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PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision	x x x x x	**Case 14-M-0101**

Initial Comments of the Joint Utilities on the October 15, 2015 Staff Proposal: Distributed System Implementation Plan Guidance

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TABLE OF CONTENTS

INTRODUCTION

In response to the Notice Inviting Public Comment on the Staff Proposal: Distributed System Implementation Plan Guidance ("Proposed DSIP Guidance")[1] issued by the New York State Department of Public Service Staff ("Staff") on October 15, 2015 (the "Notice") in the Reforming the Energy Vision Proceeding ("REV"),[2] Consolidated Edison Company of New York, Inc. ("Con Edison"), Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation (collectively the "Joint Utilities") hereby file their Initial Comments.

Following the Executive Summary, these comments address the proposed Initial DSIP filing requirements in Section I, then the Supplemental DSIP requirements in Section II. Section III presents the proposed stakeholder engagement process that will inform the Supplemental DSIP. Advanced metering infrastructure ("AMI") is addressed in Section IV, followed by the Conclusion (Section V). The appendix attached hereto responds to Staff's specific questions on AMI.

EXECUTIVE SUMMARY

The Joint Utilities support the Commission's vision for REV that was articulated in the February 26, 2015 Order Adopting Regulatory Policy Framework and Implementation Plan (the "Track 1 Order")[3] and view the Commission's upcoming decision regarding DSIP guidance as an important element for advancing REV. The Proposed DSIP Guidance establishes a two-step process: five-year DSIP filings by each utility (also referred to as "Initial DSIP filings") and a Supplemental DSIP that the utilities will file jointly thereafter. The utility DSIP filings will present self-assessments that describe current capabilities, *i.e.*, the baseline and initial enhancements to distribution system planning and other capabilities necessary to implement the Distributed System

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1 Case 14-M-0101 – *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, ("REV Proceeding"), Staff Proposal Distributed System Implementation Plan Guidance (October 15, 2015) ("Proposed DSIP Guidance").

2 REV Proceeding, Notice Inviting Public Comment on Distributed System Implementation Plan Guidance (issued October 15, 2015) (the "Notice").

3 REV Proceeding, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015)(the "Track 1 Order").

Platform ("DSP") role and REV policies and goals.[4] The Joint Utilities endorse the Initial DSIP filing objectives and are broadly supportive of the Proposed DSIP Guidance specific requirements. In particular, the Joint Utilities endorse the Proposed DSIP Guidance approach to REV implementation because it is consistent with the evolutionary and incremental nature of REV; this is especially applicable in prioritizing topics to be addressed in the Supplemental DSIP filing. The incremental nature of REV is demonstrated by the fact that many policy decisions are inter-related to the DSIP. For example, the DSIP filings are dependent on Commission resolution of issues in a number of REV-related proceedings and processes, yet the DSIP filings will potentially be filed before these other issues are decided.

Such an evolutionary approach was described in conceptual terms within a recent report published by the Lawrence Berkeley National Laboratory.[5] The chart within that report[6] illustrates how the distribution system could evolve over time under a REV vision. As Distributed Energy Resources ("DER") adoption increases, the distributed platform will develop, utility planning activities will be adjusted to better reflect DER potential, and more granular locational information will become available to market participants. As shown in the chart below, the last stage involves the development of an active market for DER products and services involving a wide variety of market participants.

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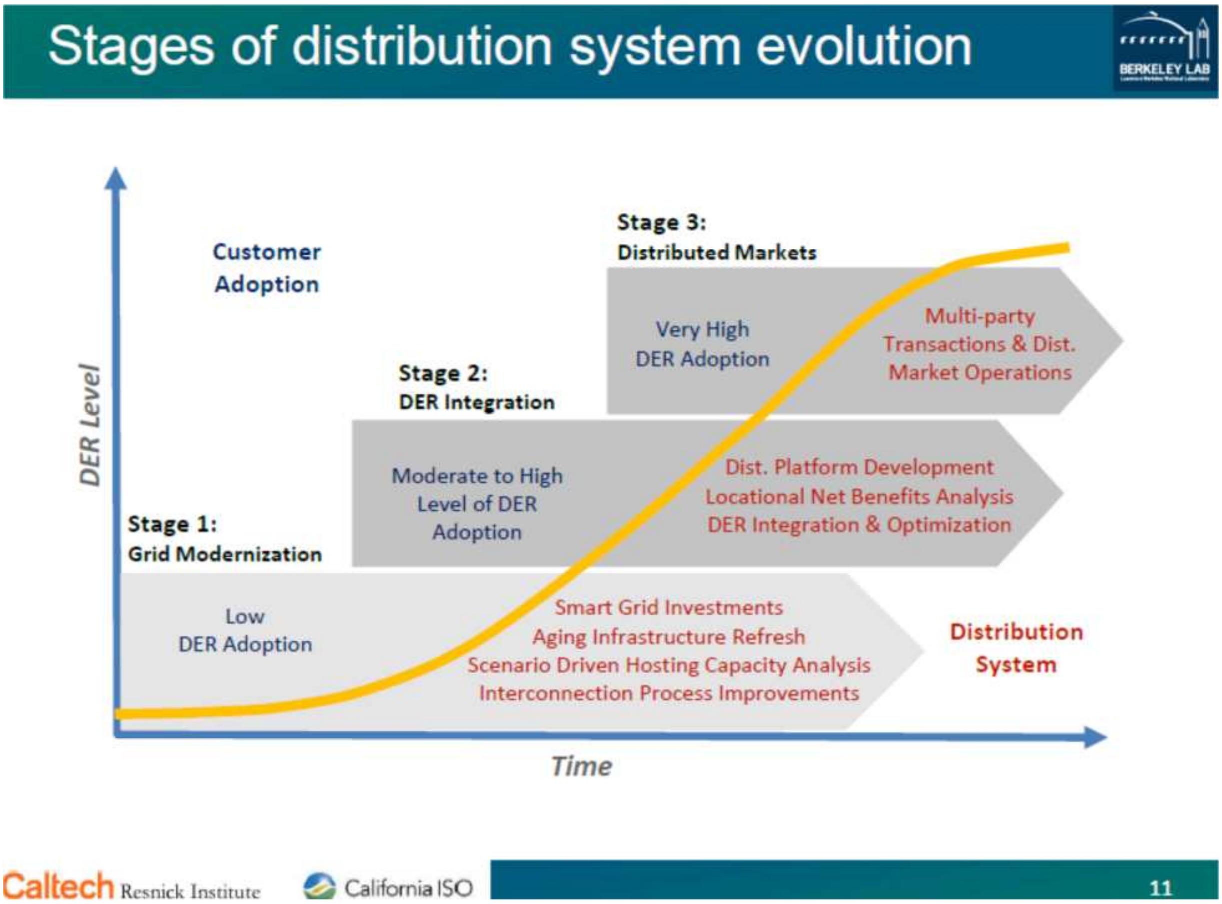
4 Proposed DSIP Guidance, p. 4.

5 Paul De Martini and Lorenzo Kristov, *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight*; Lawrence Berkeley National Laboratory (November 2015), at https://emp.lbl.gov/sites/all/files/lbnl-1003797_presentation.pdf

6 *Id.*, at 11.

Table 1: Evolution of Distribution System.



This approach stages development and implementation efforts in order to focus stakeholder resources where they can provide the greatest value at each stage of the process and deliberately defer more advanced concepts and capabilities until lessons are learned and the markets begin to develop. In fact, the Proposed DSIP Guidance expressly recognizes that certain basic information required to begin to assess the potential for DER penetration may not be available at this time.[7]

Consistent with this approach, the Supplemental DSIP filing will report progress made in prioritizing and developing tools, processes, and protocols that incorporate standardized designs and/or reflect coordination among stakeholders. The Joint Utilities will lead a stakeholder

7 Proposed DSIP Guidance, p. 12.

engagement and leverage these tools, processes, and protocols to further develop New York's electricity market while assuring that customers continue to receive safe and reliable service at reasonable rates. With respect to the Supplemental DSIP, the Joint Utilities agree with: (1) the proposed criteria to assign topics between the Initial DSIP and the Supplemental DSIP; (2) that work efforts should be prioritized; and (3) the engagement of stakeholders to address Supplemental DSIP issues.

The Joint Utilities offer recommendations within these comments to improve the quality of the DSIP filings and highlight the following:

1. Several distribution planning topics, including methodology development related to determining beneficial locations for DER and the development of forecasts of demand and energy growth (including DER forecasts) should be addressed jointly by the utilities as part of the Supplemental DSIP filing. This approach will allow for stakeholder engagement in the development of the methodology as well as identification of opportunities for a consistent statewide approach.
2. Rather than providing raw system data, the Joint Utilities propose to provide DER providers with insightful information, resulting from and in context with utility planning processes, regarding locations of system needs and the ability of the system to host distributed generation.
3. The final DSIP Guidance should expressly acknowledge the primary obligation of utilities to provide reliable service and should further address physical security, compliance with cyber security and privacy requirements for recipients prior to provision of certain customer and system data.
4. The final DSIP Guidance should defer decisions regarding the development of a comprehensive digital marketplace until more information and experience is gained from REV demonstration projects.
5. The final DSIP Guidance should affirm that utilities may propose new criteria for individual demonstration projects, rather than trying to fit every project into the prescribed set of criteria articulated in the Memorandum and Resolution on Demonstration Projects.[8]
6. The screening process for Non-Wires Alternatives ("NWAs") should be defined prior to the DSIP filings through adoption of the proposal set forth in the Initial Comments of the Joint Utilities to Staff White Paper on Benefit-Cost Analysis.[9]

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8 REV Proceeding, Memorandum and Resolution on Demonstration Projects (issued December 12, 2014).

9 REV Proceeding, Initial Comments of the Joint Utilities to Staff White Paper on Benefit-Cost Analysis, pp. 17-18.

7. Data collection and analysis at the grid edge will be critical for the DSP (either though AMI or other distribution system sensors). These capabilities will evolve over time and will vary within each utility's service territory based on the cost of implementation and the benefits associated with each service territory's unique characteristics.

RESPONSE TO THE STAFF PROPOSAL

I. <u>INITIAL DSIP FILINGS</u>

The Initial DSIP filings will present self-assessments and near-term capability enhancements to promote transparent and cost-effective planning processes that enable the utilities to operate as the DSP and advance REV policy goals. The Proposed DSIP Guidance specifies the objectives of the Initial DSIP filings:

- Present a baseline of current system capabilities and available data;
- Present the template for each utility's transparent and integrated approach to planning, investment, and operations;
- Identify prioritized near-term actions and changes that will promote DER penetration and REV goals;
- Propose capital and operating expenditures that will be necessary to build and maintain DSP functions;
- Provide planning, customer, and system information that is available as of the filing date; this information will encourage market participants to identify and respond to opportunities to develop cost-effective DER solutions that deliver value to customers while also contributing to a more efficient distribution system; and
- Describe the alignment between the DSIP and eventual Earnings Impact Mechanisms ("EIMs") and their metrics.[10]

The Initial DSIP filing will document each utility's plans over a five-year period, with formal updates filed every two years.

Where relevant, these comments identify the dependencies between the Initial DSIP filings and the Supplemental DSIP filing to support a recommended prioritization of issues to be addressed in the Supplemental DSIP. The comments also identify relationships between the DSIPs and other

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[10] Proposed DSIP Guidance, p. 2.

REV initiatives, particularly where DSIP issues have already been identified and/or addressed elsewhere in REV or REV-related proceedings and are awaiting Commission decision.[11]

A. REV DEMONSTRATION PROJECTS

The Proposed DSIP Guidance directs utilities to report on current and near-term demonstration projects in their Initial DSIP filings.[12] REV demonstration projects, along with REV experience, will inform subsequent utility implementation activities:[13]

> The REV Demonstration projects will inform decisions regarding Distributed System Platform (DSP) functionalities, measuring customer response to programs and prices associated with REV markets, and determining the most effective deployment and integration of DER. Data collected from REV Demonstration projects will also assist the process of integrating DER resources into system planning, development, and operations on a system and state-wide scale.[14]

REV demonstration projects offer an opportunity to test the market, explore new business models, and learn from real-world experiences to inform future designs and adaptations as utilities move forward. Demonstration projects also provide a range of benefits, including technology validation, testing of DSP functionalities, and modeling and testing of DER capabilities for longer term reliability and value contributions.

The Joint Utilities suggest two specific proposals to enhance the development of new demonstration projects. First, the process for approval of demonstration projects should be streamlined and the Joint Utilities' cost recovery proposals outlined in the Initial Comments of the Joint Utilities on the July 28, 2015 Staff White Paper on Ratemaking and Utility Business Models ("Joint Utilities Initial Track 2 Comments") should be adopted.[15] Second, the final DSIP Guidance should explicitly affirm that utilities can propose criteria that correspond to the unique value

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11 In these circumstances, an effort is made to avoid restating positions that have already been expressed.

12 Proposed DSIP Guidance, p. 8.

13 Staff made similar statements in recent Staff assessment reports filed with the Commission upon review of specific utility REV demonstration projects that had been filed by the utilities on July 1, 2015. *See*, *e.g.*, Reforming the Energy Vision Demonstration Project Assessment Report, Orange & Rockland: DER Residential Offering (November 10, 2015), p. 1, one of four assessment reports filed by Staff on November 10, 2015.

14 Proposed DSIP Guidance, p. 8.

15 REV Proceeding, Initial Comments of the Joint Utilities on the July 28, 2015 Staff White Paper on Ratemaking and Utility Business Models (October 26, 2015) ("Joint Utilities Initial Track 2 Comments"), pp. 8, 9, 11 & 29-30.

provided by each REV demonstration project, rather than trying to fit each project into the prescribed set of criteria articulated in the Memorandum and Resolution on Demonstration Projects.[16] The criteria should not create a bias towards any specific type of project. Rather, the utilities should be able to propose diverse projects that advance REV and that would include technology as well as business model and customer engagement projects. Clarity with respect to both issues will improve the effectiveness of REV demonstration project development efforts and benefit utilities, third-party partners, and customers.

B. DISTRIBUTION SYSTEM PLANNING

Staff has identified distribution system planning[17] as a primary function of the utility as the DSP and a principal focus of the Initial DSIP filings and the Supplemental DSIP filing. Several enhancements to the existing planning function are required to accommodate a significant penetration of DER and optimize the efficiency of the system while maintaining the fundamental objectives of system planning to ensure safety, reliability, resiliency, and security of service.

Several new processes need to be developed and consistently applied to incorporate the integration of DER into the planning process, including:

- More granular forecasts of load (peak demand and hourly energy) and DER (on coincident basis with the load forecasts);
- Methodologies to identify beneficial locations for DER deployment;
- Modeling of DER in system load flows and other planning tools;
- Transition from a deterministic planning approach to a probabilistic approach; and
- The methodology for incorporating energy storage in the planning process.

In order for these processes to be developed considering best practices and to be implemented consistently across the state, the Joint Utilities recommend that these be developed as part of the Supplemental DSIP, thus moving the efforts on forecasting and processes for identifying beneficial

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16 *Supra* note 10.

17 The Proposed DSIP Guidance refers at various points to "Distribution System Planning" and "Integrated System Planning." The Joint Utilities assume that these terms are interchangeable.

DER locations from the Initial DSIP filing to the Supplemental DSIP filing. All of the topics above are appropriate for the Supplemental DSIP because they require a consistent approach among utilities and coordination between utilities and the third parties that will provide DER data to enhance forecasts.

The Initial DSIPs request vast amounts of data and the Proposed DSIP Guidance acknowledges that utilities may not currently possess all of the data necessary to support DSP functions.[18] The Initial DSIPs also require each utility to explain how forecasts are currently derived, how DER might impact these methodologies, and how each utility is planning to incorporate new data into the planning process. The Proposed DSIP Guidance reflects the inherent tension between providing as much information as possible as soon as possible to inform DER locational value and the fact that the models and data necessary to support increased DER penetration do not yet exist. As a practical matter, additional performance data from existing and new DER is necessary to support REV markets in a safe, reliable, and efficient fashion. To meet the intent of the Proposed DSIP Guidance, utilities will identify what information is available today, identify gaps and potential security concerns, and identify the near-term initiatives to begin closing these gaps as part of the utilities' transition to serve as the DSP. To the extent possible, the Initial DSIP filings will provide:

- Peak demand and load shape forecasts for the next five years at the substation level, reflecting offsets for DER;
- The specific expected contribution to peak load, energy reduction, and load shaping for various types of DER over the next five years; and
- Certain "beneficial location" data for specific areas in the utility footprint where DER may provide reliability or operational benefits and thus have more value. The Joint Utilities note that this data requires a final resolution of the benefit-cost analysis ("BCA") framework by the Commission.

In summary, the Initial DSIP filings will provide assessments of existing processes and data availability, as well as near-term plans for individual utility enhancements and their alignment with on-going efforts in support of the development of the Supplemental DSIP. The Supplemental

[18] The Joint Utilities believe that the Commission will establish new reporting requirements for REV. After these reporting requirements are established, Staff and the utilities should perform a comprehensive review of all reporting requirements that call for similar data but in different formats and on different schedules in an effort to streamline the requirements and avoid burdensome efforts by all stakeholders to reconcile slightly different reports.

DSIP will focus on the system planning elements that require a consistent approach among utilities and coordination with third parties for the development of new tools and processes.

While the Proposed DSIP Guidance does not refer specifically to NWAs, it does ask the utilities to identify potential DER opportunities in their Initial DSIP filings.

> A key focus of the REV initiative and the MDPT [Market Design and Platform Technology] report is to defer or eliminate the need for traditional infrastructure investments. To that end, each DSIP will identify locations based on proposed capital plans where DER has the potential to resolve or mitigate forecasted system requirements that would otherwise necessitate traditional infrastructure investments – for system expansion/upgrade and/or maintenance. The locations identified should be as granular as possible to inform and encourage third party participation.[19]

The Track 1 Order directed the utilities to "identify one or more potential [NWA] projects by May 1, 2015"[20] in advance of the filing of Initial DSIPs. The Proposed DSIP Guidance also encourages the utilities to expand NWA opportunities. The initial NWA projects are similar to REV demonstration projects as they provide opportunities for learning. This is important because the ability of DER to defer utility investments is likely to vary among utilities, within service territories,, and by transmission and distribution ("T&D") investment and DER resource types.

The final DSIP Guidance can support the efficient pursuit of NWAs by adopting the four-part screening process proposed by the Joint Utilities in their Initial Comments to the Staff White Paper on Benefit-Cost Analysis.[21] This screening process would provide clarity to developers as well as utilities by identifying the specific traditional T&D investments that have the potential to be deferred or replaced by NWAs. At the same time, the experience and information provided by the initial NWAs will help inform the application of the BCA to future NWA opportunities.

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19 Proposed DSIP Guidance, p. 10. The "MDPT report" refers to the Market Design and Platform Technology Final Report, dated August 17, 2015.

20 REV Proceeding, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015), p. 131.

21 REV Proceeding, Initial Comments of the Joint Utilities to Staff White Paper on Benefit-Cost Analysis (August 21, 2015), pp. 17-18.

C. Interconnection Process

Further streamlining interconnection processes for both small (≤50 kW) and larger distributed generation ("DG") projects (>50 kW) is a priority for the Commission, as reflected in ongoing efforts to amend the New York State Standardized Interconnection Requirements ("SIR")[22] and the proposal for EIMs in the July 28, 2015 Staff White Paper on Ratemaking and Utility Business Models (the "Staff Ratemaking White Paper").[23] It is expected that the Commission's adoption of changes to the interconnection process will occur before the filing of the Initial DSIPs.[24] The priority of improving the DG interconnection process was repeated in the Proposed DSIP Guidance: "Streamlining DER interconnection practices and expanding distribution automation is also expected to occur during the first two years, as identified in the Track I Order and the MDPT Report."[25]

The Proposed DSIP Guidance states that the interconnection process can be improved through the implementation of an online portal[26] and that the automated interconnection process to be addressed in the Supplemental DSIP process is to be implemented consistently across the State.[27]

The Joint Utilities support further improvements of the DG interconnection process. This would include automation of the steps in the process where automation makes sense, including the application process.[28] The most important enhancements include: (1) continued efforts to reduce interconnection study requirements by improving the screening process; (2) clarifying the SIR process through the ongoing review and comment on the proposed SIR modifications; (3) identifying, sharing, and incorporating industry best practices among New York utilities; (4) striving to improve the quality of cost and timeliness of estimates for Coordinated Electric System Interconnection Reviews ("CESIRs"); and (5) improving cost estimates for construction of system

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22 Case 15-E-0557 – *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Small Distributed Generators*, Notice Soliciting Comments on Proposed Modifications to the Standardized Interconnection Requirements (issued November 9, 2015).

23 REV Proceeding, Staff White Paper on Ratemaking and Utility Business Models (July 28, 2015) (the "Staff Ratemaking White Paper"), pp. 58-59 & 61.

24 Comments on the proposed modifications to the SIR are due on January 11, 2016.

25 Proposed DSIP Guidance, p. 16.

26 *Id.*, p. 17.

27 *Id.*, p. 29.

28 Several of the utilities have already automated certain steps in the interconnection process and will report on these improvements in their respective Initial DSIP filings. Each utility is at a different point in the development of its online application system but all utilities are striving to improve efficiencies throughout the interconnection process.

upgrades. The Joint Utilities are committed to these enhancements and would welcome the opportunity to continue to work with Staff and industry stakeholders in a collaborative manner either prior to or during the Supplemental DSIP stakeholder engagement process. A collaborative process provides an opportunity to engage stakeholders regarding the interconnection process and unique distribution system characteristics. Such a collaborative process also creates a forum for developers to comment on solutions that incorporate automation without sacrificing the benefits of extensive utility knowledge and expertise that currently adds value to the DG interconnection process.

The September 2015 report prepared by the Electric Power Research Institute ("EPRI") ("EPRI Interconnection Report") for the New York State Energy Research and Development Authority ("NYSERDA") describes the challenges posed by the automation of the interconnection process.[29] This report presented a pathway to achieving the interconnection goals expressed in the Track 1 Order.[30] The EPRI Interconnection Report provided a "gap analysis" that assessed utility readiness, including the ability to process interconnection applications and to implement the automated online portal. This report also identified several challenges that impede end-to-end automation including: (1) incomplete feeder and substation load data to perform technical reviews and feasibility assessments and/or inaccessible data that is dispersed among various systems and databases; (2) a lack of well-defined and integrated methodologies and tools; and (3) challenges of integrating automated processes with other utility business processes. The Joint Utilities propose that the final DSIP Guidance be modified to reflect a more precise definition of "automation" that acknowledges that automation may be appropriate for certain steps in the process. The effort to determine which steps in the process can be automated need not delay efforts to streamline the interconnection process.

D. CUSTOMER DATA AND CUSTOMER ENGAGEMENT

The Track 1 Order[31] and Proposed DSIP Guidance[32] observe that the success of REV depends on the ability and willingness of customers to engage in utility DER programs directly with

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29 Tom Key, Lindsey Rogers, Nadav Enbar & David Freestate, *Interconnection of Distributed Generation in New York State: A Utility Readiness Assessment, Final Report*, Electric Power Research Institute (September 2015).

30 REV Proceeding, Track 1 Order, pp. 91-94.

31 *Id.*, pp. 58-61.

third-party providers. The Proposed DSIP Guidance requests that utilities explain how customers and third parties (with customer authorization) will obtain information regarding customer energy usage and other customer-specific information.[33] The Track 1 Order and Proposed DSIP Guidance also cite the role of a digital marketplace in connecting customers with third parties.

The Proposed DSIP Guidance provides an opportunity for utilities to describe their overall approach to customer engagement including the data-related aspects.[34] In addition, customer engagement efforts will be informed initially by REV demonstration projects, as well as by REV experience. Demonstration projects will test new business models, customer engagement strategies, and technologies. Several of the Joint Utilities are testing online marketplace concepts through their initial REV demonstration projects. The final DSIP Guidance with regard to customer data should be informed through the technical conferences being conducted in December and January. In addition any decision regarding a full-scale digital marketplace should be informed by experience and lessons learned from the multiple demonstration projects addressing this topic.

Finally, the Proposed DSIP Guidance invites comments on two customer data questions. The questions and Joint Utilities responses are as follows:

1) **Question**: What should the Commission direct, beyond current requirements, in order to improve customer and authorized third-party access to the most granular data in as near real-time as possible?

   Joint Utilities Response: The Proposed DSIP Guidance identifies potential data that could be provided to customers and third parties; some of this data is not currently measured and thus not available for provision at this time.[35] Access to customer data, whether by customers or third parties, is determined by multiple factors, including but not limited to the meter infrastructure, customer service systems, and website capabilities unique to each utility. The prospect of changes to the current state of data access necessitates careful consideration of the needs of each utility's service territory and the potential value for customers. Given the implementation and operating costs associated with measuring, storing, managing, and communicating data to customers and third parties (including the need to preserve the security and privacy of the data), the Joint Utilities support the recent Commission's notice to bring stakeholders together to discuss these issues in the first of

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32 Proposed DSIP Guidance, p. 21.
33 *Id.*, pp. 19-20.
34 *Id.*, p. 20.
35 *Id.*

several technical conferences on December 16, 2015.[36] The Joint Utilities also support continued dialogue with stakeholders on these issues as part of the Supplemental DSIP process.

2) **Question**: Specifically, what should the Commission direct in order to enhance Electronic Data Interchange (EDI) to facilitate customer and third-party access to standardized, machine-readable consumption data with industry leading protocols and practices?

   Joint Utilities Response: The utilities currently provide data access to customers and energy service companies ("ESCOs") to support competitive supply service. This access is provided through a secure connection on the utility's web site (*i.e.,* with login and password protection). ESCOs also receive usage and customer data (excluding hourly load data) through the Electronic Data Interchange ("EDI"). The technical conference approach described above in response to the first question will facilitate discussion of the role and functionality of EDI as it relates to the broader questions regarding data access needs under REV.

E. System Data

The Proposed DSIP Guidance states that system data "must be made available by the DSP at a degree of granularity and in a manner that is timely, as required by the market."[37] The Proposed DSIP Guidance is prescriptive with regard to the system data that Staff believes should be made available, including five years of historical and forecasted hourly system load curves, voltage, power quality, and reliability. The Proposed DSIP Guidance also requests individual feeder system data (load data, voltage, power quality, reliability, *etc.*) "within areas that DERs are expected to have more value."[38] The utilities are asked to describe the extent to which such data is currently available.[39] If this data is not currently available, the utilities are asked to explain their plans for providing more granular system data.[40]

Distribution system data is not self-explanatory and must be considered in the context of the local system design criteria, normal and contingency configurations, distribution assets ratings, circuit routing, potential security concerns, and local knowledge of operational performance.

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36 REV Proceeding, *et al.*, Notice of Technical Conference Regarding Customer and Aggregated Energy Data Provision and Related Issues (issued November 3, 2015).

37 Proposed DSIP Guidance, p. 17.

38 *Id.*, p. 18.

39 *Id.*

40 *Id.*, p. 19.

Without such insights, the utilization of raw system data would lead to inefficient distribution planning. This is reflected in the multi-step approach that utility distribution system planners take to distribution design:

- Create asset models from electronic mapping data to facilitate load flow analysis and maintain those models for proposed future projects such as new customer connections;
- Create peak demand load models by extrapolating monthly customer usage data and combining that data with Supervisory Control and Data Acquisition ("SCADA") information, if available. These load models place the load in the vicinity of customer use in the asset model; and
- Perform yearly peak design reviews to update existing load models or asset replacements based on new peak load cases and future load growth projections.

It is only through a comprehensive planning process, with system data as one input, that utilities can effectively conduct adequate planning to maintain a reliable and efficient network design. The Joint Utilities propose to provide DER providers with insightful information, as an output from the planning processes, to provide locations of system need and the ability of the system to host distributed generation. Such insightful information will provide significant value to DER providers. This value will become increasing vital as DER penetration grows and the system becomes more complex and dynamic. Distribution system planners can perform analyses in a cost-effective manner, interpret results, and communicate information to facilitate market growth. By providing valuable insights instead of raw data, concerns of data security and sensitivity can be more readily managed.

The process of determining which system information and insights have the greatest value should reflect stakeholder input in order to assess the relevance and value to DER providers in the Supplemental DSIP filing, the cost to the utility of providing various types of information, and the need to provide the information in a secure manner.

F. Incremental Cost Recovery and Performance Metrics

There are extensive ties between the ongoing Track 2 inquiry and the DSIP filings. Initial and Reply Comments were filed on October 26 and November 23, 2015, respectively, in response to the Staff Ratemaking White Paper.[41] It is not clear whether a Track 2 order will be issued by the Commission before final DSIP Guidance is issued, but policy clarity necessary to prepare the Initial DSIP filings depends on both decisions. The most important of these issues are the recovery of incremental costs necessary to develop and perform as the DSP, and the establishment of incentive metrics (and associated targets) that will measure utility performance as the DSP. The Joint Utilities addressed both matters extensively in the Joint Utilities Initial Track 2 Comments and Joint Utilities Reply Track 2 Comments.[42]

II. SUPPLEMENTAL DSIP FILING

The Joint Utilities endorse the two-phase DSIP guidance approach to REV implementation which is consistent with the incremental evolution of REV. With respect to the Supplemental DSIP, the Joint Utilities agree with: (1) the proposed criteria to assign topics between the Initial DSIPs and the Supplemental DSIP; (2) the prioritization of work efforts; and (3) the engagement of stakeholders to address Supplemental DSIP issues. These three items are addressed in Sections IIA, IIB, and IIC, respectively. Other comments on the Supplemental DSIP are provided in Section IID.

A. TOPICS TO BE ADDRESSED IN THE SUPPLEMENTAL DSIP

The Joint Utilities agree that the Supplemental DSIP should address requirements that benefit from consistent utility approaches and/or coordinated approaches among utilities and other parties, including the New York Independent System Operator, Inc. ("NYISO"). This approach should enable more efficient and seamless operations for market participants, resulting in better services at reasonable prices for customers. As expressed in the Proposed DSIP Guidance:

> [T]he utilities should work together to specify the tools, process, and protocols that will best be developed jointly or under shared standards in order to plan and operate a modern grid capable of dynamically managing distribution resources, as well as supporting retail markets that coordinate significant DER investment and efficiently manage resources.[43]

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[41] The Joint Utilities Initial and Reply Comments are referred to herein as the "Joint Utilities Initial Track 2 Comments" and "Joint Utilities Reply Track 2 Comments," respectively.

[42] REV Proceeding, Joint Utilities Initial Track 2 Comments, pp. 8, 9, 11 & 29-30, and Joint Utilities Reply Track 2 Comments, p. 7.

[43] Proposed DSIP Guidance, pp. 4-5.

The Joint Utilities propose minor modifications to the list of topics for the Supplemental DSIP after applying the "consistency" and "coordination" criteria presented in the Proposed DSIP Guidance.[44] As discussed above in Section I, the Joint Utilities propose to move five Distribution System Planning topics from the Initial DSIPs to the Supplemental DSIP:

- Methodology for forecasting DER penetration;
- Forecasting and incorporating into the planning process demand and energy requirements on a more granular level;
- Methodology for incorporating DER forecasts into the demand and energy forecasts and the overall planning process;
- Methodology to identify beneficial locations for DER deployment; and
- Methodology to incorporate energy storage into the planning process.

Each of these topics will benefit from a consistent approach among utilities and facilitate third-party participation in New York markets. The Joint Utilities propose to expand the scope of the data access discussion to accommodate a more holistic discussion of system information and insights that can be shared with third parties. This scope expansion is appropriate in order to engage stakeholders in determining what information has the greatest value to third parties and how to share this information in the most efficient manner. These objectives were described above in Section I. A consistent approach to sharing system data among the utilities will support broad third-party participation in New York markets in an efficient and effective manner by providing quality information that a large number of third parties can use to support their business decisions.

The Supplemental DSIP will result in common tools, processes, and protocols to support the development of an efficient New York market. However, it should be noted that the current capabilities or baseline will vary among utilities, which could require varying deadlines for implementation of the new capabilities. Each utility may also need to customize certain processes to reflect utility-specific starting points and other circumstances (*e.g.,* the need to integrate new functions into existing processes and software systems).

Finally, the Joint Utilities propose that two issues assigned to the Supplemental DSIP be addressed entirely within the utility-specific Initial DSIP filings: (1) Monitoring Capabilities for Data

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[44] *Id.*, pp. 29-30.

Collection; and (2) Plan and Budget for Communications and Information Technology ("IT") Infrastructure. Each of these two topics depends on utility-specific plans and infrastructure decisions that will be included in the Initial DSIP filings.

B. Prioritization of Supplemental DSIP Topics

The DSIP Guidance invites prioritization of the topics to be addressed in the Supplemental DSIP:

> When parties file comments regarding the material contained within the DSIPs, Staff requests that parties also explain how best to define and structure the stakeholder process to ensure open and effective communications. Comments should also prioritize subjects and issues to be addressed, and explain how the stakeholder process will continue as the utilities develop into fully functional DSPs and as technology and markets continue to evolve.[45]

The prioritization of Supplemental DSIP topics is necessary to resolve as many of the "highest value/reasonable effort" issues as possible by the recommended September 1, 2016 filing date,[46] while also presenting a plan to address issues that will require more time to resolve. Some of these issues are particularly complex and will simply take time to address (*e.g.*, probabilistic modeling approaches to system planning). Other issues will benefit from lessons learned from REV demonstration projects and/or may depend on unresolved REV policy decisions. These varying circumstances are consistent with the evolutionary and gradual approach to both REV in general as well as the development of DSP functionality. From a practical perspective, prioritization can help avoid the consequences of setting an overly aggressive agenda.

To advance the discussion, the Joint Utilities propose assignment of each of the Supplemental DSIP topics to one of three categories. Category 1 consists of near-term activities to be resolved in the Supplemental DSIP because they: (1) can be resolved in a time frame such that implementation plans can be presented in the Supplemental DSIP filing and significant implementation progress made within the first two years; and (2) provide either value to customers and advance REV goals at a reasonable cost, or develop capabilities that must be addressed early in

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45 *Id.*, p. 6.

46 The Joint Utilities note that the recommended September 1, 2016 Supplemental DSIP filing date itself, while achievable through prioritization of the issues, remains aggressive.

REV because subsequent developments that deliver value depend on these initial actions.

Category 2 consists of design, development, and/or implementation activities that, due to the evolutionary nature of the REV implementation process, will require more time and stakeholder engagement to design, test, and refine. For example, implementation of a new integrated distribution system planning process that applies a probabilistic methodology cannot be achieved within the initial two years, although meaningful progress can certainly be made on the methodology and thereafter described in the Supplemental DSIP filing. Similarly, enhancements necessary to produce valid demand and DER forecasts are likely to evolve over several years. For items in this category, progress should be made and presented in the Supplemental DSIP filing along with a plan that addresses future efforts.

Category 3 reflects the implementation activities that cannot be addressed in the Supplemental DSIP because they require development of enabling systems and new business processes, testing of these systems and processes through demonstration projects, and actual REV experience. The advanced distribution market functions fall under this category.

The Joint Utilities propose that further refinement of the priorities and scope of each topic area be addressed as the first step of the stakeholder engagement process.

Joint Utilities Straw Proposal: Prioritization of Supplemental DSIP Topics

Topic	Category 1	Category 2	Category 3
System Planning			
Demand Forecasting		●	
DER Forecasting		●	
Storage Methodology		●	
Probabilistic Planning Methodology		●	
Hosting Capacity Methodology	●		
Load Flow Analysis Process		●	
Improved Interconnection Process	●		
Grid Operations			
AMI Rollout Policy	●		
Cyber Security		●	
Granular Pricing			●
NYISO Topics			
Roles and Responsibilities			●
Coordinated DER Dispatch and Tools – Demand Response		●	
Coordinated DER Dispatch and Tools - Other			●
Coordination at T&D interfaces			●
Data Access			
Customer Data	●		
System Data	●		
Market Participant Rules		●	
Settlement Procedures			●
DER Procurement Approaches	●		
Joint System Planning and System Operations		●	

C. Proposed Stakeholder Engagement Process

Full and active engagement with stakeholders is an essential and critical element of the Supplemental DSIP filing. The Joint Utilities believe that efficient and effective stakeholder engagement will result in better solutions.

The Joint Utilities propose to retain the services of a respected energy consulting firm experienced in designing and conducting stakeholder engagement processes to lead the Supplemental DSIP stakeholder engagement effort. The consulting firm will have prior experience that demonstrates its ability to exercise the independence that is necessary for this type of engagement. The stakeholder engagement process will be designed to accomplish as much as possible within the allotted timeframe, while respecting the time and resource constraints of all stakeholders. As noted above, the Joint Utilities recommend a prioritization of the issues to be addressed in the Supplemental DSIP. By implication this prioritization applies to the stakeholder engagement process as well. Although retained and compensated by the Joint Utilities, the consultant will be responsive to all stakeholders and be directed to demonstrate independence in facilitating the engagement. This approach is consistent with the Proposed DSIP Guidance:

> When parties file comments regarding the material contained within the DSIPs, Staff requests that parties also explain how best to define and structure the stakeholder process to ensure open and effective communications. Comments should also prioritize subjects and issues to be addressed, and explain how the stakeholder process will continue as the utilities develop into fully functional DSPs and as technology and markets continue to evolve.[47]

The Joint Utilities anticipate that the consultant will work with the Joint Utilities and Staff to identify potential stakeholder engagement working group members from among the active REV participants, in an effort to secure representation from every significant interest inclusive of various customer segments, third-party vendors, and government entities.

The Joint Utilities anticipate that substantive technical conferences will be necessary at the outset in order to: (1) allow for knowledge sharing on the certain technical subjects; (2) include and engage all REV stakeholders; and (3) further refine the priorities and scope of each topic to be addressed. Technical conferences could accommodate remote participation if appropriate.

Ideally, the stakeholder engagement process will be announced shortly after the final DSIP Guidance is issued, in order to maximize the time for the participants to work together. An overall stakeholder meeting plan and schedule will be established at the outset, including the formation of a smaller core working group. The meeting schedule is likely to require in-person meetings that occur approximately once each month. The consultant will distribute preparatory materials provided in advance for stakeholder education and to frame key issues to ensure that stakeholder time is respected and leveraged as much as possible.

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47 Proposed DSIP Guidance, p. 6.

D. Other Supplemental DSIP Comments

This section expands upon certain of the Supplemental DSIP topics to explain why they have been prioritized in the Joint Utilities' Proposal herein or to offer feedback to be considered in the final DSIP Guidance. The Joint Utilities recognize that they may also have the opportunity to offer these comments in the stakeholder engagement process and have limited the comments to topics that might be useful as the Commission finalizes its DSIP Guidance.

1. Distribution System Planning

The Supplemental DSIP will address several significant enhancements to the distribution system planning process that are necessary to explicitly consider DER as a solution to meet network objectives and accommodate a higher penetration of DERs. The Proposed DSIP Guidance identifies five distribution system planning topics to be addressed in the Supplemental DSIP and the Joint Utilities have proposed adding five additional distribution planning topics that also require a consistent approach among the utilities.

The Joint Utilities have categorized most of the distribution planning topics as Category 2, indicating that progress can be made and reported in the Supplemental DSIP filing, but they are likely to require additional development efforts after that filing due primarily to the complexity and extraordinary nature of the issues and the fact that there is limited experience in other jurisdictions to draw from.

The Proposed DSIP Guidance describes the distribution system planning challenge to be addressed by the Supplemental DSIP, as well as the desired outcome, stating:

> Distribution system planning must become more dynamic, and the methods applied must adapt to and account for the changing environment. New approaches to planning, including risk-management techniques, that predict rather than prescribe, and envision flexible rather than static distribution systems, can best reduce the need for redundancy while increasing system reliability and affordability.[48]

It remains unclear whether incorporating DER into the planning process will require more or less system redundancy. Further experience is required before that determination can be made.

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[48] *Id.*, p. 9.

Because system redundancy comes at a price, this is an important factor and an underlying assumption that will need to be tested.

The Joint Utilities agree with the Proposed DSIP Guidance that it will be necessary to prioritize hosting capacity efforts. The Joint Utilities propose that the Supplemental DSIP hosting capacity analysis focus on distribution feeder backbone facilities on radial systems. Standard hosting capacity analysis does not identify issues that may arise on the distribution secondary, distribution transformer, and fused lateral level. In addition, because hosting capacity focuses on distribution facilities downstream of the substation, hosting capacity analysis will not consider constraints that develop upstream at the distribution substation bus, transformer, and transmission level that may result from multiple high-penetration circuits. These qualifications will require a modification to the definition of hosting capacity in the Proposed DSIP Guidance:

> "Hosting capacity is the level of DER penetration *on a given distribution circuit* that could be integrated without additional upgrades or expansions." (emphasis added) (quoting MDPT Report)[49]

Perhaps more significantly, while estimating hosting capacity on a radial network may be relatively straightforward, the degree of complexity increases exponentially for looped and network designs. These capabilities do not exist and need to be developed.

In order to assure a consistent approach, the Joint Utilities propose that the demand and energy demand forecasting methodology, including the impact of increased DER penetration, be addressed in the Supplemental DSIP filing. One of the issues raised in the Proposed DSIP Guidance is the requirement to prepare load shape forecasts. As part of the refinement and prioritization of issues to be addressed in the Supplemental DSIP, the Joint Utilities will assess the application of load shape forecasts for distribution planning purposes with a particular emphasis on demand forecasting and hosting capacity.

2. Data Access

These discussions will focus on identifying the information that has the greatest value, relative to the cost of data gathering, performing appropriate analyses, and communicating the

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[49] *Id.*, p. 5, n.8.

results. The Joint Utilities are confident that stakeholder engagement on system data issues, in particular, will lead to a better outcome. It is possible that the results of REV demonstration projects can add to the quality of these decisions and the efficiency of the outcome.[50] The Joint Utilities have proposed that customer data and system data be designated as Category 1 topics, to be addressed in the Supplemental DSIP.

3. Coordination with the NYISO

The Proposed DSIP Guidance recognizes that the utilities will need to coordinate with the NYISO in order to provide price signals to DERs to locate where they provide maximum value, with consideration given to benefits to both the distribution system and the wholesale market. Ultimately, the distribution and wholesale market designs should be coordinated and complementary.[51] The Joint Utilities propose to prioritize the coordination of demand response procurement between the distribution utility and the NYISO as a Category 2 topic, while deferring the topic of how to integrate newly developed distribution DER markets with NYISO markets until after the Supplemental DSIP (*i.e.*, Category 3).

4. Cyber Security and Privacy Concerns

The Proposed DSIP Guidance requires utilities to specify plans to maintain physical security, cyber security and privacy with respect to the sharing of customer and system data. The plans must also address cyber security within grid operations because cyber security must also be maintained for any communication of data within the utility (*e.g.*, to enable network condition monitoring) and between the utility and third-party facilities (*e.g.*, customer-sited DER).[52] Cyber security is receiving considerable attention by utilities throughout the country, due to the importance of electric infrastructure to national security. It is a critical issue, irrespective of the level of DER penetration, but certainly takes on increased importance in a high-DER penetration environment because an

50 *E.g.*, the recently proposed Advanced Grid Innovation Laboratory for Energy ("AGILe"), with initial funding through the New York Power Authority ("NYPA"), might be a forum for evaluating distribution grid advancements through the integration of DER products. Research agencies and business partners can effectively collaborate with utility subject matter experts to review DER integration possibilities.

51 There may also be a need for consistency between market participant requirements (including uniform business practices in New York) to operate in wholesale markets and to provide distribution services to customers and the DSP. Market participant rules are being addressed in Case 15-M-0180. Utility codes of conduct are being addressed in Case 15-M-0501.

52 Proposed DSIP Guidance, pp. 17 & 21-22.

increase in the amount of data being communicated results in the need to manage endpoints, complexity, and opportunities with value to malicious actors. Increasing risks must be met with planned and cutting edge methods and actions.

The Joint Utilities have begun a coordinated response to these challenges in order to develop a common cyber security and privacy framework that reflects current best practices and is sufficiently robust to accommodate anticipated REV requirements and accommodate changes to these requirements. The framework will likely incorporate services, vendor, and third-party assessment requirements, and the determination of acceptable risk, risk tolerance, and risk acceptance criteria based on the outcome of these assessments. This approach will require a substantial effort and is on the "critical path" as Commission programs and demonstration projects are already expanding the communication of customer and system data between utilities and third parties. Nonetheless, the Commission and other stakeholders should be aware it is possible, if not likely, that it will take time for the utilities to define the new and evolving standards and for third parties to achieve compliance with such standards. As a consequence, the final DSIP Guidance should address compliance with cyber security and privacy requirements for recipients prior to communication of certain customer and system data.

Finally, while the utilities are already working together on these issues, and will engage stakeholders on these topics, it is likely that this engagement will focus on desired outcomes and their achievability at reasonable cost, rather than the technical details of how cyber security and privacy concerns will be addressed.

III. AMI

The Joint Utilities have reviewed the AMI questions in the Proposed DSIP Guidance, provide responses to the questions in the attached Appendix, and offer the following observations:

- Data collection and analysis at the grid edge will be critical for DSP through AMI or distribution system sensors. These capabilities will evolve over time and will necessarily vary within each utility service territory based on the cost of implementation and the benefits associated with each service territory's characteristics.

- Data collection and analysis may include customer load information, outages, end-point voltage, and DER contribution. This will support system operations and market animation by enabling access to rich new data.
- AMI is one proven means of collecting grid edge data, including interval usage.
- Grid edge monitoring will support REV efforts and the deployment should be based on a positive business case.
- Deployment of AMI would support many REV objectives. In addition, AMI provides operational efficiencies that bolster the business case for wider-scale deployment and may result in more universal customer access to the benefits and capabilities envisioned in REV.
- AMI has known technical capabilities that can support grid modernization on both the customer and grid side of the meter. Smart meters have been widely deployed in the United States with proven capabilities. Extensive lessons learned on AMI should be leveraged to ensure that AMI is deployed and fully optimized to the benefit of customers and the grid.
- While the business case for various implementations will vary widely across geographical areas, what is expected is a significant increase in the availability of interval data depicting customer power use. Innovation will follow as the industry seeks to find new and improved ways of using this available data.

IV. CONCLUSION

The Joint Utilities endorse the Initial DSIP filing objectives, are broadly supportive of the specific requirements of the Proposed DSIP Guidance, and offer a number of suggestions to improve the REV implementation process. In particular, the Joint Utilities endorse the Proposed DSIP Guidance approach to REV implementation because it is consistent with the evolutionary and incremental nature of REV, including the benefit of prioritizing topics to be addressed in the Supplemental DSIP filing.

The Joint Utilities appreciate the opportunity to provide these Initial Comments on the Proposed DSIP Guidance and look forward to continuing collaboration with Staff, the Commission, and stakeholders in this proceeding.

Date: December 7, 2015
Albany, New York

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APPENDIX

ADVANCED METERING INFRASTRUCTURE QUESTIONS

The Proposed DSIP Guidance requested responses to 24 questions related to Advanced Metering Infrastructure ("AMI" or "Advanced Metering").[53] The Joint Utilities have responded to the questions that were appropriate for a joint response.

It is important to note that the following responses contain a comprehensive discussion of the benefits of AMI; however, the customer bill impact associated with AMI implementation and the value derived from deployment will vary based on the attributes specific to each utility's service territory including size, population density, customer demographics, and geography. For this reason the Joint Utilities recommend that a positive business case should accompany any plan for wide-scale deployment of AMI within a utility's service territory.

1. List major component technologies required for a successful deployment of a system with advanced metering functionality. What are they, what functions and benefits does each component provide, and where would they physically reside?

AMI is a metering system(s) where meters record consumption of electric energy in intervals of an hour or less, provides near real-time monitoring of power consumption, voltage, outages, and meter alarms.

Advanced metering networks have many different designs. AMI consists of the communications hardware and software, and the associated system and data management software, that together create a two-way communications network between the customer premise and utility business systems, enabling collection and distribution of information to customers and other parties, such as the competitive retail supplier or the utility itself. A common communications network can be leveraged to support both AMI and system operations applications.

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[53] Proposed DSIP Guidance, pp. 24-27.

Advanced metering infrastructure facilitates several beneficial applications which can lead to improvements in operational efficiency, reliability, outage response and restoration, and asset utilization as well as reduced losses from theft, remote connect and disconnect functions, consumption on inactive meters, improved safety[54] and customer service. AMI differs from traditional automatic meter reading ("AMR") in that it enables two-way communications with the meter, more granular information and more frequent and real-time communications. The following table illustrates the location and functional purpose of the hardware required to enable AMI.

Component	Physical Location	Functionality
Advanced Meter	Customer premise	• Interval usage measurement • Voltage measurement • Demand measurement • Connect/Disconnect switch
Communications Network	Poles, communications towers, buildings	• Data collection • Enable two-way communications
Head End System ("HES")	Data center (Central Office)	Controls data collection and commands to and from the network and meters
Meter Data Management System ("MDMS")	Data center (Central Office)	Validates and manages meter data

This collection of hardware and software provides certain key functionality:

- **Remote Reading** - recurring or on-demand remote capture of granular customer energy usage and other metering data, such as power quality and voltage measurements.
- **Remote Connect/Disconnect** – utilization of a remotely operable service switch in the meter to connect or disconnect a customer's electric service upon move-in/move-out, for

[54] As an example, since implementing AMI, Central Maine Power Company reduced its safety incidents by 90 percent in its Meter Operations division.

nonpayment, as a potential DER and micro grid management tool, or in response to a reported hazardous condition.

- **Outage Management Support** – automatic reporting of power outage and power restoration messages to the utility, allowing the utility to improve its ability to determine the scope and location of an outage, to improve outage response, and to verify that all affected customers are restored. Power status verification can also be determined by remotely reading the AMI meter.
- **Smart Equipment Communication** – AMI systems allow communication to customers and certain smart equipment beyond the meter to enable customer load management.

2. What are the alternative tools available today other than AMI to provide advanced meter functionality? Can these tools be used to engage customers or is AMI necessary to accomplish this goal?

There is no single alternative technology that can replace all the capabilities of an AMI system, but there are alternative "point solutions" that provide Advanced Metering Functionality ("AMF") and can support various REV goals and requirements. For instance, a separate communications infrastructure could be deployed or leveraged for a Direct Load Control ("DLC") application. However, by deploying alternative solutions to AMI, customers will not be able to participate in programs such as dynamic pricing or a real-time pricing that are enabled by the interval usage data provided by advanced meters.

The aim of this section is not to provide an exhaustive list of alternative technologies but rather to illustrate how other monitoring technologies are alternatives to AMI in providing more granular and more frequent usage information. While these technologies exist, their use across the utility's territory would require extensive review of data integrity, confidentiality and cyber security. There are three common monitoring technology types in the current market:

- **Plug-load Outlet Monitor:** Appliances plug into monitor and monitor plugs into wall outlet. Data is measured and recorded as electricity passes through the monitoring device as it measures the plug-load of the appliance.
- **Circuit-level Monitor:** Monitor is mounted near or within a breaker panel, and uses current transformers and measured or assumed voltage to determine power and energy consumption for multiple electrical circuits.

- **Whole-house Monitor with Load Disaggregation Algorithms:** Monitor is mounted near or within a breaker panel, and uses current transformers and measured line voltage to determine power and energy consumption at the electrical mains. A cloud service then uses electrical pattern detection algorithms to identify electrical signatures of specific appliances and other loads.

Various equipment and/or control system may also have monitoring capabilities, such as smart inverters. They may serve niche end-uses whereas the above-mentioned technologies have been deployed at some scale and are generally available for consumers.

3. Of those technologies described, which components should be owned and maintained by the utility, customers or third parties?

Of the list of technology alternatives, the technology could be owned by the customer, third parties, or utilities. The more diverse the ownership model, the greater is the risk of cyber security exposure.

4. Explain in detail how AMI deployment would support further deployment of renewables and DER? Explain the functions and benefits of AMI associated with renewables and DER. How will the monitoring, dispatching, and command/control of renewable/DER be performed? Has the company explored alternatives to AMI associated with the monitoring, dispatching, and command/control of renewables and DER?

Distributed energy resources ("DER") include end-use Energy Efficiency ("EE"), Demand Response ("DR"), Distributed Storage, and Distributed Generation ("DG"). A defining characteristic of these resources is that they are directly interconnected with distribution systems, including those devices that reside on a customer premises "behind the meter."

AMI can support DER by first providing much greater granularity of power use at specific intervals and in near real-time to support customer value. This interval data, at a customer level or in aggregate, will provide information to more accurately match customer and system needs with the DER profiles and characteristics. The interval data will also provide the capabilities to monitor DER usage as the resources are deployed to verify the resources meet the system needs as envisioned.

The vast majority of utility customers are measured for consumption monthly or bi-monthly. AMI enables the ability to measure peak consumption with increased granularity, i.e., daily, monthly and annually. Once DER is enabled or deployed, AMI can provide measurement and verification ("M&V") of DER implementation (*e.g.,* "net" hourly consumption data).

Markets relying on dynamic pricing models (*e.g.*, time-of-use ("TOU") pricing, real-time pricing, or critical peak pricing) cannot be enabled without deployment of AMI. Markets not relating to customer loads will at a minimum require adequate sensing, monitoring, and communications that are typical in AMI systems.

5. At what scale or market penetration does deployment of this strategy become effective? For example, is it viable for single customer deployments associated with particular rate designs or DER installations, or are regional or other scales of deployment suggested?

AMI deployment strategies will and should vary by utility based on a business case reflecting each utility's unique service territory attributes including size, population density, customer demographics, and geography. Some utilities have presented their AMI deployment in separate regulatory filings.

The following table represents some, but not all, AMI deployment options and the relative impact on the AMI system components.

AMI Deployment Options					
Type	**Meter**	**Field Area Network (FAN)**	**Head End System (HES)**	**Meter Data Management System (MDMS)**	**Incremental Integration Required**
1 by 1	Existing Interval Meter Types	Public/ None	Existing	Not Required	None
Spot	AMI	Geographically Concentrated	Sized for Deployment Area	Optional	Minimal
Canopy	AMI	Overlay Network of Entire territory	Sized for Expected Deployment	Sized for Expected Deployment	Minimal
Drop In	AMI	Overbuilt Network of Entire territory	Sized for Expected Deployment	Sized for Expected Deployment	Minimal
Full Deployment	AMI	Optimized Network Build Out	Sized for Full Deployment	Sized for Full Deployment	Full
Competitive Model	AMI or Existing Meters	Public or Private Network	Sized for Expected Market Share	Sized for Expected Market Share	Vary by individual Utility

Where:

1 by 1:	Advanced meters are deployed on a case-by-case basis utilizing point-to-point communications.
Spot:	Advanced meters and the supporting systems, *i.e.*, network, HES, and MDMS, are deployed to support selected areas, *e.g.*, by region or market.
Canopy:	Advanced meter system deployment is initiated by Field Area Network ("FAN") network build out with coverage across the territory. The capacity of FAN, HES and MDMS is built to support projected advance meter requirements. Additional network infrastructure may be required as additional meters are deployed.
Drop In:	Advanced meter system deployment is initiated with a FAN network to support advanced meters deployed across the full service area. Advanced meters can then be installed as needed without additional network infrastructure. The capacity of FAN, HES, and MDMS is built to support predicted meter deployment requirements.
Full Deployment:	All systems and network are developed and deployed to support a full advanced meter deployment.
Competitive Model:	The FAN is designed and deployed to support advanced metering requirements for a competitive market. The capacity of the FAN, HES, and MDMS is built to support the advanced meter requirements based on the projected competitive market needs.

As noted in the table above, there are many potential approaches to deploying AMI. Two key variables for those approaches are the extent of the deployment and the duration of the deployment. For example, a utility may decide to fully deploy AMI as fast as possible, or it may start with a targeted deployment in a certain area and then extend full deployment timeline across a much longer period of time. Other utilities may decide to follow an opt-in approach, where the utility gradually converts customers to AMI as they opt in to customer programs (and potentially when a meter is replaced or new customers are added).

With respect to the full-deployment of AMI, it could provide a fair and ubiquitous network for all customers and market participants if a full deployment approach is supported by a positive business case.

Each business case is unique and impacted differently by the various deployment approaches. A sound business case should evaluate various deployment variables – and other key assumptions – in order for the business case to be optimal and robust to potential changes in plans.

6. What functionality is necessary to support REV markets is available only from AMI networks? For example, control of customer loads can be achieved through alternate communications channels (*e.g.*, pager networks or customer broadband connections). What advantages are offered by AMI deployment?

In general, AMI supports increased levels of granular usage information delivered with increased frequency (daily or sub-daily). AMI offers several advantages:

- **Enhanced customer knowledge and tools that will support effective management of the total energy bill:** The majority of customers in New York have access to monthly or bi-monthly usage information. AMI provides consumers and businesses with the granularity (new deployments are targeting 15-minute intervals) to promote time-sensitive management of the total energy bill. For regions of the country that have already progressed with AMI implementation, new products and services are being offered to customers. Information and tools that are supported by AMI data include:
    - Usage alerts to inform customers of their usage – can be provided daily, weekly, or at usage thresholds set by customers
    - Web portal with daily usage
    - Time-based pricing programs such as TOU, critical peak pricing
    - Individualized capacity demand charges.
- **Market animation and leverage of customer contributions:** The introduction of AMI to New York residents may lead to the development of a number of products and services. AMI supports time variant data, and can enhance the monitoring and verification of DR and EE on the grid, and a number of other potential services within the Distribution System Platform ("DSP") market. Historical usage information provides more accurate information to support individual, customized competitive supply bids or more targeted rate

development. Today, New York's largest customers have the ability to manage their peak usage to reduce capacity demand charges. With increased penetration of interval meters, energy service providers could support a greater level of capacity demand management.

- **System-wide efficiency:** AMI data will provide DSP planners with granular data for all customer classes at the individual customer level to optimize asset utilization in the future. Prior to full deployment pockets of AMI provide similar efficiency opportunities for individual DSPs. AMI has been demonstrated to reduce customer usage through enhanced conservation voltage optimization thus creating efficiencies in system utilization.

- **System reliability and resiliency:** AMI has the ability to provide near real-time voltage and power quality monitoring information at the individual customer level to the DSP that supports enhanced reliability and resiliency investment across the grid. AMI also provides significantly increased levels of information during power outages to support faster outage assessment and customer restoration.

- **Reduction of carbon emissions:** AMI has been demonstrated to reduce customer usage, enhance conservation voltage optimization[55] and reduce truck rolls leading to overall reduction in carbon emissions.

As shown in the following table, AMI also contributes to fulfillment of several REV requirements.

Alignment of AMI and Requirements from the REV Track 1 Order

Requirement	AMI Enablement
Need to provide customer with knowledge to actively manage energy costs	Direct: provides granularity and timeliness of customer usage to enhance customer information tools (web portals, in-home gateways).
Need to provide system security	Direct: provides for a secure method to execute operational DSP tasks , maintains secure customer usage and control information .
Need to support incentives through rate making framework that drive innovative	Direct: AMI could support products and services at this time and provides flexibility to support new

55 *See* Case No. 15-E-0050, Con Edison's Updated AMI Business Plan filed November 16, 2015 that projects a 1.5% reduction in energy consumption across its territory with an anticipated 1.9% reduction in CO_2 emissions due to reduced fossil generation.

change	products and services in the future
Need to support making distributed resources a primary tool in an interconnected modernized power grid	Direct: provides granularity of energy consumption and power quality data to DSP.
Need to support the alignment of wholesale market with distribution level markets	Direct: AMI supports alignment of consistent time measurement (intervals) across the markets. Alignment cannot be completed without this consistent measurements
Need to support a cost effective grid architecture that incorporates cleaner power options	Direct: AMI enhances the measurement, verification and reporting of DER
Need to support market-based products that drive an efficient energy industry	Direct: AMI support multiple product offerings and provides flexibility to reprogram customer's meters for future new products.
Need to support an improved ability to manage distribution systems with real-time control, including rerouting of power flows while taking full advantage of DER	Direct: AMI can provide customer-level monitoring of various DER products.

7. Can AMI support demand rates for mass market customers? Are other alternatives to AMI available to support demand rates?

Yes. AMI can support demand rates for mass market customers. The Joint Utilities are not aware of any other alternative to AMI that would support demand rates for mass market customers.

8. What grid services, customer services, and essential functions will the system support?

AMI enhances several applications, including:

- **Distribution grid management:** Focuses on maximizing performance of feeders, transformers, and other components of network distribution systems and integrating them with transmission systems and customer operations. The anticipated benefits of distribution grid management include increased reliability, reductions in peak loads, increased efficiency of the distribution system, and improved capabilities for managing distributed sources of renewable energy.

AMI as well as other technologies can support grid management. AMI supports grid management by providing increased levels of granular information at endpoints throughout the distribution system. Some Fault, Location, Isolation and Service Restoration ("FLISR") solutions can run on the same communications network utilized by AMI. In addition, AMI outage/restoration information can help manage outages more efficiently. Other solutions such as Conservation Voltage Reduction ("CVR") can be augmented by utilizing AMI, premise-level voltage data in order to make optimal control decisions that maintain voltages within regulated limits.

- **Sharing and visualizing energy usage data:** Solutions that utilize AMI's granular, near-real time consumption data and open interfaces to enable new energy services:
    - Customer Web Portal for Energy and Cost Data – to support an internet-based web portal to provide customers with historical information on their energy usage and related costs. Customer web portals can be provided without AMI data; however, integration of the granular consumption data may increase customer engagement and utilization of the web portal.
    - In-Premises Devices for Energy Usage Data – utilization of the AMI system to support in-premise devices along with internet-based web portals to provide a customer with real-time information on their energy usage

  This data is available to the DSP and can be made available to the customer and customer-authorized third parties. There is a range of uses for this information including more accurate and/or customized energy services pricing and load forecasting as well as education development.

- **Dynamic Pricing:** Utilizes the AMI system to measure consumption in granular intervals so that time-varying rates can be offered, and provides customers with real-time information to encourage energy conservation at high commodity price periods or in response to critical grid operating conditions. These benefits could be reflected in individualized ICAP tags.

- **Direct Load Control:** Customer programs allowing remote monitoring and control of loads, executed by the DSP or other market participants (such as electric vehicles) can be supported by AMI networks. Additionally, AMI supports the bill quality measurement and verification.

- **Asset Optimization:** AMI data can provide enhanced system-wide visualization, asset health and performance analysis by leveraging GIS, Distribution Automation, and AMI load data.

AMI Support for DSP activities (grid operations, market operations, integrated system planning): There are a number of uses for AMI information identified within the anticipated product and services to support efficient grid and market operations. The granular information collected from interval meters can be leveraged by DSP planning to address how grid investments can be prioritized.

AMI can be a valuable component of the DSP. It supports DSP roles by providing granular information about the energy commodity and ancillary services required by the market. In addition to providing bi-directional metering of energy flows for resources such as rooftop solar and storage, advanced meters also provide greater visibility into what is occurring at the edge of the network. The DSP can leverage the communications network that is utilized by AMI to provide situational awareness of distributed resource operation.

The DSP market operations need to be transparent, flexible, scalable, and efficient. AMI technology will facilitate market operations by providing stakeholders with enhanced levels of granular data useful to consumers, third parties, and energy suppliers. Full deployment of AMI provides data for all data points where other solutions would not be as ubiquitous. AMI also enhances grid operations by facilitating grid automation and response to load down to the meter level. AMI also provides enhanced fault detection that will optimize reliability.

Additionally, AMI provides the DSP with the ability to monitor the contribution of various DER to the system at all times, thus potentially providing the value to DER, utilities, and consumers. Finally, AMI can facilitate integrated system planning by providing an increased level of information regarding circuit loading, which will enable greater specificity in integrated system planning.

9. What types of market programs or rate structures will the system support (*e.g.*, demand response programs, participation in ancillary service markets, real time pricing, time-of-use rates, demand charges, *etc.*)?

AMI provides the interval usage information to support the market programs and new rate structures. AMI has been proven at scale to provide mass implementation of market programs and rate designs. Texas, California, Oklahoma, and Ontario provide examples of mass deployment of new time varying rate, demand response programs, and innovative rate designs and market programs to meet change customer needs.

10. **What are the primary benefits that would derive from the system? For example, would the strategy support conservation voltage reduction (CVR) and associated benefits to system operation and carbon reductions? Are there other operational, societal or customer benefits that the system directly supports?**

Application	Benefit Area	Description
AMI	Meter reading	• Reduced operating costs (*e.g.*, personnel, transportation, materials) to conduct meter reads
	Field service visits	• Reduced operating costs (*e.g.*, personnel, transportation, materials) to conduct field service requests
	Theft	• Avoided energy costs • Reduce the amount of stolen energy that is socialized
	Outage	• Reduced outage management costs through improved AMI-based outage and restoration detection
	Billing	• Reduced operating costs (*e.g.*, personnel requirements) to manage and process billing estimates
	Consumption on inactive meters	• Reduced energy consumption on inactive accounts
	Bad debt	• Reduced bad debt through allowed service deactivations
	Call center	• Reduced call volume related to billing delays, estimated bills and meter reader complaints
Portal/Usage Alerts in coordination with Energy Efficiency Programs *(Real-time data)*	• Energy Efficiency	• Reduced energy consumption by participating customers
Prepay	• Energy Efficiency	• Reduced energy consumption by participating customers
Demand Response	• Dynamic Pricing	• Avoided generating capacity, fuel, T&D from reduced peak demand

Volt / VAR Optimization and CVR	• Energy Efficiency	• Reduced energy consumption by supported customers
Distribution Automation (Automated Switching)	• Outage	• Reduced outage management costs through fault location, isolation and supply restoration in coordination with other automation efforts
	• Remote Connect/Disconnect	• The ability to open and close switches for emergency load management
Demand Response	• Direct Load Control	• Avoided generating capacity, fuel, T&D from reduced peak demand

11. Will customer load data be provided to ESCOs and the NYISO in a way that allows the NYISO to settle ESCOs' load based on actual usage instead of class load shapes of their customers? What other attributes of the proposed system should staff be aware of?

Yes, daily settlement with ESCOs and the NYISO can be supported with actual customer usage information which has been proven at scale. The customer interval data can also be used to provide individualized ICAP tags to support a more efficient system and demand reduction at system peaks.