Report of the Market Design and Platform Technology Working Group

August 17, 2015

About This Report

This report culminates the work of the Market Design and Platform Technology Working Group (MDPT) in support of the New York State Public Service Commission's (PSC) Reforming the Energy Vision (REV) proceeding. Per the PSC's Track One Order, issued February 26, 2015, the MDPT stakeholder engagement sought to develop recommendations for consideration by the Department of Public Service (DPS) Staff as they develop guidance for New York utility Distributed System Implementation Plans (DSIPs) on near- and mid-term Distributed System Platform (DSP) market design and platform technology issues.

The combination of public feedback received to date and this report is being provided as a resource for the NY Department of Public Service's consideration in developing DSIP guidance and further development of the DSP market and platform.

The MDPT Working Group and advisors comprised a wide range of industry experts from across New York and across the nation. While the process facilitated by the Core Team[1] looked for common ground on many issues, it did not seek consensus nor have a formal process for resolving non-consensus issues. Instead, this report attempts to capture key themes and areas of non-consensus and, in many cases, suggests next steps in the REV process to address them. ***The report benefited greatly from the detailed work, contributions and deliberations of the MDPT Working Group and advisors and every effort has been made to capture key themes and fairly represent multiple perspectives. However, the material contained in this report does not necessarily reflect consensus views of MDPT Working Group members or advisors. Further, as stated above, the final report is intended to be an input for the NY Department of Public Service's consideration and does not represent Staff or the PSC's views.***

This effort could not have been possible without the tireless dedication of MDPT Working Group members and advisors, who devoted significant time, resources and energy to lend their expertise.

1 Comprised of representatives from NYS Department of Public Service Staff, Rocky Mountain Institute, and the NYS Smart Grid Consortium.

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Executive Summary

This report presents the work and recommendations[2] of the Market Design and Platform Technology stakeholder Working Group (MDPT) in support of the New York State Public Service Commission's (PSC) Reforming the Energy Vision (REV) proceeding[3]. Per the PSC's Track One Order, issued February 26, 2015, the MDPT stakeholder engagement sought to develop recommendations for consideration by the Department of Public Service (DPS) Staff as they develop guidance for New York utility Distributed System Implementation Plans (DSIPs) on near- and mid-term Distributed System Platform (DSP) market design and platform technology issues, in addition to developing related recommendations to the PSC to facilitate near- and mid-term implementation of the DSP market. This report seeks to advance REV objectives by summarizing stakeholder-informed recommendations for tangible and specific actions to help realize the Commission's long-range industry vision.

The MDPT Working Group and advisors comprised a wide range of industry experts from across New York and across the nation. Building off of previous REV stakeholder efforts,[4] MDPT Working Group members developed analyses and recommendations related to DSP functions and capabilities, as well as enabling platform technologies necessary to plan for and operate the market. Facilitated by the Core Team,[5] the MDPT process followed the principles of grid architecture, with a specific focus on current and potential New York markets at the retail and wholesale levels. Thus, the MDPT group assessed the policy objectives outlined in the REV vision to define the desired outcomes of the market, which inform the necessary required platform functions, capabilities and investments. The process considered how that architecture, including the role of various market participants and their interactions, might change as markets evolve.

The report assumes that the development of the DSP market will be sequential and iterative. The basic market structure is not expected to change dramatically during initial implementation. The report identifies several staged improvements to distribution system planning, market operations, grid operations and data access. These steps are essential to optimize interactions between the bulk system operator, utilities, distributed energy resource (DER) providers, and customers. Thus, the Working Group explicitly delineated development stages that consider important tradeoffs in planning the evolution of the DSP market.

2 The material in this report does not necessarily reflect consensus views of MDPT working group members or advisors.

3 State of New York Public Service Commission 2015

4 Reforming the Energy Vision Working Group 1 2014; Reforming the Energy Vision Working Group II 2014

5 Comprised of representatives from NYS Department of Public Service Staff, Rocky Mountain Institute, and the NYS Smart Grid Consortium.

A fundamental assumption of the MDPT group was that the DSP market structure, products and the DSP involvement and support of such markets should complement and not replicate the existing markets of the New York Independent System Operator (NYISO). The report recommends that DSP market participants should continue to have the ability to interact directly with NYISO programs. The foundational responsibility of the DSP should be to proactively manage and optimize distribution planning, grid operations, and DER markets at the distribution level – primarily for the purpose of cost effectively maintaining a safe and reliable system.

Accordingly, the overarching DSP mission recommended for the first five years of market development ("Stage 1"),[6] is to effectively procure DERs, using market means to the maximum extent appropriate, to directly address distribution system operational needs, and to avoid or defer the need for future distribution system capacity additions. While the electric utility hosting the DSP function will continue in its role as a retail energy service provider and provider of last resort (POLR) for all utility customers, the specific DSP functions as envisioned in this report do not include the purchase of energy for reselling from DER providers. However, the report does call for the DSP to begin investing in platform technologies to enable the functions and capabilities needed to support the continued and accelerated growth of DER markets.

Key Functions and Capabilities

This report proposes for consideration several key DSP functions and capabilities, including:

- **Enhanced Distribution Planning** – The report recommends enhancements to traditional distribution system planning to better integrate DERs into the distribution system, and improve coordination between distribution system planning and transmission planning activities in the state. The report recommends a Distribution Planning Working Group to immediately commence work to develop uniform methods for each utility to: inventory distribution system data that can be provided to market actors, calculate distribution hosting capacity and the locational value of DER, ensure the process is open and transparent, and integrate distribution and transmission planning.
- **Expanded Distribution Grid Operations** – The report recommends expanded distribution grid operations to better optimize load, supply and other power parameters at the local distribution level. These enhancements will enable the orchestration of multi-directional power flows resulting from increased DER penetration as the market matures, improved cyber-security, and improved load

6 The first five years of market development is the focus of initial utility DSIP filings.

and network monitoring and visibility to aid in situational awareness and rapid response to atypical e vents.

- **Distribution Market Operations** – A core function of the DSP is to develop and implement vibrant markets for distribution system products and services. Recommended DSP responsibilities in the areas of market operations can broadly be categorized as managing market operations and processes, and administering markets. Specific functions include identifying the standardized products to be transacted and the associated market rules with stakeholder and Commission involvement, maintaining an awareness of DERs system-wide, designing and conducting RFPs or auctions to acquire DERs, facilitating and processing market transactions, and measuring and verifying participant performance.
- **Data Requirements** – To support effective DER markets, the report recommends the DSP make available customer and distribution system data to market participants at a degree of granularity and in a manner that will best facilitate market participation. The report articulates the areas of need for specific types of data, the current availability of such data, data interface issues, and the specific data necessary for the DSP planning and operations functions. Due to the disparate nature of data acquisition system equipment deployment across utilities, the full range of system data needed to support the DSP market is not likely to be available on a universal basis at the outset. The expansion of data collection and availability could be prioritized for those areas that are in the greatest need of system capacity and operational relief.
- **Platform Technologies** - The MDPT report identifies a set of core technologies to support the functionalities identified with respect to system planning, grid operations, market operations, and data requirements. The identified technologies include: geospatial models of connectivity and system characteristics, sensing and control technologies needed to maintain a stable and reliable grid, optimization tools that consider demand response (DR) capabilities and the generation output of existing and new DERs in the grid. These tools will need to be supported by a secure and scalable communications network. The report also addresses the need to measure DER performance, recognizing that advanced metering may be needed to support DER installations, but also that any proposals for broad advanced metering infrastructure (AMI) implementation need to be accompanied by their own business case.

Key Recommendations for Staff's DSIP Guidance to Utilities

As DPS Staff develops guidance to the utilities regarding major components and analysis that must be included in their DSIP filings, the report proposes for consideration the following key areas for inclusion.

Distribution System Planning

1 Describe plans for addressing and integrating uniform analytical methods into current system planning processes, as well as overall planning schedules and milestones.

- a Identify specific locations within the distribution system that are the highest priority for distribution capacity and operational relief.
- b Provide an initial assessment of the capability of the distribution system to accommodate and host DERs. Describe how this assessment will be refined for future planning cycles.
- c Describe plans to complete a locational value analysis following a uniform methodology to determine short and long term forecasts of distribution marginal capital and operational costs.
- d Describe initial efforts to develop probabilistic and geo-spatial planning capabilities, and the schedule for integrating such methods into routine system planning.
- e Describe plans to inventory and share utility distribution system data, depending on the data acquisition systems in place, including but not limited to:
  - Planned capacity expansion projects
  - DER forecasts and load growth forecasts
  - Expected equipment maintenance
  - Planned voltage / power quality projects
  - Observed power quality violations statistics
  - Customer service complaints
  - Planned reliability / resiliency projects
  - Reliability statistics
  - Circuit models
  - Feeder-level loading
  - Customer type breakdown
  - Circuit node loading
  - Existing DER

2 Describe stakeholder involvement in the initial distribution system assessment, as well as in future distribution planning processes.

3 Provide a schedule consistent with PSC guidance for the submission and expected periodic updating of these results.

4 Describe specific plans for DER procurements and market-based initiatives to allow DER to help address identified distribution capacity and operational needs.

5 Describe plans for ongoing updates to DER mapping and installation tracking methods to track DER installations. Describe the technologies that will be used and the processes planned to keep this model up-to-date on an ongoing basis.

Distribution Grid Operations

Describe actions to be taken to ensure the DSP has the full capability set needed to meet Stage 1 REV objectives with respect to grid operations.

For each point below, provide plans for scaling these capabilities as (1) DER penetration, size and diversity increases and (2) market participation and liquidity increases.

1 Describe planned grid operations strategies to support planning and market operations to encourage DERs, while allowing continued reliable distribution system operation.

2 Describe plans to incorporate remote (de-centralized) and centralized real-time operational systems to monitor and optimize the operation of the distribution grid.

3 Provide an analysis of the potential operational opportunities, risks and power flow impacts expected with increased penetration of DER.

4 Describe plans to install advanced meters and/or other technologies to measure DER performance and exchange information with DER providers and customer participants.

5 Describe communications infrastructure capabilities planned to support the interactions with DERs and other customer participants.

6 Describe capabilities that will be implemented to perform monitoring and provide visibility into system load impacts of DER.

7 Describe operational policy or procedural changes that may be needed as a result of operating the system under increased penetration of DER. The DSIP does not need to include the actual policy or procedural changes but they should identify areas where changes would be required for Stage 1 to become operational.

  a Policy changes could be considered in the following areas and others as appropriate:

    i Specialized rules for use of DERs under stress conditions;
    ii Guidelines and/or constraints on the dispatch of certain DERs by the DSP, especially for assets being dispatched from the ISO, and under what conditions the DSP should adjust the dispatch of DER; and
    iii How DER services rendered to the DSP or ISO will be measured, verified and compensated.

- **b** Procedural changes could be considered in the following areas and others as appropriate:
  - **i** Safety procedures for de-energizing equipment prior to performing work on the distribution system, whether during planned or unplanned outage conditions;
  - **ii** Operator interaction with field personnel during planned and unplanned outage conditions;
  - **iii** Procedures for interconnecting DERs based on location and size;
  - **iv** Procedures and necessary conditions for turning certain DERs on or off by the DSP operator, for each type of DER; and
  - **v** Procedures for switching feeders to reroute power to take advantage of DER.

8 Describe methods that will be used to facilitate DER integration into grid operations and services, including direct and indirect dispatch of DERs, and communication and notification protocols recognizing that these may vary by size and other considerations.

9 Describe methods that will be used to coordinate distribution grid operations with the bulk transmission system, including operational visibility of DERs that operate in both NYISO and DSP markets.

10 Describe plans to enable distribution level ancillary services market for products such as localized volt/VAR optimization.

11 Describe the approach that will be taken to manage the risks posed by physical and cyber security.

Distribution Market Operations

Describe plans to ensure the DSP has the full capability set needed to meet Stage 1 REV objectives with respect to market operations, including:

1 Define the organizational structure and role of the market operations organization within the DSP.

2 Outline the outreach and coordination efforts that will facilitate the sourcing of assets for distribution grid services and development of distribution markets.

3 Outline a structure for coordinating resources, including an approach for coordinating among wholesale ISO markets, retail providers, and distribution operations.

4 Identify plans to integrate systems into utility operations using a common approach—developed across DSPs—for the following functions:

- **a** Measuring and verifying the performance of participating DERs.

- **b** Operating a communications portal, as well as the interface for managing market participant registration and activity.
- **c** Tracking schedules from DERs that have the ability to schedule their generation or consumption.
- **d** Managing settlements, including billing, receiving, and cash management including the interfaces needed with the utility CIS to perform cash management.
- **e** Managing disputes that will be developed to support the DSP market operations capability.

5 Outline the capabilities necessary to ensure market security, legitimacy, and optimization, and specify which entity(ies) should perform which functions.

6 Describe plans to provide longer-term signals to potential market participants and provide sufficient lead time to energy service providers and customers for successful market development

Data Requirements

The PSC will determine the processes to address standardized data platform issues, such as forums related to a digital marketplace. Consistent with such processes, utility DSIPs should describe plans to integrate a common data platform and model for customer, system, and DER data exchange across DSPs into their operations. At a minimum, utility DSIP filings should address the following:

1 Describe plans to provide customer data, depending on metering in place, to the common data platform, including the following:

- **a** Historical consumption (monthly kWh, or more granular if available)
- **b** Historical power factor
- **c** Coincident and non-coincident customer peak demand (kW)
- **d** Customer tariff
- **e** Customer charges
- **f** Reported outages
- **g** Service location
- **h** Power quality data
- **i** Customer complaints about voltage/power quality in the immediate vicinity of the customer

2. Describe the process by which the DSP will share data into scalable meter data interface solutions, such as Green Button Connect.
3. Describe the methods to provide customer data at the time interval required by the common data platform.
4. Describe the method by which data sharing will comply with existing privacy and data security requirements.
   a. Within this description, address aggregation thresholds beyond which anonymous and suitably masked customer-level consumption, billing and account information may be shared with third parties without explicit customer consent.[7]

[7] The PSC may need to make a determination on the application of privacy restrictions to circuit level data.

1 Introduction

1.1 Reforming the Energy Vision (REV)

On April 24, 2014, the New York Public Service Commission (PSC) initiated the REV proceeding to "transform New York's electric industry, with the objective of creating market-based, sustainable products and services that drive an increasingly efficient, clean, reliable, and customer-oriented industry."[8] To do so, the PSC seeks to "reorient both the electric industry and the ratemaking paradigm toward a consumer-centered approach that harnesses technology and markets."[9]

The Order stated six objectives for the initiative:

- Enhanced customer knowledge and tools that will support effective management of their total energy bill
- Market animation and leverage of ratepayer contributions
- System-wide efficiency
- Fuel and resource diversity
- System reliability and resiliency
- Reduction of carbon emissions

1.2 REV Process and Milestones to Date

As part of the April 2014 Order, the PSC separated the proceeding into two tracks. Track One pertains to the development of DSP markets, while Track Two focuses on ratemaking reform. Per the PSC's directive, DPS Staff elaborated on the REV vision in two key documents. First, in April 2014, DPS staff released their guidance, *Reforming the Energy Vision: NYS Department of Public Service Staff Report and Proposal* ("*Staff Report*"), which accompanied the PSC's Order instituting the proceeding. In August 2014, DPS staff issued *Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues*, ("*Straw Proposal*") informed by the Working Group, party comments, as well as research and discussions conducted by DPS staff. The *Straw Proposal* concluded that the REV vision is technically achievable and articulated desired principles that are fundamental to the achieve REV vision.

On February 26, 2015, the PSC issued the *Track One Order*, which lays out the regulatory policy framework and implementation plan to achieve REV. Among its directives, the

8 State of New York Public Service Commission 2014

9 State of New York Public Service Commission 2015, 3

Track One Order adopted Staff's proposed model of the DSP, stipulated the basic categories of the DSP's functions, and reinforced that the utility would act as the DSP. In addition, the Track One Order explicitly described the need for a working group to address the next level of detail around market mechanisms needed for planning, data needs, standardization across DSP markets, and interfaces with NYISO and other market participants. Furthermore, the PSC identified the need for a parallel group to identify a framework to evaluate necessary infrastructure, including communications and monitoring, support REV market design, and make recommendations to Staff on these topics.

1.3 Purpose and Objectives of the MDPT Working Group

As described in the August 2014 Straw Proposal, Staff noted that there was "significant work needed to further define, scope and plan for the full implementation of the DSP platform and market." Staff recommended a process, which included a Technical Platform Design Stakeholder Process and a Market Design Stakeholder Process, each with the objectives to further develop a proposal for Staff consideration related to the market and technology platform design for the DSP market with a particular focus on standardization.

As such, on January 8, 2015, Administrative Law Judge (ALJ) Julia Bielawski issued the following Ruling that commenced the MDPT Working Group Process:

> *"[S]taff should immediately select, convene and coordinate, with Rocky Mountain Institute and the New York State Smart Grid Consortium, two closely related groups addressing market design and platform technology. The groups will include in their membership representatives from different sectors of the electric market and industry, to be selected by Staff, and will engage market and technical experts to assist the work. The end product of these groups should include recommendations on market rules and technical standards. To facilitate the focus needed to accommodate an aggressive work schedule, the groups will be very small in size, but should periodically provide updates of their work to all parties."*

The Track One Order further elaborated on the purpose of the MDPT groups to "provid[e] guidance for utility DSIPs on near- and mid-term market design and platform technology issues, and any other recommendations to the Commission for actions needed to facilitate near- and mid-term implementation of the DSP market." Additionally, the MDPT groups are to "identify functional and business architecture for the DSP and DSP markets," and, to the extent possible, address a range of issues, including:

- Types of system data and timetables for system data availability,
- Information planning and real-time data and information needed by DER providers and by DSPs,

- Communications signaling and protocols,
- Near-, mid-, and long-term market mechanisms,
- Scheduling requirements,
- Measurement and verification (M&V) requirements,
- Settlement protocols,
- Data security requirements,
- Services to be provided by DERs and DSPs,
- DSP and ISO interface, and
- Standardization across utilities. [10]

Pursuant to the Track One Order schedule, the MDPT work plan filed March 31, 2015 further detailed the scope of work and included the focus areas of nine sub-groups tasked with developing the following interrelated outputs[11]:

Sub-group	Task
Market design 1	Identify DSP market actors & interactions
Market design 2	Identify DSP functional requirements & capabilities
Market design 3	Identify near-term products & transactional mechanisms
Market design 4	Identify use cases
Market design 5	Identify near-term data needs
Market design 6	Identify typology of market rules
Platform technology 1	Identify technology requirements to support DSP market
Platform technology 2	Develop technology deployment strategy
Platform technology 3	Identify technical capabilities of market participants
Platform technology 4	Identify standards for interfaces with DSP market

Table 1 MDPT Sub-Group Tasks

1.4 Out-of-scope of the MDPT Process

The focus of the MDPT effort is to recommend actions and infrastructure needed to enable near term DSP market functions. There are multiple policy decisions relevant to

10 State of New York Public Service Commission 2015, 42

11 New York State Department of Public Service 2015a

the DSP market evolution that may be required to support market actions when appropriate, but outside the scope of this MDPT effort. The policy decisions will be iterative and evaluated as the market develops. Consequently, many of the recommended actions in this report initiate ongoing market evaluation processes. Processes that are relevant to the development of REV policy, but outside the scope of the MDPT process, include:

- **Ratemaking reforms and performance-based ratemaking** – Track Two of the REV proceeding encompasses ratemaking issues including the utility business model and earnings opportunities, the ratemaking process, and rate design. On July 28, 2015, DPS issued a "Staff White Paper on Ratemaking and Utility Business Models" report for public comment. The purposes of the paper include: "1) describe the limitations embedded in current ratemaking practices in the context of REV, 2) describe the direction of comprehensive ratemaking and business model reforms, and 3) make recommendations for near-term reforms where possible."[12]
- **Benefit-cost analysis (BCA) and detailed cost evaluations** – An evaluation of the benefits and costs of investments is a prerequisite to be undertaken prior to determining undertaking any policy evaluation or investments. BCA is being conducted in a parallel process to the work of MDPT. While the underlying premise of considering the tradeoffs of benefits and costs was present in the MDPT work, a formal BCA is not in scope. Staff issued the Staff Benefit Cost Analysis Report on July 1, 2015.[13] The MDPT recommendations and BCA should be considered together to ensure coordination and consistency related to future investment decisions. [14]
- **Process for selecting and demonstrating REV demonstration projects** – As new business models and technologies enter the market, it will be necessary to demonstrate and evaluate the efficacy of these advancements. In the Memorandum and Resolution on Demonstration Projects, issued on December 12, 2014, the PSC encouraged the investor owned utilities to partner with third party energy entrepreneurs to undertake demonstration projects that would further the REV vision. This report suggests potential topics for continued demonstration projects to be undertaken by utilities.
- **Utility dynamic load management programs** – In December 2014 the PSC ordered each utility to develop a DR tariff and to collaboratively develop dynamic load measurement measures. These measures are relevant to the DSP

12 New York State Department of Public Service 2015d

13 New York State Department of Public Service 2015c

14 New York State Department of Public Service 2015b

market issues contained in this report; however, the DR tariffs themselves are not in scope.

- **Microgrid policies** – In the Track One Order, the PSC endorsed attributes of its policy toward microgrids and directed parties to submit comments on the microgrid proposal. While grid operations issues related to a network of microgrids are relevant to the MDPT process, the PSC policy toward microgrids is not in scope.
- **Consumer protection strategies and processes** – Ensuring equitable treatment for all consumers, regardless of their participation, is essential to the REV vision. The Consumer Protection Strategy and Proposal[15], issued by DPS in July 2015, highlights how consumers will be protected under a changing market construct. Through the proposal, the Commission will consider the extent to which it should oversee and regulate DER services, and identify the requirements to be applicable to DER suppliers, both in their interaction with consumers and with the DSP.
- **Development of a consumer-facing platform, or digital marketplace** – The Commission's Track One Order directed continued investigation of a digital marketplace linking DER providers and customers. The PSC will determine the appropriate process to address elements of the digital marketplace, to include the design, ownership, and customer data sharing mechanism. That investigation should include explicit consideration of customer data requirements described in this report, including DSIP requirements related to customer data. Additionally, DSP roles may include design, ownership and administration of this digital marketplace, subject to PSC approval.
- **Energy Efficiency Targets** – The utilities filed Efficiency Transition Implementation Plans (ETIPs) for the 2016 and 2017–2018 on July 15th, 2015. The ETIPs help to determine targets for energy efficiency going forward.

1.5 MDPT Group Members and Advisors

The 40 MDPT Working Group members included representatives from energy service and grid technology companies engaged in New York electricity markets, including each of the New York investor-owned utilities. These participants dedicated significant amounts of time and effort to contribute their expertise and critical thinking to produce the foundational work that created the basis for recommendations described in this report.

15 New York State Department of Public Service 2015e

MDPT advisors included national industry experts in grid architecture, grid modernization, energy markets, distributed generation (DG) integration and system design. Advisors provided their related expertise from a range of diverse initiatives including the GridWise Architecture Council, California's More Than Smart Initiative, and the Smart Grid Interoperability Panel (SGIP). They weighed in extensively on the market development and platform technology issues to ensure that the group's work was appropriately ambitious while realistic and met the long-term objectives of the REV effort.

1.6 MDPT Work Process

The MDPT Group process began in late January 2015 and included regular in-person meetings as well as small task team meetings via phone. The Core Team, composed of DPS staff, NYSSGC, and RMI, was responsible for convening and running the MDPT Group as well as managing final recommendations to Staff for their DSIP guidance to utilities. The sub-group members developed content and proposals within each of the sub-groups outlined above. The sub-group members provided their final work products in June 2015. The Core Team used these work products, along with input from advisors and DPS Staff, as a basis for the majority of the key recommendations contained in this report.

In order to be transparent and to incorporate feedback from the broader public, the MDPT Group provided drafts of their work products on the group's website (https://newyorkrevworkinggroups.com/) along with a form for interested parties to complete to provide feedback on each of the sub-group's draft work products. All in-person meeting notes and public feedback on the July 15 2015 public feedback draft were made available to the public for review. Public feedback addressed various aspects of the July 15 report, including MDPT process, recommendations, and follow-on processes.[16] Public feedback was taken in consideration in the development of this final revised report.

1.7 Types of Information Provided to DPS in this Report

1.7.1 Recommended Essential DSP Functions and Capabilities, and Other Foundational Actions Necessary to Support the Development of Robust DER Markets

This report includes recommendations that emerged from the deliberations of the MDPT Working Group regarding essential DSP functions and capabilities, as well as the

16 Public feedback is available here: https://newyorkrevworkinggroups.com/view-public-feedback-mdpt-report/

enabling technologies and systems, in the initial stages of the DSP market. This report was developed by the Core Team using the substantial work inputs produced by Working Group participants and advisors. While the process facilitated by the Core Team looked for common ground on many issues, there was no formal process for resolving areas of non-consensus. Therefore, the material contained in this report does not necessarily reflect consensus views of MDPT Working Group members or advisors. Every effort has been made to capture key themes and fairly represent multiple perspectives.

1.7.2 Recommended Elements to be Considered for Inclusion in Utility DSIP Filings

Pursuant to the Track One Order, utilities are required to file DSIPs containing investment plans related to DSP market development. The MDPT Report provides recommendations for consideration as Staff develops its guidance regarding major components and analyses that utilities should include in their DSIP filings. In particular, the recommendations suggest related functions that may be needed for system planning, grid operations, and market operations as well as the platform capabilities and data interfaces necessary to ensure those functions are met.

2 PSC's Guidance to Date Regarding Market Design, DSP Functions and Capabilities

In the Order Adopting Regulatory Policy Framework and Implementation Plan, issued February 26, 2015, the PSC provided guidance regarding several key Track One issues pertaining to the development of distributed resource markets. Key decisions included: the adoption of the REV policy framework, the DSP as the functional center of that framework, the role of the utility as the DSP, and clarification regarding initial products in the DSP market in order to prevent jurisdictional overlap over DSP activities.

The guidance provided in the Track One Order formed the basis for the work of the MDPT group. Key foundational elements that shape MDPT's understanding of the Stage 1 market design are described below.

2.1 REV Policy Framework

Within the Track One Order, the PSC provided a clear statement of the REV policy framework and vision:

> *"REV will establish markets so that customers and third parties can be active participants, to achieve dynamic load management on a system-wide scale, resulting in a more efficient and secure electric system including better utilization of bulk generation and transmission resources. As a result of this market animation, distributed energy resources will become integral tools in the planning, management and operation of the electric system. The system values of distributed resources will be monetized in a market, placing DER on a competitive par with centralized options. Customers, by exercising choices within an improved electricity pricing structure and vibrant market, will create new value opportunities and at the same time drive system efficiencies and help to create a more cost-effective and secure integrated grid…*
>
> *…The reformed electric system will be driven by consumers and non-utility providers, and it will be enabled by utilities acting as Distributed System Platform (DSP) providers. Utilities are responsible for reliability, and the functions needed to enable distributed markets are integrally bound to the functions needed to ensure reliability. Technology innovators and third party aggregators (energy service companies, retail suppliers and demand-management companies) will develop products and services that enable full customer engagement. The utilities acting in concert will constitute a statewide platform that will provide uniform market access to customers and DER providers. Each utility will serve as the platform for interface among its customers, aggregators, and the distribution system. Utilities will respond to new trends by adding value, thereby retaining customer base and the ability to raise capital on reasonable terms.*

Simultaneously the utility will serve as a seamless interface between aggregated customers and the NYISO. The NYISO will be able to reflect the impact of active load management in grid planning and operations, and the wholesale supply markets will evolve to properly value dynamic load management. The objective of system optimization extends beyond the physical integration of distributed resources. Central generation, large-scale renewable resources, and transmission are critical system components. Efficient integration of DER will require consistent treatment of market dynamics and values across all segments of the grid."

2.2 DSP Role and Functional Areas

To begin the transition of implementing this vision, the PSC adopted Staff's proposed model of the DSP as the functional center of the REV framework. In this adopted model, the DSP "will be regulated by the Commission, both in its new capacity as a market maker and system coordinator, and in its traditional function as distribution utility." The DSP's functions "fall into three general categories: 1) integrated system planning, 2) grid operations, and 3) market operations."[17] The PSC elaborated on these functional areas, which are described from the Track One Order below.

2.2.1 Integrated System Planning

The MDPT Working Group effort proposed that the DSP will administer the evolving role of distribution planning, which will need to be coordinated with NYISO's bulk system planning and increase transparency to support a robust market:

"…As a market enabler, the utility/ DSP will continue to have responsibility for distribution system planning and construction. However the planning process must also be sufficiently transparent to support the development of DER alternatives that meet current and future system requirements. The modernization of distribution systems must be accomplished in a way that meets and balances a variety of policy objectives... In order for this to occur, providers and customers must have access to information that allows them to make economically informed investments.

Integrated plans will include supply/demand planning, transmission and distribution (T&D) upgrades, and T&D maintenance. The NYISO will continue planning for bulk system upgrades, bulk generation forecasts, and transmission level ancillary service needs. The retail regulatory correlate of the DSP planning

17 State of New York Public Service Commission 2015,

function will be the Distributed System Implementation Plan (DSIP) which will be a multi-year plan filed with the Commission, subject to public comment, and updated regularly. The DSIP will contain (among other 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." [18]

2.2.2 Grid Operations

In its role as the distribution grid operator, this report proposes that the DSP will act as a conduit between end users, market participants and the NYISO wholesale grid operator in coordinating and optimizing DER to meet local-level distribution needs:

"DSP operational functions include real-time load monitoring, real-time network monitoring, enhanced fault detection/location, automated feeder and line switching, and automated voltage and VAR control. The DSP will commit and dispatch market-based DER and integrate net load impact information… thereby providing greater visibility and control of the grid. The monitoring and dispatch of DERs will complement the increased use of intelligent grid-facing equipment such as sensors, reclosers, switched capacitors, and voltage monitors. [19]

2.2.3 Market Operations, Structure and Products

While the DSP market structure, the products it transacts, and transactional mechanisms will evolve over time, Staff may consider that the successfully animated market may need to provide clear short and long-term signals to customers as to the benefits and costs of their market activity. Under PSC oversight, each DSP market will require standardization across the state, including conditions for market participation and product terms, as well as require coordination with NYISO:

A. Market Structure

"The structure of the market will be a function of the needs defined by the DSP and customers, the products available in the market and procurement mechanisms for those products, the identity and capabilities of market participants and their interactions among each other and with the DSP, and policy guidance of the Commission. Customers will realize the greatest benefits

18 State of New York Public Service Commission 2015, 32

19 State of New York Public Service Commission 2015, 32

from open, animated markets that provide clear signals – both long and short term - for benefits and costs of participants' market activity." [20]

B. Standardization

To attract investment and to enable DSP market liquidity across the state, there is a need to standardize several elements of the DSP market. Elements of standardization were described in the Track One Order.

> *"DSPs will need to establish a standardized market across the state. From the viewpoint of customers and service providers, there should be a single and uniform market platform. Prices and other geographically unique products can vary, both among utilities and within individual utility territories, but the conditions for market participation and even fundamental product terms must be uniform. This requirement extends beyond the 'common look and feel' of customer orientation, into the technical protocols and market rules to which aggregators and service providers must conform…"* [21]

C. Coordination with NYISO

As the DSP market evolves, the PSC suggested that additional coordination might be needed between the NYISO and the DSP.

> *"The DSP should also facilitate retail interactions with the wholesale market, in addition to operation of retail DER markets. Retail and wholesale operations should be coordinated to optimize system efficiency and full realization of the values of DER."* [22]

D. Products and Transactional Mechanisms

As described in the Track One Order, the DSP market construct aims to support the proliferation of cost effective and innovative clean energy related products and services provided by all service providers, in support of customer energy needs as well as grid support services. Products transacted and purchased by the DSP will be focused on the distribution grid services that will enable the DSP to optimize the distribution system, such as distribution capacity deferrals and voltage management and to meet State societal goals pertaining to superior environmental performance, enhanced resiliency, and resource diversity.

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20 State of New York Public Service Commission 2015, 32

21 State of New York Public Service Commission 2015, 33

22 State of New York Public Service Commission 2015, 33

> *"To avoid overlapping jurisdiction over DSP activities, utilities will not purchase power that would constitute a sale for resale under the Federal Power Act, except for purchases that are otherwise required by law (e.g. the Public Utilities Regulatory Policies Act and PSL Section 66-c)."* [23]
>
> *"Near term products procured by the DSP will include grid services such as peak load modifications, non-bulk ancillary services, and load management to enable investment deferral and more secure system operations… Initially DER can be procured through RFPs to meet particular system needs, or enabled by tariffs and programs designed to value investments that support price responsive load management and/or energy efficiency.*
>
> *Service providers will also be free to develop new offerings based on their assessment of customer needs and products offered by or to the DSP. Service products can include value-added electricity services, such as fixed commodity pricing, demand response and efficiency programs, or contracts for DER maintenance and operations. The market must also support alternative supply models such as community aggregation, microgrids and community based solar and/or storage…"*

Further, the PSC described the role of the DSP markets with respect to commodity service providers interacting in current retail markets, and its authority related to provision of electric service commodity.

> *Unlike the wholesale market, the markets that will be enabled and potentially operated by the DSP will not establish commodity prices. Commodity prices, the prices for capacity, energy and bulk ancillary services will be set by the NYISO.* [24]
>
> *Staff observes that while providers of commodity service (ESCOs) are subject to Commission supervision, REV will create new markets for other energy services beyond commodity (DERs)*[25] *The Commission will take an active role in establishing and enforcing consumer protections related to DER providers, as it has with ESCOs in the provision of commodity service.*[26]

23 State of New York Public Service Commission 2015, 43

24 State of New York Public Service Commission 2015, 50

25 State of New York Public Service Commission 2015, 101

26 State of New York Public Service Commission 2015, 104

2.3 Additional Market Enabling Activities

2.3.1 Data Access

The PSC further stipulated broad types of data that will be necessary to support market development:[27]

> *"Utility system information will be provided to the markets in two contexts. The multi-year implementation plans (DSIPs) filed by utilities and updated on an annual basis will contain system planning information sufficient to allow service providers and customers to develop products and marketing plans to meet system needs with DER services. Additionally, the DSP must make available system data at a degree of granularity consistent with the market that it operates, in a manner that is timely to facilitate market participation."*

2.3.2 Consumer Protection

To ensure consumer protection, the PSC clarified the Commission's role: [28]

> *"Where markets are created by order of the Commission, and managed by a DSP that is regulated by the Commission, the Commission has responsibility to ensure that customers and service providers can participate in those markets with confidence."* [29]

2.3.3 Guidelines for Market Design

In addition, the PSC adopted guidelines to govern market design [30]

1. Transparency: Timely and consistent access to relevant information by market actors, as well as public visibility into market design and performance;
2. Uniformity: Market rules and technology standards will be uniform statewide to encourage liquidity and participation;
3. Customer protection: Balance market innovation and participation with customer protections;
4. Customer benefit: Reduce volatility and system costs and promote bill management and choice;

27 State of New York Public Service Commission 2015, 59

28 State of New York Public Service Commission 2015, 59

29 State of New York Public Service Commission 2015, 102

30 State of New York Public Service Commission 2015, 44

5 Minimize market power: Develop DSP procurement tariffs to minimize the potential for market power;

6 Reliable service: Maintain and improve service quality, including reduced frequency and duration of outages;

7 Resilient system: Enhance system ability to withstand unforeseen shocks—including physical-, climate-, or market-induced—without major detriment to social needs;

8 Fair and open competition: Design "level playing field" incentives and access policies to promote fair and open competition;

9 Minimum barriers to entry: Reduce data, physical, financial, and regulatory barriers to participation;

10 Flexibility, diversity of choice, and innovation: Promote diverse product and program options in a competitive market including financing mechanisms to increase the value of those options;

11 Fair valuation of benefits and costs: Include portfolio-level assessments and societal analysis with credible monitoring and verification;

12 Coordination with wholesale markets: Align DSP market operations and products with wholesale market operations to reflect full value of services;

13 Economic and system efficiency: Promote investments and market activity that provide the greatest value to society, with consideration to identified externalities;

14 Avoidance or mitigation of emissions: Incorporate emission regulations and PSC policy determinations regarding local impacts of DG; and

15 Consistency with regulatory objectives and requirements: Function within Public Service Law (PSL) jurisdiction to the maximum extent possible in order to avoid overlapping regulatory regimes and provide products consistent with any applicable regulatory requirements."[31]

2.4 Utility Role

The PSC adopted the model of the regulated utility serving as the DSP[32] and limited utility engagement with DER to "sponsorship and management of energy efficiency programs; generation or storage of electricity on utility distribution property; and other

31 State of New York Public Service Commission 2015, 44 – 45

32 State of New York Public Service Commission 2015, 46

proposals for engagement specified in utility DSIPs."[33] Utilities will be allowed to own DER under the following circumstances:

- "Procurement of DER has been solicited to meet a system need, and a utility has demonstrated that competitive alternatives proposed by nonutility parties are clearly inadequate or more costly than a traditional utility infrastructure alternative;
- A project consists of energy storage integrated into distribution system architecture;
- A project will enable low or moderate income residential customers to benefit from DER where markets are not likely to satisfy the need; or
- A project is being sponsored for demonstration purposes."[34]

While the PSC limited the scope of the utility's direct participation with DER, the utility's role would be expanded via the set of DSP functions related to planning, grid operations, and market operations. These functions, as well as the platform technologies and capabilities enabling these functions, are described in the remainder of this report.

33 State of New York Public Service Commission 2015, 62

34 State of New York Public Service Commission 2015, 70

3 Framework of MDPT Approach

This section outlines the approach and considerations that guided the MDPT group's work. This framing included two basic concepts:

- First, in considering market design and related platform capabilities necessary to enable market animation, the MDPT group employed a basic "form follows function" approach. That is, the policy objectives outlined in the REV vision define the desired outcomes of the market, which inform required platform functions, capabilities, and investments.
- Second, the MDPT group recognized the development and maturation of the DSP market transition would be both sequential and iterative. Thus, the Working Group explicitly delineated development stages that consider important tradeoffs in planning the evolution of the DSP market.

These approaches are elaborated below.

3.1 Desired Outcomes Inform Necessary Functions, Capabilities and Investments

The MDPT group incorporated principles of grid architecture to guide the analytical process and scope of work. Grid architecture is a systems architecture approach to the electricity grid that focuses first on policy objectives and customer needs to delineate desired outcomes. These outcomes help to define specific system qualities and, ultimately, the system design and functional requirements. Thus, the REV policy objectives enumerated in the Track One Order form the basis of the desired outcomes. The MDPT group used the PSC's discussion in the Track One Order as the foundation upon which to further develop the recommended functions of the DSP. These functional recommendations provide the basis for proposed technical capabilities, and in turn, inform potential technology investment options and deployment strategy.

3.2 The Importance and Logic of a Staged Approach

The recommended evolution of the DSP market will be an iterative process, driven by statewide policy developments, DSP and market supplier actions and investments to optimize DER integration, changes to DER technological cost-effectiveness, operational experience and consumer demand. Implementing the REV framework will require conscious staging to minimize risk and maximize optionality as technologies, experience, and policies evolve. The key is to establish a line of sight while allowing for flexibility of the market to evolve.

Key staging considerations for Staff's use include the diversity and evolution of participant sophistication, diverse utility capabilities, overall costs and the distribution of those costs to customers, tradeoffs between economic efficiency and operational robustness and important social implications. These factors are elaborated below.

3.2.1 Diversity and Evolution of Participant Sophistication

Effective market planning and design recognizes the capabilities and myriad needs of customers – families, small businesses and industry. Customers are extremely diverse in terms of their electricity market knowledge and their ability and desire to stay at the cutting edge of technological adoption curve. As a small, but increasing, section of these participants may move from being passive consumers to active "prosumers," the future marketplace needs to be able to accommodate all customers despite their inherent diversity. Not all of these customers will be able or interested to fully participate or benefit from programs that are centered around and enabled by technologies such as smart thermostats, energy management systems, distributed storage (DS) and generation. Therefore, regulators may consider a toolkit of resources, which may include incentives, adjusting the pace of deployment, and preserving customer choice to cater to needs of the early adopters, while also ensuring that the "late adopters" are not penalized in the REV future.

3.2.2 Utility Capabilities and Systems

The six investor-owned utilities in New York have developed at different paces owing to unique customer demographics, geographies, financial, and operational circumstances. As a result, they have significantly varied infrastructure and organizational capabilities. Prominent differences include operational controls, practices, and tools, distribution network configuration and infrastructure, and modeling capabilities. As noted in the Track One Straw Proposal, "These differing starting points add a layer of complexity for utilities transitioning from their existing legacy systems to a DSP in a uniform way..." [35] Initial market development and related policies must be informed by these differences. However, to reduce transaction costs and attract DSP market actors and investment in DSP markets across the state, basic DSP planning, market and operational functions and interfaces should be standardized.[36] As stated in the Track One Order:

> *From the viewpoint of customers and service providers, there should be a single and uniform market platform. Prices and other geographically unique products can vary, both among utilities and within individual utility territories, but the conditions for market participation and even fundamental product terms must be*

35 New York State Department of Public Service 2014, Appendix A

36 Planning processes are utility specific. However the required analytical methods to be developed in the distribution planning group should be uniform. Utilities should integrate the uniform analytical approaches into their unique planning processes.

uniform. This requirement extends beyond the "common look and feel" of customer orientation, into the technical protocols and market rules to which aggregators and service providers must conform. [37]

3.2.3 Evaluating Benefit and Cost Tradeoffs

Upward cost pressure associated with peaking electrical demand, aging infrastructure, and flat sales are considered as motivating drivers in undertaking the REV proceeding.[38] While well-maintained and repaired over the years, New York's electric infrastructure is aging and, in many cases, reaching its end-of-service life. According to the Track One Order, "Based on planning reports filed by the state's utilities and the NYISO, approximately $30 billion will need to be spent over the next decade to maintain current capabilities, compared with $17 billion over the past ten years." The need for significant infrastructure replacement provides an opportunity to consider intelligent investment options that can serve to modernize the grid and leverage increasing amounts of DER to reap more benefits for each dollar invested.

Investment options to enable new functions and capabilities for grid modernization inevitably involve trade-offs between cost and the degree of operational benefit of those options. Initial costs associated with the range of platform technology options that could enable DSP functionalities must be evaluated in light of their operational benefits, total system costs, and the costs borne by customers and different customer segments. While more sophisticated and exacting technology solutions may yield robust operational benefits and optimize performance, these options may prove unwarranted from an initial and total cost perspective. Additionally, the increasing temporal and locational granularity to system operations adds significant complexity and should be considered against the potential incremental value potential to ensure net benefits. Testing and demonstrating a range of functionalities along the spectrum of efficiency and robust performance should yield optimal efficiency solutions to be deployed at a larger scale.

Investments in distributed renewable resources and distribution network upgrades must be made strategically. The costs and benefits depend on a number of factors including current DER penetration and grid hosting capacity, the location of installation of DERs and the presence or absence of additional equipment such as smart meters or inverters that could mitigate the need for some of these expenditures.[39] Further, more-accurate valuation of these benefits and costs to the grid and society will be required. Careful staging and planning is needed to ensure that any near-term impacts, and costs to all

37 State of New York Public Service Commission 2015

38 State of New York Public Service Commission 2015

39 EPRI 2015

consumers are minimized. In early stages, strategic deployment of capital and resources, such as targeting locations on the distribution network requiring capacity relief, can optimize cost and benefit.

3.2.4 Optionality and Risk Mitigation: "Future Proofing"

The electric industry is in an era of rapid technological change. In an industry in which asset lifespans have traditionally lasted 30 years, the evaluation of new technology investments requires renewed focus on strategic risk assessment. Risk assessments must factor the uncertainty associated with the future technology landscape and mitigation of stranded assets. Technological advances will also require consideration of changes to regulatory frameworks in order to better position regulated entities and their customers to achieve policy goals. Meanwhile, DSP market investors and entrepreneurs will require a minimum threshold of certainty in the basic rules and standards within which they are required to operate in order to attract capital and remain viable.

Consequently, achieving the REV vision requires planning, testing, learning, refining, and, where appropriate, setting rules and standards. Utilities, market participants, and regulators will learn from initial DSP investments and demonstrations and iterate in future evolution of the DSP markets. A phased approach in initial stages should serve to mitigate risks of capital deployment through adoption of least-regrets measures. A phased approach is proposed to include evaluation of targeted deployments in the initial stage that test options to expand distributed market opportunities through careful planning and demonstration projects. These considerations with respect to utility investment in DSP capabilities must also be informed by, and balanced with, the objective of creating a strong sense of confidence in the DSP markets to support third-party investment in DERs.

A component of the REV initiative is to shift some of the risk of capital exposure away from ratepayers to the private sector, which can more rapidly respond to technological change and manage risk accordingly. Accordingly, new DSP functions should be considered, where possible, for their interoperability with privately funded technology options to integrate state of the art systems and interfaces, but must also consider the cost of upgrading legacy functions.

3.2.5 Social Implications

The PSC, and the utilities it regulates, has the public responsibility to provide safe, reliable service at reasonable rates. The impact of electric service is particularly relevant to lower income customers that have fewer resources to pay for electricity costs. Utility programs and investments are also considered in light of their potential social benefits and costs - including environmental attributes, public safety, and resiliency - that extend beyond traditional quantifiable costs and system benefit calculations. In many markets such as New York, benefit-cost frameworks are in the process of evaluating how to appropriately represent social benefits in determining the cost-effectiveness of utility investments.

The DSP market structure should benefit utility customers and society by reducing overall electric system costs, while sharing the multi-faceted benefits of increased DER adoption, as well as reward market investors for their participation. To achieve these benefits, the DSP market structure and functions must recognize customers have differing needs and levels of sophistication. The goal as state in the Order is: "If REV markets are properly structured and supervised, utility customers will not need to participate directly in order to benefit from them." [40]

3.3 Defining Implementation Stages

In light of these considerations, the MDPT Working Group proposes the first stage of the DSP market ("Stage 1") is the period from DSIP Plan approval by the PSC through the first five years of development and implementation. Activities related to market development and maturity after five years are suggested as "Stage 2." The primary focus of the MDPT group was on Stage 1. This timeline is consistent with the utility investment forecast over the same period as contained in capital plans in DSIP filings.

3.3.1 Stage 1: 0–5 Years (2016–2021)

Stage 1 initiates the development of the DSP market and is approximately proposed as the first five-year period.

A. Phase 1: 0–2 Years

Phase I, within the first stage, should include foundational planning, demonstration projects and investments to create and develop the DSP functionalities and capabilities that will support a vibrant market for customer engagement and private investment in the DER market.

B. Phase 2: 3–5 Years

Phase 2 should reflect the growth of the DSP market. This may include continuing to develop DSP capabilities to enable economic DER growth and the increasing integration of DER into DSP planning and operations as well as statewide transmission and bulk power system planning and operations.

40 New York State Department of Public Service 2014, 31

3.3.2 Stage 2: 5+ Years (2022+)

The market will continue to evolve in order to accommodate the best technologies and improvements in market mechanisms and should demonstrate measurable increases in the number of DERs deployed, the extent of customer engagement, and the vibrancy of third-party investor activity in DERs.

4 Ingoing Assessment Regarding Market Scope and Stages

4.1 DSP Evolution

DER adoption in New York is geographically disparate and growing at varying rates across the state and within utility service territories. Most circuits in New York are not at a mitigation threshold level requiring immediate mitigation or advanced solutions to maintain required reliability and safety of the network. However, the suggested development of DSP market and platform technology can provide a measured pathway to proactively lay the planning and operational foundations for increased DER adoption levels.[41] The recommended stages of market and platform technology development, graphically presented below, consider this measured approach. At each stage, market design evolution may include expanded DSP functionality, new products and services, and greater market activity and transactions. Some aspects may occur more rapidly, depending on technology and policy developments. However, the milestones presented below for Staff's consideration are intended to provide an overview of this along the phased approach.

41 Staged evolution discussion informed by: P. De Martini and L. Kristov 2015, forthcoming, Distribution Systems in a High Distributed Energy Resource Future, Future Electric Utility Regulation Series, Lawrence Berkeley National Laboratory, pre-publication draft.

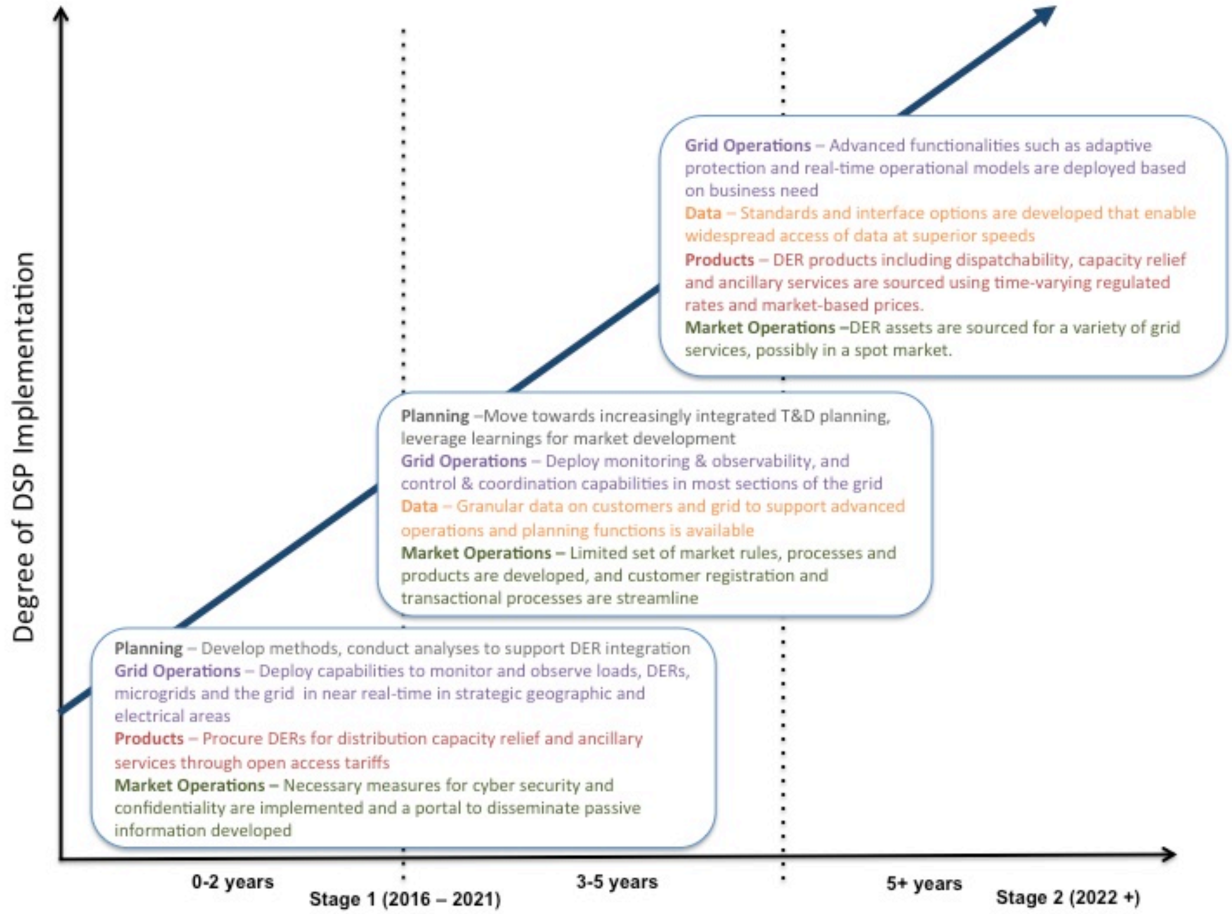

Figure 1 DSP Evolution

4.1.1 Stage 1: Phase I

The initial years of Stage 1, Phase 1 (0–2 years) may be characterized by foundational investments in platform technologies to support DER adoption and build operational capacity in the DSP market. Utility investments in DSP platform technologies, described in their DSIP filings, will begin to augment existing capabilities, and build the technical foundation required for later stage DSP planning, grid operation and market operation functions. To support the goals of market animation and customer engagement, it is important to also recognize the need for granular and timely data about customer usage and DER performance.

Primary activities are anticipated to include: removing any existing barriers to cost effective DER investment in order to increase the DER asset base, establishing necessary analytical processes for strategic DER integration at a much larger scale, and creating the data sharing mechanisms essential for the development of DER business cases. Thus, during Phase I, a key focus will be to solidify appropriate analytical methods and necessary data for evaluating the temporal and locational value of DER and the hosting capacity of portions of the distribution system to integrate DER, and communicating that information to the marketplace to enable early-mover customers and DER providers to move ahead with DER projects.

Strategic demonstration projects and rollouts will supplement market response to planning and pricing signals. For example, procurement of distribution system capacity relief in targeted areas, such as ConEd's Brooklyn Queens Demand Management (BQDM) project will be tested and provide results. These non-wires alternatives projects are opportunities to validate the capabilities of DER technologies, in order to give grid operations more confidence in DERs. Further, uniform retail DR programs initiated by the Track One Order will allow retail customers and DER aggregators to gain increased experience with demand side management (DSM), and build the foundation for greater DER utilization in later stages.

Further, since a core goal of NY REV is to 'animate the markets' and integrate customer resources as tools in the planning, management and operation of the electric system, a set of metrics that progressively measure success should be developed early in Stage 1 to ensure that DERs are being more broadly utilized, their benefits monetized and considered on par with traditional utility solutions. Some of the metrics suggested by MDPT Working Group members include the number of new DERs, MWs transacted in DSP markets, transaction volumes and new services introduced.

Additionally, this period will include increased efforts to educate and engage mass-market customers, who often lack the granularity of consumption data and the tools to better understand and act on that information. However, many mass-market customers in this stage will likely remain passive as foundational elements of the market are laid, including the deployment of advanced metering functionalities (AMF) to enable timely access to granular consumption data.

4.1.2 Stage 1: Phase 2

The second half of Stage 1, or "Phase 2," will reflect anticipated continued growth of the DSP market. Some DER growth will be disparate yet developing at a faster pace, due to procurement of DERs focused in certain geographic areas in need of capacity relief and therefore along specific electric feeders. Market participants will have the benefit of learning from data from Phase 1 implementation and demonstration projects, developing business cases aligning with distribution system needs.

In Phase 2, planning practices will continue to evolve. An initial assessment of grid hosting capacity across each utility will be complete. Methodologies to ascertain locational value of DERs would be fully developed, at least at the substation level, and employed actively by the DSP and the PSC in communicating the locational value of DER to the marketplace and evaluating various non-wires alternatives.

Phase 2 should also likely see the emergence of tariffs that are informed by the locational values of DERs across the distribution system. However, should the locational information be available sooner, the development of associated tariffs would be accelerated as well.

Several pilots to test advanced grid operation functions, such as adaptive protection, advanced sensing, communication and control, could be set in motion at more critical portions of the distribution grid to better understand the economic implications of implementing such systems, their benefits and the engineering aspects of bi-directional flows on radial distribution systems.

Lastly, standardized data platforms that disseminate market and event data to interested parties will be established and made operational to enable competitive market response, and to allow researchers and investors to identify new opportunities for market development. As a greater portion of customers move from being passive consumers to active participants (e.g., prosumers), several DER providers, aggregators and third-party participants will begin to enroll customers for a variety of products and value added services.

4.1.3 Stage 2

The end of Stage 1 will be an important milestone to assess progress against DSIP installation forecasts and progress milestones. Policy makers and DSPs should consider Stage 2 as an opportunity to recalibrate and reassess strategies to ensure continued cost-effective technology deployment. Stage 2 will be characterized by increasing momentum of DERs interconnected onto the system, which may require operational changes to distribution systems.

Experiences with demonstration projects and early competitive DER deployments will inform subsequent planning efforts with verified results of DER availability and performance. Analytical capabilities will enable location based system marginal cost forecasting and hosting capacity analysis at a majority of circuits in the utility distribution system beyond the substation level. Increased coordination in forecasting and modeling activities will enable an ever-increasing number of DERs to provide services to the DSP and NYISO markets.

DER products will begin to be sourced through increasingly sophisticated procurement mechanisms ranging from auctions to time-varying tariffs, on their evolutionary path to market-based price mechanisms. Given that a new set of market rules are expected to be fully developed to enable DERs at this stage, and technological upgrades would continue to be incorporated, Transactive energy-related communications and transaction initiatives, perhaps tested in pilots and demonstrations during Stage 1, may move to broader implementation. Such transactions may require regulatory changes. However, rule development is not static but is rather an evolutionary process that constantly adapts and at times pre-empts technological, market and customer needs.

The DSP's grid operations will move increasingly towards real-time monitoring and observability of the grid and connected microgrids, DERs and loads, and advanced control and coordination of these assets to maintain reliable and safe grid operations. DSPs would be capable of "coordinating" with DERs to increase system reliability even in the face of abnormal voltage or power flow conditions. Increased automation, and advanced control and communication protocols supported by remote-controlled switches will begin to be deployed through the grid to enable advanced functionalities, for example to re-route multi-directional power flows through alternative feeders, and also island and isolate some sections of the grid with its own dedicated DERs in near real-time, all while keeping the system operational.

In Stage 2, new standards and interface options will be developed that will enable widespread data access by customers and third-party suppliers that have obtained customer consent that will aid in the development of an ever expanding, heterogeneous market place. Further, communication protocols and infrastructure that enable higher speed data access for multiple communication devices and DERs. A wider array of companies participating in DSP markets will offer customers an expanded set of products and services, further enhancing customer engagement opportunities.

4.2 Important Assumptions Regarding Market Scope and Design

For clarity, the following assumptions apply to the DSP market structure based on the PSC's guidance and the expertise of MDPT members and advisors.

4.2.1 DSP Relationship to Wholesale Market

Today, DERs are assumed to function as either supply resources or load modifications (e.g. DR) that can participate in NYISO markets, providing wholesale services including energy and generation capacity, where those resources either meet the minimum requirements (including minimum size requirements).[42] **A basic assumption of the MDPT group is that the DSP market structure, products, and basic market sourcing methods, should complement and not replicate existing NYISO wholesale markets.** Thus, DERs may continue to be able to provide wholesale market services to the NYISO, either

42 Under the jurisdiction of the Federal Energy Regulatory Commission (FERC), the NYISO manages the reliable flow of power across New York's high-voltage transmission system ("Bulk System Operations"), administers and monitors the state's wholesale electricity markets ("Bulk Market Operations") and conducts transmission-level planning ("Bulk System Planning"). NYISO's wholesale markets encompass the procurement of energy, generation capacity and ancillary services necessary to achieve economically efficient, safe and reliable operations of NY's electricity system. See Appendix A1.5 for existing NYISO market information.

directly or via aggregators, which will maintain revenue streams currently available to DER owners.

An important implication, which is described above within market staging and further expounded upon within the implementation sections below, is the recommended need for coordination between the NYISO and the DSP across the planning and operations of the T&D systems, especially as DER penetration increases. For example, NYISO and DSP market rules may need to address the conditions for DERs to bid in capacity to participate in both distribution and wholesale markets to ensure reliable operations.

4.2.2 DSP Scope and Relationship to Other Utility Functions

As already clarified in the Track One Order, the PSC decided that the role of the DSP would be undertaken by the existing distribution utilities in New York. Thus, the MDPT Working Group begins with that base assumption. However, in the process of attempting to delineate the functions of the DSP, it became clear that the fact that the distribution utility might be authorized to perform the DSP and traditional utility as well as load serving entity (LSE) functions, by acting as the POLR, complicated the task of defining the DSP.

The recommended DSP and its functions, including distribution system planning, and grid and market operations, are distinct from providing energy to end-use customers, which is an LSE function, and also distinct from many traditional utility functions (e.g., substation and distribution construction and maintenance). **The report recommends that a foundational responsibility of the DSP is to proactively manage and optimize operations, planning and DER markets at the distribution level to achieve a safe, reliable distribution system.** In that capacity, a significant portion of its role at the distribution level is analogous to the role that the NYISO plays at the wholesale level. Again, that is not to say that the distribution utility in which the DSP group resides cannot also provide retail service to end-use customers, but that function is not directly related to the functions of the DSP. Additional detail regarding the potential organization and functional separation of the DSP is included in Section 5.4.

4.2.3 DSP Market Actors

In addition to the DSP, the primary actors in the DSP market include energy services companies (ESCOs), aggregators, DER service providers, and active end user participants. As discussed, in the first stage of the market, it is suggested that there will be a "one to many" market construct in which the DSP is the primary procurer of distribution system products. However, competitive service providers, such as ESCOs or Aggregators, may also aggregate DERs, manage their operations and the interface between active end users with DERs and provide these services to DSP and NYISO markets. These service providers play a critical role in driving innovation and customer satisfaction.

As envisioned in the Track One Order, a robust DSP market will enable service providers to:

> *"develop new offerings based on their assessment of customer needs and products offered by or to the DSP. Service products provided by competitive energy service providers can include value-added electricity services, such as fixed commodity pricing, demand response and efficiency programs, or contracts for DER maintenance and operations. The market must also support alternative supply models such as community aggregation, microgrids and community based solar and/or storage."*

4.2.4 Stage 1 Products Procured by the DSP

Given the scope of the DSP described above, the initial products transacted via the DSP market are proposed as those electricity services that DER could provide as better or more effective alternatives to traditional infrastructure investments and operational expenses to support the reliable operations of the distribution system. Thus, recommended initial products priced and transacted within the DSP market could include distribution capacity relief or deferral, voltage management, reduced line losses, and other products providing distribution system reliability and resiliency benefits.

Importantly, at the outset of the DSP market, energy is not considered as a DSP market product. As stipulated in the Track One Order, a transaction that could be considered a sale for resale remains in the jurisdiction of FERC and the NYISO wholesale market. Thus, the benchmark for the hourly price of energy is still priced in the wholesale spot market at the locational-based marginal pricing (LBMP) node[43] regardless of whether it is produced above or below the transmission-distribution interface. Once the foundation of the DSP market is established, and jurisdictional issues resolved, the potential for developing an energy market at the distribution level, including the potential to incorporate elements of transactive energy can be further explored. The development of a distribution energy market would mean that active market participants could buy and sell energy among each other at the distribution level in situations that potentially bypass the transmission system. However, as noted by the PSC in the Track One Order, this could constitute a sale for resale and may require regulatory changes.

43 In the NYISO energy spot market, the price of wholesale energy represented by LBMP is the marginal cost of generation to produce the unit of energy, the cost of transmission congestion, and the transmission losses experienced in delivering it. While there are over 2200 load busses and over 900 generation busses within the NYISO transmission network that represent unique points of power withdrawal and injection, LMBPs across New York are ultimately averaged across 11 NYISO system zones based on difference from the central Marcy bus.

A. Distribution Capacity Relief

Distribution capacity relief represents the ability of DERs to favorably reduce the loading on distribution facilities, including substation transformers and breakers, feeder lines and transformers, and defer or avoid upgrades to those facilities, such as in the ConEd Brooklyn-Queens Demand Management project. Distribution-level capacity relief is an option where load growth creates a need to manage peak load levels on the system, either through upgraded distribution facilities or through DERs to reduce or offset demands through local generation or demand reductions. The additional value stream representing distribution capacity relief would be based primarily on the avoided cost of the 'traditional' upgrades.

To fully achieve the objectives of REV, however, Staff may consider an additional aspect of potential distribution-level capacity relief should be considered. In this aspect, there is no specific capital upgrade project identified, but it is understood that reduced peak loading on the distribution facilities has benefits in terms of lowered maintenance, extended life and lowered exposure to load-related failures. By validating and quantifying that value and then making it visible to the marketplace, DERs would have the ability to choose locations on the distribution system that will have the most positive impact.

B. Distribution Ancillary Services

Distribution ancillary services provide support for the reliable operation of the distribution system and include steady-state voltage management, and reliability or resiliency. To ensure a reliable and safe distribution system, the DSP would act as the conduit for the utility in procuring these services. Some DERs are well suited to provide this service, including synchronous generators and those with smart inverters that can adjust their voltage or power factor in response to conditions sensed on the distribution system.[44]

Further discussion of the evolution of products, including services that will likely be offered by either the DSP or other providers, is included in Appendix A1.4.

4.2.5 Evolution of Transactional Mechanisms

As enumerated in the REV vision, a recommended primary function of the DSP is to gain an improved awareness of the locational and temporal cost of operating, maintaining and expanding the distribution grid – in both short-term and long-term time scales. The identification of marginal distribution costs can serve as the basis for incentives that the

44 Reference expected or needed changes to Institute of Electrical and Electronic Engineers (IEEE) standards to enable these services.

DSP can provide to DER providers and customers that offer resources allowing the utility to avoid or defer these costs.

Thus, an assumed intent during the initial stage of DSP market implementation is to incent cost effective DER through its proper valuation. A spectrum of pricing mechanisms exist that could be used to source and transact related market products that the DSP identifies would meet operational specifications to support the reliable operation of the distribution system. This spectrum of transactional mechanisms varies across a continuum based on required data and sophistication. The PSC described this evolutionary continuum in the Track One Order:

> *The modernization of New York's electric system will involve a variety of products and services that will be developed and transacted through market initiatives. Products, rules, and entrants will develop in the market over time, and markets will value the attributes and capabilities of all types of technologies. As DSP capabilities evolve, procurement of DER attributes will develop as well, from a near-term approach based on RFPs and load modifying tariffs, towards a potentially more sophisticated auction approach*[45].

The Track One Order elaborated on the importance of staging these types of transactional mechanisms: "Without predetermining outcomes, we expect that DSP markets in initial stages will consist primarily of open access tariffs as opposed to auctions. Development of auction-based markets must be undertaken with care to avoid potential exercise of market power by DSPs, DSP affiliates, or dominant DER providers."

Especially at the outset, establishing a robust DSP market environment does not require real-time spot market auctions or providing variable distribution rates based on location and time to end-use customers. Rather, as advisors to the MDPT Working Group suggest,[46] these options can be framed across an evolutionary continuum based on the type of product procured,[47] investors' and developers' needs for risk mitigation and commercial bankability, the liquidity of the market and the need to mitigate market power.

Just as there will be a portfolio of different types of DER that will be sourced as alternatives to traditional infrastructure investments to meet operational requirements of the distribution system, there will be an analogous recommended portfolio of

45 State of New York Public Service Commission 2015

46 P. De Martini and L. Kristov 2015, forthcoming, Distribution Systems in a High Distributed Energy Resources Future, Future Electric Utility Regulation Series, Lawrence Berkeley National Laboratory, pre-publication draft.

47 Elaborate: Voltage regulation versus distribution system capacity. Pricing time periods can typically be longer than the response time required for performance. For example, a fixed price can be provided to a smart inverter to provide voltage service that involves second-by-second response.

transactional mechanisms used to source those DER services. Especially starting in the first two years of Stage 1, these transactional mechanisms are expected to include:

1 **Procurements** – Targeted DER services sourced by the DSP through competitive acquisition.

2 **Programs** – DER sourced through NY's redesigned energy efficiency and DER programs administered by NY's LSEs.

3 **Prices** – DER response through time-varying regulated rates and market-based prices.

5 Implementation: Key Recommendations Regarding DSP Functions, Platform Capabilities and Organization

The following section presents key recommendations regarding DSP functions, capabilities, and organization. These recommendations take into account the PSC guidance enumerated in the Track One Order and key assumptions regarding the DSP market scope as described in Section 2.

These recommendations outline the functions of the DSP at various stages of market maturity that are necessary to encourage DER market development, integrate increased levels of DER and optimize the value of the DER while minimizing potential adverse impacts to the system. The primary focus of this section is Stage 1, or the first five years of transition. Recommendations are arranged in the following functional areas: distribution system planning, distribution grid operations, distribution market operations, data requirements, and distribution platform capability requirements.

Where possible, these recommendations reflect the consensus opinion of the Working Group members and the Core Team. However, the group did not achieve consensus on all recommendations. Therefore, differences of opinion are noted throughout this section.

5.1 DSP Functions

5.1.1 Distribution System Planning

Existing distribution system planning approaches are largely deterministic, and often based on established dispatch and flow patterns, typical system stresses, and known congested paths. However, the uncertainty of the types, amount, and pace of DER deployment complicates traditional distribution planning that often spans up to a 10-year time horizon. To better identify and integrate DER as a major means of meeting distribution utility infrastructure and operational needs, enhanced planning approaches are needed.

New planning methods have been the focus of a number of electric industry and regulatory forums. The Electric Power Research Institute (EPRI) has introduced both a proposed planning framework and a calculation methodology to assist utilities in assessing the ability of distribution systems to "host" DER capacity, and in calculating the locational benefits of DERs.[48] Meanwhile, in California and Hawaii, integrated distribution planning initiatives are underway to address engineering and economic

48 EPRI 2015; Lindl et al. 2013

valuation issues in a cohesive and multi-disciplinary fashion, with stakeholder participation. In California, in response to a California Public Utilities Commission (CPUC) ruling,[49] on July 1, 2015 utilities filed[50] Distributed Resource Plans to incorporate DER into distribution planning and operations processes.[51] Distribution utilities in Hawaii were similarly directed recently to evolve to Integrated Distribution Planning.[52] These processes offer potential methodologies and guidance that DPS Staff and New York utilities may consider as they develop DSIP guidance and DSIP filings.

The foundational elements of enhanced planning[53] are described further below. These elements of enhanced planning as they contemplate the market's design. They include: identifying and developing appropriate analytical methods, obtaining accurate planning data, determining how best to engage key stakeholders, identifying appropriate methods for considering hard-to-quantify benefits, and establishing methods for better integrating distribution planning with transmission planning. In addition to new analytical tools, there will also need to be a high priority placed on the proper training of a new generation of utility distribution system planners. Further, the timing of these recommended enhanced planning activities will need to be linked with DSIP Planning cycles and other regulatory processes, such as utility rate cases, and State energy planning efforts.

Some of these elements are already being introduced, to varying degrees, in New York's current utility planning efforts, while many are still in the early developmental stage.

Necessary Analysis:

- **Determine baseline integration capacity** of the distribution grid to integrate or "host" DER.
- **Identify the locational net value of DER** within the distribution grid.
- **Administer an efficient DER interconnection process** to accommodate the expected increased scale of requests.

49 California Public Utilities Commission 2015

50 California Public Utilities Commission 2015

51 California Public Utilities Commission Distribution Resources Plan Rulemaking (R. 14-08-013). http://www.cpuc.ca.gov/PUC/energy/drp/

52 HB 1943 Lee et al. 2014

53 Informed by: P. De Martini and L. Kristov 2015, forthcoming, Distribution Systems in a High Distributed Energy Resources Future, Future Electric Utility Regulation Series, Lawrence Berkeley National Laboratory, pre-publication draft; Bell, Mathias, Virginia Lacy, Jon Creyts and James Sherwood. 2014. Bridges to New Solar Business Models: Opportunities to Increase and Capture the Value of Distributed Solar Photovoltaics; EPRI. 2015. The Integrated Grid – A Benefit-Cost Framework. Palo Alto, CA.

Recommended Approaches:

- **Develop appropriate analytical methods**, building upon existing work, which differs in several aspects for radial- and network-based systems.
- **Utilize multiple DER adoption scenarios** when conducting grid planning, linked with a shift from deterministic to probabilistic engineering methods.
- **Obtain accurate planning data; Develop improved geo spatial knowledge and analysis capabilities** of all distribution system assets – both utility and non-utility owned.
- **Develop an integrated T&D planning process** that would require close coordination among the distribution utilities, the NYISO and stakeholders.
- **Develop a planning process that actively engages stakeholders.**

A. Scenario-based, Probabilistic Distribution Planning

To accommodate increased uncertainty, enhanced planning will require multiple DER growth scenarios to assess current system capabilities, identify incremental infrastructure requirements and to enable the analysis of the locational value of DER. Probabilistic methods address, among other things, the random variability associated with intermittent supply resources and net customer load due to DER use.

B. Interconnection Studies

The processes to accommodate the expected increased scale of requests from customers and DER providers seeking to interconnect with the utility need to be re-examined to ensure that the processes complement, integrate with, and fully support the updated utility planning and grid operation approaches.

The DPS does have a separate initiative underway to address interconnection issues and it is important that the effort is coordinated with efforts to improve distribution utility planning processes.

C. Hosting Capacity

The hosting capacity is the threshold level of DER penetration on a given distribution circuit that could be integrated without additional upgrades or expansions. Hosting capacity not only differs by "topology, configuration and physical characteristics" [54] of the specific area of the distribution grid, but also by the type and distribution of DER that would be integrated. In addition, utilities should analyze whether there are more sophisticated protection schemes or relays that will enable greater penetration of DERs and bi-directional flows.

54 For more information see EPRI 2015.

D. Locational Value of DER

DER benefits and costs vary based on location and time. The locational analysis may focus at the distribution substation level as a start, however, the longer-term objective is to extend this analysis to a lower level in the distribution system and on shorter time durations as may be desirable to optimize the distribution system and facilitate future market development. This also requires an evolution from current planning approaches, the identification of a pathway towards greater locational and temporal granularity, and needs to consider the trade-off between potential increase in economic optimization and the related increase in operational complexity and any associated risk.[55]

Implementation:

- Stage 1: The components of the locational value of DERs and the methodology to calculate it, at least at the distribution substation level, is expected to be considered and recommended by the proposed Distribution Planning Working Group. The DSPs are expected to incorporate these findings into their planning processes in order to facilitate future market development. Subsequently, this analysis could be extended beyond the substation level to individual feeder circuits and with higher temporal granularity.
- Continued Development Beyond Stage 1: Beyond Stage 1, this locational analysis could be extended to all feeder level circuits in New York that will be essential to enable future product and market development as envisaged in the REV.

E. Integrated T&D Planning

As DER net load impacts on the distribution system and transmission system increase, there will be an increased need to coordinate DSP and NYISO planning efforts. DER can offer distribution level capacity relief, enabling deferral of capital upgrades at the distribution-level. Similarly, as DER net load materializes at greater DER adoption levels, the deferment of transmission upgrades may be possible. At threshold levels, DER creates the potential for power flows from the distribution system onto the transmission system.[56] These benefits and power flow dynamics necessitate careful coordination between the two processes. The methods to perform a truly integrated engineering analysis should be reviewed and strengthened, as appropriate.

Implementation:

55 Within the New York State Department of Public Service 2015b, the PSC discussed that effective rate reform requires an understanding of the benefits that DERs can provide to the distribution system.

56 EPRI 2015

- Stage 1: As DER penetration grows significantly towards the latter half of Stage 1, there is an increasing need to commence coordination of transmission and distribution planning efforts.
- Continued Development Beyond Stage 1: There will be an ongoing need to reevaluate the need for integrated transmission and distribution planning based on then system and market conditions.

F. Distribution Grid Connectivity Model and Database

The enhanced interconnection and planning processes will identify substantial amounts of new information on distribution system connected assets – both utility and customer owned. Methods may need to be established to collect all of the information in one single integrated system for the DSP. This information, often captured in a geospatial format, will include the location of DERs, their electrical connectivity into the power system network, and other technical characteristics. This method, or model, may also need to include information regarding other distribution assets such as switches, lines, and other power system and non-power system components. Over time, it is expected that this model could include distribution system connected assets - both utility-owned and non-utility-owned.

Implementation:

- Stage 1: Data for all distribution grid connected assets, regardless of ownership, is expected to be integrated into a single database including the assets' relevant geospatial attributes in Stage 1.
- Continued Development Beyond Stage 1: As the additional distribution infrastructure is deployed, and more data becomes available, the DSP may add further datasets to this geospatial model and database.

G. DSP Planning Functions

Drawing on the work in other states, the efforts of the MDPT Working Group to describe and assess those efforts as well as their own experiences, the guidance of the MDPT advisors, and recommendations from the Core Team, it is possible to preliminarily identify certain key elements of such enhanced distribution planning that could be considered further as core functions and capabilities for the utility DSPs.

These functions and capabilities include:

1 Increased use of multiple DER adoption scenarios when conducting grid planning, to develop scenario-based probabilistic planning methodologies.

   a Initial emphasis would be on identifying appropriate methodologies, and in a timely fashion integrating such enhancements with existing planning methods.

- **b** Consider the extent to which DERs can be forecasted by location and whether there is adequate information to reasonably forecast DER by feeder circuit.

2 Developing a methodology for assessing and forecasting the hosting capacity of the distribution system, to accommodate DERs for radial- and network-based systems. Utilize the methodology to prepare forecasts in support of DERs.

3 Developing modeling capabilities that consider the location, connectivity and characteristics of major power system components, DER assets and loads on the distribution system.

- **a** Incorporating weather and economic forecasts to reflect changing system conditions by year,
- **b** Forecasting and monitoring existing and projected DER, including the degree of coincidence of DER service provision with local distribution substation peaks and to the extent viable feeder circuit peak conditions,
- **c** Through the interconnection process, regularly updating the DER connectivity into the system, and
- **d** Comparing hosting capacity and forecasted DER growth by location.

4 Acquire distribution system data that can be shared with market actors to support transparent planning efforts. A broader discussion of distribution system data is included in Section 5.2.2 Distribution System Planning Data.

5 On at least an annual basis, identifying and prioritizing locations to be targeted for distribution system capacity relief.

- **a** Prioritize which locations on the distribution system are at risk of overloading, problematic voltage fluctuations, and other significant operational problems, and by when.
- **b** Enable the procurement of long-term distribution capacity through a broad range of both dispatchable and non-dispatchable DERs to offer an alternative option to infrastructure expansion. This process should be transparent and actively engage affected customers, DER providers and other key stakeholders.
- **c** Identify new DER programs to focus on network peak reduction, operations, reliability, and to defer or defray large capital infrastructure, if cost effective.

6 Regularly assessing customer and DER provider interest and value in providing distribution capacity relief and flexibility products through DERs.

- **a** Outreach with DER providers to evaluate interest in DER projects for customer as well as market needs and identify barriers to deployment.
- **b** Issue periodic RFIs to determine market and customer interest and capabilities in providing DERs to meet utility needs.

c The DSP will be responsible for notifying the market of the timing, location and magnitude of the need, conduct the RFP process to procure alternatives, and interface with stakeholders.

d Regularly assess such DER capabilities at the substation/network and primary feeder level.

e Coordinate with the NYISO's reliability assessment process and interconnection queue.

f Coordinate with Municipalities and other government entities, including through the development of Community Energy Plans within their jurisdictions, to identify the form of, and priority locations.

7 Regularly forecasting and updating short-term, and to the extent feasible, long-term locational based distribution marginal costs (DMCs), with additional consideration of DER benefits as DERS are installed over time, initially to at least the substation level and/or network level, and eventually to the remainder of the system, as capabilities are developed.

a The level of granularity should be consistent across the distribution system.

b Such DMCs will provide the basis for valuing DER capacity benefits.

c Long-term (at least 10 year) projections of DMCs should also be established. Such longer term DMC projections will allow the design of incentive mechanisms intended to provide longer-term investment signals to customers and DER providers for DERs that result in long-term distribution system benefits.

8 Developing the capabilities to conduct integrated distribution system planning in coordination with the NYISO's transmission and resource adequacy planning.

a Consider adoption of an approach that involves using the output of distribution planning as an input into the transmission planning assumptions.

b In cooperation with other utilities and stakeholders, define a methodology for valuing the societal benefits of DER, including environmental, resiliency and other benefits, and propose a methodology for optimizing procurements and transactions based on those values.

9 Stakeholder input and engagement would-be systematic and consistent, and minimum standards for such engagement would be uniform across DSPs.

H. Planning: Establish a Distribution Planning Working Group

To further consider the planning issues described in this report, a collaborative effort among the NY DPS, NYSERDA, NYISO, utilities and interested stakeholders is suggested. Accordingly, following the completion of the MDPT effort, the Distribution Planning Working Group that includes appropriate subject matter experts is recommended to commence. The objective of this group could be to recommend common analytical methods, inventory distribution system data, develop a recommended schedule and milestones, and suggest alignments necessary to coordinate distribution planning with other State and NYISO planning efforts. The Distribution Planning Working Group is described in greater detail in Section 7.1.1.

5.1.2 Distribution Grid Operations

The objective of distribution system operations is the safe and reliable delivery of power over the distribution grid. Distribution operations involves voltage management, restoring power in the event of outages, redirecting real and reactive power flow, maintaining distribution equipment, minimizing distribution line losses, and ensuring power quality. In an era where centralized generation provided the majority of power and, correspondingly, the distribution system was designed primarily as a conduit for one-way power flow from transmission to end-use customer. The elements of enhanced distribution grid operations may be considered by Staff as they contemplate the market's design and required platform technology advancements.

At higher penetrations of DER, however, the role of the distribution grid operator will expand to adapt to multi-directional power flow and require operational modifications to maintain voltage levels, power quality, and reliability.[57, 58] By their nature, DER assets can provide multiple operational functions, including; net load reduction, energy provision, energy shifting (in both time and space), and energy absorption. Managing this mixed and non-uniformly-distributed set of DERs presents a new level of complexity in distribution grid operations. At the distribution level, generation and load volatility is of greater importance than at the bulk system level, where the aggregation of load and resources across a large territory helps to mitigate volatility. Further, distribution circuits may be unbalanced, as most loads are single phase. Future dispatch of DERs, via physical control or coordination, will need to take into account real-time conditions on the specific circuits involved.

To manage this increased complexity, the system operator will need new analytical tools that will provide improved situational awareness and controls to keep the system optimized on a real-time basis. The following sections lay out prioritized Stage 1 DSP functions related to 1) monitoring and observability, and 2) coordination and control.

As DER penetration increases from the present low levels, the DSP operations functionalities described below will evolve incrementally. Investments to support the assessment of locational value should occur regardless of the state of DER penetration

57 From a circuit or endpoint perspective, power flows can be two-way, but when considering a whole distribution system, it is useful to consider N-way flows conceptually.

58 DER that may require grid operations changes includes distributed generation, in particular from non-dispatchable distributed generation sources, such as wind, solar PV, and storage, which may supply a number of different services to the grid and to customers.

to benefit the grid at large. Key focus will be on critical sections of the distribution grid, such as the feeders and substations where the concentration of DER is greatest or is projected to grow the fastest. There will be an important connection with the planning process to strategically deploy new assets (for example, with selection of sensor type and placement, taking into account existing sensing and measurement assets and their characteristics).

A. Monitoring and Observability

To maintain reliability, it is proposed that operators will need improved situational awareness to both proactively and reactively manage voltage, real and reactive power flows, switch status, network connectivity, and other relevant real-time measurements within the distribution network. Increased monitoring and observability into distribution networks will enable DSP grid operators to manage the grid and optimize DER value under both "blue sky" grid conditions and "black sky" events.[59] To enable this, the DSP should be able to monitor and provide high-resolution views of voltage profiles and load flows throughout the network.

The DSP distribution grid operator will need to have the ability to monitor and measure key aspects of system operation, including:

- Voltage, current, and status of grid infrastructure including primary feeders, laterals and transformers on a near real-time basis;
- Net load at the customer premise or device level on a near real-time basis where appropriate based on locations where DER penetration is higher;
- DER status including voltage, current and generation on a near real-time basis for DERs of capacity higher than some nominal amount, or that are in locations where likely to impact distribution grid performance criteria;
- Real and reactive power flows at the point of common coupling for customer-sited or utility-sited microgrids at a near real-time basis.

Real time operational systems, such as distribution management systems (DMS), provide current operating state and condition of distribution grids that include geographic mapping of distribution infrastructure, power system state, and equipment status. Such systems typically include a suite of software applications that reside on top of a supervisory control and data acquisition (SCADA) system, which is responsible for collecting data and distributing control commands via a communication network. They allow the distribution grid operator to manage the grid, respond to contingencies, and manage increasingly dynamic events and behavior on distribution grids with DERs.

59 Stockton 2014; State of New York Public Service Commission 2015, p. 32.

These deployments are complex, so each DSP should perform its own cost-benefit analysis to determine if and when it is prudent to implement such a system.

Currently, multiple New York utilities are either implementing such real-time operational systems or have plans to procure them. However, it is proposed that the DSP will need to have expedient operational system capability when DERs are relied upon for the system to operate within mandated performance margins, and the ability to communicate with DERs directly as well as with aggregators.[60] Such an environment can provide many benefits that directly contribute to REV goals, including increased reliability and improved grid operational efficiency with higher asset utilization factors.

Initially, it is assumed that the DSP will build off of existing utility practices to identify equipment condition and to dynamically assess grid capabilities. The MDPT group recommends that the DSP should build capabilities to act as the single point of visibility for current status and condition of distribution grid equipment, including geographic mapping of distribution infrastructure with current operational status. As additional DERs interconnect to the grid and increased monitoring data becomes available, the DSP should broaden the scope of these capabilities to include additional assets (e.g., DERs) and greater temporal resolution.

Implementation:

- Stage 1: Each DSP should work to implement, where appropriate, a real-time operational system, including geographic mapping that acts as the single point of truth for the current status and condition of distribution grid equipment. In addition, the DSPs should assess existing risk management systems and incorporate plans to address physical and cyber threats in an increasingly interconnected and complex grid.
- Continued Development Beyond Stage 1: As DER penetration levels increase, DSPs will need to continue to assess the efficacy of their operational systems, identifying and improving the systems as needed. In addition, as the landscape of security threats will change over time, DSPs should implement a process for identifying and installing additional security protections as they are needed.

B. Coordination and Control

Coordination and control at the distribution level refers to the signaling and mobilization of distribution assets to meet system operational and reliability goals on a dynamic basis. Today, distribution utilities employ a limited version of this functionality through the use of conventional equipment, including load tap changers, line regulators, and

60 DER providers will need to communicate with the DSP for a number of reasons to include receiving customer specific data for market operations. For example, DER providers in Texas and PJM markets have the ability to receive and download customer data on a daily basis.

switches with SCADA capabilities. The DSP, however, will have the opportunity to coordinate and control both conventional equipment *and* DERs to optimize distribution system performance, maximizing DER benefits while avoiding adverse impacts.[61]

Enhanced coordination and control functionality will center on several key responsibilities:

- Administering optimal power flow management,
- Facilitating integration of grid operational needs and capabilities into market operations,
- Ensuring coordination between transmission and distribution (T&D) system operations, and
- Maintaining the physical and cyber security of the grid.

Over time, as the penetration and diversity of DERs increase, and market or market-like functions are integrated, the changing structure of the DSP may necessitate corresponding evolution of these responsibilities and their implementation.

Power Flow Management

The availability of new monitoring and observability capabilities will enable a variety of new options for optimizing power flow on the grid. As such, it is proposed that the DSP be able to analyze system performance, identify abnormal conditions, and determine optimum set points and usage of network elements.

The DSP should be able to implement this optimization using both grid assets and DERs:

Grid Assets

As with utilities today, the DSP should have the ability to control grid equipment to manage power flow on the network. In addition to using traditional control mechanisms, the DSP should also be able to incorporate and optimize around network automation technologies where they are available.[62]

DERs

It is recommended that the DSP should be able to optimally influence and integrate DERs in order to optimize their value and ensure reliable operations of the distribution grid. This may require a wide variety of techniques, ranging from coordination to direct

61 The extent of coordination and control DSPs could exert on DERs requires further investigation, as the market evolves to integrate greater penetration of DER, including DERs of varying types and sizes.

62 As detailed in Section 5.3.3, future network automation technologies may include voltage/VAR optimization; real-time feeder reconfiguration; fault location, isolation, and service restoration, and; adaptive protection.

control. For example, current demand response (DR) programs in New York (which are limited to targeted applications for load relief) use either indirect control through incentives for customer-initiated demand reductions, or through direct utility load control over customer assets. To better optimize DER value, DSPs should specifically consider DERs with complex challenges as they develop coordination and control schemes. For example, microgrids represent a unique structure and scale of load interconnected to the distribution system and need to be synchronized with the distribution grid. Because of this, the DSP should be able to evaluate the network effects of multiple microgrids operating in real time, as well as to measure and respond to microgrid power flow scenarios that could potentially threaten grid operation and reliability.

While the primary role of the DSP's power flow management should be to optimize distribution system performance under normal conditions, in some circumstances the DSP should also have the ability to curtail resources if the operational stability and reliability of the grid is threatened.

Implementation:

- Stage 1: The DSP should implement the ability to use power flow management capabilities to coordinate DER integration for reliable grid operations, including the ability to ramp, isolate, or island DERs where appropriate under normal or stress conditions. To ensure operational reliability and safety, this functionality must be deployed at specific DER installations and remain active beginning in Stage 1. The level of implementation should depend on the capacity and concentration of DERs at specific locations, feeders and/or substations.

  Additionally, DSPs should develop a set of protocols to govern DER operations for enhanced grid reliability and stability.

- Continued development beyond Stage 1: As DER penetration increases, DSPs should consider opportunities to increase automation in their power flow management processes and systems.

Facilitate Integration of Grid Operations with Market Operations

At the bulk level, grid control and market dispatch must be coordinated to preserve system reliability and prevent inappropriate interactions or interferences. Similarly, the challenge of managing heterogeneous mixes of DER along with traditional grid controls must inherently deal with the ways in which controls and markets can interact. There are three modes of interaction to be considered in the context of what may be several market products:

- *D*irect: market creates a dispatch schedule and the grid control system carries it out;
- *A*uthorized: the market selects assets to be used by the grid control system, which employs these assets as needed;

- *I*ntegrated: the market and grid controls are integrated in a single control loop.

In two of these modes, the market informs the control system in some manner. Only the integrated mode is for spot markets.

Implementation:

- Stage 1: It is recommended that this function should be implemented in concert with the implementation of DSP market operations capabilities.
- Continued development beyond Stage 1: This capability should evolve significantly as DSP market enhancements, such as spot markets or new products are implemented.

Coordination between Transmission and Distribution

Coordination between T&D systems refers to the interface requirements between the DSP and the NYISO to ensure system reliability at both the bulk power and distribution system levels. The nature of this interface depends critically on the definition of the roles and responsibilities of the DSP, which clarifies the amount and type of information that must flow between the distribution level and the ISO level. Additionally, to capture DER value streams at both the bulk power market and the distribution level will require new consideration to how bulk markets and the distribution system interact.[63] At current low penetrations, NYISO dispatch of DR for system purposes does not create issues at the distribution level.[64] However, both bulk and distribution systems adapt to rely more on DERs as important resources for reliability, T&D coordination will be important to ensure grid stability and reliability us not compromised at either level.

Providing total observability of distribution at the ISO level is unnecessary and presents a scalability issue. By defining the interface cleanly at a locational marginal price (LMP) node or at the transmission-distribution interface, the DSP can manage reliability and operations within its service area without the need to transfer massive amounts of data from every DER to the ISO. Thus, overall, each DSP service area can act as an aggregated node to the ISO although that aggregation does not preclude the ability of DER aggregators to provide service directly to the ISO.

Improved coordination, communication, and data exchange between NYISO and the DSP in the context of a clean interface definition would facilitate greater involvement of DERs in system balancing.[65] For example, at significant levels of penetration, the DSP

63 Please note that working group members differ in their opinions on the extent of coordination between the DSP and the NYISO, and about DSP responsibilities for distribution-level DERs that participate in wholesale markets. This issue may require further investigation.

64 Currently, demand response represents only about 4.1% of the NYISO summer peak demand.

65 Council of European Regulators asbl 2014

will need to be aware of the schedule and current status of resource on the distribution system that are also participating in the NYISO markets and *vice versa*.

Implementation:

- Stage 1: The expectation is that definition of the interface between the NYISO and the DSP will develop during Stage 1 and that current operational practices would evolve over the course of this stage. The DSP should incorporate systems and technologies that enable 1) information collection and the sharing between the DSP and the NYISO, 2) real and reactive power flow coordination and operational practices at the transmission-distribution interface, and 3) greater use of DERs for system balancing and to meet other distribution and wholesale market needs. The implementation of these systems, practices, and technologies should be dependent on the level of penetration of DERs, the evolution of the market place, and the specific needs that the DERs are addressing.
- Continued development beyond Stage 1: As DER penetration increases, there may be instances of reverse power flow from distribution into the bulk transmission system. This will require continued and enhanced interaction and coordination between the DSPs and the NYISO. DSPs should work with the NYISO to establish specific operational protocols to facilitate this enhanced coordination.

Grid Control Automation

Automation has the potential to enhance customer value propositions associated with participation in DSP markets, operating in conjunction with broader congestion management and optimization of DER operations. In particular, such algorithm-based operational models may provide grid benefits (e.g., alleviate congestion) faster than human-centric operational paradigms.

Key functions that are considered a part of this section include:

- *Volt/VAR optimization*, where automated voltage control provides increased operating flexibility over conventional voltage control. For example, conservation voltage reduction lowers the voltage on the distribution feeder to the lowest acceptable voltage and thereby reduces demand and energy consumption. Both of these benefits may be useful for enabling more efficient distribution system coordination and control strategies.

  This function has been employed to a very limited extent on distribution systems in New York presently. For instance, ConEd uses volt/VAR optimization on some mesh grids to reduce line losses and circulating currents.
- *Load transfers,* performed using utility-owned assets, are achieved through real-time feeder reconfiguration and optimization to relieve load on equipment, improve asset utilization, improve distribution system efficiency, and enhance system performance. Real-time network reconfiguration may depend on

dynamic customer loading, and on the unique characteristics of different distribution system designs employed in New York. For purposes of DER management, there may be a need to address load transfers within the context of DER grouping strategies.

- *Fault location, isolation, and service restoration,* (FLISR) is a function that helps decrease the duration and number of customers affected by any outage by isolating and islanding loads, or rerouting power through alternative feeders. These systems can operate autonomously in response to local events or in response to signals from a central control system.

  No NY utility has active FLISR functionality. Some utilities have implemented some automated restore capabilities, which isolate fault zones.

- *Adaptive protection,* includes functionality that enables isolation and islanding of some sections of the grid from the main system to be served by local DERs only. This is based on real-time or near real-time signals. This is particularly useful for feeder transfers and two-way power flow issues associated with high DER penetration. Accordingly, "if there is a fault and the main grid fails, the on-site power generators can support uninterrupted grid operation" by islanding some customers on certain segments of the grid, while continuing to "supply the remaining customers with electricity."[66]

Implementation:

- Stage 1: Each DSP should evaluate options for grid control automation and implement the most prudent systems and practices that enable the DSP to assess a range of operational and non-operational data to analyze system performance, identify abnormal conditions, and determine optimum set points or topologies for network elements. DSPs should employ automation techniques where necessary to facilitate customer value propositions associated with participation in DSP markets,

  DSPs should deploy real-time load transfer techniques through real-time feeder reconfiguration and optimization, as well as automated voltage control, to enable more efficient distribution system coordination and control strategies. Each DSP should prioritize deployment of such systems depending on dynamic customer loading, and on the unique characteristics of different distribution system designs employed in New York.

- Continued development beyond Stage 1: As additional DERs are installed on DSP distribution systems, the DSPs should proactively propose solutions in areas where additional automation would enable more-efficient operation.

66 Schaefer et al. 2010

C. Multi-Stakeholder Engagement

In coordination with relevant market rulemaking processes and authorities, the DSP should be responsible for fostering appropriate transparency and encouraging the engagement of stakeholders through processes to develop and evaluate DSP market, grid, and planning functions. Relevant rulemaking processes are further described in Section 7.5.

Particular processes that merit public engagement include: developing a methodology and determining DER value; distribution planning processes; distribution market operations; and identifying requirements for monitoring and or observability of multiple interconnecting assets on the distribution grid, such as DER, customer loads, and microgrid assets.

Implementation:

- <u>Stage 1:</u> DSPs should establish a platform for multi-stakeholder engagement. This platform will be core to all DSP functions in Stage 1, and will remain so beyond that time period, so DSPs should also implement a process for continuous improvement of the platform over time.
- <u>Continued development beyond Stage 1:</u> To support continued stakeholder engagement, DSPs should assess the efficacy of their engagement platforms and make improvements as needed.

5.1.3 Distribution Market Operations

New York's DSPs are to develop and implement markets for distribution system products and services. Market products, rules, and entrants will develop over time as DERs proliferate, the DSP's operations and planning capabilities expand, and the distribution markets develop.

Certain aspects of each market's operation may require customization to accommodate specific characteristics of the given DSP's service area. However, many core DSP market operations functions may need to be implemented in a standardized way across the state. As these DSP functions and market structures take shape, it is recommended that the PSC provide the requisite guidance to facilitate this standardization, including necessary product terms, technical protocols, and market rules.

The MDPT group presumes that DSPs will be responsible for performing a variety of functions to enable distribution market operations. They may also need to coordinate with the NYISO and explore opportunities to share capabilities given the synergies between many bulk- and distribution-level market functions. Broadly, these functions can be categorized as pertaining to: 1) managing market operations and processes or

2) administering markets and preventing abuse. The MDPT group's expectations for specific functions and their implementation are described here.

A. Manage Market Operations and Processes

Establish and Optimize Market Rules, Processes, and Transacted Products

The rules, processes, and structure for creating DSP market rules need to be established and should be uniform across DSPs. There is a need to identify and establish specific market rules with input from stakeholders from different market sectors and the NYISO, subject to review and approval by the Commission. It is recommended that the Commission should also determine clear policies on how rules will be enforced.

The same stakeholder process will need to assist in the determination of the needs and the standardized products that will be transacted and the rules around transacting those products. This should be part of a transparent and open process

Implementation:

- Stage 1: Initially, a limited set of products and rules should be developed. This process is expected to evolve alongside the markets during Stage 1, concurrent with development of the planned market topology. Doing so should help to ensure efficient market expansion over time and avoid unnecessary obsolescence that would raise cost and slow progress.
- Continued Development Beyond Stage 1: As the market shifts to include a spot market, DSPs should update their products and rules accordingly using the stakeholder process.

Sourcing of Assets for Distribution Grid Services

Participation from a broad and diverse pool of resources is fundamental to economic and efficient operation of electricity markets. As such, the DSP will need to "source" (i.e., have advance knowledge of) all available distribution resources at their disposal, including DER.

Implementation:

- Stage 1: Initially, it may not be possible to operate spot markets for distribution grid services due to limited existing deployment of distribution resources and a lack of visible and reliable pricing signals at the distribution level. The first step is for the DSP to identify distribution system needs. Then, based on those needs, potential alternative sourcing mechanisms to incent resource development and participation should be developed, including:
    - *Compensation*: through use of time- and location-varying regulated rates

- *Programs*: through targeted ratepayer-funded programs (e.g., existing DR, energy efficiency, etc.)
- *Procurement*: through use of competitive procurement processes

These sourcing mechanisms should be coordinated with related federal-, state-, and local-agency programs, both existing and planned, and with the NYISO.

During Stage 1, DSPs should outline the sourcing mechanisms they anticipate using. To facilitate a smooth transition to these future programs and/or markets, DSPs should explicitly define the planned transition to future methods from Stage 1 sourcing methods.

- <u>Continued Development Beyond Stage 1</u>: As resource deployment and participation increases, it may be desirable and possible to add operational spot markets for certain distribution grid services. In this stage, to source resource participation using these values, the DSP could accept bids and nominations for scheduled dispatch at a predetermined rate and to determine an appropriate market clearing price based on the marginal cost and value of the dispatched DERs.

Inter- and Intra-day Coordination of Resources

The DSP may need to coordinate participating distribution resources to determine the necessary forward scheduling and dispatch of those resources. Resource coordination is required to meet grid operations requirements in accordance with established market rules and system protocols. Specific tasks within this DSP function could include the following:

Forecasting

Short-term forecasting enables efficient market operation by minimizing the need to schedule excess capacity to accommodate unforeseen changes in supply or demand. The DSP should generate gross load, supply-side DER, and net load forecasts. These forecasts will provide information to support planning and grid operations functions of the DSP, and will be used to identify the amount and location of grid services required. The value of such forecasting is tied to the DSPs capability of managing a real time grid model and having tools to affect control in a local distribution grid.

Gross Load Forecasting

Calculation and forecasting of gross electricity consumption due to ambient temperature, other weather conditions, day of week, time of day, and other factors that would affect the quantity and timing of electricity consumption, without considering the operation of any DERs. Consumption forecasts would change with changes in input data.

Supply-Side DER Forecasting

Calculation and forecasting of electricity production from supply-side DER based on geography, forecasted fuel supply, solar insolation, wind speed, electrical network conditions, or other factors that would affect the quantity, quality and timing of electricity. Production forecasts would change with variations in input data.

Net Load Forecasting

Calculation and forecasting of net electricity consumption based on the forecast gross load, subtracting out demand-side DER performance (including energy efficiency) and expected supply-side DER performance.

Implementation:

- Stage 1: While the forecasting methodology and approach may evolve over time, it is expected that this function should be phased-in over the course of Stage 1 within the constraints of the available systems. Forecasting activities should be coordinated with the NYISO to ensure alignment.
- Continued Development Beyond Stage 1: Forecasting approaches should continue to improve as they are tested and implemented during Stage 1 in order to support optimal market operations. In particular, they may need to incorporate higher temporal or locational resolution, or new DER technologies.

Event Notification

Automatic notifications signal to market participants to respond to important situations or conditions in a timely manner. For example, participants might be notified of high-load days, transmission outages, or other situations that could create a particular need for DERs to operate or be available to respond to contingencies.

The DSP should utilize such notifications to inform market participants of events including, but not limited to: price changes, incentives, penalties, curtailments, or special circumstances; events or conditions that may affect market operations; events or conditions that may affect public safety, electrical network performance, or availability such as equipment failure, weather, or other hazards; achieving or exceeding various production or consumption targets or thresholds. Event notifications should be functionally consistent across all DSPs in the state, although conditions triggering these events may differ depending on DSP network conditions. To ensure transparency, in addition to providing notifications to market participants, the DSP should make these notifications available using a publicly accessible portal.

Implementation:

- Stage 1: It is recommended that this function would be implemented during Stage 1 and remain active going forward. Capabilities will be phased-in during this stage within the constraints of the available systems and infrastructure.

- Continued Development Beyond Stage 1: As new infrastructure is deployed and more-advanced market functionality is implemented, event notification capabilities should be enhanced to keep pace and enable timely and accurate participant response.

Scheduling, Dispatch, and Congestion Management

The DSP will facilitate the market while managing network distribution system loading and congestion. To do so, the DSP will need to construct optimized schedules at appropriate time intervals to define the set of necessary resource commitments, and finalize the use of participating resources via an optimized dispatch.

Implementation:

- Stage 1: Initially, it is recommended that the scheduling and dispatch should use participating resources, that is DERs which the DSP has the ability to dispatch, to minimize distribution system costs, while complying with facility loading limits and other reliability criteria. At first, while new distribution grid operations capabilities are installed, this process may need to rely on existing methods for operating available DERs (for example, those used in current DR programs). Over the course of Stage 1, capabilities to communicate with and dispatch DERs should be continuously expanded to enable more-responsive operation as the distribution market becomes more advanced.
- Continued Development Beyond Stage 1: As the system evolves, this function should move toward a more-advanced optimization of resource scheduling and dispatch. It may also expand to include spot markets based on coordinating bids from participating resources for economic dispatch and market clearing.

Record and Maintain Historical Operations Data

It is recommended that the DSP should collect supply and demand operations data to help inform DSP grid operations, supply injection consumption and demand forecasts and various aspects of market operations. The temporal and locational granularity of this data will hinge on the monitoring infrastructure in place, but more granular data would be most useful to support the types of market operations expected in the long-term REV vision. This should include:

Supply-Side DER Performance Monitoring

Monitoring and archiving of DER performance data including electricity production and services, availability/uptime, pricing, and other factors that would aid the development of detailed dynamic production models and production forecasting.

Historical Net Load Monitoring

Monitoring and archiving of customer gross electricity consumption and demand-side DER performance (if separately metered) to determine net load would aid in the development of detailed distribution level dynamic load models and load forecasting.

Implementation:

- Stage 1: Early market rule development should to focus on establishing any limitations on the collection of proprietary DER operations data. It is expected that this function would then be implemented over the course of Stage 1, within the constraints of the available systems and infrastructure.
- Continued Development Beyond Stage 1: To support optimal market operations, operations data collection beyond Stage 1 should evolve as new distribution infrastructure and market systems are deployed.

Measure and Verify Participant Operations

The M&V of electricity production and consumption by market participants may be done at the DSP point of service or at the level of individual DERs. The purpose of M&V is to ensure accurate billing and payment for market participants, and to help ensure a robust and trustworthy market. To that end, it is recommended that a system should be put in place to penalize participant contractual non-performance. The DSP, or an approved third party, should perform M&V in accordance with statewide guidelines and reporting requirements to be established by the NYPSC.[67]

Implementation:

- Stage 1: It is expected that this function would be implemented and remain active beginning during Stage 1.
- Continued Development Beyond Stage 1: To support optimal market operations, M&V methods should be updated to take advantage of enhanced metering and monitoring infrastructure.

Coordinate Between Wholesale, Retail, and Distribution Operations

This function encompasses the communication and exchange of market information between the ISO, DSP, and participating DER, including distribution area net demand, net interchanged supply, DER services scheduled by the DSP, DER forecasts, aggregate output of DERs, and DER services that may be offered to the ISO for wholesale market participation. The mechanisms supporting this coordination will need to be developed in partnership with the NYISO, and should be consistent across all DSPs in the state.

67 M&V methodologies may need to be established for the different products and services.

Implementation:

- Stage 1: While the granularity and breadth of the specific datasets and services coordinated between the ISO, DSP, and DER market participants should evolve over the course of market development, this function could be implemented and remain active beginning during Stage 1. This may be phased in within the constraints of the available systems, and in collaboration with the NYISO stakeholder process when appropriate.
- Continued Development Beyond Stage 1: As DER penetration levels increase; the DSP should continue to phase in coordination functionality in collaboration with the NYISO and other stakeholders.

B. Administer Markets and Prevent Abuse

Facilitate and Process Market Transactions

This covers several capabilities necessary to allow participation in the distribution market, Including functionality to support both near-term participation and future functionality where offers and bids are incorporated to enhance the competitive market.

These functions may be performed by entities other than the DSP, and the PSC will need to provide guidance about which entities may perform these functions:

Portal Design and Operation

The DSP could provide an online portal through which market participants may interact with the DSP. This should include both passive interaction (e.g., viewing market data), and active interaction (e.g., submitting offers or bids). Importantly, the participant-facing implementation of the web portals should be consistent across the state and across individual products to minimize the burden on participants seeking to engage in markets in multiple DSP areas.

Implementation:

- Stage 1: Initial implementation should focus on the passive elements of the portal, except to the extent that additional components are needed to enable Stage 1 sourcing of assets.
- Continued Development Beyond Stage 1: As the DSP market shifts to use of bids from participating resources, this function could include the required functionality to allow submission of bids.

Manage Registration of Distribution Market Participants

The MDPT group presumes that the DSP will need to manage registration of DSP market participants and maintain an up-to-date database of those participants. These efforts would need to be coordinated with DPS Staff, to the extent that the Commission adopts DER supplier eligibility requirements to be administered by the Department.[68] At any given time, the DSP may need to be aware of market participants and their availability to provide resources in the system. The DSP will be responsible for ensuring that market participants are aware of their responsibilities in their individual roles, including providing training courses and documents. Additional related activities could include qualification (e.g., credit and performance checking) of new participants, management of participant interactions (e.g., service complaints), case management and escalations, monitoring of satisfaction levels, marketing, and relationship building, and developing customized services and solutions. The access portal and database structure provided by the DSPs may need to be standardized across the state. To enable synchronization of participation data and efficient participant access, the forms, format, and participation criteria should be consistent across DSPs.

Implementation:

- Stage 1: While specific activities may evolve over time, it is proposed that this function would be implemented during Stage 1. Portal capabilities should be phased in alongside the market products and services, within the constraints of the available systems.
- Continued Development Beyond Stage 1: While the access portal and database should be fully implemented prior to the end of Stage 1, the DSPs should continue to refine and improve portal functionality to meet the needs of both participants and the market operator.

Transaction Confirmation, Clearing, and Settlement

In order to facilitate market operations, the DSP may need to receive confirmation of market participant contractual commitments. Commitments would need to be cleared (or selected) based on market rules. The DSP will then settle the market, requiring comparison of actual performance to commitment in terms of quantity, quality, timing, tracking and reconciling discrepancies, managing disputes and escalations. The settlement process could include mechanisms to handle participant non-performance, and the DSP should propose a specific settlement design. Netting functions may be incorporated to offset outstanding invoice or receivable balances. Finally, it is presumed that the DSP will manage payment settlements for all distribution-level transactions that are not settled bilaterally outside of the DSP system, within which the

68 Criteria for DER supplier eligibility to participate in DSP markets, as well as other rules and guidelines applicable to DER suppliers, is being addressed in Case 15-M-0180 New York State Department of Public Service 2015c. DPS Staff is expected to issue proposed rules for comment, on July 28, 2015. Issues concerning the delineation of responsibility for DER supplier administration between the Department Staff and DSP, are expected to be explored further in that proceeding.

focus should include the accurate invoicing of distribution system products offered by the DSP and transparently providing the data that the settlements are based on.

Implementation:

- Stage 1: The DSP could (in concert with development of market products and services) establish a transaction management system that can incorporate transactions of each product and service developed. It is expected that this function would be implemented within Stage 1, within the constraints of the available infrastructure.
- Continued Development Beyond Stage 1: As specific products and services evolve over time, the transaction management system and settlement process should likewise evolve to handle different types of exchanges. In particular, the addition of a spot market would require transaction management more in the nature of a clearinghouse.

Billing, Receiving, and Cash Management

It is assumed that the DSP will be responsible for managing the financial components of the market operations. This should include:

- Generation of invoices and statements,
- Cash management functions and banking or financial intermediary interfaces resulting in the receipt of cash for net billings receivables owed to the DSP or net payables due to providers, and
- Credit and collections processes occurring from delinquencies.

Implementation:

- Stage 1: This function may not be necessary during Stage 1 market operations, unless handling of sourcing payments is transferred to DSP market operations.
- Continued Development Beyond Stage 1: It is expected that this function would be implemented early in Stage 2 alongside the implementation of the distribution spot market.

Ensure Market Security, Legitimacy, and Optimization

This includes several capabilities that will enable secure operation of distribution markets, prevent gaming, and ensure cost minimization:

Monitor and Optimize Market Operations

It is recommended that the DSP utilize supply and demand market data to analyze market performance, identify abnormal conditions, and determine key supply and demand relationships. The purpose of this functionality is both to continually optimize market design and improve the efficiency with which market participants can transact products and services, and to identify and report potential violations, and report market power abuses. To support market optimization, the DSP may define and use both short- and long-term metrics to measure the degree to which DER integration and market development have successfully achieved REV's goals. These metrics can be used to measure whether DERs are being more broadly utilized, monetized, and placed on par with traditional utility solutions.

This function should also include proposing market rules to minimize the impact of market power and non-competitive behavior on consumers (this could include specific market power mitigation measures). While DSPs may identify potential violations and market power issues, there may also need for an independent entity assigned to further analyze market operations in all the DSPs and investigate reported violations. The objective of this entity should be to uncover market design flaws and ensure that the DSP market does not result in transactions or operations that are unduly discriminatory or preferential or provide opportunity for the exercise of market power either by market participants or the DSP.

Implementation:

- Stage 1: The DSP could implement initial market optimization functionality and processes beginning in Stage 1. Prior to the implementation of market bidding functionality, the DSP should outline and develop the capabilities needed to interface with the entity assigned to review market issues.
- Continued Development Beyond Stage 1: The DSP could continue to evolve the market optimization processes. As the DSP market shifts to use of bids from participating resources, the previously developed market issue reporting capabilities should be implemented.

Maintain Cyber Security and Necessary Confidentiality

Cyber security refers to capabilities put in place to ensure that all communications networks and programmable electronic devices, including the hardware, software, and data in those devices are secure. As with other elements of the distribution system, the cyber security of market operations should be of critical importance. The DSP could develop, continually assess, and update situational awareness tools to ensure the ability to identify, prioritize, and coordinate the protection of critical market operations infrastructure, data, and resources.

Implementation:

- Stage 1: It is expected that this function would be implemented and remain active beginning with Stage 1.
- Continued Development Beyond Stage 1: As cyber security threats evolve over time, DSPs should continuously improve market operations security measures.

Reliability Compliance

The MDPT group assumes that the DSP is expected to ensure the market's business and reliability compliance with all standards established by the NYPSC or other appointed standards bodies (and, by extension, the compliance of the grid it affects).

Implementation:

- Stage 1: It is expected that this function would be implemented and remain active beginning with Stage 1.
- Continued Development Beyond Stage 1: Reliability compliance should remain an ongoing priority for all DSPs. DSPs can identify opportunities to streamline compliance obligations for market participants, as well as work with market operations' supervisory standards bodies to similarly streamline compliance obligations for the DSP.

Provide Streamlined Access to Market Data for DSP Market Participants

The DSP may serve as the source of information and data to facilitate and animate distribution markets, and should provide and enable participant access to specific data and content to enable development of DER markets. This data and content, and its access restrictions, will need to be evaluated to ensure that it enables transparency and opportunities for innovation but does not enable market gaming. These data points should include:

- *Historical prices and volumes:* Provide streamlined access to historical price and volume statistics for market transactions by product or services.
- *Event notifications and market participation statistics:* Provide streamlined access to historical market events (where the DSP has issued event notifications) and market participation statistics.
- *Aggregated and anonymized customer use data:* Provide streamlined access to historical, aggregated, anonymized customer loading and use data.
- *Customer-authorized access to customer data:* Provide streamlined access to customer use data directly to customer or customer-authorized third party.

Implementation:

- Stage 1: Within the constraints of available distribution infrastructure, the DSP could process and make available appropriate data to participants as specified by market rules. The DSP may simultaneously develop an approach to ensuring that the data provided does not enable market gaming and respects privacy and cyber-security concerns.
- Continued Development Beyond Stage 1: As the additional distribution infrastructure is deployed, and more data becomes available, the DSP may make available further datasets to participants.

5.2 Data Requirements

Per the Track One Order, "The DSP must make available system data at a degree of granularity consistent with the market that it operates, in a manner that is timely to facilitate market participation."[69] This section lays out the need, current status, and resulting gap for: 1) customer-specific data, 2) distribution system data necessary for DSP planning and market operations functions, and 3) data interface issues.

5.2.1 Customer-Specific Data

A. Need, Type, and Application

Depending on the metering in place, customer-specific revenue-grade data that will be useful to customers, the customer's DER vendor, and the DSP, includes:

- Historical consumption (monthly kWh, or more granular if available)
- Historical power factor
- Coincident and non-coincident customer peak demand (kW)
- Customer tariff
- Customer charges
- Reported outages
- Service location
- Power quality data
- Customer complaints about voltage/power quality in the immediate vicinity of the customer

Customer-specific data is necessary to participate in existing utility and NYISO-administered DR programs, as well as the anticipated near-term market products administered by the DSP. Additionally, within wholesale market settlement processes, customer-specific data may be needed to determine the LSE's contribution to the Transmission District's load as well as in pure energy settlement at the LSE level.

The type and temporal granularity of data needed from customer meters depends on data requirements of current programs and products administered by the NYISO and utilities, as well as the preliminary products and services to be administered by the DSP. As stated, initial products priced and transacted within the DSP market could include distribution capacity relief or deferral, voltage management, transient power quality

69 State of New York Public Service Commission 2015, 59

improvement, reduced line losses, and other products providing distribution system reliability and resiliency benefits. Participating customer consumption data will need to be captured at the customer meter and provided to the DSP in Stage 1 with at least an hourly level of granularity, as the price of these products may vary temporally. The exception is distribution capacity relief, which may not require hourly data, but could instead rely on distribution system data and customer load forecasts at a more aggregated basis. Operating reserves and regulation products at the bulk system are the exception that require data measurement at the minute and seconds interval and will need to be directly telemetered to the NYISO for participation in the wholesale markets. Additional work is required in follow-on use case development processes to specify data requirements for each product described in each use case.

Beyond Stage 1, sub-hourly interval data (e.g., 15 minute interval data, minute interval level, or more granular) may support more advanced DSP market and grid operations. Considerations related to sub-hourly data include:

- Peak loading for buildings is typically determined in a 15-minute time scale. 15-minute interval data therefore is relevant for calculating capacity and billing functions, such as application of demand charges. Building management systems and HVAC systems are designed to be reactive and effective in a 15-minute time scale.
- The cost of data processing and storage has declined dramatically, reducing data storage outlays. The level of data processing required is marginally increased for the 15-minute interval.
- 15-minute interval data is suitable for studying commercial customer load profiles. Data patterns related to equipment cycling may be revealed at more granular time scales, indicating wear and tear of major electricity users such as HVAC equipment.
- In the event ancillary distribution products emerge, as expected, near real time data may be required to participate in such markets.

B. Current

For the vast majority of mass-market utility customers in New York, consumption data from their utility meter is captured on a monthly or bi-monthly basis with little or no ability to differentiate when individual customers are consuming electricity or if they are changing their usage from day to day. Customers above 300 kW have interval metering requirements, but those below falling into the mass-market class generally do not. While some customers participate in NYISO markets and provide sub-hourly data to bulk markets, sub-hourly market operations may not be practical or necessary for many of the DSP market products and services. Some NYISO markets (e.g., for ancillary services) require sub-hourly data. Although current participation in those markets is low, it may increase in the future. Similarly, future distribution-level ancillary service products (e.g., voltage support) may also require sub-hourly data.

C. Gap

There is a gap between current customer data acquisition and the need for hourly and sub-hourly customer data granularity based on future market data requirements. The metering platform that enables hourly data acquisition is addressed below in *Section 5.3, Platform capability requirements to create and animate Stage 1 market.*

Implementation:

- Stage1: Participating customer consumption data may need to be captured at the customer meter and provided to the DSP with at least an hourly level of granularity, or as required for the product and service being provided. This temporal granularity need not be universal across the DSP, however.

  Use case development processes are needed to assign customer data requirements for specific DER market products and services. Use case processes should distinguish the temporal granularity of the customer data needed to measure the customer response from the market dispatch signal.

- Continued Development Beyond Stage 1*:* Customer-specific data interval requirements may increase to sub-hourly as more granular DER products and services emerge. Market and dispatch intervals can be shortened if needed once foundational communications systems are in place and operational confidence is achieved.

5.2.2 Distribution System Planning Data

A. Need, Type, and Application

Distribution system data refers to distribution asset information upstream from the service delivery point at the customer meter up to the interface with the transmission system. Distribution system data applies to system planning, including forecasting the hosting capacity of the distribution system, as well as forecasting short and long term locational based DMCs for DER geographic markets. Distribution system data is also relevant to DSP market operations discussed in this report, including tracking DER installations and program participation.

Foundational Data the DSP Should Make Available to DER Providers

Distribution system data will assist DER providers to align investments with distribution system needs. The availability of such data today varies widely depending on the current disparate penetration of data acquisition systems on the grid.

Data Supporting DER Locational Value

The following data sources may be useful to inform targeting of locational DER deployments, and to determine locational DER benefits. The data categories, types, details, and intended use are provided below.[70] As described in the next step Stage 1 processes, it is recommended that utilities use the chart below to as a basis to inventory distribution system data in the near term, as well as the data interface to make this data available to DER providers in the near term.

Category	Data type	Data details	Intended use
Capacity	Planned capacity expansion projects	Projects planned within 5 years, and if available, 5-10 years by substation/circuit/Pnode (LMP)	Assess where DERs can be deployed to defer traditional investments
	DER forecasts and load growth forecasts vs. integrated distribution capacity[71]	DER growth Load growth Hosting capacity	Assess when DER and load growth will surpass hosting capacity; compare timing against planned projects
	Expected equipment maintenance and replacement, or upgrade	Expected need to perform usage-driven equipment maintenance	Assess where DERs might be able to alleviate usage to defer maintenance or upgrade costs
Voltage / power quality	Planned voltage/power quality projects	Projects planned within 10 years by substation/circuit / Pnode (LMP)	Assess where DERs can be deployed to defer traditional investments
	Observed violations statistics	Monitored voltage violation data	Assess whether investment plan matches needs, and identify areas to target DERs

70 Data points included in the table are not represent consensus recommendations, but and should be considered as a baseline template for discussed at the data inventory outset of the process. The granularity of data points may be impacted by data availability, and standard processes for providing summary statistics to the NYDPS. Where possible, the underlying data should be provided in addition to summary statistics. Chart and descriptive language accommodated from Solar City, NY REV public data sharing and communication methods, May 2015.

71 Utilities may be able to provide new customer growth data without compromising non-disclosure agreements with real estate development companies that exposes information related to customer growth. Forecasts that remove personally identifiable information will be useful to the marketplace without attribution to the particular source.

	Customer service complaints	Statistics for customer voltage / power quality complaints by locations	Assess whether investment plan matches needs, and identify areas to target DERs
Reliability / Resiliency / Security	Planned reliability / resiliency /security projects	Projects planned within 10 years by substation/circuit / Pnode (LMP)	Assess where DERs can be deployed to defer traditional investments
	Reliability statistics excluding and including major events	CAIDI, SAIDI, SAIFI by substation/circuit	Assess whether investment plan matches needs, and identify areas to target DERs
	Existing supply redundancy level	No. supply feeds (use as proxy for resiliency)	Assess whether investment plan matches needs, and identify areas to target DERs
	Probability of major event	Indexed probability of major event by location/geography	Assess whether investment plan matches needs, and identify areas to target DERs

Table 2 Data Types and Uses for DER Supporting Locational Value

Data Supporting Hosting Capacity Analysis

The following data support hosting capacity analysis, which may be performed by the DSP or other market actors.

- Identify interconnection limitations for proposed DER projects. Additionally, the data provide indirect incentives to third parties into invest in asset management tools that may support dynamic load management to increase hosting capacity.

Category	Data type	Data details	Intended use
Circuit Model	Circuit Models	GIS or distribution analysis software model	Base requirement for modeling distribution circuit operations
Loading	Feeder-level loading	Annual loading and voltage data for feeder and SCADA line equipment	Loading / voltage data to analyze set of steady state circuit operation scenarios supporting hosting capacity analysis
	Customer type	Aggregated customer	Estimate load curve based on

	breakdown	type by circuit node[72]	typical customer loading
	Circuit node loading	Aggregated loading by circuit node	Allocate loading along circuit
	Existing DER capacity	Aggregated existing DER capacity by circuit node	Incorporate existing DER capacity into hosting analysis
Equipment details	Equipment thermal ratings	Ratings for each piece of equipment	Evaluate thermal loading limits
	Voltage regulating equipment	Settings for each specific device	Evaluate voltage equipment performance
	Protection equipment	Settings for each specific device	Evaluate protection criteria

Table 3 Data Types and Use for Supporting Hosting Capacity

These distribution system data will need to be updated on an expedient basis to ensure timely information is available to DSP market participants and to inventory total DER installed. Such information may be updated by utility / DSP periodically to reflect actual amounts of DER on the system.

There are differing positions as to whether to provide the underlying data that is needed for calculation of hosting capacity and related DER values. It has been argued by some MDPT members that the provision of underlying data to calculate DSP planning values such as hosting capacity and LMP has the potential to reveal additional DER business opportunities. Risk assessment and prioritization concerns raised by utilities may be addressed in collaboration with DER providers within the distribution data inventory and sharing processes identified herein. To support innovation and development of new DER products and services, the DSP should provide the underlying distribution system data where feasible, consistent with existing privacy and security regulations.

To the extent that conflicts arise between the utility's analysis of hosting capacity and analyses performed by other market participants, the PSC may consider reviewing mechanisms to allow Staff to resolve disputes.[73]

72 The definition of circuit node should consider the aggregation threshold that allows for these data to be shared, based on privacy regulations. The threshold will be defined in follow-on processes.

Data Needs from DER Providers for Planning

The following DER data points may be useful for DSP planning and operational processes. Providing a robust DER inventory may require new efforts on the part of DER providers, as it has been challenging up to now to inventory DER installed in the state. Alternatively, load disaggregation techniques also have the potential to identify the presence of DER and other major loads of interest to the DSP. The data needs from DER providers will evolve with the development of the market. As with customer-specific data, specific DER data requirements should evolve with the development of new products and services administered by the DSP. Additional work is needed to further specify these data requirements in follow-on processes, but at a minimum DER providers should prepare to provide the following data:

- DER location (point of common coupling)
- Customer service panel size (A)
- DER technology (e.g., solar PV, battery storage, DR)
- DER capacity (kW)
- DER controllability and responsiveness
- Production profile (kWh/min)
- Output power factor range
- DER historical performance

Data Needs from DER Providers for Market Operations

With respect to DSP market operations functions, DER providers (or directly participating customers) will need to regularly communicate with the DSP about the DERs they are managing and provide specific operational data necessary for inter- and intra-day market operations and processes. DSP market operators may require access to the data listed directly above, as well as potentially the following data:

- Daily forecasted DER production for variable resources
- Daily participation for variable DERs
- Planned DER outages
- Opt-in versus opt-out status of the customer[74]
- DER bid price information for individual units

73 For example, the Small Generator Interconnection Rules allow DPS Staff to be brought in regarding interconnection disputes, which may be a model for hosting capacity analytical disputes.

74 Availability of the resource to respond to DER provider coordination and control.

- DER bid price and grouping information in aggregate for like resources within a given network including if the DER is not going to provide a price, but instead will dispatch the DER according to the intermittent fuel source, or the customer's needs independent of the DSP needs

The DSP may need to manage the bi-directional communication process for signaling DER providers to deploy resources (e.g., event notification) and to know the current status of DERs. As part of this, the DSP and the DER providers would need to access the consumption data from participating DERs in Stage 1.

DSPs will need to design processes to be able to report on individual DER performance at least once a day so that both the DER providers and the DSP can assess what happened at the end of the day to be able to project what's available/likely the following day, information that may be needed for commercial market functions. Certain DER are installed behind the meter and DERs vary in size. The distribution planning group may need to assess the extent of DER provider coordination requirements with the DSP based on these DER attributes.

B. Current Distribution System Data

Current System Data Monitored by Utilities

There are a variety of system data that the DSP could monitor and act upon to support grid operations. Currently, the utilities have a varying range of grid management capabilities that monitor key elements of the distribution system including primary substations, secondary substations and other field devices.[75] At a high level, the capabilities of these systems should capture distribution system data elements such as:

- Real power, reactive power, voltage, current, status indications, and power quality information;
- The current state of specific devices (e.g. transformers, voltage regulators, reclosers, switches, protection devices) and their operation.

However, the level of monitoring, visibility and control can vary by utility and within each utility. For example, National Grid has SCADA deployed at just 52% of the company's substations[76].

Utilities rarely provide detailed distribution system cost and forecasted load growth data externally to market participants, outside of sanctioned processes to determine

75 Data acquisition systems: GIS, Outage Management Systems, Distribution Management Systems, Transmission Management Systems, Data Historians, Asset Management Systems, Distributed Energy Resource Management Systems (DERMS), Demand Response Management Systems, etc.

76 Reforming the Energy Vision Working Group II 2014

costs of service in PSC rate cases.[77] There are exceptions, however, including utility targeted DSM programs. For example, ConEd publishes maps to help customers know if they are in "Tier 2" networks and therefore eligible for higher Distribution Load Relief Program (DLRP) payments.[78] In addition, other utilities have filed proposals in response to the Track One Order requirements to "publish information regarding portions of the system that need upgrades but are amenable to non-wires alternatives and identify at least one such potential project to allow market participants to begin planning for projects that may follow initial DSIPs"[79]

Additionally, utilities record a variety of system data information tied to customer account numbers via the Electronic Data Interface (EDI) system.[80] Provided that the customer has not previously requested to block access to their account, the utility will provide up to 24 months of historical usage/billing information via an EDI (867) response. This information includes a number of data elements that should help a potential DER provider develop a proposal and for existing DER providers to monitor performance:

- Utility rate / service class
- All billing elements including energy usage by billing period and, if applicable, peak demand and on and off-peak energy use.
- Service address
- The Standard Industrial Classification (SIC)
- Whether the account is fed from multiple meters
- Customer NYISO load, their capacity obligation and whether they are taking commodity service from an ESCO.
- Whether there is interval data, which can also be requested via EDI and is provided in a separate electronic transaction.

Also, when an ESCO "enrolls" a customer and supplies their electric and/or gas commodity, the utility will send them a monthly EDI transaction with their current metering information along with their interval data on a monthly basis. For ESCOs desiring more frequent access to the interval data, the utilities can provide that on a weekly or daily basis for an additional charge.

77 In addition to DPS Staff, authorized researchers and consultants may be able to access system data, subject to data sharing agreements.

78 ConEdison Green Team 2015)

79 As per State of New York Public Service Commission 2015, Appendix B NIMO, NYSEG, RG&E, O&R, and CECONY filed proposals in May 2015 in response to the Ordering paragraph. As part of its rate case, Central Hudson issues a solicitation for demand response in three targeted networks in 2014.

80 ESCOs are subject to uniform business practices. (UBP) Pending PSC determination on DER provider regulation, similar standards may be required of any other entity seeking such access when a customer agrees to this access.

Current Data Provided by DER Providers to Utilities

New York approves standardized interconnection requirements and application processes for new distributed generators with a nameplate rating of 2 MW or less. These requirements include design requirements for generators, inverters, minimum protection function requirements, metering requirements, and others. Engineering guidelines require that DER providers develop performance models.

According to these application requirements, utilities receive system type, size and location data via interconnection processes at the point of common coupling. Generally, utilities do not receive DER performance data subsequent to the interconnection process. The degree of performance data provided by the DER is expected to evolve as market processes mature.

C. Gap

Data the DSP Should Make Available to DER Providers

Due to the disparate nature of data acquisition system equipment deployment on existing distribution systems, the full range of system data that would support the DSP market likely cannot be made available on a universal basis in the near-term.

Implementation:

- Stage 1: It is recommended that the DSP should inventory available distribution system data assets and begin making those underlying data available to the marketplace to conduct DSP planning and operational functions, subject to privacy and security safeguards. The proposed Distribution Planning Working Group called for in the previous planning discussion should further consider this topic.

  It is assumed that expansion of communication and control systems will be prioritized for those areas and devices that are projected to be overloaded and/or can benefit from such installations.

  In Stage 1, in addition to the existing EDI elements, there are additional data fields that the utilities could be able to report out in the EDI streams that would help customers and DER providers evaluate and implement DER measures. Specifically, the EDI stream may identify what network or substation the customer is fed from and, if applicable, whether they are participating in DER or other utility incentives.

- Continued Development Beyond Stage 1: The penetration of data acquisition systems – owned by utilities and DER providers – should approach uniform availability across each DSP. The need to coordinate data formatting and communication through standards development is both a near term issue, and further work will likely be required beyond Stage 1.

Data the DSP Needs from DER Providers

Implementation:

- Stage 1: Currently, utilities receive DER system type, size and location data from DER providers via standard interconnection processes. In Stage 1, however, DER providers should prepare to provide status and standardized performance data that would be necessary for DSP operations. To the extent possible, data sharing protocols should be coordinated with other state efforts, e.g., the California Smart Inverter Working Group, to reduce data sharing protocol costs.
- Continued Development Beyond Stage 1: Data sharing may expand to integrate a larger set of heterogeneous market actors. The data from third party resources could be integrated into DSP operations – provided it meets revenue grade requirements.

5.2.3 Data Sharing interface

A. Need: Data Sharing Interface Options

The data interface enables the transfer of customer and system data to support DSP functions and facilitate the deployment of DERs. Consistent with other technology investments utilities intend to make in the DSP, the interface method should achieve the following objectives:

- Enhances customer engagement
- Scalable
- Consistent with best practices
- Interoperable with a competitive, heterogeneous marketplace
- Maintains privacy and security protections

Green Button, which is an XML protocol for providing utility metering data in a standard format regardless of meter type or manufacturer, has the potential to augment the current EDI processed and provide customers and DER providers with streamlined access to metering data for individual customers. Green Button Connect is an example of an interface that enables the customer to authorize the release of their data broadly or to specific third parties. However, Green Button is limited in its ability to support scaling to transfer large amounts of customer data, inhibiting near real-time customer notifications.

Additional data platform options employed in other jurisdictions such as Texas may offer an example for providing interval usage metering data in near-real time, on a large scale. Multiple data sharing platforms may be useful to enhance EDI functions, and provide complementary data services.

Subject to the customer data process determination by the PSC, the DSPs could establish an efficient process for delivering interval customer consumption data on an expedient basis to third parties who have obtained their customers' consent to access that data.[81]

B. Current Data Interface Options

EDI is the predominant customer data transfer method for customer and related system data, if available and approved by the PSC and is primarily used for processing customer account switching and billing. EDI supports communication of customer-specific data to Energy Service Companies (ESCOs) licensed by the PSC. Access to customer data is governed by the PSC approved Uniform Business Practices (UBPs) and requires that the ESCO obtain customer consent. EDI was initially developed 30 years ago, prior to the widespread availability of AMF. While there are many EDI data fields that are potentially valuable for DSP market actors, such as service address, EDI may not be scalable to meet industry standards in the future. Moreover, EDI's primary value with respect to interval usage data is for billing purposes. It may not be a useful method for more transmission of more granular interval usage data to third parties.

C. Gap: Data Interface Options

Implementation:

- Stage 1: Adopting a specific customer data interface standard is beyond the scope of the MDPT effort. However, within Stage 1 follow on efforts, consistent with PSC processes related to the customer data digital marketplace, DSPs and other stakeholders could consider data interface solutions that are compliant with the objectives listed in this report. Open, industry-led interface options such as Green Button Connect and best practice options such as those implemented in other jurisdictions such as Texas may offer near-term options to expand and potentially augment EDI as a means of providing metering data. Further work is needed in Stage 1 to identify means to fully address the market's data needs, and to implement strategies to employ advanced data interface solutions in Stage 1.
- Continued Development Beyond Stage 1: In later market stages, the interface options for customer, system, and DER data may increase and allow for greater speed of data access across the market. It is anticipated that the Internet of Things (IoT) will grow to 26 Billion units installed in 2020. IoT suppliers will interface

81 Best practice data access methods are offered in examples from in Texas and by Pepco. In Texas, a standardized web portal offers access interval usage data for all customers. Customer data is updated and may be downloaded at one time by suppliers on a daily basis.

with the DSP market to the extent these devices may be integrated with energy management tools and services through standard data interface mechanisms.

5.3 Distribution Platform Capability Requirements to Create and Animate the Stage 1 Market

The functional center of the REV framework is the DSP. As defined previously in this document, the DSP is an intelligent network platform that will provide safe, reliable, and efficient electric services by integrating DER to meet customers' and society's evolving needs. A substantial amount of the MDPT Working Group's effort was devoted to identifying the specific platform technologies and capabilities necessary to enable the DSP's needed functionalities.

The Working Group established that the functionalities of the DSP as currently envisioned are achievable with existing technology, with certain cases requiring new software specially developed to adapt technologies to these new purposes. However, some of these requirements may be very different based on the size of DER, the type, and the level of penetration. Although system development and standardization are needed to adapt technologies to DSP functions, these modifications are well within the range of existing technologies and capabilities.

This section will review the set of platform technologies that are necessary to deliver the DSP functions identified in Section 5.1. While previous sections have noted a number of these technologies, this section summarizes all of the technical capabilities needed for an operational DSP, with an emphasis on the near- and mid-term.

For the purposes of this report we define the following sets of broad classifications:

DER types: (listed alphabetically)

- Biofuels, including biogas
- Cogeneration
- Demand response
- Energy efficiency
- Energy storage, including batteries, fuel cells, flywheels, thermal, etc.
- Hydroelectric generation
- PV
- Wind

DER sizes:

- Small DER: Less than 50 kW capacity
- Medium DER: Between 50 kW and 300 kW capacity

- Large DER: Greater than 300 kW capacity[82]

The distribution platform may need to accommodate different DER requirements based on these size and type classifications. Utilities should identify these differences in their DSIPs, as well as any additional considerations necessary to accommodate aggregations of similar or dissimilar DERs. Increasing DER penetration levels and diversity will require new techniques and algorithms to manage operational constraints, phase imbalance, control and management, and data cleansing from both real-time and advanced metering-based sources.

Operationalizing the distribution platform will require more than technology alone. DSPs should also improve and create related methods and standards. For example, to ensure that market transaction decisions are based on accurate system and DER data, DSPs may implement methods to address data cleansing and bad data detection. As this data proliferates, it will become an important asset for improving overall power system management.

5.3.1 Required DSP Capabilities - Distribution System Planning

The DSP's distribution system planning function, critical to Stage 1 REV implementation, will require several new platform capabilities, including the ability to both better estimate DER hosting capacity and to perform improved forecasting and analysis. While many of these planning tools and methods are developmental, it is possible to highlight the capabilities likely to be needed.

As recommended in this report, a planning working group comprised of key stakeholders could be established to further define the appropriate analytic methods, tools, and schedules. The methods and tools to identify include those supporting: (1) scenario analyses, (2) consideration of worst-case contingency scenarios, and (3) probabilistic or time-series assessments.

This report presumes that each DSP should also plan to do the following:

- Develop a mechanism to access, verify, cleanse and store a range of data from disparate sources—existing and future. This may include a combination of static data (e.g., size, location, etc.), historical profile data, and real-time data (where appropriate). This data needs to be classified and designed properly to ensure it can be exchanged effectively in accordance to the standards that will be established for DSP interactions.

82 The 300 KW threshold is a starting point based on the New York PSC's Standard Interconnection Requirements document issued in 2014, which allows a fast track application process to inverter-based generators (such as PV) below 300 KW, with some exceptions. This is not intended to be a prescriptive or static threshold but rather an indicative demarcation. For more information,, see State of New York Public Service Commission, 2015.

- Develop a verifiable network model for the DSP's service territory that is representative of all known existing and future DER installations, including operational, planned, and permitted systems. The model should account for any operational systems or practices that would impact how DERs are operated. Within the network model, the means of modeling each DER type will need to be specified in a standard manner for steady state simulations, new technologies, and dynamic/transient studies.

The platform technologies needed to support enhanced distribution system planning are expected to include:

A. DER Installation Tracking and Modeling

Geospatial model-based tools are needed that can track DER installations along with the characteristics of both actual and proposed DERs in the distribution system. This should include operational installations, proposed installations (i.e., those with pending interconnection studies), DERs permitted to be installed, as well as locations where customers/DER providers have indicated interest.

A detailed model of the distribution network is needed to support the needs of distribution system planning, market operations, and grid operations. This detailed and centrally located system should:

- Support modeling of DER behavior and performance at their locations and also the estimation of hosting capacity and calculation of distribution LMPs.
- Support the needs of market operations, such as scheduling and settlements.
- Support the needs of grid operations and systems such as SCADA, distribution management systems (DMS), distributed energy resources management systems (DERMS), and other systems used to manage and operate the grid.

Implementation:

- <u>Stage 1</u>: DSPs may need to update GIS and associated models for distribution assets, both from a technology perspective as well as from a process and data governance perspective. These changes would allow the models to become the primary source of information for the distribution system and all components connected to it. This should be a focus area during the first two years of Stage 1. A priority should be on creating standardized representations of the model that are carefully managed with secure access so that they can be shared with multiple applications, each making use of the latest approved version at any one time.
- <u>Continued Development Beyond Stage 1:</u> To support ongoing continuous maintenance of the geospatial models, DSPs should investigate and pursue more-automated means which will be needed when DER penetrations increase and the additions become more frequent.

5.3.2 Required DSP Capabilities - Distribution Market Operations

Initially, while DSP market operations capabilities are put into place, the market operations function will focus on procurement of DERs based on identified system needs as determined through the DSP planning function. At first, this will likely involve RFP processes or auctions. Over time, market operations are expected to become more complex due to: (1) the anticipated increase in DER penetration, capacities, and diversity of participation; (2) increased DER participation in the market leading to more liquidity in the marketplace; and (3) active integration between retail and wholesale markets.

A. Scheduling

Initially, the DSP may expect certain individual and aggregated DER participants to submit a schedule of when they will be available to deliver power (and/or other services) to the grid. These schedules should be available to the DSP for both the capacity procured ahead of time as well as for any ancillary services. As the market shifts toward a bid-based system, the scheduling process should adapt by accepting bids and formulating a schedule accordingly. This is akin to the schedules that the NYISO tracks for generators (and wholesale DER participants). At all stages the DSP should coordinate these scheduling activities with the ISO.

Implementation:

- Stage 1: The DSP must procure or develop scheduling tools to allow tracking of DER availability, both ahead of time for operational purposes and for after-the-fact settlement. DSPs should follow a standardized approach to model the schedules, and their interfaces with market participants. Given the level of penetration anticipated in this stage, this platform capability is likely to be a foundational tool that can effectively manage these new tasks but also has the ability to move rapidly to full automation as projected DER penetrations increase. This tool would allow the DSP to:
  - Track market participants' availability, operational schedule, and dispatch for those DERs that have the ability to schedule their services.[83]
  - Confirm that the scheduled product was delivered based on actual measurements from advanced metering or real-time readings.
  - Pass this information on to settlements.

  The DSP could also develop and implement protocols and standards that govern market participants' availability submission.

83 Not all DERs will need to submit schedules. The idea is to move to a more dynamic and automatic local optimizations process.

- Continued Development Beyond Stage 1: As DER penetration, locations, and diversity grow, there will be increasingly active market participation. To support efficient market operation, this tool and the information it tracks should become more automated.

B. Settlements, Billing, Cash Management, and Dispute Resolution

This functionality will be very similar to that in place at the NYISO, and there should be systems that:

- Track the energy, capacity, and ancillary services delivered to the grid.
- Track prices for services based on locational and temporal value components determined by both planning and real-time calculations.
- Perform settlements for each participant (i.e., a report that is sent to the DER provider).
- Perform cash management of two-way transactions with DER participants.[84]
- Manage dispute resolution.

Equally important is the need to interface this function with the utility's normal billing system to ensure that other cash management processes are not duplicated here. The functional details of settlements, billing, cash management, and dispute resolution are described in Section 5.1.3. It should also be consistent with the data specified in Section 5.3.4, and the frequency of data collection and updates should be standardized.

Implementation:

- Stage 1: In Stage 1, while overall DER penetration rates are low, DSPs could perform necessary calculations via existing processes or as an add-on module to the DSP/utility CIS system. DSPs may assess the feasibility of this approach early in Stage 1 and propose alternatives as needed. The calculations performed would cover the settlement needs of: (1) verifying actual delivery of power/energy, (2) matching delivery against forecasts, (3) developing the settlements statement, and (4) the bill.
- Continued Development Beyond Stage 1: As DER penetration increases, this tool may need to become more sophisticated and may evolve into an independent system similarly to how the ISO settlements systems have evolved over time.

84 The cash management is two way because many of the DER participants may also be consumers under some circumstances and, in any given month, may be net cash negative (i.e., they need to pay the DSP).

C. DER Program Management and Tracking

The DSP may need to implement a system to track DERs to manage DER information and market performance in a centralized place, akin to the NYISO market participant management system. DSPs would need to collect data in a standardized manner and request equivalent data from all DER providers.

The core information that should be gathered and stored by this system has been defined earlier in this report. The data collected should be consistent with that in the Market Data and Information Portal described earlier, and will similarly change based on DER size and type.

In addition, this system may contain DER-specific information, such as:

- Customer name
- Customer location (i.e., street address and GPS location)
- Customer meter information
- DER capability and characteristics at this location, including environmental and regulatory permits
- Ownership of the DER
- DER provider credit rating

Much of this information may be similar to that stored in the utility's customer information system, but DSP market operations may need to access this information to perform forecasting and settlements.

DSP market operations could also track specific programs, especially for demand-side programs. For example, for a DR program the specific information could include:

- DR program name.
- DR program characteristics.
- Names of all DR providers who are participating in the program, including aggregators and the capacity they are making available under the program.
- DR capacity available under the program.

Implementation:

- Stage 1: In Stage 1, DSPs could develop simple program management systems, similar to those used to track DER implementation and participation.
- Continued Development Beyond Stage 1: Over time, DER participation is anticipated to increase, leading to greater market animation and necessitating a more-sophisticated DER participant tracking mechanism. This mechanism may be akin to the market participant tracking mechanisms used in ISOs. To ensure

manageability, this development should consider modifications needed to standardize information collection and management across all types of DERs.

5.3.3 Required DSP Capabilities - Distribution Grid Operations

As with DSP market operations, the complexity of distribution grid operations will increase over time based on: (1) the anticipated increase in DER penetration in numbers, capacities, and diversity of participation; (2) more DER participation in the market leading to more liquidity in the marketplace; and (3) active integration between retail and wholesale markets.

Utilities are already integrating existing DERs in their respective systems despite limited observability of their generation or impact. This means that the planning for DSP grid operations should evolve based on the amount of DER penetration and should include close integration with DSP planning from where information on DER interconnection approvals and long-term growth projections can be obtained.

A. Monitoring and Observability

This topic can be divided into two distinct capabilities: (1) advanced metering measurements, and (2) real-time sensing necessary to maintain distribution grid reliability. Both of these capabilities are also needed to support market operations and maximize DER contributions.

As described in Section 5.1.2, in Stage 1 the DSP is expected to procure DERs mainly as a capacity offset and to meet system operation needs, supplemented by demonstration/pilot projects using DERs to provide ancillary services. Accordingly, the highest priority need for advanced metering deployment during Stage 1 is where there is a DER provider or customer actively participating in DSP markets. Investments made by DSPs both for advanced metering and real-time sensing should enable the direct participation of DER providers. Additional investments should also be made to enable the anticipated increase in both new customer participants and the diversity of DERs in the grid.

Any other broad-based advanced metering deployment beyond the scope of the recommendations included in this report will necessitate a business case analysis by the utility and subsequent Commission review and approval.

Advanced Metering

The functionalities enabled by advanced metering include:

- Diversifying the types of data collected (e.g., energy, voltage, instantaneous demand, reactive power)
- Increasing the granularity of the data collected and reported

- Facilitating improved two-way flow of information between parties (to utilities, customers, and third-party service providers)
- Improving the business functions of metering (including functions like tamper detection and measurement, verification, settlement, and billing).

In general, advanced metering supports increased granularity of information delivered on a timely basis. This supports better-informed customers, system planning and operation, and other third party stakeholders. Advanced metering can also support a number of the specific policy goals articulated in REV, such as:

- *Enhanced customer knowledge and effective bill management:* The majority of customers in New York have access to monthly or bi-monthly usage information. Advanced metering can provide consumers with the granularity required to promote effective management of their electricity bill.
- *Market animation and leverage of customer contributions:* The introduction of advanced metering to New York customers provides the foundation for a number of products and services planned by the market. Advanced metering supports time variant data, monitoring and verification of DERs on the grid, more-granular pricing and signaling of system needs, and numerous other services expected to be included within the DSP market. Historical usage information provides more accurate information to support customized competitive supply bids, or more targeted rate development. With increased penetration of advanced metering, energy service providers could support a greater level of capacity demand management.
- *System-wide efficiency:* Advanced metering can provide DSP distribution grid planning with the granular data needed to support better asset utilization in the future. Short of full deployment, pockets of advanced metering can provide similar efficiency opportunities for specific areas of individual DSPs' grids.
- *System reliability and resiliency:* Advanced metering can provide voltage and power quality monitoring data to the DSP to support enhanced reliability and resiliency investment. Advanced metering can also provide significantly increased visibility during outage events to support faster outage assessment and restoration through "last-gasp" outage notifications and visibility into when customers are restored. Advanced metering is particularly helpful during restoration to ensure that repair assets are efficiently dispatched, nested outages are located, and customer restoration is accurately verified.

- *Reduction of carbon emissions:* Advanced metering has been demonstrated to directly reduce both customer electricity usage and the number of maintenance crew deployments, leading to reduced carbon emissions.[85]

Advanced metering measurements may also be required to support market settlements and planning where DERs are actively participating in the marketplace, or where new rate designs are adopted that include time varying components and/or other more-sophisticated rate elements. This report recommends that all advanced metering implementation efforts should also evaluate the availability of other sensing equipment that can be easily reconfigured (e.g., to support multiple interval granularities), preferably remotely. Such flexibility could be prioritized to help ensure the long-term usefulness of the equipment and minimize disruptive and expensive replacement in the future.

Enabling DER Participation in DSP Markets

The DSP should take specific metering needs into consideration when DERs are interconnected or new rates are approved. The DSP may need to ensure that meters are in-place and communicating with the DSP market operator with adequate precision based on the market needs. It is expected that these meters would be installed at the DER prior to bringing the DER online. The requirements for metering to enable DSP markets may be broken down according to the size of the specific DER in question, as shown in this example:

- *Certain small DERs,* such as residential rooftop PV systems, may not require advanced metering capability. The DSP will need to ensure specific requirements, as approved by the PSC, are readily available to utility customers and DER providers.
- *Medium DERs (< 300 kW)*, may require advanced metering or other grid-located sensing devices on potentially consequential generation resources, and/or at specific locations (e.g., near the substation, on specific wire types, within specified zones). A minimum of hourly metering capability should be adequate for systems of this size unless they are likely to impact distribution grid performance.

  An exception would be if a previous PSC directive, such as net metering programs, applies to the DER. If advanced metering is not used, the DSP could employ an alternative that provides sufficient data functionality and reasonable accuracy to enable Stage 1 DER market and procurement functions. Any alternative used to supplement advanced metering must provide data that is of revenue quality and meets bill quality measurement requirements. The DSP may

85 U.S. Department of Energy 2012

also choose to supplement existing load research samples, add stratified sampling to specific locations, or employ additional sensors to improve forecasting, where advanced metering data is not readily available.

- *Large DERs (> 300 kW)*, (and DERs participating in certain ancillary service programs) should be supported by SCADA-based remote sensing and control capabilities or equivalent. More information on this is provided in the next section. Where possible, redundancy in DSP-owned and DER-owned SCADA should be avoided. Instead, a focus on common methodologies, minimum technical requirements, and standardized protocols is preferred for interoperability.

Implementation:

- Stage 1: Universal deployment of advanced metering may be unnecessary to support the REV mandates covered under the Track One Order. However, DERs participating in REV markets may require advanced metering capabilities to do so, and advanced meters could be installed by either utilities or third parties to support such direct participation.[86] The requirements of the type of sensing device will be governed by the size of the DER capacity as defined above in this section.

  As noted above, a utility wishing to deploy advanced metering across broad sections of their service territory should develop a business case that is not wholly dependent on the Track One Order requirement, including details regarding operational benefits and full supporting cost-benefit analysis.

- Continued Development Beyond Stage 1: Scalability will be critical for utility investments in advanced metering data management systems. As REV markets grow, the adoption of advanced metering is expected to increase. Utility meter data management systems should have the ability to be scaled to accommodate this anticipated growth in DERs, when broader advanced metering deployment may be required to support grid operations.

Grid and DER Monitoring

Sensors that enable observability of the distribution grid are often housed in power equipment and connected to a communications network capable of delivering measurements either to other distributed control systems or to a central system. Depending on the type of equipment being monitored, the data can be measured

86 Metering guidelines for third parties will need to be developed including meter installations, calibrations, meter reading, validation and estimation of meter data, etc.

and sent in intervals ranging from anywhere between seconds and one hour.[87] Where protection, automation, and control needs require faster communication, it is also possible to have sub-second data transfer, if determined necessary.

At present, New York utilities have installed "smart" distribution devices or distribution automation at varying levels of penetration across their networks. These devices provide the ability to perform some level of grid monitoring and control. The devices themselves only provide the capability to acquire (and in some cases store) grid operational data and perform localized control. To provide the grid monitoring and visibility functionality described in Section 5.1.2, a communications system and a centralized system to monitor the data beyond what exists now is likely to be needed.

Implementation:

- Stage 1: For areas of the distribution system with known or potential operational concerns (for example, feeders exceeding a specific level of DER penetration), the DSP could assess existing availability of remote, SCADA-based, real-time sensing in the area to determine whether it can provide adequate monitoring and control. The sensing installed should provide data on power flow, voltage, power quality (e.g., harmonics and voltage deviations), connection status, and other data points as appropriate. For large DERs (>300 kW), data should be SCADA-quality and sent to the distribution SCADA at 2–4 second intervals (or better). This will provide visibility to the grid operator to be able to handle intermittent DER while still managing the grid in real time.

  Where existing sensing is inadequate or does not exist, the DSP should evaluate the feasibility and merits of specific technologies to provide the necessary services and pursue deployment as needed. DSPs should also consider alternatives to SCADA for interfacing, collecting, processing, and acting on DER data, if they are more appropriate.

- Continued Development Beyond Stage 1: Based on the anticipated increase in DER penetration over time, DSPs may propose additional measures to support grid and DER observability. This may require centralized real-time operations systems, which could also offer additional advanced optimization capabilities.

Net Load Monitoring and Visibility

The DSP will need to have the ability to monitor the net load on the distribution system, including the effect of DERs that directly affect load. For example, DR, which currently focuses on targeted load reduction achieved through signals or requests sent by the

87 For instance, SCADA measurement often returns data at two-second intervals, while typical existing AMI deployments return data at 5–60 minute intervals. For more information, see Mohassel 2014.

utility using instructions to reduce loads for a specific period, rates (e.g., time-of-use rates or incentives), or direct control of specific appliances. For this type of DER, the DSP could monitor load reduction and compare it with expected behavior. Some utilities already have well-developed methods for measuring and verifying load-affecting DERs, and they should continue to be employed and enhanced as new DER products are developed.

At present, there is limited real time load monitoring and visibility on NY distribution systems. Interval meter data and systems are available for a limited number of commercial and industrial customers, but no visualization platforms are currently in use. The need for these capabilities is expected to increase based on the DER monitoring and observability needs identified earlier.

Implementation:

- <u>Stage 1:</u> The DSP may begin by augmenting short-term forecasting information capabilities with advanced metering data (where available), and should continue to deploy monitoring where needed to enhance the quality of the forecast.
- <u>Continued Development Beyond Stage 1:</u> As more DERs and monitoring/metering infrastructure is installed, the DSP could assess the quality of the net load monitoring to determine whether new approaches or equipment are needed to provide sufficient accuracy.

Real-Time Operational Systems

Real-time operational systems such as DMS combine granular geospatial/economic load forecasts, SCADA data, sensor data, load research data, and other datasets to model 3-phase power-flow. Ideally, these systems can be used within the utility's normal power flow modeling platform. This modeling is used to identify potential operational risks and opportunities in various parts of the circuit modeled. In conjunction with SCADA, this can allow the distribution grid operator to operate the system in real-time. The DSP capabilities that may enable this, include:

- Gaining visibility into the distribution network and the output from some or all of the DERs where sensing in the form of advanced metering or real-time SCADA-based measurements are available.
- Performing real-time monitoring of the distribution grid through these sensors and the SCADA displays that allow the operator to view the flows on electrical circuits
- Track system/locational overloads, deficiencies or other limiting factors.
- Track system/locational requirements of other operational factors such as voltage support, power factor, losses, and related issues.
- Monitor the distribution system through alarms that may indicate overloads and take actions as appropriate.

- Take appropriate action as needed to keep the system operating in a reliable and safe manner, under all operating conditions. This may require the development of batch run scenario analyses of various DERs, combinations, or other.
- Utilize distribution optimization functions, which can advise the operator of actions that could be taken to alleviate system overloads or other conditions.

In addition to these platform technologies, DSPs should define and implement policies, procedures, and processes for normal and emergency operating modes. These may include:

- Operational policies from the DSP market rules aimed at operating the system under an increased penetration of DER products and services.
- Operational processes and procedures for operators to manage the system in a reliable manner under different operating conditions both normal and emergency. Consideration should be given to the long-term risks and opportunities of these shorter-term operational policies and procedures.

Implementation:

- Stage 1: Because the resource requirements to develop a real-time operational system are significant, a pragmatic approach is needed. In Stage 1, DSPs should:
    - Implement real-time operational interconnectivity with the measurement mechanisms defined above,
    - Invest in demonstration projects to test specific advanced functionality,
    - Develop specifications and plans for broader implementation in Stage 2.
- Continued Development Beyond Stage 1: As DER penetration levels and DSP market activities expand, the DSP should pursue implementation of the systems identified in Stage 1.

B. Coordination and Control

Grid interactive DERs require control mechanisms that can turn them off from delivering power to the grid and/or control them against set points issued by the DSP or DER provider. This capability is needed for both reliability and for safety reasons (to avoid unanticipated line energization when field crews are working on equipment). This could be required in the interconnecting agreement that is signed when DER projects are approved. The required control mechanism may vary by DER capacity and type:

- *Small DERs (< 50 kW)*, can often use controls that are manual, localized, performed over the phone, or based on remote control that is generally not time-critical and updated periodically.

- *Medium (50–300 kW) and large (> 300 kW) DERs*, may need control to be remote and based on real-time SCADA, similar to the requirements of the NYISO for DER interconnections. However, any control capabilities beyond dispatch should be standardized and included in the DER's interconnection agreement.

In addition, new and advanced optimization functions may be needed for both centralized and decentralized coordination to achieve additional objectives in tandem with Track One Order requirements.

Distribution Control Systems (Distributed and Centralized)

The distributed nature of DERs may be leveraged to best support grid operations if deployed in conjunction with localized controls to coordinate volt/VAR support alongside DER production. For example, this could be achieved through currently available solutions like integrated volt/VAR control (IVVC) and conservation voltage reduction (CVR) systems supported by capacitor banks, voltage regulators, and transformer tap changers. However, new and innovative solutions should be considered as well. Some of this control may also be centralized to optimize across a larger segment of the distribution grid.

The DSP could also consider implementing fault location isolation and service restoration (FLISR). DSPs may consider implementing fault locators in various locations in the network that are capable of detecting fault currents and taking action either automatically or under operator supervision. While most implementations of FLISR have a primary distributed component, the distributed components may also be integrated with the central system. This may enable more-optimal switching scenarios and enhanced use of DERs present in the network.

Control systems deployed by the DSP should be capable of supporting communication between grid devices that may be required in future stages. These control systems may also have an automated capability to locally disconnect when their behavior exceeds the bounds of control system management, which may be needed in Stage 2 to provide an additional safeguard beyond the on-board disconnect functionality of individual DERs.

Implementation:

- <u>Stage 1:</u> DSPs may continue existing approaches to distribution automation, but with an added focus on existing and planned DERs. Based on system conditions where the DERs are being installed, beneficial automation capabilities may be achieved using a combination of FLISR, volt/VAR compensation, or others.
- <u>Continued Development Beyond Stage 1:</u> As the DSP deploys additional distribution-level infrastructure, control capabilities may be migrated to a centralized system where appropriate to drive a common approach to reliability and resiliency of the grid.

DER Optimization Systems

Functionality allowing the DSP to optimize DER production may enable improved system operations. Depending on the control capability and assets available to the distribution grid operator, this might involve operations such as:

- Turning on/off energy storage on a given feeder,
- Providing for dynamic control of DERs on the feeder,
- Calling for DR if available on the feeder,
- Switching feeders to take advantage of intermittent DERs when they are generating power.

DER optimization systems are currently in-place in a few locations in New York in the form of DERMS, which have the ability to optimize DERs across a broad portfolio.[88] These systems account for DER locational and generation characteristics, and can dispatch both switching and generation. As DERs proliferate, DERMS will become increasingly necessary tools for monitoring, aggregating, and dispatching DERs to offset resource intermittency and manage market participation. .

To ensure that installed DER optimization systems achieve the desired functionality, the DSP may need to consider approaches to integrating market operations and grid operations within the system. DSPs could propose potential approaches that could be tested prior to broader deployment.

Implementation:

- Stage 1: DSPs may plan mixed-asset capabilities to optimize the availability of both supply- and demand-side DERs in their system. For these implementations to be effective, the DSP may need to ensure that an accurate and up-to-date GIS model exists supported by adequate measurements and control capabilities. Early implementation should target priority areas of the grid, such as those with high DER penetration.

  To ensure long-term cost effectiveness, DSPs could also assess alternative options for DER control and optimization, particularly considering existing and planned utility systems.
- Continued Development Beyond Stage 1: As DER penetrations increase, DSPs may continue expansion of DERMS (or alternative) capability.

88 DERMS can be segmented into three broad categories: DR-driven, supply-driven, and mixed-asset. DR-driven DERMS integrate demand-side resources, supply-driven DERMS leverage existing generation resources, and mixed-asset DERMS aggregate the abilities of both demand-response-driven and supply-driven DERMS. For more information see Munsell 2014.

Short-Term Forecasting

DSPs will likely need to implement short-term forecasting systems. These systems may be very similar to the long-term forecasting under distribution planning, with several specific differences: (1) the time period is on the order of days to one or two weeks, (2) the temporal granularity is hourly (or less), and (3) the output is used by both the DSP grid operator and market operator.

Implementation:

- Stage 1: The DSPs could enhance their existing short-term forecasting systems to include the inputs from existing DER sources, test and improve forecast accuracy, and provide forecasts to the distribution grid and market operator.
- Continued Development Beyond Stage 1: As DER penetrations increase, and forecast accuracy becomes increasing critical to efficient system operations, the DSP should continue to refine and enhance its forecasting methodology and tools to improve forecast accuracy.

5.3.4 Required DSP Capabilities – Cross-Functional Platform Capabilities

A. Market Data and Information Portal

This report assumes that in order to maintain transparency of DSP market operations, it is imperative that each DSP plan for and implement a market data and information portal that is commensurate with the projected penetration level, size, and diversity of the anticipated DER rollout in its service territory. Key aspects of this portal could include:

- Storing all PSC-authorized data that is provided to market participants, including: (1) DER production data, (2) feeder-level power flow, (3) voltage at specific locations in the network, and (4) others as identified by the DSP functions in *Section* 5.1.3. The types and amount of data to be provided would need to be determined by the PSC.
- Making data accessible to market participants, regulators, and other groups within the DSP. Key to this data access is the need for a strong combination of privacy and physical and cyber security:
  - Privacy is needed to ensure that each use can only access the data they are entitled.
  - Security is needed to ensure that the data stored is safe and secure. The security requirements should include NIST requirements for cyber security.

- Standard data analytics and reports that can be released to inform the markets on:[89]
  - *DER performance,* including:
    - Actual DER generation tracked by location, feeder, and grouping, stored and displayed over time;
    - Performance of DERs to their schedule over time.
  - *Market participation dynamics and liquidity*, displaying the amount of DER capacity actively participating by:
    - DER type;
    - DER location;
    - DER class (e.g., individual, aggregator, microgrid, etc.), as standardized across all DSPs.
  - *Market price dynamics*, tracking market costs and prices (e.g., LMP+D). The granularity of such data will possibly be driven by improvements in analytical capabilities and market needs, and should be displayed by:
    - Location;
    - Time of day;
    - Day of week (e.g., weekday vs. weekend);
    - Season.
  - *Market opportunities,* made available to the market by providing key information to existing and potential market participants to inform their operations and investment decisions. Information made available should be standardized across all DERs, and could include:
    - DER need by location, including capacity and characteristics (energy, time of day, etc.);
    - RFP or auction terms.
  - *Additional information,* which that may be identified in the future.
- Open-access mechanisms for the data from the front-end (e.g., web-based displays) or from the back-end (e.g., electronic data interchange) for downloading large quantities of data for larger participants. The access mechanisms for both front and back-end should be standardized across all DSPs.

89 Note that this type of data may require aggregation to preserve confidentiality, particularly due to concerns about commercial sensitivity, or the potential for the exercise of market power and non-competitive behavior.

Implementation:

- Stage 1: To support Stage 1 activity, DSPs should develop a market data and information portal with the properties described in this section.
- Continued Development Beyond Stage 1: As DER participation and market activity increases, the market data and information portal could expand to become more sophisticated, similar to today's ISO market portals.

B. Communications

Communication systems at most levels of the distribution system may need to be upgraded to enable the functions anticipated for the DSP markets. This includes communication protocols and assets located at substations, local feeders, and at/in the customer premise. Common networks could be considered (i.e., one network serving many applications) as these systems are upgraded to ensure ratepayer value and long-term scalability. Communications capabilities should support:

- *Advanced metering communications*: The Working Group did not reach consensus regarding the level of deployment of advanced meters. The underlying expectation is to start with just those places where DERs are being located. However, any communications network being implemented may need to scale up when the utilities feel it is appropriate for business needs beyond those needed during the early phases of REV market implementation.

  The Working Group is not in consensus regarding the type of communications structure needed to deploy advanced meters. Some favor a utility-owned, vertically-integrated AMI deployment, enabling REV functionalities as well as operational benefits beyond REV (e.g., synergies with other smart grid infrastructure, improved outage management capabilities, etc.). However, the installation of AMI will not necessarily include a communications network capable of supporting all data traffic and applications. Also, it may not be necessary to deploy a utility-owned communications network to enable the functionalities associated with advanced metering. Using a cellular network and/or a customer's Wi-Fi network coupled with their broadband internet connection may be able to augment the communications needs of advanced metering as required to support DER deployment.[90]
- *SCADA real-time communications*: This could take advantage of existing SCADA communications networks and extend them to include feeders and substations where DER penetration is above a certain level. This same network could also be leveraged for SCADA controls. To the extent that utility-owned networks are

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deployed (e.g., to support SCADA-connected devices, DA/FLISR, etc.), then synergies may be realized by also incorporating communications support for advanced meters.

- *DSP market interactions*: Regular broadband communications supported by a secure web-based browser mechanism could be adequate for much of the needs of DSP market operations given the expectations of the Stage 1 rollout. The DSP market operator could make available web-browser-based mechanisms (web-pages) available for the DER providers to interact with the DSP.
- *Phone and email*: The report also assumes that in Stage 1, some control of DERs may occur using phone or email, which would not require complex communication networks. However, where this is the case the DSP should outline plans to transition toward modern alternatives.

Implementation

- Stage 1: Each DSP should, across all functions, holistically evaluate the communications capabilities needed to support Stage 1 development. Any near-term gaps should be addressed quickly, and a plan to meet longer-term communication needs should be created (and implemented when appropriate).
- Continued Development Beyond Stage 1: To accommodate the expected increases in number of DERs and their diversity, DSPs may plan for more automated approaches to handle them through the communications means defined in this section.

5.4 Utility and DSP Organization

As part of its Order directing existing distribution utilities to serve in the role of the DSP, the PSC recognized the concern expressed "both in written comments and by many individuals at the public statement hearings, that utilities in the role of DSP will exercise market power in their own interests, and suppress innovation, at the expense of customers and market participants."[91] To address the concern, the PSC put in place several stipulations including:

- Preventing utilities from participating as owners of DER "where a market participant can and will provide these services;"
- Noting pending ratemaking reforms in Track Two that will be "designed to reward utilities for outcomes that benefit customers and achieve our objectives"

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- Establishing close monitoring via the "DSIP process, rate cases, and outcome metrics established in the ratemaking context"
- Calling for the development of a dispute resolution mechanism that expedites review and action on activities that deter DER investments"
- Noting open consideration of removing an underperforming utility-as-DSP to "allow other entities to serve that function."

Additionally, the PSC left open the possibility for functional separation if necessary and directed the MDPT Working Group to "examine whether there are specific functions of the DSP that could or should be subject to separation from other utility operations." As the PSC noted, "This analysis extends beyond the issue of market power and applies to a utility's performance in meeting all of the responsibilities of the DSP."

Addressing the topic of functional separation requires a clear delineation of both the new, enhanced or expanded functions that must be fulfilled to support smarter integration of DER at various levels of system evolution, as well as the key attributes that would guide the determination of necessary functional separation. Several of the PSC's adopted market design guidelines serve well as guiding attributes:

- **Transparency** – Timely and consistent access to relevant information by market actors, as well as public visibility into market design and performance;
- **Minimize market power** – Develop DSP procurement tariffs to minimize the potential for market power;
- **Fair and open competition** – Design "level playing field" incentives and access policies to promote fair and open competition;
- **Minimum barriers to entry** – Reduce data, physical, financial, and regulatory barriers to participation.

In this context, the question is whether and how much functional separation is necessary to achieve these desired market attributes. As discussed in the MDPT process, the overarching responsibility of the DSP during Stage 1 should be to carry out the planning, operations and market functions necessary to acquire cost effective DER to meet the distribution utility's short and long term capacity and operational needs.

Given this focused scope of responsibility, there does not appear to be a need for immediate functional separation of the proposed DSP functions from other functions within the utility. However, it will be essential to improve transparency in proposed DSP functions. Distribution planning, in particular, should be carried out in a way that is open and transparent to all stakeholders. The analytical methods and assumptions used to determine the capability of the system to host DER and to identify specific locations on the system that are the highest priority for capacity relief, for example, should be agreed to by the Commission and understood and available to all stakeholders. The proposed Distribution Planning Working Group, when reviewing and attempting to identify preferred analytical methods and planning schedules, should also identify how those methods and processes can be more transparent. As a second example, when the DSP issues RFPs or conducts auctions by which stakeholders can propose alternatives to traditional utility investments to address identified system needs, the criteria for selection and processes used to do so should be approved by the Commission and they need to be open and transparent. In all such situations the DPS staff, possibly with the support of a neutral consultant reporting directly to them, must ensure that the approved methods and processes are appropriately followed by the DSP, and the outcomes are fair and reasonable.

As experience is gained during the implementation of Stage 1, and if situations arise where functional separation appears to be appropriate, steps should be considered to implement further safeguards to ensure that markets are evolving in a way that meets Commission expectations.

6 Key Recommendations for Staff's DSIP Guidance Document

This section provides discussion on key topics for DPS Staff to consider as it develops guidance regarding the structure and substance of utility DSIP filings. While utilities will separately file individual DSIPs, Staff's guidance should consider a minimum level of uniformity with respect to common approaches specified below. Additionally, it is recommended that, for each recommended DSIP component, the utility's proposal should address how investments maximize optionality for customers and DER providers, support a diverse, heterogeneous marketplace, and ensure consumer protections are met. For the following recommendations, pursuant to the Track One Order, the DSIPs should include a description of the organization of both DSP and traditional utility functions.[92]

6.1 Distribution System Planning

a Describe plans for addressing and integrating uniform analytical methods, as informed by the Distribution Planning Working Group, into current system planning processes, as well as overall planning schedules and milestones.

b Identify specific locations within the distribution system that are the highest priority for distribution capacity and operational relief.

b Provide an initial assessment of the capability of the distribution system to accommodate and host DERs. Describe how this assessment will be refined for future planning cycles.

c Describe plans to complete a locational value analysis following a uniform methodology to determine short and long term forecasts of distribution marginal capital and operational costs.

d Describe initial efforts to develop probabilistic and geo-spatial planning capabilities, and the schedule for integrating such methods into routine system planning.

e Describe plans to inventory and share utility distribution system data, depending on the data acquisition systems in place, including but not limited to:

- Planned capacity expansion projects
- DER forecasts and load growth forecasts
- Expected equipment maintenance

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- Planned voltage / power quality projects
- Observed power quality violations statistics
- Customer service complaints
- Planned reliability / resiliency projects
- Reliability statistics
- Circuit models
- Feeder-level loading
- Customer type breakdown
- Circuit node loading
- Existing DER

2 Describe stakeholder involvement in the initial distribution system assessment, as well as in future distribution planning processes.

3 Provide a schedule consistent with PSC guidance for the submission and expected periodic updating of these results.

4 Describe specific plans for DER procurements and market-based initiatives to allow DER to help address identified distribution capacity and operational needs.

5 Describe plans for ongoing updates to DER mapping and installation tracking methods to track DER installations. Describe the technologies that will be used and the processes planned to keep this model up-to-date on an ongoing basis.

6.2 Distribution Grid Operations

Describe actions to be taken to ensure the DSP has the full capability set needed to meet Stage 1 REV objectives with respect to grid operations.

For each point below, provide plans for scaling these capabilities as (1) DER penetration, size and diversity increases and (2) market participation and liquidity increases.

1 Describe planned grid operations strategies to support planning and market operations to encourage DERs, while allowing continued reliable distribution system operation.

2 Describe plans to incorporate remote (de-centralized) and centralized real-time operational systems to monitor and optimize the operation of the distribution grid.

3 Provide an analysis of the potential operational opportunities, risks and power flow impacts expected with increased penetration of DER.

4 Describe plans to install advanced meters and/or other technologies to measure DER performance and exchange information with DER providers and customer participants.

5 Describe communications infrastructure capabilities planned to support the interactions with DERs and other customer participants.

6 Describe capabilities that will be implemented to perform monitoring and provide visibility into net load modifications.

7 Describe operational policy or procedural changes that may be needed as a result of operating the system under increased penetration of DER. The DSIP does not need to include the actual policy or procedural changes but they should identify areas where changes would be required for Stage 1 to become operational.

- a Policy changes could be considered in the following areas and others as appropriate:
  - i Specialized rules for use of DERs under stress conditions;
  - ii Guidelines and/or constraints on the dispatch of certain DERs by the DSP, especially for assets being dispatched from the ISO, and under what conditions the DSP should adjust the dispatch of DER; and
  - iii How DER services rendered to the DSP or ISO will be measured, verified and compensated.
- b Procedural changes could be considered in the following areas and others as appropriate:
  - i Safety procedures for de-energizing equipment prior to performing work on the distribution system, whether during planned or unplanned outage conditions;
  - ii Operator interaction with field personnel during planned and unplanned outage conditions;
  - iii Procedures for interconnecting DERs based on location and size;
  - iv Procedures and necessary conditions for turning certain DERs on or off by the DSP operator, for each type of DER; and
  - v Procedures for switching feeders to reroute power to take advantage of DER.

8 Describe methods that will be used to facilitate DER integration into grid operations and services, including direct and indirect dispatch of DERs, and communication and notification protocols recognizing that these may vary by size and other considerations.

9 Describe methods that will be used to coordinate distribution grid operations with the bulk transmission system, including operational visibility of DERs that operate in both NYISO and DSP markets.

10 Describe plans to enable distribution level ancillary services market for products such as localized volt/VAR optimization.

11 Describe the approach that will be taken to manage the risks posed by physical and cyber security.

6.3 Distribution Market Operations

Describe plans to ensure the DSP has the full capability set needed to meet Stage 1 REV objectives with respect to market operations, including:

1 Define the organizational structure and role of the market operations organization within the DSP.

2 Outline the outreach and coordination efforts that will facilitate the sourcing of assets for distribution grid services and development of distribution markets.

3 Outline a structure for coordinating resources, including an approach for coordinating among wholesale ISO markets, retail providers, and distribution operations.

4 Identify plans to integrate systems into utility operations using a common approach—developed across DSPs—for the following functions:

a Measuring and verifying the performance of participating DERs.

b Operating a communications portal, as well as the interface for managing market participant registration and activity.

c Tracking schedules from DERs that have the ability to schedule their generation or consumption.

d Managing settlements, including billing, receiving, and cash management including the interfaces needed with the utility CIS to perform cash management.

e Managing disputes that will be developed to support the DSP market operations capability.

5 Outline the capabilities necessary to ensure market security, legitimacy, and optimization, and specify which entity(ies) should perform which functions.

6 Describe plans to provide longer-term signals to potential market participants and provide sufficient lead time to solution providers and customers for successful market development

6.4 Data Requirements

The PSC will determine the processes to address standardized data platform issues, such as forums related to a digital marketplace. Consistent with such processes, utility DSIPs should describe plans to integrate a common data platform and model for customer, system, and DER data exchange across DSPs into their operations. At a minimum, utility DSIP filings should address the following:

1. Describe plans to provide customer data, depending on metering in place, to the common data platform, including the following:
   a. Historical consumption (monthly kWh, or more granular if available)
   b. Historical power factor
   c. Coincident and non-coincident customer peak demand (kW)
   d. Customer tariff
   e. Customer charges
   f. Reported outages
   g. Service location
   h. Power quality data
   i. Customer complaints about voltage/power quality in the immediate vicinity of the customer
2. Describe the process by which the DSP will share data into scalable meter data interface solutions, such as Green Button Connect.
3. Describe the methods to provide customer data at the time interval required by the common data platform.
4. Describe the method by which data sharing will comply with existing privacy and data security requirements.
   a. Within this description, address aggregation thresholds beyond which anonymous and suitably masked customer-level consumption, billing and account information may be shared with third parties without explicit customer consent.[93]

93 The PSC may need to make a determination on the application of privacy restrictions to circuit level data.

7 Recommended Stage 1 Process Next Steps

This section outlines recommended Stage 1 process next steps along with actions to implement them.

7.1 Planning

7.1.1 Establish a Distribution Planning Working Group

The Planning Section to this report outlines suggested enhancements to planning to appropriately integrate DERs with distribution utility operations and to support the development of robust DSP markets. Some of the key recommended planning enhancements are as follows:

- A shift from deterministic to probabilistic planning methods
- Determining the baseline capability of the distribution system to host DER
- Identifying the locational net value of DER
- Identifying and prioritizing locations to be targeted for distribution system capacity relief
- Developing an integrated distribution and transmission planning process

Many of the recommended enhanced planning functions are in various stages of development; planning methods may differ between utilities, depending on physical characteristics of the systems. However, the report recommends utilities adopt a uniform approach and methodology to develop new planning processes, and accommodate those uniform processes to their own unique planning methods. Additional work is needed to identify distribution system data, identify and develop appropriate analytical methods, acquire and provide accurate planning data, determine how best to engage key stakeholders, and to establish methods for better integrating distribution planning with transmission planning. Further, the timing of these recommended enhanced planning activities will need to be linked with DSIP Planning cycles, NYISO planning processes, and other regulatory processes, such as utility rate cases, and State energy planning efforts.

The Distribution Planning Working Group should be established following the completion of the MDPT effort, with the added participation of appropriate subject matter experts. The objective of this group would be to develop a "DSP Planning Roadmap" that contains recommendations regarding common analytical methods, an inventory of distribution system data assets, a recommended schedule and milestones for planning activities, suggested alignments necessary to coordinate distribution planning with other State and NYISO planning efforts, and any other key planning issues the group believes are important to enable the functionality proposed in this report. Preliminary recommendations from this working group should be provided by the end of 2015.

7.2 Markets

7.2.1 Products and Services

Initial DSP and DER provider interactions could inform the iterative development of products, services and transactional mechanisms in the DSP market. In order to test DER response to these procurement options, it is proposed that the Commission direct utilities to conduct demonstration projects that test the ability to meet reliability needs using DERs that are not under their direct control. As transactional mechanisms evolve, appropriate testing and validation of later stage mechanisms may be required.

7.2.2 Demonstration Projects

The implementation of the REV vision would potentially introduce many new products, services, and functions into the market. Utilities may need to develop demonstration projects to test these new innovations. As noted in the Track One Order, the Commission has adopted a resolution on December 12, 2014 "encouraging utilities and energy entrepreneurs to partner in demonstration projects in order to inform the continuing development of markets and policies in REV."[94]Furthermore, the Commission stated the follow, "Each utility is directed to engage third parties and develop concepts for demonstration projects, and file initial demonstration projects consistent with the guidelines developed in the December Resolution, not later than July 1, 2015, unless demonstration projects have already been proposed within a rate filing." [95]

As a part of the demonstration projects envisioned by the Commission, utilities and energy entrepreneurs should be encouraged to assess the following additional topics:

- Impacts of increasing DER penetration levels,
- Technical capabilities of establishing a distribution market platform, and
- Appropriate level of granularity in distribution locational and temporal market price structures.

94 State of New York Public Service Commission 2015, 115

95 State of New York Public Service Commission 2015, 115

7.2.3 NYISO and DSP Interaction

The extent of DSP involvement in transactions or information flows between DERs and NYISO requires further deliberation. Within the follow-on data inventory efforts, stakeholders could consider information flows from connected DERs to the DSP for planning and operational purposes and seek input from NYISO and the New York State Reliability Council (NYSRC).

7.2.4 Evolution of Distribution Asset Sourcing

A designated working group could determine a recommended evolution from Stage 1 sourcing to spot markets. This recommendation could prioritize stages of market development for different services, or focus on resources that already exist in some critical mass (e.g., load curtailment/DR) and suggest development of capacity relief or ancillary service markets based on the services these resources are readily capable of providing. The recommendation could then propose expectations around how additional market services are to be layered on as Stage 1 evolves.

7.3 Standards Development

Standards establish consistent protocols that can be universally understood and adopted thus increasing efficiency and consistency of the overall system. As a part of the MDPT process, existing standards and protocols were evaluated to determine their applicability to the REV vision as well as what types of standards were missing that were needed to ensure proper DSP function. The MDPT group reviewed the catalog of standards (CoS) that is published by the SGIP.

It is recommended for consideration that the Commission consider a process to decide how to prioritize and determine standards application to DSP functions. To facilitate the review of standards, the Commission could form a working group that is responsible for the creation of simple architectural diagrams subject to public comment and review to illustrate how certain standards apply to the REV process as well as reviewing additional standards outside of the CoS.

7.4 Use Case Development

A use case is "a story, told in structured and detailed steps, about how actors work together to reach a goal. A use case would be represented in the conceptual model by a path connecting several actors across multiple domains."[96] Standardized use case processes will serve to develop and define new product requirements with statewide

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application. To ensure standardization of product requirements across DSPs, the DSPs could jointly develop one set of use cases for the Stage 1 core functions. Of course, after the core use cases are developed, each DSP could customize for their specific operational needs, but the essential components should be common among all DSPs.

This report recommends that the process for adopting, revising, and developing new use cases be clearly identified by Staff or the PSC to ensure consistency in approach and functionality. The following high-level components could be included in follow on processes:

- What criteria determine which existing or newly-created use cases are adopted by the DSP (e.g., system needs, future needs);
- Which individuals or organizations, including a process for identifying these individuals and/or organizations, are included in the group that revises/develops use cases;
- The process for availing the use case to the public, allowing for public input, and responding to public input; and
- How the use case should guide policy decisions and the how the use case should be implemented in New York State.

The process for developing new use cases should rely extensively on experts in the domain of the use case being developed (i.e., when the process includes individuals outside of the PSC/DSP in question).

7.5 Market Rules

Market rules are a set of explicit regulations governing conduct within a particular activity or sphere. Market rules are necessary so that all of the participants in REV understand both what they can and cannot do to ensure that efficient and stable markets are developed. Uniformity of rules for similar applications across DSPs will encourage more robust market participation, make it easier for the PSC to oversee and to judge performance, and may result in reduced costs for market participants. One of the first priorities of the creation of the REV market could therefore be to establish the rules, processes, and structure for creating DSP market rules. Prioritization of the development of needed rules could be part of the forum for developing market rules and could be done with input from stakeholders from different market sectors and the NYISO. The Commission could also have clear policies on how rules will be enforced.

In order to approach rule development in a holistic manner, a statewide committee of the DSPs could be developed as the entity that governs statewide market rules and incorporates a stakeholder process to vet proposed rules or to propose new rules for the DSPs to consider. The Commission would be the governing entity approving the rules to be adopted. The stakeholder process could be similar to the NYISO's stakeholder process that includes time for deliberation of the rules prior to filing with the

PSC. Alternatively, the Commission could develop an independent entity to administer the process for creating the rules. In either event, substantial resources would need to be committed both initially and on an ongoing basis to create, vet, modify, and file these market rules.

In Stage 1, rule enforcement could continue to be through the Commission. In the longer term, as robust markets are developed, the Commission could possibly consider adopting an approach similar to the FERC's Office of Enforcement and develop a similar specialized group within the PSC. The FERC's Office of Enforcement is a specialized group that seeks to encourage compliance with the FERC Commission's statutes, rules, and orders. In that regard, the enforcement program gathers information about market behavior, market participants, and market rules; works to bring entities into compliance with the applicable energy statutes, FERC Commission rules, regulations, and tariff provisions; and conducts audits and investigations to evaluate compliance with Commission requirements. Where violations occur, the enforcement program seeks the imposition of appropriate remedies, including compliance commitments, disgorgement of unjust profits resulting from the violations, and civil penalties. The Commission could require participants in the retail market, the DSP and any utility department providing competitive services to adapt Codes of Conduct to ensure compliance with market rules as well as standard financial practice, as was adopted by the NYISO.

To enhance rule development in support of the REV vision, the PSC will need to provide clarity around DER-related activities including transactive energy related transactions and customer-to-DSP transactions, as well as the ability of microgrids to cross public rights of way and/or use utility facilities. Follow on processes could focus on necessary market rules for price transparency, data use, and confidentiality to allocate cost responsibility.

7.6 Data Requirements

This report proposes a working group process commence in coordination with the Distribution Planning Working Group to inventory and publish available and future distribution system data available within utilities. The process could identify means to update the data on a regular basis. DSPs may need to regularly report to Staff data currently provided, geographic coverage (if not universal), expected augmentation of existing available data and timelines for implementation.

The initial inventory could include:

- Underlying utility data availability for each field identified in Table 2 and 3 (type, period, quality).

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- Make distribution system data available to DSP market actors, subject to existing privacy constraints, utilizing best practice, and open standards methods.

The working group could:

- Develop requirements for receiving data from DER providers and DER owners.

7.7 Cyber Security

As advancements are made towards the REV vision, cyber security measures will need to be continually assessed and updated to ensure that all systems and customers are protected.

A separate cyber-security working group may be formed to assess potential threats. This group's tasks could include identifying best practice areas from various authorities, including NIST, for cyber security and privacy and developing a security and privacy framework to address the identified vulnerabilities.

8 Continued Development Beyond Stage 1

The following summarizes recommended functions beyond the scope of Stage 1 to allow utilities and other market participants to invest in infrastructure that enables market movement in that desired direction. These functionalities are proposed with full recognition that they might be enhanced, replaced or adopted earlier than proposed based on the market conditions in the future. Each of these functionalities summarized below, however, helps meet specific REV objectives endorsed by the PSC.

8.1 Distribution System Planning

Planning efforts will potentially integrate experiences with an expanding set of non-wires alternatives projects developed and implemented in Stage 1. As the impacts of DER materialize upstream from the substation and primary feeder level, continued efforts may be needed to integrate economic DER growth into bulk system planning, Concurrently, efforts related to coordination between the NYISO and the DSP across the planning and operations of the T&D systems are likely to improve,

8.2 DSP Market Operations

Increased numbers of market participants coupled with increases in the level of their sophistication and business models may require DSP market operations to become increasingly automated through the use and implementation of well-defined market rules that govern items such as scheduling, pricing, dispatch and settlements. Eventually, it may be desirable and possible to add operational spot markets for certain distribution grid services. The spot market could include a more-advanced optimization of resource scheduling and dispatch as well as the coordination of bids from participating resources and market clearing.

Many functions of market operations may need to advance to ensure optimal participant response including event notification, M&V methods, and the web portal design and operation. In addition, forecasting approaches could continue to improve and they may need to incorporate higher temporal or locational resolution. After stage 1, the transaction management structure may evolve towards a clearinghouse.

8.3 DSP Grid Operations

Increasing penetration of DER could add complexity to distribution grid operations. Distribution systems are currently designed to support unidirectional power flows. Distribution networks are less flexible than transmission networks in their capabilities to manage multi-directional power flows that DERs in increasing numbers will introduce to the system.

As a result, for capabilities beyond stage 1, there may be a need to manage an expanding array of heterogeneous DER assets. In addition to new modeling and analytical tools, the operator may also need increased optimization and control capabilities—both centralized and distributed. As intelligence becomes more decentralized, new businesses processes may be required to transform the DSP from a command and control center to a monitoring and signaling role to automated systems at the distributed edge.

8.4 Data Requirements

This report recommends that the DSPs provide streamlined access to customer and utility system data assets. As DER adoption improves beyond Stage 1, so does the need for increased data acquisition from a more heterogeneous, expanding marketplace, at increasingly more granular intervals. There may be a need beyond Stage 1, therefore, to continue to accelerate data acquisition system installations, and means to improve standardized data access and communications through integration of additional data interfaces meeting best practices.

Additionally, as DSP planning operations processes become more advanced, there may be a need to continually align DER data requirements for DSP operations. The platforms and the models for data exchange may require standardization in the way data is exchanged across different customers and utility territories.

8.5 Platform Technologies

As the penetration of DERs increases over the course of Stage 1, significant impacts are expected on the need for supporting platform technologies. The need for continued development of platform technologies beyond Stage 1 may be closely tied to the evolution of DSP market Increased numbers of participants, increases in the level of their diversity and sophistication, and new business models may require DSP market operations to become increasingly automated through the use and implementation of well-defined market rules that govern elements such as scheduling, pricing, dispatch and settlements.

To support this evolution, the DSP should look to build on the results of their Stage 1 research and development to deploy successful technologies at scale. For example, the DSP may test and Implement new set of grid optimization methods as traditional optimization approaches may not translate well enough to perform in this new paradigm as defined above.

APPENDIX 1

A1.1 TABLE OF ACRONYMS

Acronym	Definition
AC	Alternating Current
ADMS	Advanced Distribution Management System
ALJ	Administrative Law Judge
AMF	Advanced Metering Functionality
AMI	Advanced Metering Infrastructure
API	Advanced Programming Interfaces
BCA	Benefit-Cost Analysis
BTU	British Thermal Unit
BQDM	Brooklyn Queens Demand Management
CO2	Carbon Dioxide
ConEd	Consolidated Edison Company of New York
CoS	Catalog of Standards
CPUC	California Public Utilities Commission
CVR	Conservation Voltage Reduction
DC	Direct Current
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DLC	Direct Load Control
DLRP	Distribution Load Relief Program
DMC	Distribution Marginal Cost
DMS	Distribution Management System
DOE	Department of Energy
DSM	Demand Side Management
DPS	Department of Public Service
DR	Demand Response

Acronym	Definition
DS	Distributed Storage
DSIP	Distributed System Implementation Plan
DSP	Distributed System Platform
EDI	Electronic Data Interface
EPRI	Electric Power Research Institute
ESCO	Energy Services Company
FDIR	Fault Detection, Isolation, and Recovery
FERC	Federal Energy Regulatory Committee
FLISR	Fault Location, Isolation, and Service Restoration
GIS	Geographic Information Systems
ICAP	Installed Capacity
IEEE	Institute of Electrical and Electronic Engineers
IoT	Internet of Things
IOU	Independently Owned Utility
ISO	Independent System Operator
IVVC	Integrated Volt/VAR Control
kVA	Kilo-volt Ampere
kW	Kilowatt
kWh	Kilowatt Hour
LBMP	Locational Based Marginal Pricing
LMP	Locational Marginal Price
LMP+D	Locational Based Marginal Pricing + Distribution
LSE	Load Serving Entity
M&V	Measurement and Verification
MD	Market Design
MDMS	Meter Data Management System
MDPT	Market Design and Platform Technology
MW	Megawatt
NOx	Mono-nitrogen Oxide
NYISO	New York Independent System Operator

Acronym	Definition
NYPA	New York Power Authority
NYSERDA	New York State Energy Research and Development Authority
NYSRC	New York State Reliability Council
PoC	Point of Common Coupling
POLR	Provider of Last Resort
PSC	Public Service Commission
PSL	Public Service Law
PT	Platform Technology
PV	Photovoltaic
R&D	Research and Development
REV	Reforming the Energy Vision
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standards
SCADA	Supervisory Control and Data Acquisition
SGIP	Smart Grid Interoperability Panel
SIC	Standard Industrial Classification
SO2	Sulfur Dioxide
T&D	Transmission and Distribution
TOU	Time of Use
UBP	Uniform Business Practices
VAR	Volt-ampere Reactive

Table 4 Acronyms

A1.2 DEFINITIONS

Administrative Law Judge (ALJ) – A member of the staff of an autonomous Office of Administrative Hearings, who conducts hearings, rules on motions, prepares a written recommended decision, and analyzes parties' exceptions in Commission proceedings.

Advanced distribution management system (ADMS) – is a collection of applications designed to monitor and control the entire distribution network efficiently and reliably. It acts as a decision support system to assist the control room and field operating personnel with the monitoring and control of the electric distribution system.

Advanced pricing – Pricing that can change in response to various factors such as time, variable peak, location and proximity to load, resource, supply conditions, system conditions, incentives/penalties, and "controllability" of supply and demand resources.

Aggregation – The assemblage of DSP related products and services into groups from individual customers to be offered into markets.

Aggregator – A party that manages the DERs of one or more customers under agreement with the customer.

Auction – An auction is an open process of buying and selling standardized goods or services by offering them up for bid, taking bids, and then selling the item to the winning bidder(s).

Automated feeder and line switching (FLISR/FDIR) – Automated feeder switching is the automatic isolation and reconfiguration of faulted segments of distribution feeders via sensors, controls, switches, and communications systems. These devices can operate autonomously in response to local events or in response to signals from a central control system.

Automated voltage and VAR control – Automated voltage and VAR control is the coordinated operation of reactive power resources such as capacitor banks, voltage regulators, transformer load-tap changers, and distributed generation (DG) with sensors, controls, and communications systems. These devices could operate autonomously in response to local events or in response to signals from a central control system.

Avoided cost – The cost of generating power that a utility avoids by purchasing the same amount of power from another source.

Balancing – A process that compares actual customer commodity use with the amount of commodity delivered over a period of time (e.g., daily or monthly).

Bilateral agreement – A method by which two parties enter into an agreement to exchange goods or services for compensation.

Billing system – The software platform that accepts metered usage and pricing data, processes it and provides appropriate billing formatted information

Bulk market operation – Operation of the wholesale energy, ancillary services and capacity markets including the financial settlement of these markets.

Bulk power capacity – Generation capacity or load reductions/demand response that qualifies for payments under the NYISO Installed Capacity (ICAP) market.

Bulk system operation – Operation and monitoring of the bulk power transmission facilities under ISO operational control to maintain these facilities in a reliable state, as defined by the Reliability Rules.

Bulk system planning – Planning for the bulk power transmission system, including reliability, resource adequacy, and economic planning and public policy transmission planning.

Bypass – A situation that allows a customer to purchase full or partial electricity service from a non-utility supplier instead of a local distribution company.

Capacitor – a device that can adjust the voltage on a distribution circuit by providing/absorbing reactive power (often referred to as volt-amperes-reactive or VARs). Automated capacitors can be switched in coordination with other voltage control devices with signals from local sensors, distribution automation systems, or grid control systems.

Capacity – An amount of electricity that would be available from a generating unit, local distribution company, or system. Capacity is valued in units of energy such as megawatts of electrical power.

Circuit hosting capacity – is the amount of distributed energy resources (DERs) that can be interconnected on a distribution grid circuit while maintaining acceptable reliability and power quality.

Cogeneration – A source that generates electricity and also provides steam or other energy for industrial or commercial uses.

Commodity – A product for sale.

Consumption forecasting – Calculation and forecasting of electricity consumption based on ambient temperature, weather, day of week, time of day, electrical network conditions, or other factors that would affect the quantity and quality of electricity.

Controllable/regulating inverter (for DER) – Inverters are used to convert Direct Current (DC), the form of electricity produced by solar panels and batteries, to Alternating Current (AC), the form of electricity that comes from most wall plugs. A controllable/regulating inverter can adjust its output to help control voltage and power factor, enabling it to provide grid support. This is important because today, inverter standards are designed to prevent inverters from trying to regulate power beyond the point where they are connected to the grid.

Customer charge – The charge to a customer, which is designed to compensate the utility for the costs it incurs as a result of that customer's subscription to utility service, irrespective of the customer's eventual demand or energy use. For example, metering costs, including the cost of this meter and the cost of reading, are components, which contribute to the customer charge.

Customer portal – A web site or application designed to allow customers to view information related to their electricity usage, including consumption data, pricing information, billing information, and other messages and resources from the utility or third party energy services provider. The web portal may also be used to allow customers to provide information back to providers. Customer web portals may be accessed through web browsers or applications on personal computers or mobile devices such as smart phones.

Data collection/analytics – A service offered to utilities, customers, or third parties that gathers and analyzes information related to DSP transactions, such as target DER programs, energy efficiency and consumption or demand management services

Data manager – Receives energy and financial data from multiple sources, sorts and stores it, and distributes it according to demand, contract, and policy.

Data portal – A source where customers may access their historic energy usage and billing information, and may choose to authorize one or more third parties or vendors (analytic services provider) to receive the customer's historic data. The portal will provide the meter data in a transparent, standardized format in a timely manner so customers or their designees can analyze the data, as they require.

Delivery service – The service involved with the transport of electricity throughout the distribution system to the ultimate customer. This service also will allow the transport of electricity from a DER producer to the grid.

Demand (or load) – The amount of electricity that must be generated to meet the needs of all customers at a certain point in time.

Demand side management (DSM) – The planning, implementation and monitoring of utility activities designed to help customers use electricity more efficiently.

DER – Distributed energy resources include a range of devices and strategies to either generate or store electricity and/or thermal energy located either at customer premises or elsewhere within the distribution grid and devices and strategies to manage loads at customer premises and for grid support.

DER generation – Energy injections sold from behind the meter DERs or from grid connected DERs within the distribution system.

DER optimization – Determine the values for the controllable factors of one or more DERs to maximize, minimize or balance system performance on either side of the DSP service point. Optimization goals could include, but are not limited to, energy efficiency, reliability, supplying peak demand, or providing ancillary services such as frequency regulation or reserves.

DER performance monitoring – Monitoring and archiving of DER performance data including electricity production and services, availability/uptime, pricing, and other factors that would aid the development of detailed dynamic production models and production forecasting.

DER provider/vendor – An entity that provides and/or manages energy efficiency solutions, DER assets (e.g. distributed generation, energy storage, microgrid, energy efficiency products) and related technologies and management systems as its primary business.

DER services – Services including load management, energy efficiency, distributed generation, storage, EVSEs and performance contracting that enable customers to manage their net energy consumption from the grid. The services may be provided on either side of the customer meter.

DER visibility – The ability of the DSP planning function and distribution operations center to 'see' the existence of and operating status of DER units. The timing and granularity of the visibility may vary by type of DERs, size of the units, DSP infrastructure, etc. Visibility includes size and type of unit, scheduled maintenance, operational contracts, electrical characteristics, etc.

Direct load control – Demand side management programs where the utility or third party pays the customer to install a switch (typically radio operated), which allows for control of the customers' equipment (air conditioners, water heaters, pool pumps, etc.) as a way of reducing demand during peak periods.

Distribution – The delivery of electricity to an end-user through low-voltage lines through pipeline systems.

Distribution ancillary services – Services offering non-energy or capacity value to the grid, providing operational support for the distribution system such as reactive power for voltage support.

Distribution capacity relief – this practice involves the DSP using non-wire alternatives to address current or future congestion within identified areas in the distribution grid.

Distribution circuit switches –used to transfer load between circuits.

Distribution LMP or "nodal price" – LBMP prices at transmission nodes today reflect the system energy price + the transmission constraints and losses from the system price (the specific trading point where supply and demand are balanced) and the locational node. In effect, LBMP is the system energy price + the "basis" differential to a node. The same concept applies to distribution, based on the marginal cost of energy delivered to any point on the distribution system, i.e., the LBMP price + distribution constraints & losses value (positive or negative). The delivery component of delivered energy costs could also be 'shaped' to reflect differential pricing based on location and time.

Distribution system operation – Monitoring & running the distribution network to ensure safe, reliable, and efficient delivery of electricity supply to customers.

Distribution system planning – A sufficiently transparent and timely process of developing long-range plans that maintains distribution system reliability and helps guide the future of a local energy system topology within a utility's service territory, and in the long term potentially includes the interaction with neighboring service territories.

Dynamic pricing – Pricing that can change in response to various factors including, but not limited to time, variable peak, location and proximity to load, resource, supply conditions, system conditions, incentives/penalties, and "controllability" of supply and demand resources.

End users (active and passive) – End users are retail customers. They can be classified based on their level of participation in DSP markets and can switch between being active and passive. Active End-Users are consumers who participate in the DSP mechanisms/markets. Customers who participate in "set and forget" DER programs are included here. Passive End-Users are consumers who do not participate in the DSP mechanisms/markets.

Energy – The ability of electricity to do useful work. Electric energy is measured in multiples of watt-hours (e.g., kilowatt hours).

Energy management system – can control other energy devices such as thermostats, lighting, and direct load control devices, or distributed energy resource within the customer premise. These devices may also receive information or control signals from utilities or third party energy service providers. These devices can help customers manage electricity usage automatically by utilizing information from service providers, or preferences set by the customer.

Energy service company (ESCO) – A non-utility business that provides gas or electric commodity or provides a range of energy products and services to end-users, such as energy efficiency and other demand side management measures.

Energy storage – Storage of electricity (or energy generally) for later use. An electricity storage device can convert electricity into another form of energy in its charging state.

Environmental attributes – Characteristics of a product, service, program, or project (such as particulate emissions, thermal discharge, and waste discharge) that determine the type and extent of its short-term and long-term impacts on the environment.

Event notification – Notification by the DSP to market participants of events such as price changes, incentives, penalties, or special circumstances; events or conditions that may affect market operations; events or conditions that may affect electrical network performance or availability such as equipment failure, weather or other hazards; achieving or exceeding various production or consumption targets or thresholds. Such notification would be intended to provide market participants the ability to respond to important situations or conditions in a timely manner.

Federal Energy Regulation Commission (FERC) – The federal agency that regulates the price, terms, and conditions of energy sold through interstate commerce and all transmission services.

Investor/financier – An entity, which provides capital, financing, or line of credit for a project or business.

Kilowatt-hour – The basic unit of electric energy equal to one Kilowatt of power supplied to an electric circuit steadily for one hour (equivalent to about 3,450 Btu).

Latency – refers to any of several kinds of delays typically incurred in processing of network data. A so-called low latency network connection is one that generally experiences small delay times, while a high latency connection generally suffers from long delays.

Line sensors – Distribution line sensors monitor power flows, line voltages, power quality, and faults.

Load forecast – An estimate of the level of future energy needs.

Load management – activities designed to influence the timing and magnitude of customer use of electricity. Traditional load management objectives include peak shaving, valley filling, and load shifting.

Load monitoring – Monitoring and archiving of customer electricity consumption

Load transfer – feeder reconfiguration and optimization to relieve load on equipment, improve asset utilization, improve distribution system efficiency, and enhance system performance.

Marginal cost – The cost that it takes to produce an additional energy unit, or the cost saved by not producing such unit.

Market design – The design of the market structure rules and processes for the exchange of energy products and services

Market maker – An entity that facilitates increased level of participation in a market, leading to improved liquidity and transparency.

Market participant – An entity that buys or sells products, services, or information through the DSP market (including a third party who facilitates such transaction).

Market price – The monetary value per unit of goods or services determined in the market by the interaction of supply and demand under current market conditions, and is publicly visible, such that it can be used as a reference for pricing and settling transactions.

Market settlement – the accounting of the purchase or sale of a good, service, or information and the corresponding payment.

Market-based (economic) demand response – Demand response that can be targeted at certain market participants to optimize system performance. Response incentives and penalties would be calculated based on real-time network conditions including supply, demand, congestion, energy efficiency or other factors.

Measurement and verification (M&V) – demonstrate that reductions in energy use or output from distributed generation have actually occurred. M&V is often used as the basis of financial settlement in markets.

Meter data management system (MDMS) – performs long-term data storage and management of data from advanced metering systems.

Microgrid – is a localized grouping of electricity sources and loads that normally operate connected to and synchronous with the traditional centralized grid (microgrid), but can disconnect and function autonomously as physical and/or economic conditions dictate.

Municipality – A city, town, village, or hamlet.

Network monitoring – measurement of voltage and current within the network. This monitoring can provide voltage and load profiles for use in operations.

New York Independent System Operator (NYISO) – manages the bulk power market in New York State. Their responsibilities include bulk system planning, operations, market oversight, and financial settlement.

New York Power Authority (NYPA) – A public authority created by law that generates and transmits electricity for wholesale and retail customers in the state.

New York State Department of Public Service (DPS) – A state agency established by law with oversight responsibilities regarding the operation of regulated monopoly utilities.

New York State Public Service Commission (PSC) – A five-member Commission within the Department of Public Service with the authority to implement provisions of the Public Service Law.

Off-peak – Period of relatively low demand on a utility's generating system.

On-peak – Period of relatively high system demand on a utility's generating system, season and time-of-day specific for each utility.

Outage and restoration notification – Provides power status information down to the customer service point. Upon loss or restoration of power, status sensors will send a notification message to a central monitoring system.

Performance monitoring – Monitoring and archiving of performance data including electricity production and services, availability/uptime, pricing, and other factors

Price signals – Transparent signals reflecting the value of a product or service at a given location at a given time.

Production forecasting – Calculation and forecasting of electricity production from DER based on geography, forecasted fuel supply, solar insulation, wind speed, electrical network conditions, or other factors that would affect the quantity and quality of electricity.

Provider of last resort (POLR) – A legal or regulatory obligation to provide electric supply to customers who may not select or might otherwise have no access to competitive suppliers.

Renewable resource – An inexhaustible energy resource, such as solar, wind, water (hydro), geothermal, or biomass, used to produce electricity or thermal energy.

Request for proposal (RFP) – An agreement to purchase goods or services provided in response to a public solicitation by a utility or other party seeking proposals from third parties to solve identified needs. The information received allows the buyer to determine which third party proposal provides the most valuable solution. The terms of the resulting agreement are provided to bidders in advance and are public.

Spot market – A market option that offers short-term contracts for set amounts of electricity.

Substation – The location for equipment that makes up the interface from transmission to distribution. This includes transformers and various protection devices.

Tariff – A compilation of a utility's rates and rules governing its relations with customers; changes are subject to review and approval by the Commission.

Telemetry – is the highly automated communications process by which measurements are made and other data collected at remote or inaccessible points and transmitted to receiving equipment for monitoring.

Time of use (TOU) pricing – The establishment of rates that vary by season or by time of day to reflect changes in a utility's cost of providing service.

Transactive Energy - A software-defined grid managed via market-based incentives to ensure grid reliability and resiliency. This is done with software applications that use economic signals and operational information to coordinate and manage devices' production and/or consumption of electricity in the grid. Transactive energy describes the convergence of technologies, policies, and financial drivers in an active prosumer market, where prosumers are buildings, EVs, microgrids, Virtual Power Plants or other assets.[97]

Transformer – A device that changes electricity from one voltage to another (e.g., from transmission voltage to distribution voltage).

Transmission – The transportation of electric energy in bulk at high voltages, generally from a generating unit to a substation or for transfer between utility systems.

Volt – The unit of electromotive force, analogous to water pressure in pounds per square inch. One volt, if applied to a circuit having a resistance of one ohm, will produce a current of one ampere.

Watt – The electrical unit of power or rate of doing work: one ampere flowing under a pressure of one volt. It is analogous to horsepower of mechanical energy; about 746 watts equals one horsepower.

A1.3 DEFINITIONS OF ACTORS

- *Active End-user* – An electricity customer who engages with the DSP market to provide energy, distribution grid services, demand response, or reduce load through energy efficiency. Active end-users may provide these services directly to the DSP market or through an intermediary, such as an aggregator. Active end-users are also known as prosumers.
- *Passive End-user* – An electricity customer who does not participate in the DSP Markets. It is possible to move from a passive end-user to an active end-user.
- *DER Provider* – An entity that provides and/or manages energy efficiency solutions, DER assets (e.g. distributed generation, energy storage, microgrid, energy efficiency products) and related technologies and management systems as its primary business.
- *Aggregator* – An intermediary between customers and the DSP or NYISO markets who gathers a portfolio of customers with distribution assets, such as DER or DR, and sells the resources on behalf of the customers to the DSP or NYISO markets. The benefit of using an aggregator as opposed to directly participating in the market from a customer viewpoint is that it mitigates their risk of non-compliance and associated penalties. The DSP or NYISO would pay the aggregator on behalf of the customer, and the aggregator will pay the customer according to previously agreed upon contractual terms.

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- *Meter Data Service Provider* – Entities, including corporations, municipalities, and persons, that install, test, maintain, or operate electricity meters used for billing customers.
- *Microgrid* – A physically proximate grouping of energy loads and resources that are logically formed as a controlled system such that, while paralleled with the utility grid most of the time, it can function independently of the utility grid in the event of a grid failure in island mode.
- *Load Serving Entity (LSE)* – A provider of electricity supply to end-use customers. LSEs contain two main groups including:
    - *Provider of Last Resort (POLR)* - A legal or regulatory obligation to provide electric supply to customers who may not select or might otherwise have no access to competitive suppliers.
    - *Energy Services Company (ESCO)* – a provider of retail electricity. ESCOs offer both fixed and variable commodity rates that vary depending upon customer type and the sophistication of the customer. Currently, ESCOs offer expanded products and services in mostly the Large Time of Use Customer class, including fixed rates, green power, furnace repair or maintenance service, frequent flier miles or telephone service bundled with your energy bill, demand response, and energy efficiency. The products and services offered to the Large Time of Use Customers are expected to one day be offered to additional, smaller customer classes, in particular the Small Commercial and Residential customers. Further engagement of these customer classes will continue as technological innovation increases, rate design improves, and customer data becomes more readily available.
- *Distribution Owner* - A state regulated private entity, regulated municipal entity, or a cooperative that owns an electric distribution grid in a defined region. The distribution owner is responsible for maintaining and servicing the distribution system assets, such as wires and transformers. The distribution owner is responsible for the reliability of the distribution system.
- *Distribution System Operator* - The entity responsible for monitoring and running the distribution network to ensure safe, reliable, and efficient delivery of electricity supply to customers. The distribution system operator will need to operate the distribution system reliably with increasing amounts of DER and multi-directional energy flows.
- *Distribution System Planner* – The entity responsible for developing long-range plans that maintain distribution system reliability and helps to guide the future of a local energy system topology within a utility's service territory in a timely and transparent manner.
- *NYISO* - The independent, federally regulated entity that operates the transmission system, operates the wholesale market, and acts as both the

balancing authority and a planning authority for the state of New York. Under the jurisdiction of the Federal Energy Regulatory Commission (FERC), the NYISO manages the reliable flow of power across New York's high-voltage transmission system ("Bulk System Operations"), administers and monitors the state's wholesale electricity markets ("Bulk Market Operations") and conducts transmission-level planning ("Bulk System Planning"). NYISO's wholesale markets encompass the procurement of energy, generation capacity and ancillary services necessary to achieve economically efficient, safe and reliable operations of NY's electricity system.

- *Municipality* – A town or city that has a local government. Municipalities promote and advocate on energy issues for their own accounts but also on behalf of their residents, institutions and businesses. They do this by actively participating at the New York Independent System Operator and formal and informal proceedings before, among others, the Federal Energy Regulatory Commission, New York State Public Service Commission, New York State Department of Environmental Conservation, New York Power Authority and the New York State Research and Development Authority.
- *Market Monitor* – An independent state-jurisdictional entity that monitors competitive performance of the DSP markets for the various products on an on-going basis and ensures that buyers or sellers of products are not manipulating or unduly influencing prices.
- *New York Power Authority (NYPA)* – A state public power organization that provides low cost electricity and operates generating facilities. NYPA does not own distribution assets. NYPA has energy customers in the various distribution utility territories and offers energy efficiency services and facilitates development of DERs for both its energy customers and public facilities throughout the New York State. NYPA facilitates such development by providing financing as well working with third party DER providers/developers/vendors and independent consultants to provide design, construction, and related services to customers.

A1.4 PRODUCTS AND SERVICES

The following table provides information regarding additional products and services that may be provided by numerous potential sellers, and are expected to change with the evolution of the DSP market and with policy development. Per the Track One Order, "technology innovators and third party aggregators will develop products and services that enable customer engagement."[98]

98 State of New York Public Service Commission 2015, 12

Further, the Commission described its role as "providing policy initiative and guidance, while participants will provide initiative in the development of products and market practices.[99]" Accordingly, the market development and product development process is anticipated to be iterative, driven primarily by the private sector. Therefore this preliminary assessment of additional products and services is expected to change as the market progresses, and new products and services emerge.

Category	Otherwise Known As	Description	Possible Sellers
Aggregation	• Resource Aggregation	This service involves assembling a portfolio of DERs for the purpose of enabling those smaller resources to participate in the wholesale or distribution markets for which each individual DER might be ineligible, or for which the costs or complexity of participation would make it infeasible for an individual DER.	• ESCO • Conventional Demand Response Aggregator • Utility, as Providers of Last Resort
Billing		This service involves assembling customer usage data and combining it with the applicable rate structures to create a bill for the customer on a periodic basis.	• Independent Contractor • Utility • ESCO • Meter Service Provider
Customer Data Analytics	• Analytic Services	This service would consist of analyzing customer meter data and demographic, real estate and other energy-related data to assist suppliers in their marketing efforts.	• Data Analytics Provider • Utility

99 State of New York Public Service Commission 2015, 30

Category	Otherwise Known As	Description	Possible Sellers
Delivery Service	• Electricity Delivery • Distribution Service	This service includes transporting electric power to customers from the transmission system.	• DSP
Data Exchange	• Customer Portal • Digital Marketplace	The data exchange would be the clearinghouse for information about DERs, aggregators and customer engagement opportunities. The data exchange could include information on DSP tariffs and pricing, NYISO pricing, environmental credits, competitive service provider offerings, as well as other information for customers. In addition, the data exchange could include customer information such as monthly usage data and other information for DER Service Providers.	• DSP • Independent Contractor
DER Services		This suite of services includes sales and installation of any type of DER equipment, management of customer energy-using devices and their interaction with the markets, and the operations and maintenance the DER equipment.	• DER Provider • ESCO
DG/DER Interconnection	• Interconnection Process	This service involves processing a customer or DER provider request to interconnect a new or modified DER. This may involve engineering studies, interconnection planning, project scheduling and installation. Interconnection	• Utility as distribution owner/asset manager

Category	Otherwise Known As	Description	Possible Sellers
		services should be provided in a timely manner in order to facilitate increased penetration of DG and DER. As distribution planning services evolve to include objective hosting capacity methods described in this report, the interconnection calculation performed by the DSP may be different from the process undertaken by the asset manager to actually execute interconnections.	
Energy Advisory	• Energy Consulting Service	This service involves providing consulting services to customers seeking to install DERs. These consulting services would include advice on DER technology selection, DER configuration and installation, DER pricing, and operations strategy.	• ESCO • Aggregator • DSP
Enhanced Reliability and Resiliency Services		This service involves providing premium levels of reliability and resiliency over and above reliable electricity delivery. This would be a value-added service available for additional cost to customers who wish to reduce or eliminate entirely the risk of electricity interruption.	• DER Provider • ESCO • Utility
Financial Services		These services include a broad range of financial transactions, such as leases and loans to enable customers to install DERs and	• Financial Service Providers • ESCO • Utility • NY Green Bank

Category	Otherwise Known As	Description	Possible Sellers
		hedging services to provide customers with price stability or other benefits with respect to their energy costs.	
Market Settlement	• Settlement of Transactions	This service involves processing market quantities into invoices and processing billing and collection of amounts transacted in the wholesale or distribution markets.	• NYISO • DSP
Metering	• Metering Information Services	This service involves measuring the quantity of the product consumed by the customer. This involves having metering equipment that will accurately measure usage that can be combined with the applicable rate schedule to calculate the total amount owed by the customer, as well as means to collect the meter data and manage it for use in billing and other applications. There is a distinction between meter ownership and data administered from a meter, therefore these services can be provided by multiple entities.	• Meter Service Providers • Utility
Monitoring and Verification	• Measurement and Verification Services	This service involves determining a baseline consumption level for DERs that do not have direct metering and are participating in DR programs and then comparing the baseline to the actual	• ESCO • Aggregator • Utility

Category	Otherwise Known As	Description	Possible Sellers
		consumption to determine the demand response actions. These results are then communicated to appropriate parties, such as the NYISO, to settle.	
Retail Supply	• Generation Supply Service • Energy Supply Service	This service includes all of the services that are required to serve the needs of retail customers, including energy, installed capacity, ancillary services and administrative costs of participating in the NYISO wholesale markets, and all administrative costs associated with metering, billing, back office and providing customer service. This service may one day include transactive energy related transactions; however there will need to be significant regulatory changes for this to take place.	• ESCO • Utility as Provider of Last Resort

Table 5 Products and Services

A1.5 "AS-IS" MARKET MODEL

Industry structure diagrams depict the set of entities involved in an industry and their relationships and are rendered in the form of Entity-Relationship (E-R) diagrams. Entity classes are depicted as boxes, with the entity class labeled inside the box (when there is only one entity in that class, it is named). These diagrams help document essential bounds on overall industry operation and are also used to identify structural limitations inherited from the legacy system that may require changes and can assist in identifying potential unintended consequences of changing roles and new kinds of entities. They are part of a larger architectural representation of the industry that would include physical infrastructure, regulatory structure, information and communications structure, control structure, coordination frameworks and convergences with other network such as fuel, transportation, and social networks.[100]

In these diagrams, lines connecting entity class boxes represent relationships and are terminated at the entity boxes with symbols indicating cardinality of the relationship. Relationships are collections of behaviors that relate one entity class to another. Relationships can include interactions, which are behaviors of mutual or reciprocal influence; and transfers, which are conveyances from one entity to another. Relationship lines are also labeled with text that names the relationship and provides an indication of direction using angle brackets as arrows. Bilateral relationships are denoted with arrows at each end of the text string. The diagrams are constructed in multiple layers but in these renderings all of the layers are composited, so the diagrams are visually extremely complex. Layers are distinguished by the colors of the relationship lines.

The figure below is a depiction of the present state or "as-is" structure of the New York electric utility industry. It was developed from multiple interviews of various member of the New York electric utility industry, including the ISO and regulators. Utility members reviewed and validated drafts of the diagram. The diagram should be considered a best effort to represent key aspects of the highly complex New York system. There is no guarantee that every aspect of industry structure has been captured or that every detail is exactly correct. In this diagram, the ISO's Operations have been drawn separately from the markets operated by the ISO, so that market relationships can be more clearly depicted. Certain regulatory relationships are shown as dashed lines where regulation is conditioned on certain activities. Regulatory relationships in New York are complex and the dashed lines are best viewed as indicating areas where care should be taken to obtain more detail if changes are under consideration. In this work, no regulatory changes were reviewed.

100 Jeffery Taft, Pacific Northwest National Lab, contributed the As-Is Market Model and accompanying text.

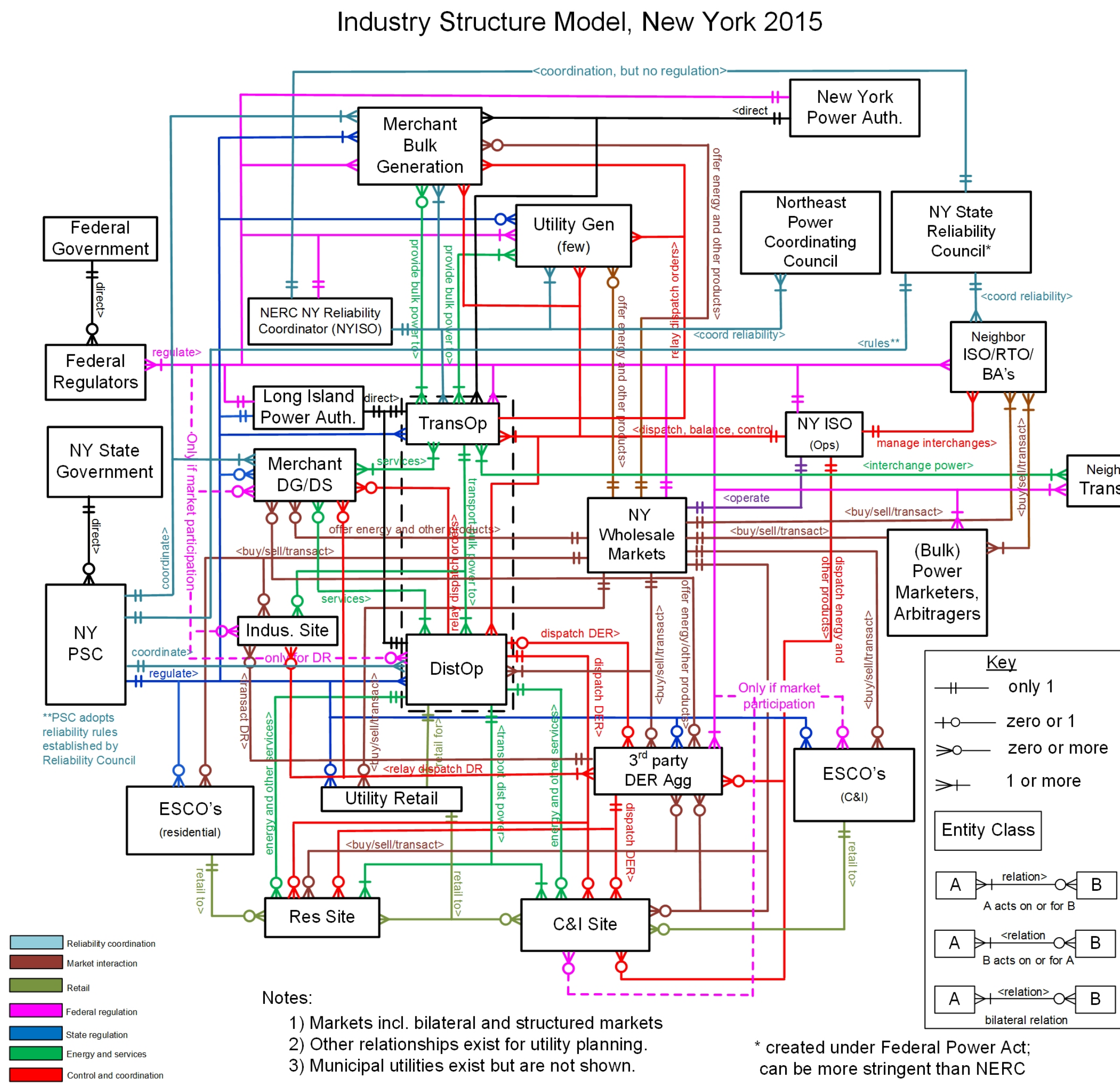

Figure 2 As-Is Market Model

A1.6 DETAILS OF CURRENT STATE

A. Existing Utility Distribution Systems and Capabilities

The existing utility systems in New York have assets and functionalities that have broad similarities, but there are specific differences as well. Each existing utility distribution system relies on three broad categories; asset management tools, operation and modeling systems, and enabling technologies. But each utility is a separate entity, and the distribution systems were developed in different environments to meet different needs. As a result, the asset management tools, operational controls, and system technologies are not always consistent amongst the utilities. These differing starting points add a layer of complexity for utilities transitioning from their existing legacy systems to a Distributed System Platform (DSP) in a uniform way. For example, there are various levels of visibility and communications networks, as well as diverse geography and varied demographics across utilities. Additionally, capabilities across a given utility's service territory are not necessarily homogenous. Utility systems are large and complex and getting to a fully functional DSP will be an evolution. The necessary investments will be key considerations in the cost/benefit analysis and build out of infrastructure required to effectuate the DSP.

No utility currently has a distribution system with the level of visibility, control and communications network that would be adequate to support the 'end-state' DSP. For example, there is SCADA on only about half of National Grid's substations, while Central Hudson has connectivity to a majority of substations. Visibility to field devices is typically limited, but also varies across utility, as do automation and distribution system control. The platforms for the Customer Information System (CIS), Geographic Information System (GIS), asset database, Outage Management System (OMS), and Energy Management System (EMS) vary across utilities and are a mix of internally developed systems and 3rd party vendor software.

Geography and customer density have been key factors that shaped utility distribution systems. As a result, the needs and priorities for each utility and their customers have often been much different and led to diverse decisions that shaped the distribution systems differently. Consolidated Edison's network system, for example, has thousands of miles of underground lines and numerous underground facilities. The other New York utilities predominantly have radial systems with overhead wires and above ground substations. In all likelihood, these factors will continue to drive divergent approaches across utilities, and unique customer and system demands will need to continue to be met by each utility.

The REV process is an opportunity to re-focus distribution systems so that the DSP can make the most efficient and economical decisions for the benefit of all customers. In addition to the supplemental functions and technologies to meet the different system demands, there will be foundational functions the DSPs will need to execute uniformly. Interoperability and standardization will be essential to the development of thriving markets.

B. Utility Advancement towards a Smart Grid

All New York utilities have been planning and deploying technologies that will improve system visibility, enhance control, and support analytics that can help achieve the Commission's policy objectives described in REV. Utilities are also attempting to flesh out advanced, fully integrated communication and control systems to replace their current approaches which have developed in a piecemeal fashion. In addition, New York can build on advancements being made in advanced grid technology and the support of Distributed Energy Resources (DER) around the world by utilities and industry leaders.

Enhanced visibility is critical to advancing both system planning, and operational control. Each of the utilities has on-going work and projects that would enhance system visibility. One example of an approach to increase visibility is Advanced Metering Infrastructure (AMI). AMI is a grid edge technology that enables real time visibility and control up to and beyond the meter with significantly greater granularity and frequency than traditional meters. AMI also provides customer-by-customer data that the utilities/DSP would be able to use for models, planning and operational decisions. AMI could allow the DSP to communicate directly with the meter, which would be a valuable asset for Outage Management Systems (OMS), among other uses. Iberdrola USA envisions an energy control system that would utilize AMI to achieve better granularity of real-time system visibility and control.

There are alternative methods of enhancing system visibility and control that do not rely on AMI. Central Hudson, Consolidated Edison and National Grid also have efforts to increase grid visibility as part of larger projects for a fully integrated system.

Enhanced and integrated communication is also critical because it allows for real or near real-time information updates to the control center, substations and/or other devices on the network. An integrated communication system is critical to properly tie together advances in the Distribution Management System (DMS), mapping and geographic data, outage management, and intelligent device installations in order to maximize optimization and system automation.

Central Hudson has a proposed architecture with a multi-tier network. Still in the development phase, testing of tiered networks such as microwave for Tier 1 (fast) and mesh networks for Tier 2 (medium) are some of the development efforts.

The utilities also have many projects and demonstrations that utilize automated/intelligent devices and sensors. Iberdrola USA has a conceptual map for substation automation and integration design. Central Hudson is considering intelligent devices that provide 2-way status and control such as electronic reclosers/midpoint ties, switched capacitors, regulators, and voltage monitors. These devices allow the utility to meet two objectives (1) Conservation Voltage Reduction (CVR)/Volt-VAR Optimization (VVO) and (2) Fault Location, Isolation, and Service Restoration (FLISR) and Automatic Load Transfer. CVR/VVO is not a new idea or technology, but is becoming a popular strategy to increase efficiency by managing voltage as system granularity improves thanks to smart grid/meter advances. Central Hudson already has a successful initial trial result that decreased demand over an 11-month testing period, with a significantly bigger demonstration slated for 2016 that will involve a mix of over 1,000 customers.

National Grid is also looking specifically at VVO as a non-wires alternative that can help in the deferral of expensive capital expenditures. National Grid is also investigating the effectiveness of different feeder configurations. The project uses a primary system monitoring to incorporate a centralized optimization and control scheme. The project will measure the improvement of delivery system efficiency and efficiency of consumption.

Each utility has a vision and/or is involved with R&D efforts to develop a fully integrated and centralized control system. Consolidated Edison developed a Demand Response Management System (DRMS) and Distributed Energy Resource Management System (DERMS), which are being used as engineering design tools, but have the capability to be operational tools. The engineering design aspect gives Consolidated Edison a platform to model and run various scenarios, which is critical for advanced planning of DER and DR programs. For example, Consolidated Edison has issued DR calls on the model and has achieved load reduction as a result. A notable difference between DRMS and DERMS is that DRMS is a blunt DR tool where the call goes out to all DR participants, while DERMS would facilitate targeted DR.

The DRMS has an extensive architecture that enables a number of functionalities such as event management, device & load management, dispatch optimization and strategies, baseline calculations and settlement preparation as well as customer notification. DRMS can send specific information and requests to customers. The communications can be through Consolidated Edison systems and/or 3rd party systems such as mesh networks, point to point, or the Internet. DRMS, however, does not plan as granular as building planning/analysis, which at the moment would be required by the building management, an aggregator, or another 3rd party vendor. DRMS also interfaces with Consolidated Edison tools and systems such as CIS, load forecasting, GIS/visualization platform, meter data system, and settlement system.

An example of one DRMS process is the built in functionality of the baseline calculation, which uses historical usage to determine average usage prior to an event, and then calculates the actual performance during a DR event. This information is fed into the settlements preparation engine, and interfacing with Consolidated Edison's settlement system, calculates performance based payments. The credits/payments are then automatically submitted to Consolidated Edison's billing system.

The DERMS is a more comprehensive tool as it includes DR and DER integration with the distribution system. DERMS utilizes decision aid software that can make recommendations to mitigate overload conditions in the network. There is continuous information flow that enables new analysis about every 5 minutes, which at the moment Consolidated Edison considers to be more than adequate due to typical response times of current devices. The analysis is granular down to the feeder level, and when feeders are overloaded, the program looks across the entire system grid to optimize the DR call and target the most efficient DER. In addition, DERMS tracks the resources that have been used and the remaining availability. Analyses can then be run with known future environmental conditions (sun going up/down, load forecast going up/down, battery storage reserve/depletion, etc.) and operators have the ability to then potentially make proactive decisions. DERMS is currently deployed on a limited number of Consolidated Edison feeders. As advanced versions of DERMS become more widely deployed, they should be able to inform automatic and real-time functions of the DSP.

The goals of Central Hudson's smart grid and integrated communication strategy are to improve grid efficiency and better utilize existing assets, enhance resiliency, and allow for greater DER penetration. Three strategic components critical to achieving these goals are developing an advanced DMS (ADMS), installing intelligent devices and sensors, and developing an Integrated Communications System. Objectives of the ADMS include development of an integrated, near real-time model of the distribution system to enable optimization as well as an integrated transmission system, and further development of modeling and integration of DER, and a centralized workstation to manage data. The system model developed for a demonstration project (NYSERDA PON 1913) includes the modeling of 4 circuits at a substation. The modeling includes all conductor attributes such as capacity and impedance, all customers such as load data and transformer connectivity, and all switches to assist in fault location determination.

Iberdrola has described a system that includes Energy Control Systems, advanced substations, and Advanced Metering Infrastructure (AMI). The Energy Control System would essentially be an advanced control center that would facilitate centralized real-time control and monitoring across the entire grid, and better accommodate distributed generation and active load management. Such a platform would increase grid and energy efficiency and improve reliability and resiliency. A key step is the full integration of components such as SAP, GIS, DMS, OMS, all within compliance of FERC and NERC requirements. Real-time (T&D) situational awareness will follow from full integration. The re-engineering of systems and processes to modern or advanced levels will facilitate automation on the network and allow for centralized, efficient operation. Another critical aspect for Iberdrola is development and integration of an advanced OMS. The OMS would capture meter-level outage information. Real-time information on customer outages and improved identification of interrupted equipment and circuits would significantly decrease outage times. In addition, meter events or "pings" can determine power status and clear outage work orders. As part of the integrated system, geographic mapping also becomes possible, which improves cost-efficiency of restoring power to as many customers as quickly as possible.

National Grid favors upgrading their existing EMS and OMS systems to an ABB Network Manager, which is built on an open platform with a component architecture. The common platform enables current and future capabilities to be more quickly and easily leveraged. Initial benefits include real-time exchange between the EMS and OMS that includes device status for optimization of outage prediction and enhanced situational awareness due to integration of telemetered analog data. National Grid is expecting future capabilities to be leveraged on the system to include VVO, AMI, and Restoration Switching Analysis that would be a powerful tool for fault and outage management.

Additionally, because each function is a separate entity that interfaces with the rest of the system through the Network Manager, it is easy to tailor the system to user requirements, define execution sequences, and add software modules from 3rd party suppliers.

A National Grid project in Massachusetts includes a combination of Grid Facing and Customer Facing elements. There is an overall effort to optimize utilization of the existing equipment. The grid capabilities being employed include increased visibility (monitoring efforts of distribution circuits and individual transformers), distribution automation, voltage control devices such as capacitors and regulators, and various experiments to determine fault location. As part of the customer initiative, smart meters were installed (15,000), as well as deployment of in-home tools (i.e. Home Displays, Smart Thermostats) at various levels in order to test customer adoption rates and the impact of increased visibility and control on customer efficiency. A local support center has also been setup to offer counseling to customers with hopes to improve customer knowledge base.

C. Energy Markets

At present, the NYISO operates a number of wholesale competitive markets. There are two distinct markets for the electric energy, the Day-Ahead market, and the Real-Time market. Approximately 98% of the electric energy used in the State is scheduled in the Day-Ahead market with the remaining 2% accounted for in the Real-Time market.

In the Day-Ahead market, the NYISO co-optimizes the Energy, Operating Reserves and regulation markets by utilizing bid-based Security Constrained Economic Dispatch (SCED) and Security Constrained Unit Commitment (SCUC). Day-ahead bids are due by 5:00 a.m. on the day before the unit will run, and the NYISO posts the day-ahead schedules and the market clearing prices by 11:00 a.m. Clearing prices are based on LBMP (Locational Based Marginal Pricing), which is the cost to supply the next MW of load at a specific location in the grid. By so doing the NYISO ensures that resources are available to satisfy loads that are forecast for the day.

The NYISO also runs Real-Time markets to efficiently and economically balance actual system loads and a large number of changes continuously taking place on the system, such as unanticipated transmission and generation outages. Real-time bids are due 75 minutes prior to the hour of operation. Differences between day-ahead schedules and actual load and generation are priced at real-time LBMPs, which are calculated every 5 minutes.

D. Capacity Markets

The NYISO establishes Installed Capacity (ICAP) requirements to ensure sufficient resources are available to adequately serve the forecasted summer peak New York Control Area (NYCA) system load. ICAP suppliers must satisfy semiannual tests of maximum output, and must meet deliverability requirements (sufficient transmission to reach load in their respective capacity regions). The NYISO operates capacity markets to facilitate the purchase, by Load Serving Entities (LSEs), of the capacity they are required to procure. In this context, "capacity" is not the electricity itself, but instead the ability to produce electricity when necessary.

ICAP requirements are set based upon projected peak NYCA load, plus an additional reserve amount to ensure the system can reliably serve peak demand even in cases of unplanned outages (known as "contingencies"). This reserve amount is known in New York as the "Installed Reserve Margin" (IRM). In addition to the Statewide IRM, the NYISO imposes minimum Locational Capacity Requirements (LCRs) in areas of the State that have limits on their ability to import power from outside areas. Thus, there are LCRs established for New York City (Zone "J"), Long Island (Zone "K"), and the newly established Lower Hudson Valley capacity zone (Zones "G" through "J"). LSEs are subject to ICAP requirements based on their respective share of coincident system peak load for the State (i.e., the IRM). Where applicable, they must satisfy part of that requirement with resources, which are electrically located within their Zone.

All ICAP supplies must "clear" in the mandatory, NYISO-administered, "spot" markets, which are held monthly. LSE bids in the spot auctions are determined by administratively-set "demand curves". Supply offers in New York City (Zone "J") and the Lower Hudson Valley (Zones "G" through "J") are subject to bid caps (for incumbent suppliers) and bid floors (for new entrants), under market power mitigation rules established by FERC. ICAP suppliers within a zone subject to LCRs (i.e., Zones "J," "K," and "G" through "J") receive the higher of the statewide capacity price or the applicable locational price for their respective zones.

The NYISO also operates voluntary forward auctions, for the summer (May-October) and winter (November-April) capability periods. Supplies obtained in the forward auctions must also be offered into and clear the spot auctions in order to satisfy LSE ICAP requirements.

E. Ancillary Services Markets

In addition to the energy and capacity markets, the NYISO operates markets for "ancillary services." There are five separate categories of ancillary services at the wholesale/bulk power system level: regulation services, voltage support services, synchronous and non-synchronous reserves, black start services, and demand side ancillary services. These will each be briefly discussed in turn.

Regulation Services

System "regulation" is the practice of continuously balancing power supply resources with load. Regulation service is accomplished through transparent day-ahead and real-time markets, which receive bids from participating, qualified energy suppliers (having automatic generation control capability), demand-side resources (also see

DSASP) and energy storage resources. A bid evaluation program selects specific resources and the amount of power to be delivered on the basis of each participant's bid price, unit response rates, location and existing transmission constraints. Updates to the desired generation levels expected from each unit, occur every six seconds.

Voltage Support Service

Voltage Support, more formally known as Reactive Supply and Voltage Control Service ("Voltage Support Service" or VSS), is necessary to maintain transmission voltages within acceptable limits. Facilities under the NYISO control are operated to produce or absorb reactive power, as necessary, to maintain transmission voltages within acceptable limits.

VSS facilities must meet a number of criteria to be eligible to participate. For example, they must have a demonstrated the ability to produce and absorb reactive power within specific limits, be able to maintain a specific voltage level under both steady-state and post-contingency operating conditions, and be capable of automatically responding to voltage control signals. In general, eligible VSS providers are generators with automatic voltage regulators, synchronous condensers, and qualified non-generator Voltage Support Resources.

Payments to eligible providers are based on an annual VSS rate established by the NYISO. Generators that are given energy delivery schedules may be eligible to receive lost opportunity costs under certain circumstances when dispatched for voltage support reasons. VSS providers can also be assessed penalties if they fail to provide VSS as directed or if they fail to maintain their automatic voltage regulators.

Synchronized and Non-Synchronized Reserves

To ensure reliable operation of the bulk power system, the NYISO's "Operating Reserve Service" provides needed reserves in the form of generation or demand response if a real time power system contingency requires emergency corrective action. The NYISO provides markets for 10-minute spinning, 10-minute non-synchronized, and 30-minute non-spinning reserves with a NYCA-wide requirement as well as an Eastern and Long Island requirement and a Long Island requirement.

The minimum reserve requirements are based on the largest single "contingency" (in MW), as defined by the NYISO. Providers of Operating Reserves must be properly located electrically and geographically to ensure the ability to deliver energy reserves as necessary. The NYISO must procure sufficient Operating Reserves to comply with applicable Reliability Rules and standards. All suppliers of Operating Reserves must be located within the New York Control Area, and under NYISO Operational Control.

The NYISO administers two ancillary services markets (Day Ahead and Real-Time) through which LSEs can procure needed resources for required Operating Reserves. Each supplier that bids into these markets must be able to provide electric energy or reduce demand when called upon.

Black Start Services

In the event of a partial or system-wide blackout, Black Start Capability Service is provided by generators having the ability to re-start their facilities without the need for an external supplier of electricity. Such black start generators are either under the control of the NYISO or, in some cases, under the control of the local Transmission Owner. The NYISO selects the generating resources with black start capability by considering a number of design and operating characteristics, including electrical location, startup time in response to a NYISO order to start, response rate, and maximum power output.

Generation resources providing black start service must successfully conduct and pass annual black start capability testing. Payments for service, called Restoration Services payments are provided under the NYISO's Open Access Transmission Tariff. Any Generator awarded Restoration Services payments that fails a Black Start Capability Test must forfeit all payments for such services since its last successful test.

F. Demand Side Services

The NYISO also administers a Demand Side Ancillary Services Program (DSASP) intended to facilitate economic use of demand side resources to meet electricity needs. Participation is allowed for interruptible loads for Spinning Reserves or Regulation. Loads with qualified behind-the-meter generation may provide Non-Synchronous Reserves. The minimum resource size is 1 MW and there is a $75/ MWh minimum bid. The payment is the Regulation or Reserve-clearing price.

G. NYISO Demand Response Programs

The NYISO also administers several different demand response programs. These include the Special Case Resources Program (SCR), the Emergency Demand Response Program (EDRP), and the Day Ahead Demand Response Program (DADRP).

Special Case Resources

Participation in the NYISO's SCR Program is open to interruptible loads or loads with a qualified behind-the-meter Local Generator. There is a minimum of 100kW reduction, and participation is mandatory during reliability events. There is a mandatory test each capability period and capacity can be sold either in a bilateral contract or through the NYISO capacity auctions. Payments are in capacity and energy payments.

Emergency Demand Response

Participation in EDRP is open to interruptible loads or loads with a qualified behind-the-meter generator. Load reduction is voluntary and there is a minimum of 100 kW reductions for participation. Participants are compensated through an energy payment equal to the greater of $500/ MWh or the applicable real-time LBMP.

Day Ahead Demand Response Program (DADRP)

The DADRP allows end-users to participate in the day-ahead energy market by offering load reduction bids. DADRP participants are paid at the LBMP market price for the amount of their winning bid and have a performance obligation much like winning generators.

Participation in the NYISO's DADRP is currently limited to curtailable load. A recent FERC Order, however, ruled that behind-the-meter generation must also be allowed to participate. Eligibility is limited to providers that can demonstrate an ability to curtail at least 1 MW of load, and at present, there is a $75/MWh minimum offer floor. However, in the NYISO's compliance filing in response to FERC's Order 745, the new monthly floor will be determined through the application of a "net benefits test."

A1.7 "TO BE" MARKET MODEL

The figure below is a depiction of the possible future state or "to-be" version of the same New York electric utility industry under a DSP model as discussed in the Working Group proceedings. This future-facing E-R diagram has not been validated by the working teams due to time considerations and so should be considered to be a draft. The changes from Figure 3 are based largely on the interaction diagram create by the MD 1 Working Subgroup along with consideration of the multiple full Working Group discussions on how structure and processes may change in a DSP environment. Interaction diagrams, which are commonly used in enterprise information technology design, are a form of drilldown detail for E-R diagrams and therefore for industry structure diagrams. In the forward-looking industry structure diagram, the Distribution Operator (DO) has been altered to be a DO with DSP component. Some of the relationship lines still terminate on the DO box; others terminate on the DSP box so that it is clear how certain functionalities are partitioned. A complete definition of the entity classes and their roles and responsibilities would be used in a full architecture to clarify these points but here only the diagram is available. New market transaction lines exist to connect DER's to the DSP markets. Original transaction lines to the ISO markets have been preserved but coordination of DER's for dispatch and operational purposes has been adjusted to take into account the responsibility of the DO/DSP to assure distribution reliability and safety. Due to the existence of two distinct markets in this model, a new set of market transaction lines, denoted by a new color, have been introduced to connect third parties to DER's in a way that clarifies that not only can DER's participate in either market, but so can aggregators and energy services companies. For clarity, direct interactions with DSP markets are denoted in a different color than direct interactions with the ISO market. Regulatory changes were not considered in the drafting of this diagram, so all regulatory relationships are depicted as unchanged.[101]

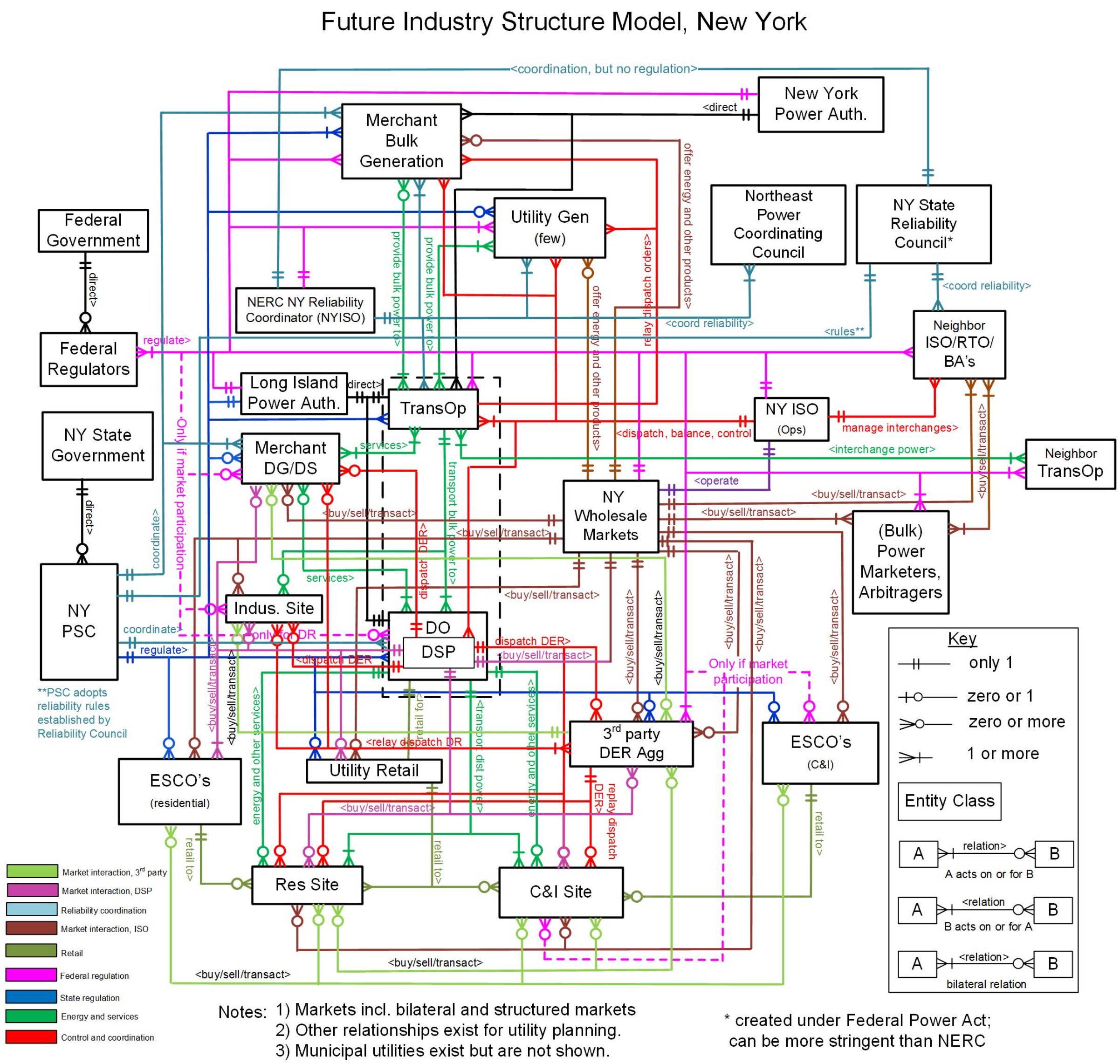

Figure 3 To-Be Market Model

101 Jeffery Taft, Pacific Northwest National Lab, contributed the To-Be Market Model and accompanying text.

A1.8 SUBGROUP SCOPE OF WORK

For more information about the MDPT Working Group's efforts, please see the work plan filing from March 31 2015 located at the link below:
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={04F02232-A6C7-4675-B082-08D0AD0F2380}

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