions" that can accelerate DER market maturation.

Improved price signals do not need to reach the customer in order to animate DER markets
As in the discussion about data access, it is more important to transmit improved price signals to DER providers than to individual customers. At least as a first step, it would be best to transmit price signals that "[let] the market determine opportunities in geographic areas." From there, rather than revamping distribution pricing to reflect dynamic distribution costs, it would be less expensive and quicker to translate those costs into rewards for DER providers. Discussants characterized this approach as a class of "subterranean" rates, in the sense that they do not directly propagate all the way to the customer and thus leave the relationship between customers and service providers largely unchanged. This approach could still permit providers to aggregate DER for the purpose of providing grid services, which may lie at the heart of the Commission's intended results.

D. What, if Any, Are the Limits to the Commission's Jurisdictional Authority to Implement REV?

The extent of the Commission's authority hinges on how federal cases are resolved
Some of the transactions that feature prominently in robust DER markets might require authority that the Commission may not ultimately possess. Federal courts have recently addressed a pair of jurisdictional questions with important implications for REV and the Commission's authority to shape the markets it seeks to create. This section provides an overview of these cases and their potential implications for REV as presented by one meeting participant.

Before describing these cases, however, it is important to address the division of regulatory authority over the U.S. electricity sector. The Federal Power of Act of 1935 vests the federal government with exclusive jurisdiction to regulate the "wholesale" electricity market, which encompasses the production, sale, and highvoltage transmission of electricity. At the same time, the Act gives the States jurisdiction over the "retail" electricity market, which encompasses the localized distribution and sale of electricity to end-users. The Federal Energy Regulatory Commission (FERC) exercises jurisdiction to regulate wholesale markets, while the New York State Public Service Commission is an example of a state authority with jurisdiction over retail markets.

Major cases:

The first line of cases involves state regulations that were held to intrude on FERC's exclusive jurisdiction over wholesale markets. These cases addressed similar efforts by Maryland and New Jersey to promote the construction of new generation in capacity-constrained areas of those states. In both instances, the states tried to incentivize new plants to be built by providing a semi-guaranteed revenue stream through an arrangement known as a "contract for differences."[23]

Federal courts have rejected both the Maryland and New Jersey programs. The Fourth Circuit Court of Appeals, which has jurisdiction over Maryland, held that the state's program had intruded on the federal government's exclusive jurisdiction over wholesale markets. In reaching that conclusion, the Court relied on a doctrine known as "field preemption," which provides that where the federal government has comprehensively regulated an area of the law, any state regulation of that same area – even regulation that is arguably consistent with the federal law – is impermissible and must be invalidated. Applying this doctrine, the Court concluded that the contract for differences was preempted because, by making the generator insensitive to the market-clearing price, Maryland had "supplant[ed] the rate generated by the [PJM] auction with an alternative rate preferred by the state."[24]

Another major case presents the mirror-image situation – a court concluding that a federal law intrudes on the states' exclusive jurisdiction over retail markets. In an effort to promote demand response in wholesale energy markets, FERC issued Order 745, which required that demand response resources[25] be compensated in wholesale markets at the same level as an increase in electricity generation.[26] A group of generators promptly challenged this rule in the D.C. Circuit Court of Appeals, arguing that FERC lacked authority to issue the rule because a reduction in consumption was, at root, a retail transaction.

The Court agreed, holding that by setting a price to be paid for a decrease in demand in the wholesale market, FERC had essentially set the opportunity cost of consumption in retail markets. The Court concluded that doing so amounted to a regulation of the retail market and therefore intruded on the States' exclusive jurisdiction over retail transactions. In reaching that conclusion, the Court appeared deeply troubled by its belief that there was no "limiting principle" on the extent to which FERC could use its jurisdiction over rates and practices affecting the wholesale market to regulate behavior with roots in the retail market.[27] Although

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[23] The contracts worked as follows: once a new plant was constructed, it would offer its electricity and capacity into the relevant PJM wholesale market. If the plant's bid were accepted by PJM, the state would guarantee a price for each unit of energy or capacity that cleared the market. If the market-clearing price were below this guaranteed level, the state would make up the difference through a surcharge on ratepayers; but if the market-clearing price were above this level, the generator would rebate the difference to the state. The result of this program was to make the generator essentially insensitive to the price at which the market cleared – all that mattered to the generator was that its bid was accepted by PJM. *E.g.*, *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467, 473 (4th Cir. 2014).

[24] *Nazarian*, 753 F.3d at 476.

[25] *I.e.,* a decrease in electricity consumption made pursuant to a demand response program.

[26] Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187 (Mar. 15, 2011).

[27] *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216, 221 (D.C. Cir. 2014).

the full implications of this decision remain unclear, many commenters believe that it could prevent demand response from participating in markets subject to FERC jurisdiction, including all RTOs and ISOs.

Both cases have been appealed to the U.S. Supreme Court. The Court has already decided to hear the demand response case, which will likely be argued in the fall of 2015 with a decision to be announced by the first quarter of 2016, but has not yet decided whether to hear the preemption cases. As FERC supported the generators arguing in favor of field preemption,[28] it appears likely that the government will recommend that the Court decline to hear these cases, which would leave the lower-court decisions in effect.

<u>Implications for REV:</u>
The Supreme Court's decision in the demand response case will likely have the most direct and immediate impact on REV, regardless of which way the Court rules. A ruling that affirms the D.C. Circuit's decision – i.e., if the Court agrees that FERC's rule must be invalidated – has the potential to hamper aspects of REV that rely on a robust two-way market for electricity. That is because the RTOs and ISOs under FERC's jurisdiction provide significant and stable levels of compensation for demand response, which in turn helps to foster a large "supply" of entities willing to provide demand response services. Although New York could still pursue retail demand response programs – and has recently taken steps to increase the availability of demand response within the state[29] – it is not clear that a state-level program can provide the same level of predictable compensation for demand response. By the same token, a ruling that reverses the D.C. Circuit's decision – i.e., if the Court holds that FERC can set the price for demand response in wholesale markets – would likely promote a more robust market for demand response, both at the federal level and within New York, thereby bolstering the aspects of REV that rely on two-way electricity markets.

A win for FERC could, nevertheless, present some risks for REV, especially if, as seems likely, the Court decides not to hear the preemption cases (or decides to hear them, but agrees with the Fourth Circuit decision applying the field preemption doctrine).[30] That is because a Supreme Court decision ruling in favor of FERC will almost certainly articulate an expansive view of FERC's jurisdiction under the Federal Power Act. When combined with a holding that the areas under FERC's jurisdiction are "field preempted" – that is, even state actions that do not conflict with FERC's regulations are prohibited – a broad understanding of FERC's authority could place important limits on the Commission's ability to issue regulations that affect the wholesale markets under FERC's jurisdiction.

In the near term, the likely effect of these outcomes is increased uncertainty about the limits of a state public utility commission's authority. Both sets of cases have observed the difficulty with drawing a bright-line distinction between what constitutes a retail-market regulation versus a wholesale-market regulation and declined to issue a rule that would apply outside the particular case at issue. Accordingly, unless the Supreme Court provides a new standard for distinguishing between retail- and wholesale-market regulation, state rules and regulations that address the "border" between these markets will remain subject to considerable legal uncertainty.

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[28] *See, e.g.*, Brief for the United States Federal Energy Regulatory Comm'n As Amicus Curiae, PPL ENERGYPLUS, LLC v. Solomon, No. 13-4330 (Mar. 20, 2014).
[29] Case No. 14-E-0423 *et al.*, Order Adopting Dynamic Load Management Filings with Modifications (N.Y. Pub. Serv. Comm'n, June 17, 2015).
[30] None of the preemption decisions issued to date establish a precedent the federal courts within New York are obligated to follow. Thus, a federal court with jurisdiction over challenges to REV could, in theory, reach a different conclusion than in the cases discussed above. Nevertheless, the federal courts' unanimity so far and the strength of the arguments in favor of preemption suggest that such a result is unlikely.

In light of this uncertainty, and the relatively early stage of the REV proceedings, it is difficult to identify the specific reforms that could be susceptible to a jurisdictional challenge. This is particularly so given that the technologies and market formats involved in REV are quite novel and not easily comparable to the programs that are at issue in the pending cases.

Nevertheless, these cases indicate that the more that a particular reform interacts with or affects wholesale markets – which, for New York, largely means NYISO – the greater the risk of a successful jurisdictional challenge. For example, any reforms that require the DSP to accord special treatment or preference to DERs whose electricity or ancillary services are then bid into NYISO would appear to be at the greatest risk of successful jurisdictional challenge. In addition, these cases suggest that the Commission can mitigate the risk of a jurisdictional challenge by designing these regulations in a manner that avoids affecting the incentives of entities that participate in wholesale markets.

The DSP model itself introduces jurisdictional questions that cloud the investment picture

The DSPs envisioned by REV may also present jurisdictional issues. That is because, by purchasing DER for the purpose of resale, DSPs will be involved in the purchase and sale of "wholesale" products – *i.e.*, products, such as capacity or ancillary services, that are traded in FERC-jurisdictional markets. While existing arrangements for net energy metering and demand response can plausibly be classified as wholesale transactions, FERC has disclaimed authority over such transactions because they encompass a relatively small share of total energy produced and consumed. However, robust DSP-administered DER markets will increase the volume of wholesale-type transactions that take place at the retail level, and could trip a threshold that would lead FERC to assert jurisdiction authority over these markets.

The resolution of the above legal uncertainties is critical to establishing a sound investment climate for New York's electricity system. An industry representative explained how this uncertainty plays out in practice: "From a financing perspective, the fact that this remains very much up in the air really makes it appear that there's a big battle going on between states and FERC, so it's hard to invest."

Conclusion

The roundtable discussions provided a more detailed vision of how utilities and other actors may interact in a robust DER market of the sort REV envisions. To bring this end-state closer to reality, it is important that the Commission take more decisive actions to advance prerequisite features of robust DER markets, namely enhanced data access and dynamic network pricing. To date, however, the Commission has not indicated how it intends to implement these features.

Even so, the Commission's ability to implement its DSP vision depends on the resolution of ongoing litigation, which leaves its legal authority over DER markets unclear. These sources of uncertainty cloud investment prospects and threaten to hamper REV's push to activate DER markets. Further clarity on these issues will help to mobilize private capital in pursuit of the competitive DER market vision that REV seeks to achieve.

II. Mapping Out Market Actors and Transactions in the REV End-State

The vision of the REV end-state outlined above paints a more complex distribution system than the one that has evolved to this point. To indicate the scale of transformation, we attempt to map these fundamentally different systems under the *status quo* and in the REV end-state. In particular, we chart the high-level market actors, their roles in the distribution system, and the relevant flows of products and services between them.

The Market Design and Platform Technology Working Groups have conducted a similar exercise in an effort to trace out transitional business and technological pathways to DSP markets. Of particular relevance, a recent draft report includes a schematic representation of the "to-be" DSP market vision that intricately details market interactions and extends to the bulk system.[31] In this section, we proposes a simpler view of the high-level interactions between classes of actors in distribution markets at the REV end-state, constructed from the points of consensus from the roundtable discussions summarized above. Taken together, these visuals paint a more comprehensive view of the DER markets that should emerge at the REV end-state.

As illustrated in section B (see next page), the traditional *status quo* system obeys a linear pathway in which electricity-related products and services flow from the utility to the customer. By contrast, the proposed REV end-state features a radial configuration with bi-directional flows between an expanded set of market actors. In addition, the extent of monopoly functions, which encompass all flows and roles under the *status quo*, should be confined to provider-of-last-resort, grid operations, and market operations under REV's DSP model. Importantly, system planning, currently carried out by regulated utilities, should be entrusted to the DER marketplace, which will mediate flows between customers, DER providers, and the DSP.[32]

The table in section C lists representative, though not exhaustive, transactions that characterize each end-state flow depicted in section B. Some of these transactions are financial in nature, in which case a compensation description is proposed. For instance, in the REV end-state, the purchase of electricity – whether from a DSP or a DER provider – should be governed by a market-driven rate that depends on locational and temporal characteristics of the distribution grid. Other flows, namely those that are discrete and potentially one-time interactions (e.g., interconnection), are conducive to fee-based compensation. Still other transactions can be considered elements of basic electricity service (e.g., provision of reliability-related grid services, measurement and verification), and need not be compensated separately.

A. Relevant Definitions

Market Actors

- Customers encompass residential, commercial, industrial, and institutional end-users (and in some cases producers) of electricity;
- The distribution utility is a regulated entity with exclusive franchise to deliver electricity (*status quo*);
- The distributed system platform (DSP) is a regulated entity that will be responsible for administering and coordinating the distribution system and DER markets in the REV end-state[33]; and
- DER providers include ESCOs, distributed generation owners, microgrid owners, equipment vendors, leasing companies, curtailment service providers (aggregators), etc.

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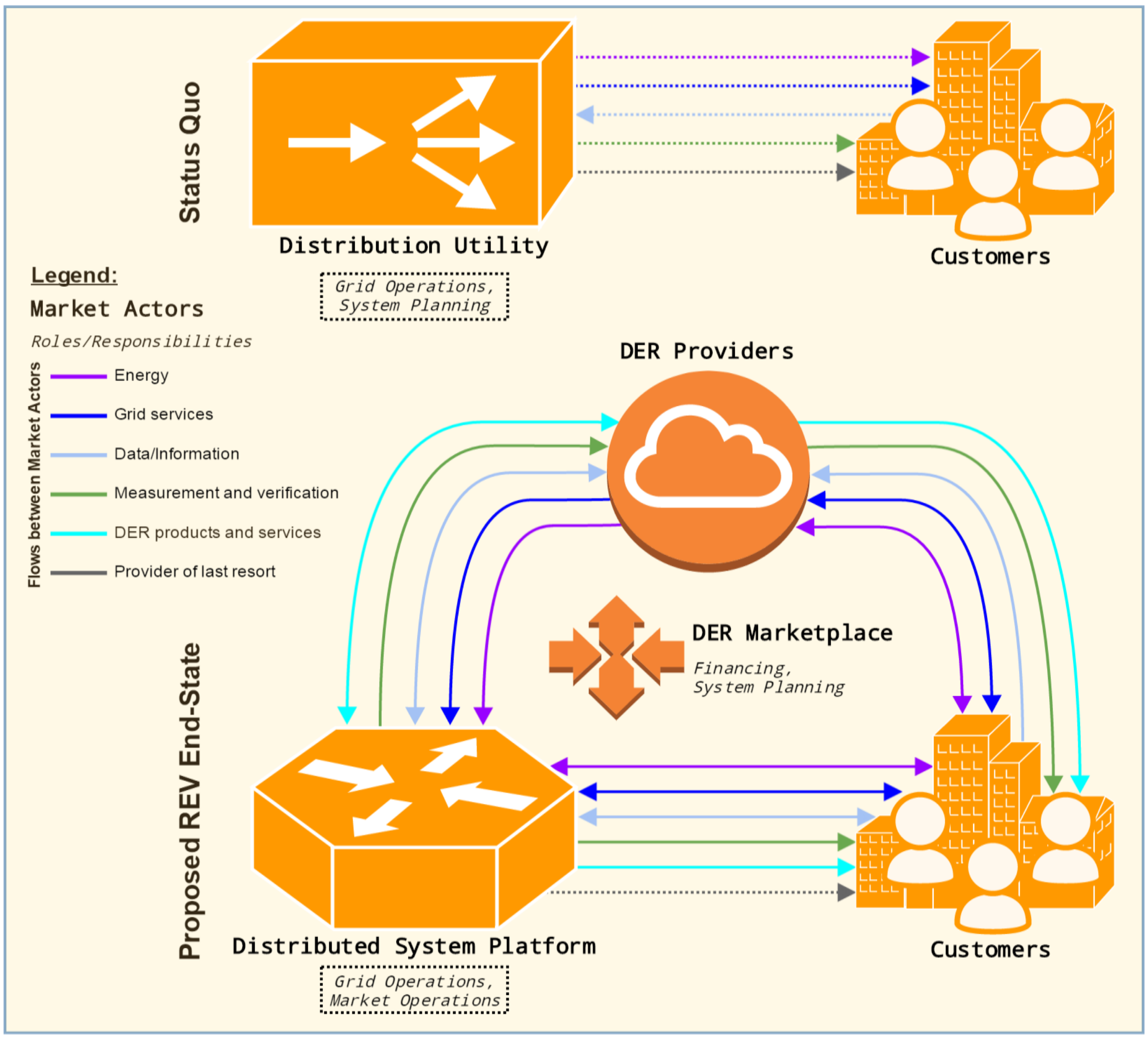
[31] *See* Draft Report of the Market Design and Platform Technology Working Groups (Public Feedback Draft) at 141.
[32] We assume that DER market pricing monetizes environmental externalities in a way that allows market participants to address grid needs at least cost with low- or zero-carbon solutions.
[33] *See* Draft Report of the Market Design and Platform Technology Working Groups (Public Feedback Draft) at 20.

Flows between Market Actors

- Energy is the flow of electricity from one point in the distribution network to another;
- Grid services support reliability and assure power quality by providing ancillary services through technological (e.g., advanced distribution hardware/software) or behavioral (e.g., load curtailment) means;
- Data/information concerns consumption, production, and curtailment of electricity, production capacity, and system condition (e.g., congestion);
- Measurement and verification deals with metering of consumption and production and/or validating reported flows of energy;
- DER products and services include installation, interconnection, and leasing of distributed generation assets, provision of communications software/hardware, aggregation of DER, etc.; and
- Provider of last resort describes a regulated entity's obligation to provide backup power in the absence of other supply.

B. New York's Electric Distribution System, Now and in the Future



Note: Dotted lines indicate monopoly control of a given role or flow of products/services.

C. DER Market Transactions in the Proposed REV End-State

Flows between Market Actors			Characteristic Market Transactions	
From	**To**	**Flow**	**Description/Example**	**Compensation**
DSP	**Customer**	Energy	DSP sells electricity to customer	Market-based rate
		Grid services	DSP ensures reliable provision of electricity to customers	
		Data/information	DSP provides location- and time-specific system information to inform customer decisions	
		Measurement and verification	DSP meters customer's net electricity consumption, load curtailment, etc.	
		DER products and services	DSP offers installation, interconnection, and/or aggregation services for customer-sited DER	Fee
		Provider of last resort	DSP provides backup service to customer	Regulated standby tariff
Customer	**DSP**	Energy	Customer receives credit from DSP for on-site generation	Market-based rate
			Customer sells excess generation to DSP	
		Grid services	Customer provides ancillary services (e.g., through load management) to DSP	Market-based rate
		Data/information	Customer generates consumption and production data that the DSP monitors	
DER Provider	**Customer**	Energy	Community shared solar project sells electricity to customer	Market-based rate
		Grid services	Microgrid owner ensures reliable power for microgrid customer	
			ESCO provides metering, load management services to customer	
		Measurement and verification	ESCO measures customer's net electricity consumption	
			Aggregator measures customer's load curtailment	
		DER products and services	Solar leasing company provides third-party ownership of customer-sited photovoltaics	Fee
Customer	**DER Provider**	Energy	Customer receives credit from ESCO for on-site generation	Market-based rate
			Customer sells excess production to aggregator	
		Grid services	Customer provides ancillary services (e.g., through load management) to aggregator	Market-based rate
		Data/information	Customer shares on-site consumption, production, and/or curtailment data with DER provider	
DER Provider	**DSP**	Energy	Aggregator sells DER to DSP	Market-based rate
		Grid services	Aggregator provides ancillary services (e.g., aggregated load management) to DSP	Market-based rate
		Data/information	DSP collects and integrates data on DER either produced or aggregated by DER providers	
		DER products and services	Battery storage vendor leases storage facility to DSP for enhanced grid operation	Fee
DSP	**DER Provider**	Data/information	DSP provides dynamic feeder-level information so third parties can identify system "hot spots"	
		Measurement and verification	DSP verifies total demand reduction submitted by curtailment service provider	
		DER products and services	DSP provides interconnection for community shared solar project	Fee