Locational and Temporal Values of Energy Efficiency and other DERs to Transmission and Distribution Systems

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ABSTRACT

As utilities and regions across the country experience increased penetration of energy efficiency and other distributed energy resources (DERs), many are exploring ways to comprehensively assess the multidimensional value of DERs. When strategically situated to target locational and temporal needs, DERs can defer or even avoid transmission and distribution (T&D) investments that would otherwise be needed to meet increasing demand. The potential avoided electric T&D investments are immense: annual U.S. investments have grown 9.2 percent on average between 2013 and 2016 (Knutson 2017), and transmission investment alone is projected to exceed $68 billion from 2018 to 2020 (EEI 2017).

Avoiding T&D investments with energy efficiency and other DERs requires jurisdictional efforts to evaluate locational and temporal needs (including load forecasts and congestion) and the capability of DERs to respond to those needs. Utilities and regulators can encourage the strategic siting of DERs by: (1) requiring utilities to consider DERs as a resource in distribution planning; (2) developing better screening and selection practices for DERs; and (3) creating and refining methodologies to derive locational and temporal (L-T) values of DERs to T&D.

This paper focuses on L-T valuation methodologies and emerging practices being developed in two innovative states: New York and California. The paper also provides a summary of how these states addressed several key considerations. This summary is useful for utilities, states, and other stakeholders when developing similar methodologies. Utilities are testing a variety of approaches, and refinements are likely to occur over time as lessons are learned.

Introduction

Utilities nationwide are responding to the continued proliferation and penetration of energy efficiency and other DERs in a variety of ways. As customers procure more and more DERs—either through utilities, self-procurement, or with the assistance of third parties—utilities need to better evaluate the potential risks and opportunities these new technologies bring to their T&D systems.

This paper explores the emerging practice of considering DERs on a locational and temporal level. We are closely following the ways in which utilities in two particularly innovative states—New York and California—are improving distribution planning processes to better incorporate DERs.[1]

In general, states are considering three primary ways to improve distribution planning:

[1] We also provided comments during the development of some of the New York methodologies (CEP 2018).

1. Developing better screening and selection practices for infrastructure upgrades that could be avoided or deferred by EE and other DERs. This requires detailed understanding of short-, mid-, and long-term needs and projected growth at the substation- and circuit-levels, as well as the area's integration capacity for EE and other DERs.[2]
2. Better incorporating DERs into distribution planning. Consideration of DERs as alternatives to traditional capacity expansion projects can be integrated into distribution planning processes.
3. Creating and refining methodologies to derive L-T values of EE and other DERs to T&D. Implementation of these methodologies will provide utilities and third parties with a better understanding of areas in which EE and other DERs are valuable. The implementation can also send appropriate price signals to encourage the development of DERs in these areas.

While this paper focuses on the third approach, we support the consideration and appropriate implementation of all these methodologies in distribution planning.

Summary of Important Considerations

As the ability of DERs to avoid utility and societal costs becomes more apparent (for example, by cost-effectively deferring and perhaps avoiding T&D investments), we can expect to see additional states develop similar locational valuation and screening methodologies. In developing these methodologies, jurisdictions will need to balance many considerations and issues. These include:

1. The extent to which utilities should and can determine locational and temporal values and compensation in advance, such that DER providers can develop economically attractive DER projects.
2. The number of years to use a locational and/or temporal valuation as a compensation, and the appropriate frequency of valuation updates.
3. Whether the compensation should provide locational or temporal price signals, or a combination of the two.
4. The impacts of these valuations on different types of customers. This includes the potential difference in locational values between urban and rural areas, and between regions with customers of different income classes.
5. The efficiency that comes with a standardized methodology vs. the benefit of building flexibility into a state's methodology (such that utilities can better respond to regional needs).

The responses to these considerations will almost certainly vary by state and utility to appropriately meet the needs and context of each region. Table 1 summarizes New York's and California's methodological approaches to several of these considerations. The following sections of this paper provide additional detailed description of and discussion on these state methodologies.

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[2] An innovative example of this strategy can be found in a case study focusing on the deferral of a proposed infrastructure project in the Mt. Vernon area of Washington, DC (Hopkins and Takahashi 2017).

Table 1. Summary of New York and California methodologies

Consideration	New York	California	Discussion
Temporal Valuation	Locational values are applied to the 10 peak hours of the system in the previous year	Locational values are developed on an hourly basis, i.e. 8,760 hourly locational values for non-leap years; a compensation methodology has not yet been developed	Developing granular temporal values may help attract DER developers and will produce more refined valuations, but it could overcomplicate methodologies
Value Components	Energy, generation capacity, environmental, demand reduction, and locational system relief	Energy, losses, generation capacity, ancillary services, T&D capacity, environment, avoided RPS, distribution capacity, steady-state voltage, power quality, reliability, and resilience	Including more value components will further refine the L-T valuation process, but it could overcomplicate the development and refinement of methodologies
Valuation Period	Selected projects will receive Locational System Relief Value (LSRV) compensation (discussed in detail below) for a period of 10 years before needing to update to the most recently derived LSRV value	The utilized model produces 30-year time horizons with hourly values; the methodology does not yet produce compensation amounts	Having a longer compensation period may better attract DER developers if there is sufficient price certainty, but it could result in overcompensation if the prices are not set correctly
Eligible Resources	Includes resources that were previously net energy metering (NEM) eligible (e.g., solar and wind); non-generation resources (e.g., energy efficiency and demand response) are not eligible in the Phase One tariff	Includes distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies	Including all resources allows for consideration of all options, and creates a level playing field across resources

New York

The state of New York, through Governor Andrew Cuomo's *Reforming the Energy Vision* (REV) initiative, is undergoing a substantial effort to reform its energy practices. The efforts are in response to the changes happening in energy generation, distribution, and consumption, including the increasing penetration of DERs. Efforts included in the REV initiative include: strategically identifying locations where additional capacity investments can be avoided through DERs, and properly compensating DERs for the L-T value that they provide to the system. This section discusses one of the proceedings which addresses these REV goals: The Value of Distributed Energy Resources.

Value of Distributed Energy Resources

On March 9, 2017, the Commission issued an order which addresses the development of a standardized Value of Distributed Energy Resources (VDER) Phase One tariff. The VDER Phase One tariff is designed to "provide immediate improvements in granularity in understanding and compensating for the value of DER to the electric system while setting the foundation for continual improvement" (NY PSC 2017a, 3-4). It replaces the NEM tariff, and includes benefits that were previously unquantified, including—notably—locational and temporal benefits. The VDER Phase One tariff includes two components: The Phase One NEM tariff and the Value Stack tariff. The Phase One NEM tariff is currently only open to new projects for residential and small commercial customers, leaving only the Value Stack tariff open to new projects of other types. DER projects that are deemed eligible to receive the tariff will be compensated for 25 years from the project's in-service date.

Currently, non-generation DERs (such as demand response and energy efficiency) are not eligible for compensation under VDER Phase One.[3] However, the Commission notes that future phases of VDER tariffs should include additional DER technologies (NY PSC 2017a, 15). Therefore, this section provides a description of the proposed valuation of DERs in the proceeding and includes a discussion on important considerations when expanding the VDER Tariff to non-generation DERs.

The Value Stack

In this proceeding, the Commission and the Joint Utilities are developing a common framework for more comprehensive valuation and compensation of DERs.[4] One of the key concepts of this common methodology is the L-T value of DERs, included in the "Value Stack." The Value Stack—a payment methodology based on stacking benefits—includes four complementary elements (NY PSC 2017a, 15):

1. Energy Value. The Energy Value is calculated using the day-ahead hourly zonal locational-based marginal price (LBMP) and is inclusive of losses.
2. Generation Capacity Value. The Capacity Value is derived using retail capacity rates for various intermittent technologies, as well the technologies' performance during the previous year's system peak hour.
3. Environmental Value. The Environmental Value is based on the New York State Energy Research and Development Authority (NYSERDA)'s latest Clean Energy Standard Tier 1 Renewable Energy Certificate procurement price, or the Social Cost of Carbon. The higher of the two is used for this component.

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[3] The Phase One Tariff is a transition from NEM to a new form of DER compensation and is currently available only to resources that were NEM-eligible.

[4] The Joint Utilities are: Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

4. Demand Reduction Value (DRV) and Locational System Relief Value (LSRV). These values are calculated by deaveraging the utility's marginal cost of service (MCOS) studies, exploring the DERs' performance during the 10 local peak hours, as well as additional considerations discussed below.

Notably, the fourth component attempts to capture the locational value of DERs through a location-specific value called the LSRV.

As the first step in the development of L-T values, the Commission required the Joint Utilities to develop long-run avoided costs of incremental distribution system upgrades. These costs represent a significant portion of the locational benefits of DERs where they can be used to effectively defer or avoid the distribution system upgrades. These long-run avoided costs of distribution system upgrades form the basis of the standardized DRV and LSRV. They are to be based on modified versions of the utilities' current MCOS studies. For context, the next section provides a summary of the Joint Utilities' MCOS studies.

Marginal Cost of Service (MCOS) Studies

The Commission has approved MCOS studies for each of the five New York investor owned utilities (IOUs). However, the MCOS studies predate the VDER proceeding, and—in general—provide only system-wide values or values by rate class. Each MCOS study identifies transmission and primary distribution marginal costs, and several include marginal costs for secondary distribution. These values are to be used in the development of the Value Stack tariff.

The underlying data and the methodology used to derive the marginal costs vary by utility, and the derived marginal costs do not provide granular price signals that can assist in value-based, targeted DER penetration. Rather, they provide system-wide marginal costs. The Commission, in its VDER Order, notes that: "The development of granular prices to reflect locational distribution value has not progressed at a pace consistent with the reality of the DER marketplace. Locational indifference now can lead to unnecessary stranded costs in the future, as rapidly improving distributed generation technology outpaces traditional utility response" (NY PSC 2017a, 116).

Thus, the Joint Utilities were required to develop work plans and timelines for developing these granular, location-specific, distribution-related needs that may be met by the penetration of DERs. Commenters have highlighted that numerous benefits cannot be achieved without a standardized process, including: (1) added transparency to the VDER process; (2) assurance that the valuation methodology is based on full avoided costs; and (3) assistance in helping the state meet its goal of developing a DER market that can drive down distribution costs (SEIA 2017, 42).

Locational Values

On September 14, 2017, the Commission issued an order on the Joint Utilities' proposals to implement a Phase One Value of DERs (NY PSC 2017b). Included within the Order are determinations on the calculation of the DRV and LSRV—values that attempt to capture the system-wide value of demand reduction and location-specific values of demand reduction, respectively.

The Commission accepted the utilities' proposals for calculating the DRV and LSRV (which are based on the utilities' MCOS methodologies).[5] DRVs—calculated by dividing the necessary investment to complete growth-related projects by the expected total capacity that will be added to the system by the projects—represent the investment per kW of load growth. DRVs will be used to compensate eligible DERs under the VDER Phase One Tariff. The annual DRV values developed are $29.67 and $31.92 (in dollars per kW per year) for NYSEG and RG&E, respectively (NYSEG and RG&E 2017, 4).

To calculate the LSRVs, NYSEG and RG&E first identified the non-wires alternative (NWA) projects that were introduced in their 2016 Distribution System Implementation Plans (DSIP) as the initial group of LSRV-eligible projects (NYSEG and RG&E 2017, 4). There were five potential NWA projects in NYSEG's service territory and two in RG&E's service territory. Using the same MCOS methodology used in calculating the DRV, the potential LSRV-eligible projects were evaluated to see whether their locational values were greater than the system-wide DRVs. If a project has a greater locational value, it remains included in the group of LSRV-eligible projects.

Finally, the "net" LSRV compensation—that is, the value from the DER project above and beyond the DRV—is determined by separating the characteristics of the LSRV area from the initial MCOS and finding the difference between the area's marginal costs and the DRV. This difference is the final LRSV, and it reflects the added value of connecting DERs in a high value area. The final LSRV is annualized and time-differentiated based on available information on substation load patterns.

Because the LSRV projects are considered individually, there is a separate marginal cost estimate for each LSRV project.[6] The difference between the DRV and the LSRV is the final "net" LSRV, or the additional value of DER in the LSRV area. Table 2 shows the LSRV compensation per kW-year for each of the six LSRV-eligible projects in NYSEG's and RG&E's service territories.

[5] However, the Commission noted limitations: "Other value streams, such as the benefits of local reactive power or the valuation of quick local response, are currently not modeled in either the wholesale or retail markets" (NY PSC 2017a, 111).

[6] Utilities currently include varying levels of locational granularity for the LSRV. Consolidated Edison, for example, develops one LSRV and one DRV which—combined—equal 150 percent of the system-wide MCOS (ConEd 2017, 5).

Table 2. LSRV compensation for NYSEG and RG&E LSRV-eligible circuits

Project Name	Company	LSRV ($/kW-yr)
Station 117	RG&E	47.96
Station 46	RG&E	9.47
Hilldale 115kV source	NYSEG	53.59
Holland Transformer Replacement	NYSEG	56.26
Orchard Park	NYSEG	21.82
West Davenport Sub	NYSEG	48.89

Source: NYSEG and RG&E 2017, 5.

Figure 1 compares the stacked LSRV and DRV compensation per kW-year for each of the six LSRV-eligible projects in NYSEG's and RG&E's service territories.

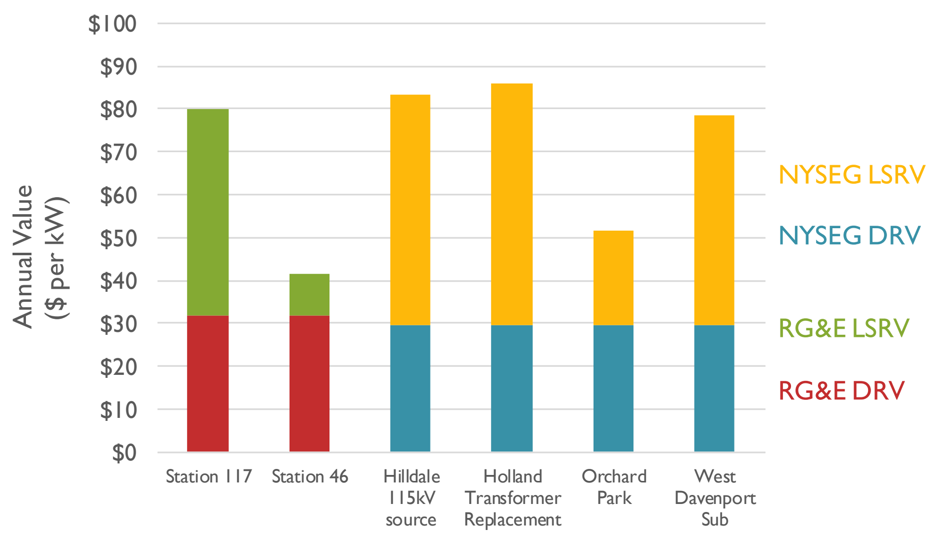

Figure 1. Comparison of NYSEG and RG&E LSRVs and DRVs, by project.

NYSEG's and RG&E's development of LSRVs is a significant step towards developing proper price signals to encourage the implementation of DERs in areas where they will be particularly valuable. All of the utilities would benefit from including similar levels of locational specificity in the development of LSRVs.

The DRVs and LSRVs also include temporal signaling: in addition to locational value, DERs will be compensated for performance during the 10 peak hours of the system in the previous year (NY PSC 2017a, 117-18). The combination of locational and temporal values sends price signals that can better attract the type(s) of DER—e.g. solar photovoltaics or energy efficiency—that best meet the needs of the location. For example, if a region is forecasting significant load growth only during specific hours, and EE is most capable of reducing load during those hours, the proper locational and temporal compensation can be used to encourage EE development to meet this need. However, the temporal metric used in New York—10 peak hours—can vary significantly by year. This metric provides temporal uncertainty to potential developers.

Future Plans

The Commission and the Joint Utilities have started discussing the development of a VDER Phase 2 Tariff. During this development, we recommend stakeholders consider including non-generation DERs (i.e., demand response and energy efficiency).[7] Energy efficiency is often effective at addressing energy load growth, but has not been effective at addressing peak load growth as implemented in many jurisdictions. Including energy efficiency in this framework might encourage the focused use of this resource on reducing peak load. Furthermore, if other DERs receive revenue through this tariff but non-generation DERs do not, the playing field is skewed in favor of generation DERs. Therefore, we recommend thoughtful consideration be given to developing methodologies that can be used to provide appropriate L-T values of non-generation DERs to T&D.

Finally, the Commission has determined that utilities' DRVs and LSRVs will be updated by the utilities on a three-year basis, at which point eligible projects will receive an updated DRV compensation. Projects that receive LSRV compensation will receive the compensation for a period of 10 years before updating to the most recently derived LSRV value (NY PSC 2017a, 116). We suggest the Commission and the Joint Utilities give additional consideration to the period of time between DRV and LSRV updates. An appropriate balance needs to be reached between the acknowledgement of changing circumstances and changing locational values of a region, as well as the long-term certainty that third-party developers require for confidence in their projects. Striking such a balance will need to be handled delicately and with input from all relevant stakeholders.

California

California IOUs are undertaking two major reforms to their distribution planning processes: the first is a series of filings and plans called Distribution Resources Plans (DRPs), and the second is a second series of filings—focused on integrating DERs into the distribution system—called Integrated Distributed Energy Resources (IDER). This section focuses on the DRP proceeding.

The DRP proceeding requires the California IOUs to file separate proposals that "identify optimal locations for the deployment of distributed resources" (CPUC 2015a).[8] The California Public Utilities Commission (CPUC) is to review each of the submitted proposals and modify and approve these plans as needed.

In 2015, the CPUC issued a guidance document for the California IOUs' DRPs (CPUC 2015b).[9] The document outlined three analytical frameworks with which to address the following topics including: (1) integration capacity potential for DERs; (2) quantification of the locational benefits of DERs; and (3) projections of future DER growth. The frameworks are meant to increase the IOUs' abilities to assess, on a locational and temporal basis, the benefits that DERs

[7] However, expanding the VDER Tariff to non-generation DERs requires careful consideration. For example, a tariff-based approach to energy efficiency funding should not be pursued until there has been sufficient demonstration that such an approach will account for all the benefits of EE and will install a socially optimal quantity of EE.

[8] The Code defines DERs as "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies" (CPUC 2015a).

[9] The IOUs are: San Diego Gas & Electric, Pacific Gas & Electric, and Southern California Edison.

can provide to regional demand changes that have traditionally been solved by building new wires and other traditional projects.

The Guidance document required the California IOUs to develop a common methodology to evaluate the capacity needs of their distribution systems and the potential to integrate DERs into their systems. Though the methodology is consistent between the utilities, the parameters will differ slightly due to design standards and operating criteria, according to San Diego Gas & Electric (SDG&E)'s 2015 DRP (SDG&E 2015, 21). This reform requires a significant update and refinement of the methodologies used to value the benefits and determine the integration capacity of DERs on a locational and temporal basis. This section summarizes the updated methodologies used to derive these valuations.

Integrated Capacity Analysis

The integration capacity of a region—in tandem with a locational valuation of DERs to that region—can be used to encourage the development of appropriate levels of DERs. This section focuses on SDG&E as an example of a utility's approach to the frameworks listed above. In its 2015 DRP, SDG&E proposed a process in which it performs an integration capacity analysis (ICA) on each of its distribution system circuits and provides the results on a Geographic Information System map on its website. The utility defines integration capacity as "the amount of DER capacity that can be installed on a distribution circuit without requiring significant distribution upgrades" (SDG&E 2015, 22).

To identify the DER integration capacity, SDG&E first reviewed and forecasted the minimum loading at each distribution circuit. These minimum loads were then used to identify the maximum amount of integration capacity that is possible on that circuit. The maximum integration capacity is defined as the last megawatt (MW) of DER capacity that can be installed before reverse power flow begins; in other words, it is the last MW of DER capacity before electricity flows from the DERs to the substation bus.

Locational Net Benefits Methodology

The Guidance document instructed the California utilities to develop a Locational Net Benefits Methodology (LNBM) that provides detailed information on the locational net benefits of DERs. The methodology is used to develop locational net benefit values of DERs; it is not yet used to develop compensation amounts to be paid to DERs. Each California IOU develops an LNBM by working off the existing E3 Distributed Energy Resources Avoided Cost Tool (DERAC), a model that breaks down the impacts of DERs into seven valuation components including: (1) generation energy; (2) losses; (3) generation capacity; (4) ancillary services; (5) T&D capacity; (6) environment; and (7) avoided renewable portfolio standards (RPS) costs.

The model produces 30-year time horizons with hourly values for these components. The hourly values represent the costs the utility would avoid if demand-side resources (e.g. EE and other DERs) reduced energy during those hours. However, many of the value components in the DERAC model are provided at the system-level. While developing its LNBM, SDG&E modified the value concepts to focus on locational value concepts where possible. Table 3, developed by SDG&E, documents its modified DERAC value components, identifying the locational values included in each value component.

Table 3. SDG&E's LNBM value components

Component	Locational Value
Generation Energy	Generation energy replaced with locational marginal price
Losses	Location-specific loss factors
Generation Capacity	Local Capacity Requirements (LCR) for resource adequacy
Ancillary Services	Percentage of generation energy value
T&D Capacity	Avoided Sub-Transmission, Substation and Feeder Capital and OpEx Avoided Distribution Voltage and Power Quality Capital and OpEx Avoided Distribution Reliability and Resiliency Capital and OpEx Avoided Transmission Capital and Operating Expenditures
Environment	Qualitatively describe the societal avoided costs by using the CalEnviro Screening tool
Avoided RPS	Cost of a marginal renewable resource less the energy market and capacity value associated with that resource

Source: SDG&E 2015, 41.

SDG&E also identified distribution *services* that DER projects may provide to the system. These include: distribution capacity, steady-state voltage, power quality, and reliability and resilience. The locational values in Table 3, combined with these potential distribution services, serve as the foundation for SDG&E's LNBM.

Each of the components identified above are evaluated for proposed DER projects, and together are combined to determine the net value of the DER project. SDG&E notes that there will be locations on its distribution system in which a DER project will have a net negative value, indicating that the project is not cost-effective when compared to a traditional upgrade. The LNBM therefore seeks to identify the locations that represent the most cost-effective sites to interconnect DERs into the system.

Each project is then assigned a stacked value based on the components described above. This provides a granular view of the values provided by DERs in any given region: some regions may, for example, have a particularly high environmental value, whereas other regions may receive the most value from avoided T&D capacity costs.

Notably, these locational values are developed on an hourly basis. Creating these values on both locational and temporal levels over 30-year horizons send very clear value signals about the needs of a region. Resource planners and potential project developers can then identify the most appropriate technology or portfolio of technologies to meet these needs and, consequently, maximize the value contributed to the area from DERs.

Future Plans

On January 9, 2018, the Locational Net Benefit Analysis (LNBA) Working Group released a Long-Term Refinements Report to the CPUC, providing recommendations on further refinements and improvements to the LNBA methodology (LNBA 2018). The report addressed many topics, with six deemed priority topics including: (1) locational avoided energy value; (2) locational avoided capacity value; (3) locational avoided line losses value; (4) incorporation of reactive power priority (VAR profiles); (5) automatic input of DER profiles; and (6) locational avoided transmission value.

These topics were given substantial consideration in the report, with lengthy discussions on ways to further refine these values and how best to address data limitations. The considerations provided in the report are nuanced and developed collaboratively. They provide examples on how to engage stakeholders in the development of locational valuations. For example, the Working Group recommends that the DERAC locational avoided energy value be updated to reflect the default load aggregation point price. The Working Group discusses the collaboration between the IOUs and E3 in the development of two options for this refined valuation, and it then asks the Commission to review and provide a determination on the proposals (LNBA 2018, 6-7).

The report also discusses the need to incorporate the locational values developed in the utilities' LNBMs into tariffs. At this point, the locational values developed by the IOUs are used to identify areas where DERs can provide the highest value to the system. The locational values are not included in tariffs, contracts, or compensation mechanisms. The report notes that workshops will be held to develop the incorporation of utility-modified DERAC models in the development of future tariffs and programs (LNBA 2018, 85). While developing the incorporation of these locational values into compensation mechanisms, we recommend stakeholders consider issues that are being worked through in New York, such as the appropriate number of years to include between updates to locational values and compensation amounts.

Conclusion

As the penetration of DERs continues to grow across the country, utilities, commissions, and other relevant stakeholders will continue to innovate to ensure DERs are being accounted for in planning processes. This paper highlights two states that are leading these efforts—New York, through its REV efforts, and California, through its DRP proceeding. We compared the ongoing efforts in these two jurisdictions, and identified high-level differences. Importantly, the jurisdictions are taking two separate approaches to incorporating DERs into transmission and distribution planning processes. New York is first developing lower-resolution L-T valuation and compensation methodologies for DERs, with the intention of exploring finer resolution in future phases. California, on the other hand, is developing higher-resolution L-T valuations of DERs, with plans to discuss compensation methodologies in the future. There are pros and cons to each of these approaches, and opportunities for the two regions to learn from one another as they continue to develop their valuation and compensation methodologies.

As more states pursue advanced planning processes that value DERs based on time and location, we are seeing differences in methodologies based on, for example, geographic differences, policy goals, and regulatory environments. The differences already emerging are representative of the many factors that must be considered while developing these methodologies. These differences include the value components that are included or excluded in the valuation methodology, the way in which temporal values are integrated with locational valuations, and the types of DERs that are eligible to receive locational compensation, to name a few. We recognize and expect that approaches may need to be structured differently by jurisdiction. However, it is important for states to remain aware of the methodologies being developed in other state proceedings and the issues being identified and addressed. This will allow for general best practices to emerge. And it will help demonstrate and propagate policies that ensure that DERs are being developed in a manner that fully recognizes their many benefits.

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