KEYES, FOX & WIEDMAN LLP

Via U.S. Mail Delivery and Electronic Mail:

September 17, 2015

Debra A. Howland, Executive Director
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, NH 03301

RE: Docket # IR 15-296, Investigation into Grid Modernization

Dear Director Howland:

Please find enclosed for filing the original and six (6) copies of the *Comments of SolarCity Corporation* in the above-captioned proceeding. This document was electronically filed on September 17, 2015 with the New Hampshire Public Utilities Commission.

Please contact me if you have any questions regarding this filing.

Sincerely,

Blake Elder

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cc: Service List IR 15-296
Enclosures

BEFORE THE NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

IR 15-296

ELECTRIC DISTRIBUTION UTILITIES

Investigation into Grid Modernization

COMMENTS OF SOLARCITY CORPORATION

Pursuant to the Order of Notice issued in the above docket by the New Hampshire Public Utilities Commission ("Commission") on July 30, 2015, SolarCity Corporation ("SolarCity"), by and through its undersigned counsel, respectfully submits the following comments on the Commission's investigation into grid modernization.

1. Introduction

SolarCity is a full service solar power provider for homeowners and businesses – a single source for engineering, design, financing, installation, monitoring, and support. The company provides cost-effective financing that enables customers to go solar without high upfront costs.

2. Comments

SolarCity thanks the Commission for seeking comments on the scope of this proceeding regarding grid modernization. As was noted in the order opening the proceeding, a consideration of grid modernization issues relevant to New Hampshire could be extensive.[1] Once considered focused primarily on smart grid technologies, the concept of grid modernization has been increasingly expanded to include the comprehensive process of creating a more sustainable, resilient, reliable, and affordable electric system. States that are considering grid modernization initiatives, such as Hawaii, New York, Maryland, and California, look at them from a technical and policy perspective, as well as from the perspective of the changing nature of customer

[1] Order of Notice (Jul. 30, 2015), at pp. 1-2.

engagement. The vision stated for New Hampshire's Ten-Year Energy Strategy reflects this broad scope:

> In 2025, consumers are empowered to manage their energy use by taking full advantage of the information, market mechanisms, energy efficient technologies, diverse fuel sources, and transportation options available to them. These services extend from the city centers and coastal areas of Southern New Hampshire to the rural corners of the Western regions and the North Country - closing the gap in disparity of energy services across the state. The results of these widespread consumer empowerment initiatives are lower energy bills, greater choice for the consumer, increased self-reliance, and a cleaner, more sustainable and resilient energy system.[2]

Given this context, SolarCity provides both procedural and substantive recommendations for the Commission to consider in scoping this important and relevant proceeding.

Procedural Recommendations

- The Commission should establish whether the outcomes it anticipates from this proceeding should effectuate the energy vision established in the Ten-Year Energy Strategy, or if there are different objectives.
- The Commission should consider phasing this proceeding to consider similar categories of issues, including smart grid implementation, customer engagement, and regulatory reform.

Substantive Recommendations

- Customers support expanded choices in their electricity supply and movement towards cleaner renewable energy options. This trend is evidenced by the recent and rapid growth in the distributed solar generation industry and growing interest in storage and other energy management technologies. The ability to seamlessly connect customer sited DERs is fundamental to making the choice to self generate easy, affordable, and efficient. The diversity of technologies available increases customers' ability to manage their total energy

[2] New Hampshire Office of Energy & Planning, New Hampshire 10-Year State Energy Strategy (2014), *available at* http://www.nh.gov/oep/energy/programs/documents/energy-strategy.pdf.

bill. Accordingly, the industry should evolve to increasingly enable participation of "prosumers."

- However, current efforts to utilize DERs to support the broader electric system are hampered by the systemic failure of the utility industry to adequately and efficiently integrate DERs into the distribution planning process. Traditional distribution planning is siloed and planning efforts are considered independently of interconnection efforts. To fully leverage customer sited DERs to benefit the grid, utility interconnection, planning, procurement, and data sharing efforts should be modernized.

- In its recently published integrated distribution planning ("IDP") whitepaper (Attachment A)*,* SolarCity offers a blueprint that can help inform policies regarding how distribution systems can be planned and procured to achieve the objectives stated above. IDP is a holistic approach to meeting distribution needs and expanding customer choice by unlocking the benefits of DERs. The approach (a) expedites DER interconnections, (b) integrates DERs into grid planning, (c) utilizes DER portfolios as procurement resources, and (d) ensures broad access to critical data. Utilizing IDP can also help regulators avoid unwarranted costs to ratepayers.

    Expediting interconnection - Today's utility interconnection processes often follow idiosyncratic rules and timelines that differ from utility to utility, suffer from a general lack of process automation, and are subject to burdensome technical reviews or arbitrary requirements that slow or prevent DER interconnections. In its whitepaper, SolarCity offers a menu of examples and recommendations on how interconnections can and should be streamlined. Two aspects are foundational to initiate this modernization: (1) enable a transparent, timely interconnection application approval process, and (2) consider alternatives to the typical utility mitigations, which require costly equipment upgrades. The Commission should carefully scrutinize these issues so as to ensure that utilities are not adding unwarranted costs to DER projects, stalling further deployment.

    Integrating DERs into grid planning - While *Interconnection* focuses on allowing increased penetrations of DERs on the system, a modernized *Distribution Planning* process focuses on meeting distribution needs and unlocking the benefits of DERs. The traditional distribution planning process involves three steps: (1) forecasting growth, (2) identifying grid needs, and (3) specifying solutions. This framework should be modernized to actively leverage the value of DERs. For example, utilities will need to become much more proficient at forecasting customer DER growth than they are today to accommodate rapidly expanding DER technologies, and to progressively signal preferred locations. In identifying grid needs and finding solutions, utilities should also take advantage of the benefits offered by DERs, particularly at their specific, granular location. Solutions may involve minimal changes to existing utility equipment settings, or changes to customer and utility equipment operating requirements, use of existing DERs to defer traditional capital investments, and moving towards probabilistic planning, so that grid operators can fulfill distribution system needs based on observed customer participation levels.

Utilizing DERs as procurement resources - Today's status quo planning model does not consider *Procurement* of customer-owned assets to meet the distribution needs. Utilities instead rely on traditional infrastructure (i.e. "wires") funded by rate base, where utilities self-supply 100% of the self-prescribed distribution system need. Under this model, regulators rely on the expertise of distribution planners to deploy capital that meets customer demand in the most cost-effective way possible, but this model lacks independent input and scrutiny. However, utilities can and should look to procuring cost-effective DER resources that can meet these needs. For example, advanced inverters can be utilized to provide voltage and reactive power support, customer batteries can provide peak capacity support, load shifting can absorb over generation, and tweaks to distribution equipment configurations can accommodate dynamic power flows.

Ensuring broad access to critical data - Data sharing is critical to grid modernization as it informs customer choice, spurs economic development, supports innovation, enables credible auditing of utility investment plans, supports public safety, and eventually will foster a robust transactive energy marketplace. Solely publishing outcomes of utility analyses rather than sharing the underlying data does not enable sufficient industry stakeholder engagement or innovation.

- The Commission should consider utility distribution planning and procurement reform and move towards a holistic approach to meeting distribution needs and expanding customer choice by modernizing utility interconnection, planning, sourcing, and data sharing processes. In addition to increased reliability and resiliency, renewable energy, distributed resources and energy storage could be used to significantly improve the utilization of existing and needed transmission, distribution, and generation infrastructure, creating long-term savings for customers. However, these benefits can only be realized through regulatory reforms.

- Changing technologies and customer preferences are demonstrating the fundamental flaws in the traditional utility business model. Regulatory practices can help drive positive change that allows utilities to embrace renewable energy, distributed resources, energy storage, and meaningful participation by customers in how they manage energy. For example, New York's Reforming the Energy Vision proceeding is reconsidering traditional ratemaking and how regulatory practices that prioritize utility capital investment can be converted into a level playing field for customers and third-party distributed energy resource providers.[3] To the extent this proceeding considers infrastructure modernization and how to increase customer engagement, these traditional practices will need to be reconsidered as well to ensure that customers ultimately experience reduced costs, but higher value. Among the many efforts that could be considered is integrated distribution planning, which is described in more detail in Attachment A, SolarCity's whitepaper.

- Access to reliable and meaningful data is a core component of any initiative for grid modernization. First, customers should have access to information about their own energy consumption in standardized, nationally recognized data formats. At the same time, third parties, such as energy efficiency and solar companies, research institutions, and other entities, should be able to understand the options they have to augment the distribution grid with distributed resources that will provide benefit to the overall system. For example, as

[3] *See, e.g.*, New York Department of Public Service, Staff Track II White Paper on Ratemaking and Utility Business Models, Case 14-M-0101 (Jul. 28, 2015), at pp. 1-4.

part of California's initiative, utilities are providing information about optimal areas for interconnecting distributed resources like solar and energy storage.

- The Commission should include in the scope of this proceeding the implications for consumer behavior. The Commission could consider the usefulness of different kinds of time-of-use pricing and demand response alternatives, and whether additional pilots or programs may be useful.

While the scope of this grid modernization proceeding could be extensive, SolarCity welcomes the opportunity to provide input as this process evolves.

3. Conclusion

SolarCity thanks the Commission for considering its comments in this proceeding and looks forward to engaging as the process moves forward.

Respectfully submitted,

/s/ Jason B. Keyes

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Counsel for SolarCity Corporation

September 17, 2015

ATTACHMENT A

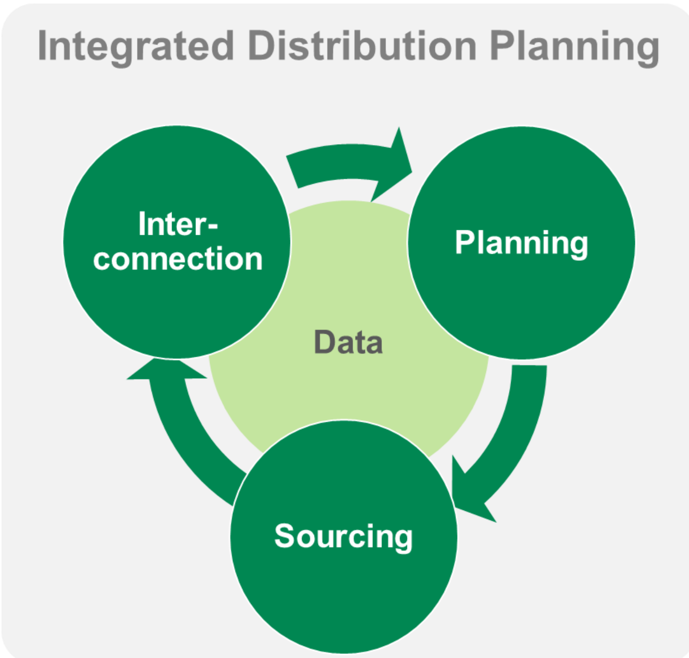
SolarCity

Grid Engineering

Integrated Distribution Planning

A holistic approach to meeting grid needs and expanding customer choice by unlocking the benefits of distributed energy resources

White Paper



Key takeaways

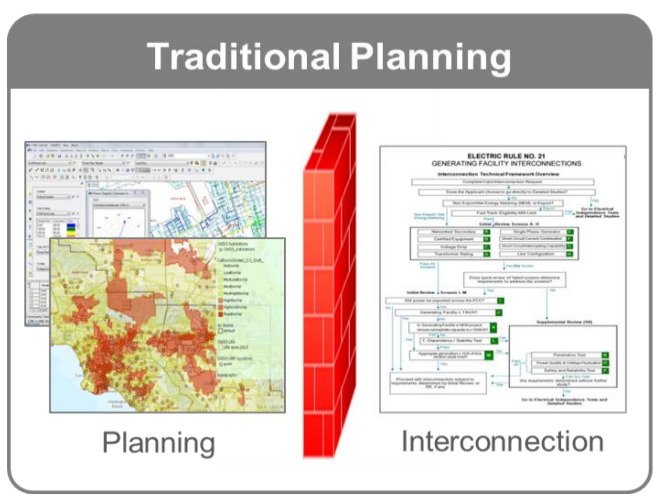
Takeaway 1
Integrated Distribution Planning is a holistic approach to meeting distribution needs and expanding customer choice by modernizing utility *interconnection*, *planning*, *sourcing*, and *data* sharing processes.

Takeaway 2
Hosting Capacity analyses should be incorporated into the interconnection of distributed energy resources to streamline and eventually automate interconnection

Takeaway 3
Adopting *Distribution Loading Order* policies will encourage the sourcing of cost effective distributed energy resources before conventional distribution equipment

Background

Designing the electrical grid for the 21st century is one of today's most important and exciting challenges. In the face of evolving electricity needs and an aging electrical grid that relies on centralized and polluting sources of power, it is imperative to transition to a grid that actively leverages the wave of renewable distributed energy resources proliferating across the industry. Distributed energy resources offer tremendous benefits to this new grid by actively engaging customers in their energy management, increasing the use of clean renewable energy, improving grid resiliency, and making the grid more affordable by reducing system costs. Designing a grid that fully harnesses these assets is a key undertaking for all industry stakeholders, including utilities, regulators, legislatures, and DER developers.



Current efforts to utilize DERs to support the broader electric system, however, are hampered by the systemic failure of the industry to integrate DERs into distribution planning efforts. As the figure to the right depicts, traditional distribution planning is highly siloed and planning efforts are considered independently of interconnection efforts. To fully leverage DERs to benefit the grid, utility interconnection, planning, sourcing, and data sharing efforts must be modernized.

Challenge: Existing utility interconnection, planning, sourcing, and data sharing processes do not leverage DERs to benefit the grid and enable customer choice.
Solution: Modernize distribution interconnection, planning, sourcing and data sharing processes by adopting a holistic *Integration Distribution Planning* framework.

Integrated Distribution Planning is a holistic approach to meeting distribution needs and expanding customer choice by unlocking the benefits of distributed energy resources. The approach expedites DER interconnections, integrates DERs into grid planning, sources DER portfolios as grid resources, and ensures broad access to critical data. Ultimately, the approach reduces overall system costs while increasing customer engagement. In the following paper, we introduce four components of *Integrated Distribution Planning* (*Interconnection*, *Planning*, *Sourcing* and *Data*) and offer recommendations for how to seamlessly integrate distributed energy resources into the modernized process.

We offer this paper as an initial vision for a holistic process to leverage DERs to benefit the grid. However, there are many details to develop in order to realize this vision. SolarCity continues to work on developing these details for the concepts proposed in this paper, and we welcome collaboration with industry thought leaders to do so. Our ultimate goal is to help provide the concrete recommendations and justification needed by regulators, legislatures, utilities, DER providers, and industry stakeholders to create the impetus for change needed to transition to a cleaner, more affordable and resilient grid.

Interconnection

The utility DER interconnection process consists of rules and requirements that govern the connection and operation of distributed energy resources within a utility's electric grid.

Today's utility interconnection processes often follow idiosyncratic rules and timelines that differ from utility to utility, suffer from a general lack of process automation, are subject to burdensome technical reviews or arbitrary requirements that slow or prevent DER interconnections. In many regions, the current interconnection process is not keeping pace with the local DER growth, threatening an inefficient backlog that will burden utilities until a more streamlined approach is adopted.[1] As a result, customers who want to invest in energy infrastructure to play an active role in managing their energy usage are increasingly unable to expediently and cost effectively to do so.

Some utilities have begun reforming their practices to create a more efficient interconnection process, with several existing "best practices" serving as a guide for the industry. Overall process improvements have been limited in scope, however, and the pace of change is measured. A more comprehensive set of enhancements is needed to streamline the interconnection process, eliminate unnecessary costs, and expand allowable interconnections.

Challenge: Existing utility interconnection processes can be avoidably slow, include unwarranted costs, and unnecessarily limit DER interconnections.
Solution: Streamline the DER interconnection process, eliminate unwarranted costs, and expand allowable interconnection approvals.

Streamline the Process

There are four critical steps in interconnecting a system to the grid: application, construction, inspection, and permission to operate (PTO). Utilities control the timeline for critical elements of this process. While many states establish timeline requirements for the initial utility application review, these targets frequently are not met. For example, a study by the National Renewable Energy Laboratory (NREL) found that most utilities routinely exceed time limits for application review by 37-58%.[1] Similarly, EQ Research published findings showing that PTO timelines increased 68% from 2013 to 2014.[2]

Several states have embarked on initiatives to update aspects of the interconnection process. While positive, these developments often focus on a few low-hanging fruit, such as the creation of an online portal to submit and track application review progress, rather than a more comprehensive set of improvements. Streamlining the entire interconnection process should be considered by utility engineering organizations and regulators, especially when many of these improvements have been individually implemented by various utilities across the country. A comprehensive set of best practices and recommendations are presented in the following table.

Interconnection Process Improvement Best Practices

Category	Best Practices & Recommendations
Documentation	• Accept single line diagrams in applications in lieu of three line diagrams[3] • Allow project drawings to be approved by licensed contractors without Professional Engineer stamps[4] • Document utility inspection procedures and include time limits[5] • Follow a PTO closeout checklist template for sequence of operations and witness test procedures[6] • Maintain an online list of certified equipment by part number and settings approved for interconnection.[7]
Visibility	• Make pre-application reports available online on the utility website[8] • Enter all application correspondence by project into a password-protected online portal, starting with the initial application and including regular status updates • Publish impact studies on the utility website • Create and publish interconnection maps online for identification of favorable interconnection sites[9]
Simplicity	• Do not require a signed construction contract with an interconnection application[10] • Allow construction to proceed at third party's risk with no required utility conditional approval prior to start of construction[11] • Eliminate multiple-part applications in favor of a single, comprehensive application
Cost Certainty and Cost Minimization	• Budget impact study costs by man-hours at an hourly rate, with outsourcing costs stated as a line item[12] • Do not charge ordinary service and maintenance fees for utility-owned equipment required for interconnection[13] • Do not charge interconnection application fees for Net Metered projects[14] • Establish a process through which interconnection upgrades and costs are identified prior to interconnection application submission • Publish standard upgrade unit costs to allow better planning and budgeting by third parties[15]
Cost Allocation	• Allocate upgrade costs equitably to all beneficiaries (i.e. both DER owners and non-DER customers)[16] • Consider the clustering of projects within a common geography when possible[17]
Standards	• Set the standardized interconnection project size limits to no lower than 5 MW • Perform simplified/fast-tracked review for verified non-export and smart export projects • Do not allow the presence of an existing DER service on a parcel of land to prevent the installation of new DER service for virtual net metered projects[18]
Mitigation Equipment	• Ensure utilities have sufficient mitigation equipment on hand to meet interconnection volume • Increase the flexibility of mitigation requirements where cost effective alternatives exist • Allow meter socket adaptors or alternate supply-side taps to facilitate customer-sided DER installations
Review & Reform	• Institute a fully online application process rather than written applications • Prohibit paper forms or hard copy mailings in application process[19] • Accept electronic signatures on all required documents[20] • Accept electronic payment • Allow certified third party contractors to perform metering work related to interconnection (e.g. meter pulls or replacements)[21]
Incentives & Penalties	• Create penalties and incentives governed by regulatory agencies to encourage compliance with legislated time limits[22] • Conduct annual audits with independent reviewers to determine utility compliance with timelines.[23] • Publish results of annual processing timelines • Require utility-developed plan if backlog is over acceptable threshold

Eliminate Unwarranted Costs

Many utilities worried about real and perceived impacts of DERs are specifying equipment upgrades to mitigate their concerns. However, these mitigations are often based on outdated standards or made without regard to the advanced capabilities of modern DERs, which can often preempt the concerns underlying the proposed mitigations. The result is that utilities are requiring overly conservative and often unnecessary upgrades as a condition of interconnection.

Sourced from SolarCity's interconnection efforts across the United States, we identify below the most common utility mitigation requirements. Based on the latest body of technical research and standards available, as well as our own research into many of these topics in collaboration with utilities and national laboratories[24], we offer cost effective, safe and reliable alternatives to these upgrades when applicable, with the goal of reducing overall system costs to all customers.

Typical Utility Mitigations and Recommended Approach

Mitigation	Utility Rationale	Recommendation
Protection Equipment - SCCR	DERs may cause desensitization of relays, miscoordination of protective devices, and/or surpassing of interrupting rating of line clearing element (e.g. breaker, fuse, etc.).	When short circuit contribution ratio (SCCR) of all generating facilities downstream of a protective device is less than 10%, DER customers **should not pay** for upgrades to protective equipment because DERs do not impact relay desensitization, miscoordination, or interrupting ability.[25,26,27] When SCCR exceeds the conservative 10% limit *and* a protection review indicates technical concerns, settings changes to protective devices should be investigated before proposing equipment upgrades.
Reclose Blocking	Islanding may occur if generation and load are balanced. If an island persists longer than reclose delay, equipment may be damaged.	Reclose blocking due to unintentional islanding concerns **should not be required** because reclose blocking is not intended to prevent an island and standard inverter anti-islanding features are effective at preventing unintended islanding.[25,28,29] If specified by the utility as a redundant measure, reclose blocking should be considered part of normal utility business and should not delay interconnection.
Direct Transfer Trip (DTT)	Unintentional islanding may occur if generation and load are balanced at an automatic sectionalizing device.	DTT installation due to unintentional islanding concerns **should not be required** because standard inverter anti-islanding technology is effective at preventing unintended islanding.[25,28,29] If specified as a redundant measure, DTT should be considered part of normal utility business and should not delay interconnection.
Reconductor	Aggregate DERs exceed the thermal capacity of conductor and/or causes voltage issues.	Customer payment **can be justified** if new DERs exceed conductor thermal rating. However, if multiple and/or future customers will benefit from the upgrade, equitable cost allocation across all beneficiaries should occur.
Transformer replacement	Aggregate DERs exceed the transformer thermal capacity, requiring replacement.	Customer payment **can be justified** if new DERs are the sole reason for the transformer upgrade. However, if multiple and/or future customers will benefit from the transformer upgrade, equitable cost allocation should occur. Additionally, utilize smart inverter functionality before replacing transformer.
Grounding transformer	Transient overvoltage conditions caused by DERs during unbalanced fault conditions may damage equipment.	DER customers **should not pay** for installation of grounding transformers because inverter-based ground fault overvoltage magnitudes and durations are within safe limits with Yg-Yg distribution transformers.[30] Additionally, with Yg-Yg distribution transformers, any overvoltage is not a result of neutral shift overvoltage and therefore would not be mitigated by grounding measures.[31]
SCADA Recloser	Utility requires remote control and monitoring of DERs for feeder safety and reliability.	DER customers **should not pay** for dedicated SCADA reclosers because reclosers are a redundant and/or overly expensive solution for the desired use. Less expensive alternatives exist for monitoring and remotely disconnecting DERs. Reclosers used for anti-islanding and/or crew safety are redundant to existing standards. [32,33]
Monitoring equipment	Increased visibility is needed to observe DERs' impact on loading and power quality.	DER customers **should not pay** for utility monitoring equipment because grid monitoring is part of normal utility business operations, regardless of the existence of DERs, and benefits all customers.
Voltage Equipment – Variability	High DER penetration and the resulting intermittency could cause line voltage violations including both steady-state voltage and voltage flicker.	DER customers **should not pay** for utility voltage regulating equipment installations when inverters can eliminate need for incremental equipment via advanced features including ramp rate control, dynamic power factor settings, and/or utility Volt VAR Optimization control.[34] Furthermore, voltage variations due to distributed PV have been shown to match the existing voltage variations from normal load fluctuations.[35]
Voltage Equipment – Reverse Flow	DERs may cause reverse power flow on unidirectional voltage regulating equipment or require replacement of a fixed capacitor with a switched bank	• *Regulators* – If equipment upgrade is justified, DER customers **should not pay entire upgrade costs** as the upgrades benefit the entire distribution system. • *Capacitor banks* – customers **should not pay** to upgrade fixed capacitor banks to switched capacitor banks when smart inverters can provide the same power quality management capabilities as switched capacitor banks.

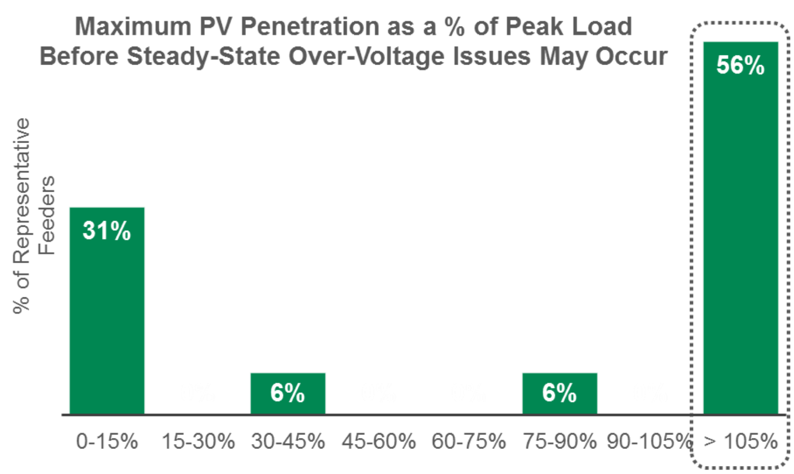
Expand Allowable Approvals

Low DER Penetration Levels

At low DER penetration levels, utilities should enable fast-tracked interconnection of most DER applications while adopting a streamlined *Supplemental Review* process that utilizes simplified, shorthand impact calculations to increase allowable interconnection approvals without the need to implement more complex impact analyses.

At the heart of traditional DER interconnection processes are technical screening rules that determine the eligibility of a proposed DER project to interconnect. These screening rules are often universally applied to all circuits (e.g. interconnection allowed when DERs are less than 15% of peak load), even though circuits are unique. These existing screening rules are often overly conservative for most circuits given the most recent technical research. For example, the Hawaiian Electric Company imposed a moratorium on solar PV in Hawaii from September 2013 to February 2015. The widespread halting of solar PV interconnections within the state was the result of the utility's concerns over the impact of high penetration PV – concerns that were later dispelled after technical study.[36]

Applying a 'one-size-fits-all' or 'rule of thumb' screening process inherently limits the amount of DERs that can be safely interconnected on the majority of circuits. The figure on the right depicts NREL findings that identify the maximum amount of PV penetration that can be accommodated without steady state voltage violations by various distribution circuits. As shown, 56% of circuits can accommodate over 105% PV penetration as a percentage of peak load.[37] This data highlights that circuits are unique, and that even in low penetration scenarios universal screens are ineffective at identifying technical concerns.



At low DER penetration levels, utilities should utilize simplified, shorthand impact calculations in lieu of universal screens to increase allowable interconnections without the effort required to implement more complex impact analyses. The Electric Power Research Institute (EPRI) proposes a set of shorthand calculations as an alternative to universal screens, which can serve as a model for utilities.[38]

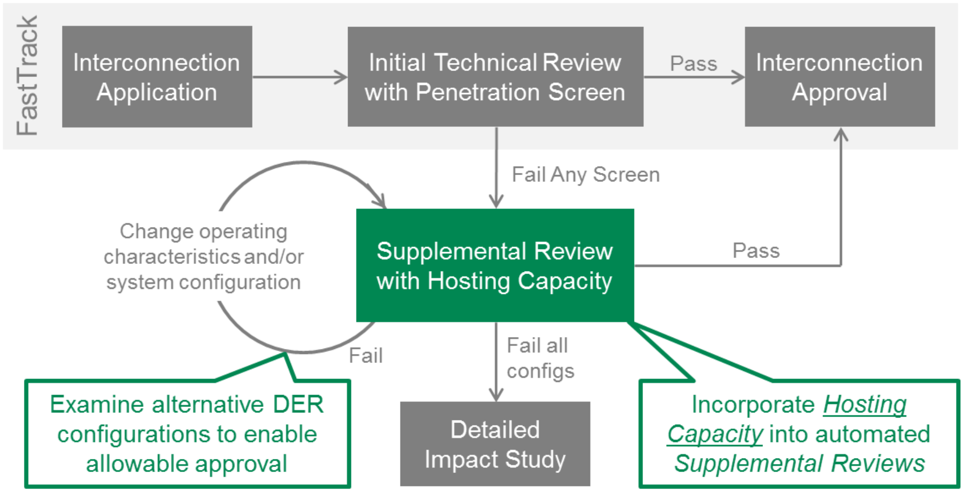
High DER Penetration Levels

At high DER penetration levels, utilities should incorporate automated DER *Hosting Capacity* analyses into the interconnection review process to increase allowable interconnections while decreasing the application review timeline.[39]

While the shorthand modifications to screening rules discussed above can be an effective approach to streamlining interconnections at low DER penetration levels, this approach quickly breaks down as DER penetrations increase and more circuits hit the limits prescribed by this simplified method. Therefore, shorthand screens should be phased out in favor of detailed, location-specific impact analyses that determine the amount of DERs that can be accommodated on a specific circuit. Such analyses are called DER *Hosting Capacity* or *Integrated Capacity* analyses.

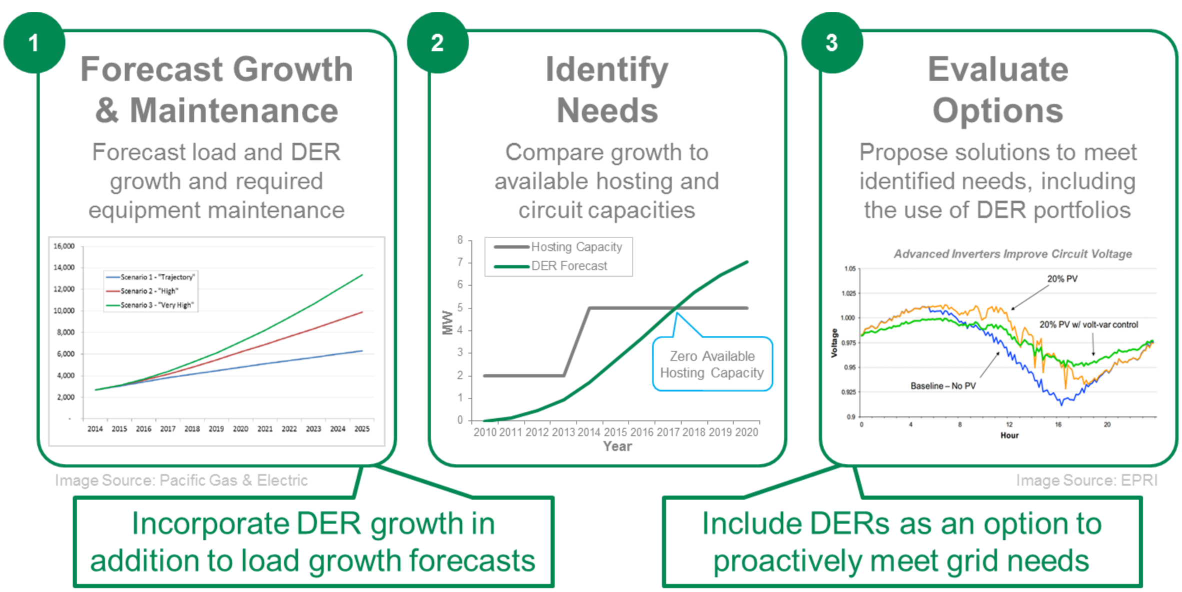
A circuit's *Hosting Capacity* is the amount of DERs that can be safely and reliably interconnected – or *hosted* – on any given feeder based on its specific characteristics. A hosting capacity analysis evaluates a variety of circuit operational criteria – including voltage, loading, protection, power quality and control – under the presence of a specific level of DER penetration – and identifies the limiting factor for DER interconnections. Hosting capacity analyses provide an indication of how many DERs can be accommodated given existing utility and customer-owned equipment on a circuit. The result is a more tailored, circuit-specific screening tool for the DER interconnection process: proposed projects that fall under the available hosting capacity can be quickly processed through interconnection approval, while projects that exceed the hosting capacity require further engineering analysis.

A process flow for incorporating hosting capacity into the interconnection process is depicted below. Note that if an interconnection application fails the *Initial Technical Review*, the application goes through a *Supplemental Review* where hosting capacity analyses are used to evaluate approval. In order to facilitate efficient application processing, this Supplemental Review should be streamlined by incorporating automated hosting capacity analyses. Furthermore, if an application fails the Supplemental Review, then the utility should work with the customer to iterate DER system design configurations and/or operating characteristics to examine whether an alternate design would pass supplemental review.



Planning

While *Interconnection* focuses on allowing increased penetrations of DERs on the system, a modernized *Distribution Planning* process focuses on meeting distribution needs and unlocking the benefits of DERs. As depicted in the figure below, the traditional distribution planning process involves three steps: forecasting growth, identifying grid needs, and specifying solutions. This framework remains suitable for distribution planning in the presence of high DER penetrations, but it must be modernized to actively leverage the value of DERs.



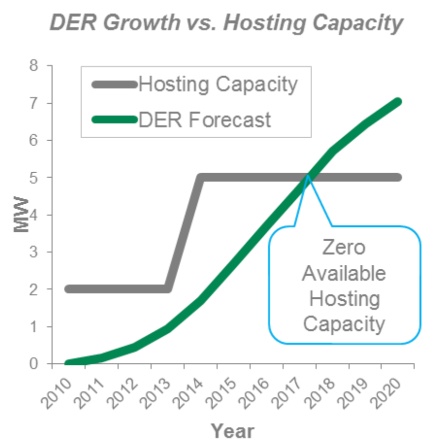
Challenge: Current utility planning process does not leverage DERs to provide grid services, lower systems costs, and increase grid resiliency.
Solution: Modernize utility distribution planning to leverage DERs.

Forecast Growth & Equipment Maintenance

All utility planning efforts begin with identifying the grid and customer needs that must be met, as well as required maintenance to existing equipment. Traditionally, utilities have established grid needs focused on meeting peak demand and power quality requirements as a result of customer load growth. However, in a high-penetration DER grid, customer choice related to deploying DERs must also be accommodated into grid needs. As such, utilities will need to become much more proficient at forecasting customer DER growth than they are today. The required proficiency is achievable since at its core, forecasting DER growth requires a similar skillset to forecasting load growth. Both forecasts are contingent upon a variety of demographic, economic, technological, location-specific, and historical trends that are probabilistic in nature. Although utilities are currently only beginning to forecast DER growth, they can leverage modern forecasting techniques and computing power to analyze increasing amounts of data to become as adept at forecasting DER growth as load growth.

Identify Needs

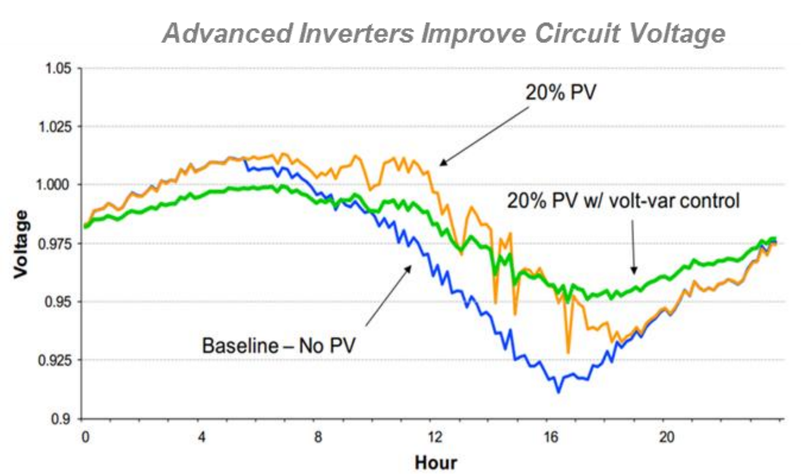
After forecasting customer DER adoption and load growth for a defined area, utilities will need to compare the forecasted growth to the distribution grid's available capacity. This effort mirrors current utility efforts of comparing load growth to available circuit capacity, except that now utilities must also compare DER growth to DER hosting capacity. Such comparisons will enable utilities to proactively identify when circuits may reach their current threshold for accommodating additional DERs. Using this information, utilities can prioritize which circuits to proactively evaluate for increasing available circuit and/or hosting capacity. As discussed below, there are a host of options available to increase circuit and hosting capacities at no or minimal cost. See figure on right for an illustrated comparison of DER growth to available hosting capacity, indicating when zero available hosting capacity will occur for the specified location.



Evaluate Options

Once grid needs are identified, planners evaluate available solutions to meet those needs. Solutions can include tweaks to existing utility equipment settings, changes to customer and utility equipment operating requirements, use of existing DERs to offset circuit or hosting capacity needs, changes to technology and/or software systems, and the sourcing of incremental assets. Sourcing efforts and mechanisms utilizing DERs are outlined in the *Sourcing* section below.

Alternatives to traditionally procured infrastructure investments are often available at low or no cost, increasingly so with the increased deployments of DERs. Advanced inverters can be utilized to provide voltage and reactive power support, customer batteries can provide peak capacity support, load shifting can absorb over generation, and tweaks to distribution equipment configurations can enable higher levels of reverse power flow, among others. For example, the IEEE figure[40] below illustrates the benefit that advanced inverters can offer for the dynamic support of circuit voltage.



Sourcing

Today's status quo planning model does not consider *Sourcing* of third-party solutions to meet the distribution needs. Utilities instead rely on 'steel-in-the-ground' infrastructure funded by regulatory rate case proceedings, with utilities self-supplying 100% of their distribution system solutions. Under this model, regulators rely on the expertise of distribution planners to deploy capital that meets customer demand in the most cost-effective way possible.

Given recent technological advancements and growing customer DER adoption, the self-supply distribution sourcing model must evolve to grant utilities the flexibility to consider the full scope of solutions available to meet grid needs, including third-party DER portfolios. While this evolution requires modernizing an entrenched distribution planning process to utilize the *Sourcing* tools described below, the end result will be more cost-effective solutions at planners' disposal.

> *Challenge*: Current utility distribution sourcing processes does not adequately leverage DERs to provide grid services, lower systems costs, and increase grid resiliency.
> *Solution*: Modernize distribution sourcing to evaluate, select, and deploy DERs to meet grid needs.

Select Least Cost / Best Fit Portfolio

The first stage of utility *Sourcing* is the evaluation and selection of options available to meet the identified need. Traditional distribution planning limits the scope of available sourcing options to conventional solutions: namely self-supplied, utility-owned distribution equipment such as transformers, capacitor banks, reconductored wires, and other capital equipment. In a future with high levels of DERs connected to the grid, distribution planners must be willing and able to consider the full range of solutions available. If this opportunity is not realized, planners risk making, and regulators risk authorizing, redundant investments that increase system costs for ratepayers.

In order to bridge this disconnect, we propose a distribution-level policy concept to encourage the adoption of DER portfolio solutions: *Distribution Loading Order*. The *Distribution Loading Order* borrows an existing concept from some states' regulated utility energy procurement, which prioritizes procurement of renewable energy ahead of fossil fuel-based sources. For instance, in 2003 California's principal energy agencies established a "loading order" for energy efficiency, demand response, renewables and distributed generation with the intent of operating the electricity system in the best, long-term interest of consumers, ratepayers and taxpayers.[41] Similarly, introducing a *Distribution Loading Order* provides a framework for sourcing distribution solutions based on a specified prioritization that is consistent with longer term policy objectives to support cleaner and more resilient electric systems.

In the context of distribution needs, the *Distribution Loading Order* prioritizes the utilization of individual DERs or portfolios of DERs over traditional utility infrastructure, when such portfolios are cost-effective and able to meet grid needs.

Distribution Loading Order: Sourcing Solutions

Proposed Distribution Loading Order	Selection of Resource Examples
1. **Distributed Energy Resources** (DERs)	Energy efficiency, controllable loads/demand response, renewable generation, advanced inverters, energy storage, electric vehicles
2. **Conventional Distribution Infrastructure**	Transformers, reconductoring, capacitors, voltage regulators, sectionalizers

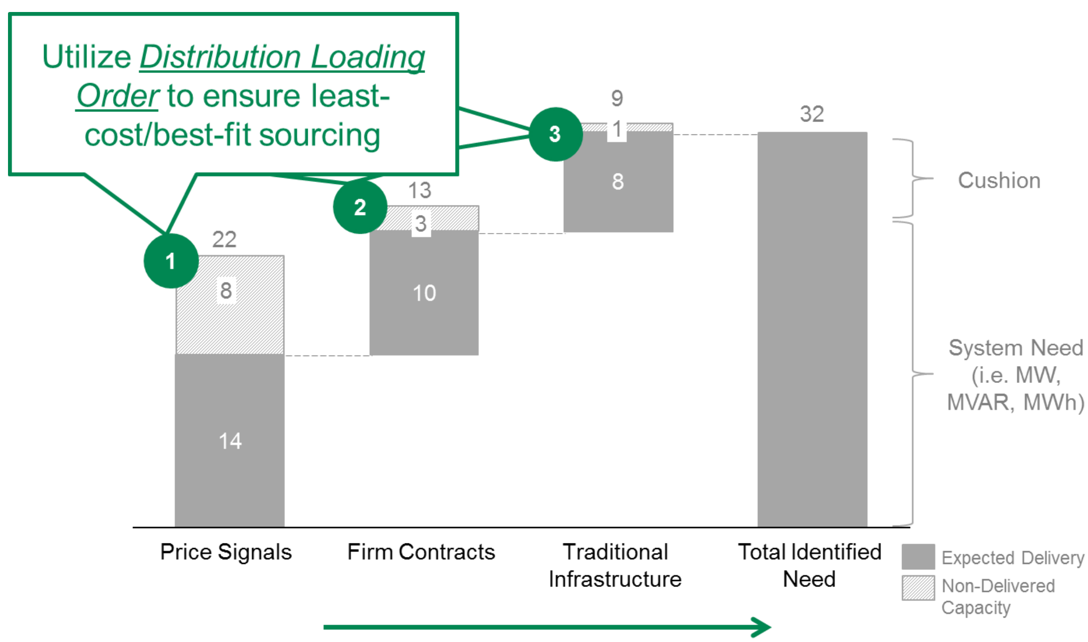
While the *Distribution Loading Order* provides an explicit hierarchy to evaluate and prioritize resources, it is equally important that the loading order include new *sourcing mechanisms* given the scarcity of existing competitive sourcing at the distribution level. These new sourcing mechanisms must accompany a *Distribution Loading Order* to ensure that planners have channels to fairly consider alternative solutions against conventional utility investments. In practice, a planner would meet a specified grid need by executing a standard sourcing process, considering DER solutions ahead of traditional utility infrastructure. The distribution sourcing mechanisms proposed in the table below provide a guide for how and in what prioritized order utilities should evaluate grid solutions to comply with the Distribution Loading Order.

Distribution Loading Order: Sourcing Mechanisms

Rank Order	Sourcing Mechanism	Description	Selection of Practical Examples
1	**Price Signals** (DERs)	DER portfolios that voluntarily respond to price signals sent from the utility that incent the desired behavior to meet grid needs.	• Voluntary Critical Peak Power / TOU Pricing • Voluntary Distributed Marginal Pricing (DMP) • Voluntary Voltage Support Pricing
2	**Firm Contracts** (DERs)	DER portfolios that are contractually obligated to deliver grid services based on contracted prices.	• Week-Ahead Reactive Power Payments • 1-10 year ahead availability contracts for peak substation real power capacity
3	**Traditional Utility Infrastructure**	Traditional utility infrastructure self-supplied through General Rate Case capital budgets.	• Utility investment in Substation transformer • Utility investment in feeder reconducturing

As with *integrated resource planning* utilized at the wholesale level, *asset availability* must be considered when deploying DERs to meet grid needs. While DERs – or any grid resource – voluntarily responding to price signals may respond less consistently than an asset under direct utility control, utilities can quantify the expected availability of such assets. While perhaps a new concept in the distribution context, methodologies exist for assessing availability-based resources, such as *Effective Load Carrying Capability* (ELCC) and other probabilistic methods currently used in demand response programs.

The figure below provides a conceptual illustration of how availability methodologies could be used to probabilistically discount the different types of distribution products. In this example, the utility has identified a total grid need of 32 MW of, say, capacity. To meet this need, the utility first sources capacity through price signals where it obtains 22MW of nameplate capacity, but availability of only 14MW. The utility continues to utilize the remaining sourcing mechanisms until its need is met. Note that the availability of resources responding voluntarily to *price signals* is discounted by a larger ratio than *firm contracts* and *traditional infrastructure*.



Distribution Loading Order: Sourcing Mechanisms

Several economic and policy principles provide the underlying rationale for the recommended sourcing approach:

1. Since DERs are often paid for fully or partially by customers, DER portfolios will increasingly offer grid services to distribution and bulk system operators at a lower cost than conventional investments. Thus, utilizing price signals to leverage embedded DERs holds the potential to reduce the overall cost to ratepayers to meet grid needs.
2. Leveraging customer DERs in favor of building new utility infrastructure is desirable when technically and economically feasible because it encourages further customer engagement in their energy management, utilizes assets voluntarily chosen by customers, and enhances grid resiliency by supporting further adoption of DERs.
3. In the absence of a *Distribution Loading Order*, utilities will overlook the potential for DERs to meet grid needs. This

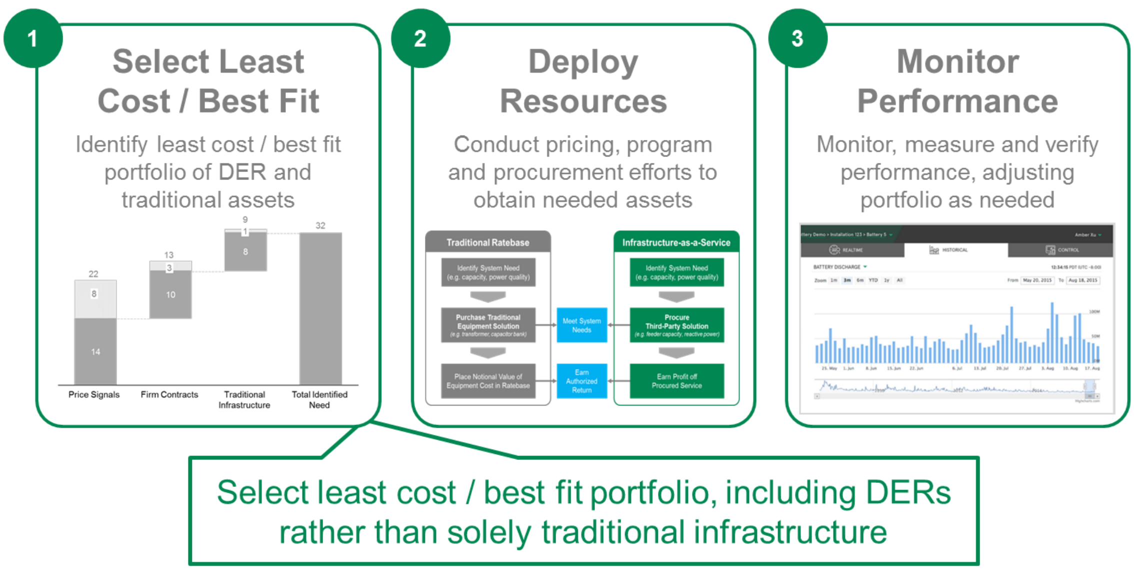
structural bias is highly likely due to organizational inertia and, more importantly, the explicit financial incentive that utilities face to invest capital in traditional infrastructure that generates regulated shareholder returns.

4. Since the *Distribution Loading Order* retains planners' flexibility to deploy conventional infrastructure after evaluating DERs, utilities can always deploy traditional infrastructure if needed to ensure system reliability.

While conventional utility distribution equipment offers familiar functionality to distribution operators, these assets can be expensive, bulky, long-lived, and inflexible. By prioritizing the consideration of DER portfolios to meet distribution needs via a *Distribution Loading Order,* utilities will maximize the value of advanced DERs on the grid to the benefit of customers.

Deploy Portfolios

After evaluating the potential options to meet grid needs, utilities select and deploy the solution that is least cost / best fit, consistent with standard utility operating practice and the *Distribution Loading Order*. The least cost / best fit portfolio is likely to be a combination of product categories, including *price signals*, *firm contracts* and *traditional infrastructure* assets. Once the portfolio is selected, utilities must deploy the resources through a variety of mechanisms including voluntary enrollment in customer pricing/tariffs, customer deployment programs, solicitations (i.e. request for proposals), price-clearing markets, and utility infrastructure deployment. Each of these assets are likely to have a different deployment timeline, so utilities and regulators will need to revisit planning timelines to ensure the longest lead time assets and programs are sourced and deployed first with a sufficient buffer in place to install traditional infrastructure if some sourced assets do not materialize. After deployment, utilities will need to monitor performance to verify that DERs are delivering the grid services as required. The figure below depicts the stages of deploying portfolios to meet grid needs.



Data Transparency & Access

With the ever increasing deployment of DERs, grid operational and planning data is critical to continued market innovation. Currently, utilities hold the vast majority of grid data and little of it is available to the industry.

Data sharing is critical to grid modernization as it informs customer choice, spurs economic development, supports innovation, enables credible auditing of utility investment plans, supports public safety, and eventually will foster a robust transactive energy marketplace. Conversely, solely publishing outcomes of utility analyses rather than sharing the underlying data does not enable sufficient industry stakeholder engagement or innovation. Data access and transparency is the foundation of current ratepayer advocacy efforts and should be extended into *Integrated Distribution Planning*.

Challenge: Utility data critical for driving innovation is not readily accessible by broader industry.
Solution: Utilities must commit to data transparency and access to enable industry innovation.

Data Transparency

There are a number of foundational reasons to actively promote grid planning and operational data sharing:

- *Data sharing informs customer choice and economic development*
  - Should customers pursue projects on a specific feeder?
  - Do DER providers have enough business runway to retain local employees?
  - Should DER providers open a warehouse/office in a specific geographic area?
- *Data sharing supports industry innovation*
  - Data sharing unlocks third party engagement, dramatically increasing pace of innovation
  - Third parties have knowledge to engage in and improve distribution planning, particularly in new skillsets that are not traditional utility strengths (e.g. data analytics, software/product development)
- *Data sharing enables credible auditing of utility investment plans*
  - DER providers can suggest alternative means to meet distribution system sourcing needs
  - Solely publishing outcomes of analyses (i.e. hosting capacity analyses) does not enable sufficient auditing of utility methodology/decision making
  - Data access is the foundation of ratepayer advocacy and should extend into distribution planning
- *Data sharing supports public safety*
  - Transparent data increases visibility into potential public safety concerns

Five categories of data should be shared by utilities and DER providers. Additional categories may be required in the future.

- *Locational Value* – Locational value data identifies the costs and benefits of locating DERs in a specific location. Currently, this data is not made available, which impedes efforts to locate DERs where most beneficial to the grid.
- *Hosting Capacity* – Due to the critical nature of hosting capacity information for every DER provider and customer, the underlying data to calculate hosting capacities should be made available. Simply publishing hosting capacity values themselves is inadequate, and limits the innovation that third parties can provide.
- *Planning & Investments* – Utility planning and investment data by circuit is critical to understanding which investments could be offset by DER portfolios. Planning and investment data is typically shared via utility regulatory rate making proceedings, and this data should be shared at increasingly granular circuit-levels.
- *Operational Support* – As utilities make more use of price and dispatch signals to support grid needs, access to real-time and historical operational data will be critical to enabling and evaluating performance. The more real-time data is shared, the more valuable grid services DER portfolios will be able to provide.
- *Market Support* – As transactive markets begin to take shape, sufficient pricing data and event statistics should be shared in order to support well-functioning markets.

Data Access

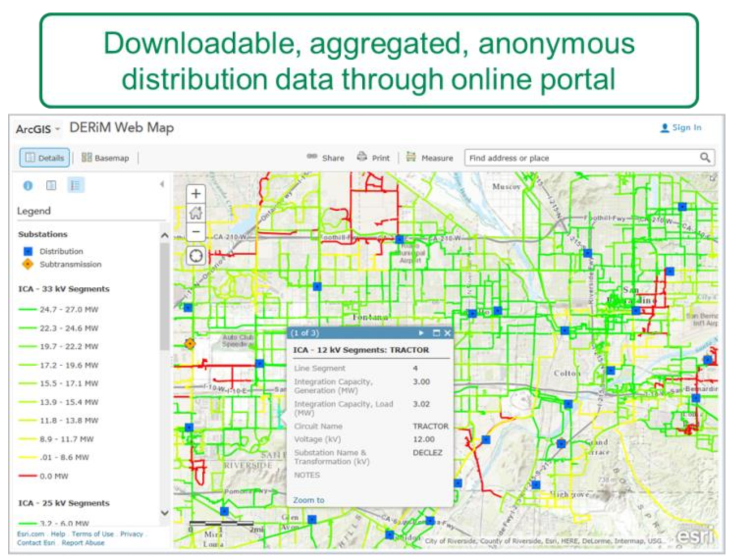


Image Source: Southern California Edison

In addition to identifying which utility data must be shared to support the market, the mechanism for sharing that data is critical to market animation. Online access to bulk, downloadable data is critical to spur market innovation. Simply making data viewable but not downloadable is not sufficient, as third parties require the ability to perform analyses on the underlying data to develop insights.

Data access best practices are emerging as a result of utility innovation. Recent enhancements to the Renewable Auction Mechanism (RAM) maps from Southern California Edison (see figure on right) and Pacific Gas & Electric offer examples of online platforms that third parties can use to access utility data.[42] While improvements remain to enable streamlined access to data from these platforms (i.e. downloadable data rather than just viewable data), these maps serve as innovative examples of the data sharing platform.

Conclusion

Electricity demands across the world are growing, yet our outdated electrical grids rely on centralized, finite sources of power. Transitioning the grid to one that leverages the wave of distributed energy resources proliferating across the industry is imperative to meet this need. Distributed energy resources offer tremendous benefits in the form of lower system costs, improved grid resiliency, and increased use of clean energy. DERs empower customers to become active participants in their energy management and fuel job creation as we collectively modernize the grid for the 21st century.

Evolving utility interconnection and planning processes into a holistic and proactive *Integrated Distribution Planning* process is essential to unlocking the promise of distributed energy resources. We offer this paper as an initial vision for a holistic process to leverage DERs to benefit the grid. However, there are many details to develop in order to realize this vision. SolarCity continues to work on developing these details for the concepts proposed in this paper, and we welcome collaboration with industry thought leaders to do so. Our ultimate goal is to help provide the concrete recommendations and justification needed by regulators, legislatures, utilities, DER providers, and industry stakeholders to create the impetus for change needed to transition to a cleaner, more affordable and resilient grid.

For more information, please visit us at solarcity.com/gridx or contact us at gridx@solarcity.com

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RE: Docket No. IR 15-296, Investigation into Grid Modernization

I hereby certify that a copy of the foregoing *Comments of SolarCity Corporation* has on this 17th day of September 2015 been sent by electronic mail to persons listed on the attached Service List for the above-captioned proceeding.

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