STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

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

STAFF PROPOSAL

DISTRIBUTED SYSTEM IMPLEMENTATION PLAN GUIDANCE

Dated: October 15, 2015

<u>TABLE OF CONTENTS</u>

<u>Page No.</u>

I. INTRODUCTION 1

Recommended Two-Phase Approach to the Initial DSIP Filings 4

Stakeholder Engagement Process 5

Development of the DSIP Guidance 6

II. INTEGRATION OF DEMONSTRATION RESULTS IN DSIPs 8

III. CONTENTS OF THE INITIAL DSIP – AN INVITATION TO INNOVATE 8

A. Distribution System Planning 9

Forecast of Demand Energy Growth 12

Available Resources 12

Delivery Infrastructure Capital Investment Plans 13

Identify Beneficial Locations for DER Deployment 14

B. Distribution Grid Operations 15

System Operations 16

Volt/VAR Optimization (VVO) 17

Interconnection Process 17

C. Distribution System Administration 17

System Data Acquisition and Sharing 18

Customer Data and Engagement 19

Customer Data Questions for Comment 21

Advanced Metering Functionality and Communication Infrastructure 22

IV. SUPPLEMENTAL DSIP FILING 28

V. CONCLUSION 30

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I. INTRODUCTION

On February 26, 2015, the Commission issued its Order Adopting Regulatory Policy Framework and Implementation Plan in its proceeding entitled Reforming the Energy Vision (REV).[1] The Track I Order details the regulatory framework and implementation plan required to promote the REV initiative. The Order requires each utility, as a Distribution System Platform (DSP) Provider, to file a Distributed System Implementation Plan (DSIP).[2]

The Commission's Track I Order described the goals of the DSIP: to "serve as a source of public information regarding DSP plans and objectives, including specific system needs allowing market participants to identify opportunities. It will also serve as the template for utilities to develop and articulate an integrated approach to planning, investment and operations. The DSIP will enable the Commission to supervise the implementation of REV in the context of system operations." The Commission continued, "[t]he DSIP will contain (among other

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[1] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan, (issued February 26, 2015) (Track I Order). The proceeding, Reforming the Energy Vision, hereinafter shall be referred to as REV.

[2] Id. at 32 and 129-130.

things) a proposal for capital and operating expenditures to build and maintain DSP functions, as well as the system information needed by third parties to plan for effective market participation.”[3]

To effectuate the Commission’s goals, the DSIPs must contain certain information addressed within this Guidance. The DSIPs should demonstrate how the utilities are working with, and intend to further stimulate the involvement of, current and would be market participants. Moreover, a utility’s DSIP should align with the eventual Earning Impact Mechanisms and their metrics.[4] Additional detail of what data should be included in the DSIP to satisfy these needs is contained herein.

The Commission envisions the DSIP as a multi-year plan filed with the Commission, subject to public comment, and updated regularly.[5] This process is intended to promote transparent and open planning and consistency with performance incentive mechanisms. It should also explain how the utility expects to maximize option value of the distribution system for consumers through better planning, system operations and management and vastly scaled integration of DER – without making unnecessary investments. This open process is expected to promote utility/stakeholder relations, enable third parties the opportunity to provide cost-effective market solutions to identified energy needs, and drive consumer value related to the regulated distribution system. The DSIP will document a utility’s plans over a five year period, with a formal DSIP filing occurring every two years.[6]

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[3] Id. at 32.

[4] See, Case 14-M-0101, Staff White Paper on Ratemaking and Utility Business Models, (July 28, 2015) p. 51-52.

[5] Track I Order at 32.

[6] Id.

In presenting this proposed DSIP Guidance document, the Department of Public Service Staff (Staff) invites and anticipates detailed comments by utilities as well as all interested parties. Once approved by the Commission, the DSIP Guidance will specify the information components that the utilities will be expected to include in their initial DSIPs. The intent of this Guidance document is to achieve a uniform approach to the utilities' submission of information in their DSIPs.

The REV initiative continues to have goals of more efficient use of energy, deeper penetration of distributed energy resources (DER), establishment of vibrant markets to transact electric grid services, and adoption of innovative and sustainable energy technologies. These goals are substantial and require a long-term approach comprising incremental steps, each one meant to bring us toward a cleaner, more resilient and more affordable energy system through the development of dynamic, self-sustaining markets that eventually will set the pace of industry change. As a first step, utilities and stakeholders need to assess and better understand the present status of each service territory and determine the starting point – both within individual utilities and collectively as a state.

This Guidance document will represent the first chapter in what will be an evolving understanding of the information that utilities will be required to disclose to achieve the State's objectives under REV. As the market matures, the Commission, utilities, market participants, and other stakeholders will develop a deeper understanding of the opportunities to benefit consumers through DER deployment and more intelligent networks. Future DSIPs will be expected to recognize the continuing discourse and market developments, and account for changes as necessary. Thus, Staff recommends that the Commission view this Guidance document as an ongoing dialogue.

Recommended Two-Phase Approach to the Initial DSIP Filings

As the Commission recognized in the Track I Order, development of fully capable DSP Providers will be an ongoing and evolving process. The Commission expects the utility DSP market administration functions to be fully compatible and operate seamlessly in the marketplace.[7] Historically, however, the utilities operations and practices (including system design, data collection practices, etc.) have been, and in many aspects remain, quite divergent. Therefore, Staff recommends that the utilities' 2016 DSIPs involve two separate filings. The first, or Initial DSIP filing, is intended to be a thorough "self-assessment" addressing each utility's system and denoting immediate changes that can be made to effectuate REV policies and goals. The Initial DSIP shall focus on the information each utility presently possesses, and initial changes that may be necessary to conduct a more comprehensive and transparent planning process. The Initial DSIP filing shall be filed by June 30, 2016.

Following the Initial DSIP filings, Staff recommends that a Supplemental DSIP be filed jointly by the utilities. In addition to the individual efforts presented in the Initial DSIP filings, the 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

[7] Track I Order at p. 12.

significant DER investment and efficiently manage resources. Staff recognizes that many of the operating tools and functionality required to incorporate and rely on large scale DER deployment, including the requisite algorithms to price the marginal value of DER as efficiently as practicable, should be developed collarboratively to capture, where possible, economies of scale, but also to ensure interoperability, state-wide transparency and energy markets that avoid seams or rifts at utility service territory borders. For example, there should be a uniform interface with the markets and very extensive interactions and interoperability among the utilities.

Also, the requirements for reliable integration and dispatch of DER will depend upon the levels of penetration. In order to ensure that the hosting capacity[8] for efficient deployment of DER is not impaired by insufficient operational and management capabilities, Staff recommends that the Commission direct the utilities to jointly make a supplemental filing. With this Supplemental DSIP, the utilities would develop plans specifying the tools and protocols required and a coordinated approach for deployment. Staff recommends that the Supplemental DSIP be filed by September 1, 2016.

Stakeholder Engagement Process

Meaningful stakeholder consultation will be critical for the Initial DSIP to provide stakeholders with information that will be used to develop the methodologies applied in the Supplemental DSIP. Improving the transparency of utility planning and operations has been a continuous goal of the REV proceeding, and an open DSIP development process is consistent

[8] Hosting capacity is the level of DER penetration on a given distribution circuit that could be integrated without additional upgrades or expansions. Case 14-M-0101, Market Design and Platform Technology Working Groups Final Report (issued August 17, 2015) (MDPT Report).

with that proceeding. Staff expects a stakeholder engagement process that includes focused technical conferences and discussions to allow each subject area to be appropriately vetted. Staff expects this process will achieve the desired results to be presented in the Initial and Supplemental DSIPs, and participating stakeholders will understand the intent behind the filings. Collaboration among the utilities and other parties in preparing the Initial and Supplemental DSIPs will ensure consistency, and allow greater information sharing required for the development of long-term projects.

Given the timeframe for filing the DSIPs, utilities and other interested parties need to begin to define the stakeholder process. 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.

Finally, each utility DSIP and the Supplemental DSIP shall be filed with the Commission and made publicly available on the Department website. Once filed, a process for stakeholder comment and input will be set forth pursuant to public notice(s).[9]

Development of the DSIP Guidance

Several documents provided Staff with direction in preparation of this Guidance document.

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[9] Track I Order at 130.

- The Commission’s Track I Order provided the Commission’s expectation for DSIPs, and acted as a directive to Staff.[10]
- The Market Design and Platform Technology Working Group’s (MDPT) final report presents the groups’ recommendations in support of REV implementation.[11] Staff reviewed and incorporated, where appropriate, the recommendations of the MDPT report.
- The Staff White Paper on Benefit Cost Analysis (BCA) which proposes a framework to address the marginal costs and benefits of distributed energy resources (DER) in comparison to traditional utility investments.[12] The cost-benefit analysis described in the BCA has been considered in this Guidance document and should be included in DSIPs.
- The Staff White Paper on Ratemaking and Utility Business Models. This document details how the value of DER and reduced environmental impacts need to be considered in ratemaking.[13] Additionally, ratemaking should be used to encourage, and not deter, the proliferation of DER. The White Paper discusses using the DSIP to identify areas where durable reductions in demand through energy efficiency programs will have value to the distribution system,[14] and inform a utility’s overall capital plan.[15]

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[10] Id. at 32 and 129-130.

[11] See generally, MDPT Report.

[12] Case 14-M-0101, Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding (issued July 1, 2015) (BCA).

[13] Case 14-M-0101, Staff White Paper on Ratemaking and Utility Business Models (July 28, 2015) (Track II White Paper).

[14] Id. at 48-49.

[15] Id. at 68.

- Staff has also researched utility modernization efforts in other jurisdictions to help inform the development of this guidance document.[16]

II. INTEGRATION OF DEMONSTRATION RESULTS IN DSIPs

Utilities should discuss relevant current and near-term REV Demonstration projects in their DSIPs. 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. Staff expects that the DSIP will reflect ongoing work as issues continue to be resolved or focused, within the demonstration projects and elsewhere.

III. CONTENTS OF THE INITIAL DSIP – AN INVITATION TO INNOVATE

Staff recommends each utility use the DSIP to present innovative approaches to address the fundamental objectives of REV, as well as to specific outcomes addressed by the DSIP. For example, a central objective of REV is the improvement of overall system efficiency; the Track I Order specifically articulated the benefits of reducing State system-wide peak loads during the top 100 usage hours of the year. Staff, however, expects the utilities to include innovative solutions for integrating DER, including energy efficiency in ways that

[16] See, e.g., Calif. Public Utilities Commission Rulemaking 14-08-013, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans, Ruling on Guidance for Public Utilities Code Sec. 769 – Distribution Resource Planning (issued August 14, 2014).

most effectively increase overall system efficiency and lowers costs for their system and customers.[17]

Achieving these goals will require significant DER penetration, customer engagement, and tariffs that support cost-effective procurement of load reduction. An effective strategy could focus on system and network peaks. The DSIP should present the company's plans to improve system efficiency, including specifying what portion of its load may be reduced in the next five years, together with an action plan to accomplish this objective. The utilities are also expected to propose additional demonstration projects, as appropriate, in order to continually improve, refine, and otherwise drive toward the State's energy objectives.

As noted above, this process is incremental. Therefore, the DSIPs must prioritize work efforts so that the most significant and cost effective changes and actions are implemented first.

A. Distribution System Planning

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. The rate of growth of both demand management and DER adoption will impact distribution system planning decisions. The MDPT report focuses on developing two key aspects of advanced planning: integrated

[17] Track I Order at 20.

system planning[18] and hosting capacity.[19] Integrated planning requires that the utilities recognize and incorporate the value of all available resources. Essential to a more integrated planning process is developing the ability to forecast demand, load shape, and DER penetration, and the effect that these factors will have on the existing system and any planned capital expenditures. A utility's ability to more accurately forecast the impact and location of these dynamics on their system would provide the utility with a better tool set for managing its system to maximize its value to consumers. As noted in the Track I Order, developing and sharing granular forecasts with all appropriate stakeholders will animate markets around the distribution system further expanding the system's value and benefits to New Yorkers.[20]

The DSIP will also present capital budgets for review by stakeholder and market participants.[21] A key focus of the REV initiative and the MDPT 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.

[18] MDPT report at 22.

[19] Id. at 47.

[20] Track I Order at 129.

[21] Id. at 58-59.

While the MDPT report emphasizes the need for establishing and defining hosting capacities,[22] investigating and sharing information with customers and third-parties on hosting capacity should be done with some level of consistency among the distribution utilities. The Joint Utilities comments highlighted the importance of requiring uniformity in calculating hosting capacities.[23] Staff agrees with this approach. Therefore, the Initial DSIP will define initial utility activities related to hosting capacity, and the Supplemental DSIP filing will be used to put forth a standard approach applicable to all the utilities.

Storage technologies integrated into grid architecture can be used for reliability and to support the deployment of other distributed resources. The Track I Order states that utilities should develop information on optimal locations and levels of storage facilities, either on the system or behind the customer's meter, as part of their DSIP plans and rate filings. In this initial DSIP, the utilities should define how to evaluate and incorporate the use of energy storage as part of the overall planning process, and as part of solutions to avoid more traditional infrastructure investments, to improve grid functions or to increase the level and/or utilization of DER.[24]

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[22] MDPT report at 50.

[23] Joint Utilities - Informal Feedback on Draft Report of the Market Design and Platform Technology Working Groups (July 31, 2015) at 5.

[24] The integration of energy storage into modern energy infrastructure is likely as necessary as it is inevitable. See U.S. Department of Energy, "Electric Power Industry Needs for Grid-Scale Storage Applications," (December 2010), http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Utility_12-30-10_FINAL_lowres.pdf. However, care must be taken that such storage is integrated and utilized in a manner that promotes, and does not detract from, the State's energy and environmental goals. <u>See</u>, Hittinger and Azevedo, "Bulk Energy

The following sections related to distribution system planning should be included in the Initial DSIP:

Forecast of Demand and Energy Growth

- Provide annual peak demand, peak day load shape, and energy (kWh) load forecasts for each of the next five years at the company-wide level.

- Prepare peak demand and load shape forecasts for the next five years at the substation level. Identify what data is available at the time of filing and the utility's plans to provide the data across the service territory. Explain the process for categorizing the information (geographically, size, etc.) and making substation level forecasts available to outside stakeholders.

- Identify the impact of significantly increased DER penetration on the methodology used for regional and company-wide system forecasts. Describe how new DER-related factors are reflected in load forecasting models.

- Explain how the forecasts were derived (e.g., performing a top-down analysis of a companywide peak forecast and/or a bottom up aggregation of substation level peak demand forecasts) and why the utility uses that methodology. Explain whether the combined use and synchronization of both top-down and bottom up methodologies could produce increased accuracy of company-wide and substation specific forecasts cost effectively.

- Describe how to ensure accuracy of forecasts as DER penetration levels increase.

Available Resources

Available resources include various DERs (energy efficiency, peak load shaving, demand response, dynamic load management, storage, distributed generation, etc.) as well as traditional delivery infrastructure.

- Describe the process for gathering information from DER providers, other stakeholders and other available resources in order to enhance forecasts of expected DER performance and penetrations levels over time.

Storage Increases United States Electricity System Emissions," Environ. Sci. Technol. 2015, 49, pp 3203-3210.

- For each type of DER resource, identify the specific expected contribution to peak load, energy reduction and load shaping in the next five years. Assumptions used should be described clearly.

- For each type of DER resource, explain how the utility will incorporate expected peak load, energy reduction and load shaping in its planning process.

- Describe the details of other procedures/programs that may be implemented to increase the quantity and value of DER resources.

Delivery Infrastructure Capital Investment Plans

- Identify current reliability planning criteria.

- Describe the current capital budgeting process for investment in delivery infrastructure.

- Explain how the planning and budgeting process integrates consideration of DER resources.

- Provide historical spending amounts over the past five years for transmission, substations, and distribution infrastructure.

- Provide capital budgets for a forward five-year period, broken down into transmission, substations, and distribution categories.
  - Include detailed project listings for each grouping, similar to those provided in annual filings and rate cases.

- Present historical spending over the past five years for information technologies, communications, and shared services.

- Provide the forecasted budgets, including an explanation of the basis for the selected approach, for developing monitoring, communications, and information technology (IT) systems to support anticipated data and analytical needs as a DSP.

  - Include details on distribution infrastructure upgrades to support DSP capabilities (e.g., low-cost, high-resolution sensors that enhance system visibility and increase option value, power flow controllers, or solid-state distribution transformers for meshing radial networks or interfacing with microgrids).

- Identify all T&D projects (categorically) with a focus on highlighting where DER, future or existing, has the potential to impact the project needs.
    - o Identify all projects within this grouping that will need to move forward regardless of DER deployment, due to other operational limitations and describe any limiting factors and their implications.

- For areas with large budgetary changes from current spending:
    - o Identify the driving factors/projects behind the increase or decrease.
    - o Identify what mitigating techniques, such as extending overall implementation timeframe or limiting the number of areas for installation or use of DERs, were considered, possibly included, or rejected for each of the drivers. Indicate why those rejected were not appropriate.

Identify Beneficial Locations for DER Deployment

- Include a plan to reveal (spatially and temporally) more granular (further disaggregated zonal) wholesale energy prices in the utility service territory in a way that will allow DER providers the ability to make informed decisions for investing in and siting new resources. Utilities should consult with the NYISO in determining the level of granularity that can be provided based on currently available systems.

- Identify the process of collaborating with stakeholders to develop and implement ways for various DERs to be substituted for traditional grid-based solutions in order to avoid or reduce utility capital or operating costs.

- Identify specific areas in the utility footprint where there is an impending or foreseeable delivery infrastructure upgrade need and thus DERs would have more immediate delivery infrastructure avoidance value.

- Identify specific areas in the utility footprint where DER may provide reliability or operational benefits and thus have more value but reliability deficiencies are not otherwise significant enough to be funded in a capital plan (e.g., power quality issue affecting a smaller number of customers).

- Identify specific areas where there is no forecast delivery infrastructure need for years to come and hence the infrastructure avoidance value of DERs are likely to be lower or insignificant in the short-term.

- Consistent with the T&D capital investment plans, list specific infrastructure projects by location, and describe the process used to identify the projects where DER solutions should be compared as potential alternatives to traditional grid infrastructure under varying scenarios of DER integration.
  - Identify what would be needed to avoid the infrastructure project (e.g., X MW of peak shaving).

- Describe how the utility will use the BCA handbook for performing the comparative analysis of substituting DERs to defer infrastructure investments.

- Describe the efforts to determine and share hosting capacity information with market participants and stakeholders. Initial efforts should be focused on locations with an impending or foreseeable delivery infrastructure upgrade need as DERs are likely to have more delivery infrastructure avoidance value that is also easier to quantify.

B. Distribution Grid Operations

Utilities will continue to be required to operate the grid in a safe and reliable manner.[25] The operational details required to meet this obligation will continue to evolve based on increasing DER penetration and multi-directional power flows. Operating the distribution system going forward will require a combination of technologies and modernized and improved standards. In the longer term, the DSP must incrementally progress from adequately equipping the distribution system with monitoring and communication infrastructure to 1) enabling intelligent, rapid, and precise control; 2) deploying automated

[25] Public Service Law §65.

solutions across the system; and 3) facilitating transactions for grid services via an animated market. The MDPT report recommends that initial grid operation activities be focused on 1) monitoring and observability, and 2) coordination and control.[26] Utilities will need to evaluate the effectiveness of existing systems to determine what modifications may be needed to operate the system safely. It is expected that forecasted DER penetration levels, types, and locations will provide the basis to establish new policies, protocols, and visibility requirements. 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.[27]

The following sections should be included in the Initial DSIP:

<u>System Operations</u>

- Specify the expected or potential near-term effects of increased DER penetration on the ability to serve customers, with specific reference to each type of DER and its grid interface.

- Describe the changes to existing policy and processes that will be required in order to ensure that safety and reliability are maintained or improved at the same time that DER penetration is encouraged, expanded and integrated into system operations.

- Describe the visibility and communications protocols to observe/interact with DER providers that will be implemented in the next several years while continuing safe and reliable system operation.

- Identify and distinguish operational needs during normal operations and during outage events or other periods of system stress (e.g., low voltage condition, near thermal limitations, etc.) and plans to implement reliability-

[26] MDPT report at 54.

[27] Track I Order at 32, 92; MDPT report at 46, 59.

enhancing protocols like fault location, isolation, and service restoration (FLISR).

- Specify plans to maintain cyber security.

Volt/VAR Optimization (VVO)

- Describe plans to implement VVO in the near-term, and over the long-term and how third parties can interact and provide VVO services.

- Evaluate and discuss the costs and benefits of upgrading VVO capabilities.
    - o Discuss new VVO capabilities and how they fit in with the evolving grid within the utility's service territory.

Interconnection Process

- Explain how the utility interconnection process complies with the Track I Order.

- Describe the process for interconnecting DERs and the capability to improve this process through an online portal.
    - o Provide a status of current efforts and future plans.
    - o Indicate how this function will be integrated into the planning process improvements and monitored to measure the effectiveness of the interconnection process.

- Describe plans for optimization of planning by modeling system impacts of DER, risk assessments, and resiliency.

C. Distribution System Administration

Data collection and sharing is imperative to achieve the objectives of REV. There are essentially two types of utility data: system data and customer data, both of which are essential to achieve robust customer engagement and market animation. 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. Accurate and timely information regarding specific aspects of the distribution system will enable DER suppliers to make investments and operational decisions and develop products that will help the grid meet the needs of utility customers and promote the societal benefits driving New York State energy policy initiatives. Similarly, DSPs require data from DER suppliers to ensure that DER is appropriately integrated into DSP planning and operational processes.

Although there is a need for commonality in approaches to accessing and sharing data, which will be addressed in the Supplemental DSIP Filing, certain system data currently exists that should be available for consumers or third party use. Therefore, the Initial DSIP will focus on making available utility system data and locations where DER would have system value. These concepts are consistent with the MDPT report to facilitate planning and investments activities.

Additionally, Staff seeks further comments with respect to data and advanced metering. The Initial DSIP should reflect the current state of development of these tools and present each utility's plans to utilize them to reach associated policy objectives. The Supplemental DSIPs should focus on developing common standards and protocols for sharing and protecting customer information.

The following sections should be included in the Initial DSIP:

<u>System Data Acquisition and Sharing</u>

- Include a description of the extent that system data is currently available for sharing with third parties, including the level of granularity (system level, substation level, etc.).
    - Prepare system data on a substation basis: 8760 load curves, voltage, power quality, reliability. Five year historical and forecasted load curves should be available.
    - Prepare individual feeder system data (load data, voltage, power quality, reliability, etc.) for feeders within areas that DERs are expected to have more value.

        - Provide a process for prioritizing the development of the feeder data. The process should be explained in sufficient detail to ensure its transparency.
    - Explain plans for the expansion of collection of granular system data.
    - Describe the process for making the data available to stakeholders.

- Identify, with as much granularity as possible, what data would be provided to assist DER providers in selecting target locations to invest capital.
    - Explain the process for making the data associated with the "Identify Beneficial Locations for DER Deployment" section available to stakeholders.
    - Describe efforts to present locational benefit information available geographically, such as a map within a portal.

- Discuss plans to make efficient use of advanced meter infrastructure (AMI) or other technologies to increase the availability of granular data to support system planning, market administration, and third-party market participation.
    - Explain how the plans will support operations, DER interaction, and/or customer interaction (e.g., usage data).
    - Identify how the utility plans to prioritize the installation of monitoring systems to maximize benefits and describe how to achieve a low-latency, secure communications network expected to support this expansion.
    - Explain how the utility will integrate customer/third-party meters and communications equipment.
    - Explain the existing communications network that will support the collection of granular data, and how the utility will be seeking to change the network to support the goals of REV. Provide a cost breakdown and defined schedule for implementation of the proposed communications system.

<u>Customer Data and Engagement</u>

- Identify and explain the means by which utility customers can obtain information regarding their energy usage:
    - Include a description of the extent and granularity of data is currently available for customers to review.

        - Describe the processes for making the data available to customers.
    - Explain plans to expand the collection of granular usage data and how to make it available to consumers.
    - Explain plans to enhance the ability of utility customers to obtain information regarding their energy usage.

- Identify and explain how vendors can obtain customer specific information from the utility, with authorization from the customer:
    - Include a description of the extent and granularity of the customer-specific energy usage data that is currently available for sharing.
    - Describe the process(es), protocol(s) and practice(s) for customers to share information with third parties they designate and how the data is transmitted to authorized third parties.
    - Identify which of the following data fields are transmitted. For fields not currently transmitted, explain whether and how they could be transmitted.
        - Historical consumption (monthly kWh, or more granular, if available)
        - Historical billing amounts (total dollars, supply charges)
        - Historical power factor
        - Coincident and non-coincident customer peak demand (kW)
        - Customer tariff
        - Reported outages
        - Service location
        - Power quality data
        - Customer complaints about voltage/power quality, including complaints in the immediate vicinity of the customer
    - Describe the extent to which existing data transfer processes and protocols described above, can accommodate increasingly granular customer usage data transmitted at more frequent intervals. Explain whether an alternative national standard protocol should be explored to accommodate the need to transmit such granular data, if acceptable, and identify plans to move toward that new standard.
    - Describe plans to enhance the ability of customer-specific information to be provided to third parties with customer authorization, using industry-standard protocols.

- Describe required enhancements to privacy and security requirements and practices to accommodate increased data sharing that will accompany a movement to DSP markets.

- Describe, in detail, plans to achieve enhanced consumer engagement, particularly in the time before the implementation of the digital market platform or web-based market is implemented.
    - Include new or enhanced tools and initiatives accompanied by descriptions, budgets, and timelines.

Customer Data Questions for Comment

Consumers must have ready access to their energy usage information as well as the capability to easily direct transfer that information to the customer's choice of vendors. With that information, DER and energy commodity vendors can better target and address the consumer's specific energy needs.

The Commission concluded in its Track I Order that a means to deliver data necessary to facilitate transactions between potential DER and/or commodity vendors and customers is essential. The Commission also anticipated that data sharing issues would be addressed as part of the planned customer engagement platform, or digital marketplace.[28] In addition, because of the potential benefits that sharing customer-specific usage information will have on consumer engagement and the development of DER markets, the Track II White Paper includes a proposed earnings incentive mechanism based on utility development and implementation of an online portal.[29]

Issues relating to the sharing of customer data for the purpose of stimulating customer engagement and increasing DER deployment are currently the subject of Commission inquiry and include consideration of the mechanisms for the collection and dissemination of data and strengthening privacy, cyber

[28] Track I Order at 60.

[29] Track II White Paper at 56.

security and protection of customer rights. These issues may be pursued contemporaneously with the development of the DSIP. To the extent these customer data issues are not otherwise resolved by the Commission, they should be addressed in DSIP filings.

Comments filed should address the following:

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

Advanced Metering Functionality and Communication Infrastructure

The MDPT report discussed the benefit of using AMI to aid in the collection and transmission of data for purposes including system monitoring and control.[30] The report noted that in some instances, advanced meter capabilities may be required for DERs to fully participate in real or near real-time markets.[31] While Staff agrees, to some extent, with the MDPT working group recommendations that some level of advanced metering functionality is likely required in order to achieve REV objectives, it remains far less clear which technologies, ownership structures, and deployment strategies are likely to optimize AMI as a tool for achieving REV objectives. For example, while a robust communication backbone may be vital for system and market operations, the specific ownership model, communication technologies, system architecture, and required bandwidths are open to discussion. In practice, communication systems are expected to include a mix of mediums and ownership structures, depending on local geography, density, and the

[30] MDPT report at 89.

[31] Id. at 92.

required functionality. Therefore, utilities should be determining the appropriate methodology to integrate communications systems capable of collecting and disseminating the information needed for a modern distribution system.

The need for AMI is currently being addressed within each individual utility through the rate case process. Consolidated Edison Company of New York, Inc. (Con Edison),[32] Orange and Rockland Utilities, Inc. (O&R),[33] and most recently the Iberdrola companies (Rochester Gas and Electric Corporation and New York State Electric and Gas Corporation)[34] have AMI before the Commission. Issues being addressed include, but are not limited to, consideration of the appropriate roll out strategy, and whether third-party meters or smart inverters with metering systems could provide appropriate REV functionalities. As part its request for a rate plan extension in Case 13-E-0030, Con Edison proposed implementation of AMI across the entirety of its electric and gas service territory. Con Edison, in collaboration with interested parties, is developing an AMI business plan expected to be filed with the Secretary on October 15, 2015. Similarly, O&R proposes implementation of AMI across its electric and gas systems in Rockland County as part of its current rate proceeding (Case 14-E-0493). O&R, in collaboration with interested parties, is developing an AMI business plan to

[32] Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service.

[33] Case 14-E-0493, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

[34] Case 15-E-0283, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service, and case 15-E-0285, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service.

be filed with the Secretary either as part of, or at the same time as, the company's DSIP filing. Comments will be sought on the filing and parties active in the REV proceeding should also be active in these proceedings. Decisions in the case of Con Edison are expected early in 2016 and will be informed by the process within the case proceeding, but also by the responses to this DSIP guidance proposal.

To better inform the Commission's interest in unleashing innovative and cost-effective solutions, Staff underscores its invitation for the utilities and other interested parties to include in their comments to this DSIP Guidance document detailed descriptions of the benefits advanced metering technology can provide and how those benefits can be captured to further REV goals. Comments should include details on functionality, benefits provided, required deployment levels and whether the data and related benefits expected from advanced meters could be (or should be) provided by third-parties' technologies.

Likewise, proponents of widespread utility-deployed metering systems should file descriptions of those systems to describe their specifications and functions.

<u>Comments filed on AMI should address the following:</u>

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

- Utilities should describe in detail what type of communications technology and infrastructure would be proposed for AMI deployment in your service territory? Explain why this communications strategy was selected versus other potential means of communications such as (mesh/point-to-point/fiber/internet/etc.). What are the pros/cons of the proposed communications system versus other potential means described above? Does the communication system proposed have the capacity to handle the large amount of data needed to support REV goals/initiatives? If not, is the communications system scalable to eventually meet the REV goals/initiatives?
- 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?
- 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?
- Over what timeframe is the deployment anticipated to take place? If market-driven, what will be the key determinants of uptake in the market? How will the deployment schedule affect overall costs?
- What are the characteristics of the utility service territory that impact economics of AMI deployment? For example, if a utility has fully deployed automatic meter reading or only reads meters bimonthly, this may limit the operational savings available from AMI deployment.
- Filings should examine the issue of AMI deployment from the perspective of three alternative scenarios: (a) full AMI implementation by the utility, (b) utility implementation of AMI to 20% of customers, with remaining customers receiving AMR (automated meter reading) meters, and (c) AMR implementation by the utility, with AMI deployed to individual customers by ESCOs and/or competitive DER providers. In each scenario, assume the utility will maintain the communications network, and meter data management systems. Compare the costs and risks of each alternative scenario, including flexibility, scalability,

and level of ratepayer investment, as well as overall net benefits.

- What functionality 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?
- Can AMI support demand rates for mass market customers? Are other alternatives to AMI available to support demand rates?
- Describe the anticipated costs associated with the strategy? Provide detail according to capital versus operating expenses, including break-down of costs to specific components including labor costs for installation and operational requirements. Who would bear the costs of the metering strategy?
- What additional system infrastructure (e.g., backbone communication infrastructure) does considered advanced metering system require? What protocols or standards would be required for interoperability? In the case that metering devices and other assets are provided by a third-party service provider, how would ownership and transfer of assets be managed if the customer opts to change service providers? How will ownership and transfer of customer data be managed?
- What grid services, customer services, and essential functions will the system support?
- 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.)?
- 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?
- What data will be collected, and for what purposes will it be used?
- Who will own the collected data, and how will access to data be managed?

- Will the system be able to control end-use devices within the consumer’s premise? How will information about controlled events be communicated to customers?
- How should cyber-security concerns be addressed on the system and how will customer data be protected?
- How will privacy concerns be addressed on the system described?
- How will individual customer load data be shared with third parties such as energy service providers (ESCOs), demand response providers, and energy service providers?
- 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?
- Does a scenario exist where utilities or third parties could offer a customer advanced services without a full scale deployment of advanced meters and what is the rationale behind the response? If not, what limitations would be required to change the response?

Commenters should provide as much detail and specificity as possible. In particular, parties should provide detailed comments and justifications for how proposed strategies would address the issues of asset ownership and whether a universal or more targeted deployment is recommended. Where helpful, strategies and system designs can be described in terms of both detailed business plans and engineering designs, in a similar manner as would be required for Commission approval of the investment or program design. To the extent that these plans can be described in detail, Staff and the Commission will be able to evaluate their merit toward achieving REV objectives, including in comparison to universal rollout of utility-owned advanced meters.

IV. SUPPLEMENTAL DSIP FILING

The utilities will collaboratively prepare and jointly file a Supplemental DSIP. It is expected that the utilities will begin their efforts on this document simultaneously with the development of the Initial DSIP, in preparation of filing the Supplemental DSIP with the Commission by September 1, 2016. In addition to coordination between the utilities, the development of the Supplemental DSIP will include a stakeholder process, as previously discussed and about which comments are being sought.

The purpose of the Supplemental DSIP will be to provide additional information necessary for long-term planning and coordination. The Supplemental DSIP will also be used to further develop the concepts presented in the Initial DSIP filing. By defining common processes or methodologies, the level of divergence across companies will diminish over time. DER penetration levels are expected to increase. Many of the items to be addressed by the Supplemental DSIP are intended to recognize that expectation and prepare for this development. With respect to planning efforts, the MDPT report seeks to enhance the process using additional analytical methods based on enhanced data and coordination among the utilities, NYISO, and stakeholders.[35] Therefore, the Supplemental filing is intended to identify the initial foundational approaches. As highlighted in the MDPT report, concepts including power flow management and integrating grid operations with market operations, including scheduling and dispatching of assets need to evolve as the market develops and DER deployment increases.[36]

The development of the market will result in additional issues to be coordinated jointly. This includes

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[35] MDPT at 46-47.

[36] Id. at 55-56.

establishing market rules, pricing granularity, and a process for market transactions.[37] Finally, the utilities need to develop the tools for market participants to readily access data in a timely manner to facilitate market participation.[38] The MDPT report identifies several data sharing considerations that should be considered by the utilities when developing the joint approach.[39] As previously identified, the process for the Supplemental DSIP should include an opportunity for outside stakeholder comments to allow for a transparent process.

The Supplemental DSIP shall address the following topics:

- Describe the stakeholder process used to develop the information provided in the Supplemental DSIP
- Distribution System Planning
    - o Plan and process to move from deterministic to a probabilistic modeling approach.
    - o Process to Identify Methodology for Estimating and Maximizing Host Capacity.
    - o Expand Monitoring Capabilities for Data Collection.
    - o Process for Performing Load Flow Analyses.
    - o Automated Interconnection Process consistently across the State.
- Distribution Grid Operations
    - o Plan and Budget for Communications and IT Infrastructure.
    - o AMI rollout policy.
    - o Identify where new protections need to be developed to provide Cyber Security for high DER penetration levels.
- Granularity of pricing
    - o Locational and frequency – Staff expects the DSP to develop substation level, hourly or sub-hourly pricing.

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[37] Id. at 61-69.

[38] Track I Order at 59.

[39] MDPT at 81.

- NYISO/DSP roles, responsibilities, and interaction
  - Holistically determine the obligations of the DSP and the ISO, including the aggregation and dispatch of distribution-level resources.
  - Determine the interactions that will occur between the DSP and the ISO at each transmission-distribution interface.
  - Identify tools needed for visualization of DER resources and for commitment and dispatch of resources for optimization.

- Data access to facilitate markets
  - Share data to enable third party engagement and market innovation, including but not limited to:
    - Customer data, with appropriate authorization
    - System information
      - DER hosting capacity
      - Loading and voltage data

- Market participant rules
  - Rules should recognize ongoing cases:
    - Regulation and Oversight of Distributed Energy Resource Providers and Products (Case No. 15-M-0180).
    - Review of Utility Codes of Conduct (Case No. 15-M-0501).

- Settlement procedures

- Approaches (Standard offer tariffs, RFPs, auctions, market transactions, and other means) for procuring DERs

- Joint System Planning and System Operations progress

V. CONCLUSION

The Commission directed Staff to develop guidance regarding the contents of DSIPs in consultation with utilities and other interested parties. To continue the collaborative efforts effectuated, comments are welcome and encouraged. Initial comments may be filed by December 7, 2015, and reply comments may be filed by December 21, 2015. Staff looks forward to continuing this discourse with other parties.