December 7, 2015

VIA ELECTRONIC FILING

Hon. Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
Empire State Plaza, Agency Building 3
Albany, New York 12223-1350

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

Dear Secretary Burgess:

The Advanced Energy Economy Institute (AEEI), on behalf of Advanced Energy Economy (AEE), the Alliance for Clean Energy New York (ACE NY), the New England Clean Energy Council (NECEC), and their joint and respective member companies, submit for filing these Initial Comments to Staff's proposed *Distributed System Implementation Plan Guidance* in the above-referenced proceeding.

Respectfully Submitted,

Ryan Katofsky
Senior Director, Industry Analysis

Initial Comments on Staff Proposal: Distributed System Implementation Plan Guidance (Case 14-M-0101)

Advanced Energy Economy Institute
Alliance for Clean Energy New York
Northeast Clean Energy Council

Introduction

The mission of Advanced Energy Economy Institute (AEEI), the charitable and educational organization affiliated with Advanced Energy Economy (AEE), is to raise awareness of the public benefits and opportunities of advanced energy. As such, AEEI applauds the New York Commission for opening this proceeding on Reforming the Energy Vision (REV), which seeks to unlock the value of advanced energy to meet important state policy objectives and empower customers to make informed choices on energy use, for their own benefit and to help meet these policy objectives.

In order to participate generally in the REV proceeding and respond specifically to the Staff Proposal on Distribution System Implementation Plan Guidance ("DSIP Guidance"), issued on October 15, 2015, AEEI is working with AEE and two of its state/regional partners, the Alliance for Clean Energy New York (ACE NY) and the Northeast Clean Energy Council (NECEC), and the three organizations' joint and respective member companies to craft the Initial Comments below. These organizations and companies are referred to collectively as the "advanced energy community," "advanced energy companies," "we," or "our."

AEE is a national business association representing leaders in the advanced energy industry. AEE supports a broad portfolio of technologies, products and services that enhances U.S. competitiveness and economic growth through an efficient, high-performing energy system that is clean, secure and affordable. ACE NY's mission is to promote the use of clean, renewable electricity technologies and energy efficiency in New York State, in order to increase energy diversity and security, boost economic development, improve public health, and reduce air pollution. NECEC is a regional non-profit organization representing clean energy companies and entrepreneurs throughout New England and the Northeast. Its mission is to accelerate the region's clean energy economy to global leadership by building an active community of stakeholders and a world-class cluster of clean energy companies.

The advanced energy community strongly supports the efforts of the Commission in this proceeding, and is committed to playing its part to create a high-performing electricity system in New

York State. We were pleased to see the level of detail contained in the DSIP Guidance and the intent of Staff to move utilities towards greater transparency and stakeholder engagement in their planning processes. Given the nature of the changes occurring within the electricity industry, planning needs to be more transparent and inclusive, as customers and third party providers become more active participants in meeting individual customer needs and system needs. We recognize this represents a departure from existing practices, and we look forward to working with the Commission and the utilities in a constructive manner to advance the goals of REV – with the DSIPs being a crucial part of this evolution.

Comments on the DSIP Guidance - by Section

I. Introduction

We recognize that the full establishment of the DSP will take time and will be done via iterations on planning and investment, and we agree that the initial DSIP filings are an important first step in this process. As such we support Staff's position that the Initial DSIP filings include a thorough "self-assessment" by each utility and that they encompass immediate changes that the utilities can make, along with an eye towards longer-term changes, including what is needed to conduct a "more comprehensive and transparent planning process".

Coordination between ETIPs and DSIPs

Among other goals, the DSIPs are designed to support greater investment in energy efficiency (EE), along with the Clean Energy Fund (CEF) and the Energy Efficiency Transition Implementation plans (ETIPs). Although we expect the DSIPs to ultimately have an important role to play in how energy efficiency is delivered, we remain concerned that there is inadequate support for energy efficiency in the near term, especially in light of the latest delays in the approval of the CEF. Given the overall timeline laid out by the Commission, implementation of the initial DSIPs by the utilities will realistically begin in late 2016 or early 2017, and it is currently unclear how quickly DSIP implementation will have a material impact on EE deployment. Thus, as we have commented previously in filings with the Commission, there needs to be strong support for EE in the near term, so that there is a smooth transition and no backsliding. However, the current utility ETIPs and the NYSERDA CEF proposal do not provide enough near-term support for EE. Thus, even if implementation of the DSIPs provides strong support for EE, there remains a gap of about two years in which New York State may backslide on EE deployment. As such, we reiterate our recommendation that the Commission take immediate action to require greater EE investment via the ETIPs, subject to cost effectiveness tests, even as it pursues changes to how EE is delivered over the longer term via implementation of the CEF market transformation efforts and the DSIPs.

We would also note that, given the recent announcement by Governor Cuomo that he has directed the Commission to develop a program to achieve 50% renewable energy generation by 2030 (essentially turning the State Energy Plan into a binding target), energy efficiency represents an important means of assisting with the achievement of that goal: by driving down demand with EE, less investment will be needed to achieve the 50% target.

Recommended Two-Phase Approach to the Initial DSIP Filings

We strongly support the intent of Staff to ensure coordination among utilities and the use of common tools, processes, protocols and standards via the Supplemental DSIP filing. Creating a single, consistent marketplace will result in lower costs and more rapid realization of benefits from REV. Nevertheless, we are concerned about the burden being placed upon stakeholders with the proposed addition of the Supplemental DSIP filing. See our comments in the "Stakeholder Engagement Process" section below for our recommendations on how to ensure continued active participation by a wide range of stakeholders.

Stakeholder Engagement Process

We wholeheartedly agree with Staff that meaningful stakeholder engagement is critical and that greater transparency is needed in utility planning and operations. As REV implementation moves into ever-greater detail, there is a need to support continued, active, broad-based stakeholder engagement. With respect to the DSIPs there are three components to this engagement:

- While the DSIPs are being developed
- After the DSIPs have been filed and are being reviewed for approval
- After the DSIPs have been approved and are being implemented

During the DSIP development stage we concur with Staff that utilities should implement a stakeholder engagement process. The draft DSIP Guidance lacked details on what this should entail, but suggested that the process include "focused technical conferences and discussions…" (See draft DSIP Guidance at page 6). We recommend that the Commission set forth a more specific set of stakeholder engagement requirements to ensure that each utility implements a comprehensive and consistent outreach program. The Commission should also define what aspects of this would be conducted under the auspices of the Commission/DPS versus led by the utilities. We would support, for example, a structure in which the Commission held a Technical Conference and each utility was required to present their proposed DSIP and answer questions from Commission Staff and stakeholders.

Given the detailed nature of the draft DSIP Guidance, we expect the DSIP filings to be large, technical documents needing quantitative analysis by groups with deep knowledge of the New York electric system. Moreover, there will be separate DSIP filings from each utility, further compounding the volume of material to review. In order to support continued, active, timely, and meaningful engagement by the wide range of stakeholders that have been active in REV to date, we recommend that the Commission consider ways to support these stakeholders during the DSIP review period. This could include directing the utilities to provide summaries of the DSIP filings, directing Staff to prepare these summaries, or hiring an independent consultant(s) to review and analyze the DSIPs and publish a report on their findings. We envision these summaries being condensed versions of the DSIPs that would contain all the essential elements of the DSIPs so that stakeholders would be able to get a complete picture of the plans. This will facilitate continued involvement by the many stakeholders that have been active in and important to the REV process to date. The timeline for filing Initial Comments and Reply Comments on the DSIPs (or whatever process the Commission decides) should reflect the anticipated complexity of the DSIPs and the time needed to fully analyze them, but should not introduce delays into the REV timeline.

Once DSIPs have been approved and implementation has begun, the Commission should monitor how utilities are performing relative to their DSIPs and provide opportunities to update stakeholders and gain feedback from stakeholders. This should include some regular, periodic reports from utilities on specific DSIP milestones.

Given the effort that will be involved in reviewing and approving the DSIPs, we recommend that that they be reviewed and approved/disapproved once. The dollars associated with the approved DSIPs would then be incorporated into a utility's rates, but there should not be a second review of the approved DSIPs in the next rate case. Beyond that, the Commission should consider how to best manage the timing associated with updated to DSIPs and how to best align that activity with future rate cases.

II. Integration of Demonstration Results in DSIPs

We have no comments on this section at this time.

III. Contents of the Initial DSIP – An Invitation to Innovate

We fully support the guidance given in this section that utilities should present their action plans for increasing system efficiency and reducing peak demand in their DSIPs. This is an overriding objective of REV, and therefore should be a main focus of the DSIPs. This section of the DSIP Guidance states that utilities should specify "what portion of its load may be reduced in the next five years" (see draft DSIP Guidance at page 8). We request that the Commission clarify that utilities should also specify what portion of its peak demand may be reduced in the next five years. Given the focus on system efficiency in REV, it leads one to believe this was intended to be included in the DSIP Guidance, but confirmation in the final guidance would be helpful.

Moreover, as noted in our Track 2 comments, expert, independent analysis should be used to determine the potential for reducing load and peak demand in each utility territory. The analysis should account for all forms of peak demand reduction capabilities. Without such analysis, the reduction goal will not have the necessary credibility, and could result in suboptimal outcomes from a cost-effectiveness perspective. Therefore, the Commission should require utilities to include such analysis in the section of their DSIPs relating to reduction potential. The most sensible approach would be for the Commission to retain a single consultant to conduct this analysis on a utility-by-utility basis, as was done by the Pennsylvania Public Utilities Commission.

A. Distribution System Planning

Delivery Infrastructure Capital Investment Plans

We enthusiastically support the concept of utilities identifying "all T & D projects (categorically) with a focus on highlighting where DER, future or existing, has the potential to impact the project needs" (see DSIP Guidance at page 14). We are particularly pleased to see the focus on avoiding large-scale transmission projects, as much attention to date has been placed on avoiding smaller-scale distribution projects. Given the NYISO's role in transmission planning, the DSIPs should therefore include consideration of how utilities will work to ensure that DER is properly considered as part of the NYISO planning process. In instances where DER can be used to avoid or defer a new a transmission project, that will need to be identified several years in advance of the project commencement date. The Commission should also encourage the NYISO, to the extent possible, to ensure DER is considered before any new transmission infrastructure is constructed.

B. Distribution Grid Operations

We have no comments on this section at this time.

C. Distribution System Administration

Customer Data and Engagement

While access to data is critical, we recommend that the Commission include more detail and additional clarity in the DSIP Guidance relating to customer engagement. We propose three specific changes:

1. We are concerned that access to data and customer engagement continue to be lumped together. The overwhelming majority of customers will not take action to achieve the objectives of REV based solely on access to data. Rather, they will need utilities and third parties to leverage the data to provide actionable insights. Access to data is really just one element of customer engagement; the granularity and timeliness of that data is another element, and the Commission needs to provide clear guidance to utilities on what is expected regarding customer engagement. We commend the Commission for creating an EIM that includes customer engagement, but as noted in our Track 2 comments, we believe the metrics for customer engagement need to be modified. We would urge the Commission to include those suggested modified metrics (known as the "Reach, Usage, Effectiveness, Feedback" model) into the DSIP Guidance, so that utilities provide detail on how they will achieve high scores under that framework.
2. The draft DSIP Guidance suggests that utilities should "Describe, in detail, plans to achieve enhanced consumer engagement, particularly in the time before the implementation of the digital market platform or web-based market is implemented" (see draft DSIP Guidance at page 21). However, there is no more detail provided on what consumer engagement entails. In addition to our recommendations in point 1 above, we would recommend that the DSIP Guidance be changed to read, "Describe, in detail, plans to deploy a customer engagement portal and communications plan to drive awareness and usage of the portal by the end of 2016, as well as any additional customer engagement initiatives." Customer engagement will be instrumental to achieving REV outcomes, and there is no reason to delay the deployment of portals, when they can be brought to market quickly. This would also send a strong market signal to the advanced energy community that REV will create near-term opportunities. The

Commission should also provide a clear definition of what is meant by a customer engagement portal. We recommend the definition used in our Track 2 comments.[1]

3. On page 21 of the DSIP Guidance, it appears that the customer engagement platform and digital marketplace are used interchangeably. We think it is important to distinguish these two, as we did in our Track 2 comments ("We define the Customer Engagement Portal separately below to distinguish a platform that any party could operate for facilitating customer and business transactions for DER (Digital Marketplace) and the utility means for communicating with and motivating customers to manage their energy usage more intelligently (customer engagement portal.")) The digital marketplace may take longer to develop and deploy than customer engagement portals, and so there should not be confusion around the functionality of the portal.

Staff also posed the following specific questions (in italics). Our answers follow each question.

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

The Commission should direct the utilities to use the same data exchange standard across all the utilities and use a third-party tester to verify consistent implementation. Green Button and Green Button Connect are promising standards for this purpose (also known as Energy Service Provider Interface, adopted by NAESB). The Commission should direct all utility DSIP plans addressing metering to conform with the minimum data requirements provided in the Commission's 2009 Order 09-M-0074 issued February 12, 2009.[2]

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[1] We suggested a definition of "customer engagement portal" as a "portal hosted by the DSP that allows end-use customers to obtain and visualize their energy usage data; receive information and recommendations for DER products or services; receive analysis of energy usage on a comparative basis along with recommendations for energy savings and energy management. Upon customer or utility request, the portal should facilitate data sharing between customers and DER providers/third parties. The Portal can either include Digital Marketplace capabilities, such as facilitating transactions between customers and DER providers, or direct users to another Digital Marketplace. The Portal could also include information on optimal DSP tariffs and pricing for customers, NYISO pricing, and environmental credits. For each customer class (i.e., residential, small & medium commercial, etc.) a utility/DSP would only have one Customer Engagement Portal and may choose to provide the information and insights from the portal to customers through other communication channels including mobile and mail."

[2] We understand that this Order includes a mechanism for obtaining data via the Home Area Network (HAN) interface of an advanced meter. The most common protocol for such near real-time data is ZigBee from the advanced meter to a nearby device, such as an in-home display or bridge connected to an Internet router. The utility's responsibility generally ends at delivering the data to the nearby device, which includes registering the device with the utility and ensuring that the meter communicates only to approved, registered devices.

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

See above.

Advanced Metering Functionality and Communications Infrastructure

The draft DSIP Guidance notes that advanced metering functionality is being addressed within individual rate cases, but that Staff would also like detailed comments on this topic in the responses to the draft DSIP Guidance. We have provided responses below to the questions posed by Staff, but also note that the Platform Technology team within the MDPT Working Group provided similar inputs as part of that working group process, including information on the most common rollout approaches.

Within the advanced energy community we distinguish between Advanced Metering Functionality (AMF) and Advanced Metering Infrastructure (AMI). AMF refers broadly to the capabilities and functionality desired, whereas AMI refers to a specific set of technologies used to achieve the desired functionality. Particularly, AMI is understood as the utility-owned[3] complete technology solution that has been utilized to date to provide AMF, both in regulated and deregulated marketplaces. Historically, the primary approach that utilities have pursued to achieve the desired functionality has been via utility deployments of AMI, which is generally understood to include smart meters, a two-way communications system and the back-office systems used by utilities to interact with the smart meters via the communications system.[4] Although AMI as typically deployed is a complete technology solution to deliver AMF, we recognize that as technology evolves, there may be additional options for achieving the desired functionality and possibly adding in new functionality as well.

Our responses below attempt to be as specific as possible with respect to these two definitions, and we assume that when Staff refers to AMI in the DSIP Guidance that they are referring to the traditional technology platform as defined above.

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

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[3] As we describe in more detail below, the utility need not own or operate all components of an AMI system.

[4] AMI essentially is a continuously available two-way communication link to an advanced meter capable of storing advanced interval data. Parts of the communications network may or may not be privately owned.

As a starting point, we offer the following, more detailed definitions of advanced metering functionality (AMF) for the Commission's consideration, which supports the current New York State Order in case 09-M-0074.[5] Advanced Metering Functionality as defined by FERC, NIST and based on the Grid Modernization Proceeding in Massachusetts is as follows:

- Near real-time collection of customers' interval usage data
- Automated notification of outages and restorations
- Two-way communication between utilities and customers
- With a customer's permission, communication with and control of appliances

As we have previously commented to the Commission[6] the functionality of AMF includes:

- Near real-time load monitoring
- Outage/restoration notification
- The ability to use dynamic pricing
- Support for residential demand response
- Dynamic electricity consumption forecasting
- Confirmation and settlement
- More effective customer education and engagement

Alternatives to traditional AMI to provide partial AMF include:

- DER monitoring and control through cellular networks or via Wi-Fi and broadband networks.
- Communicating service panel meters
- Communicating sub-metering, including:
  - Metering and communicating photovoltaic inverters
  - Metering and communicating load control devices
  - Metering and communicating point switches and monitors
  - Metering and communicating streetlight control
- Ancillary devices past the meter could be also utilized; these devices would include:
  - Communicating thermostats
  - Home Area Network (HAN) devices
  - 24V load control devices

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[5] Order Adopting Minimum Functional Requirements for Advanced Metering Infrastructure Systems and Initiating an Inquiry into Benefit-Cost Methodologies.
[6] *Comments on Track 1 Straw Proposal (Case14-M-0101)*, Advanced Energy Economy Institute, Alliance for Clean Energy New York, New England Clean Energy Council, filed September 22, 2014.

The above alternative tools can be used to successfully engage customers for specific programs such as direct load control and energy disaggregation, but have not been pursued by utilities to deliver the full range of AMF. To be comparable to traditional AMI, alternate solutions will need to provide accurate, interoperable and timely interval data to support settlement and planning purposes within a common market data exchange. At the same time, traditional AMI deployments alone have not guaranteed that the broadest set of AMF listed above are actually realized. Rather, AMI acts as platform foundation for additional applications like distribution automation, demand response and customer engagement initiatives.

Fundamental to the success of REV is near real-time measurement and communication of utility attributes (e.g., energy, demand, and voltage) to provide additional visibility, control, and total asset awareness of the distribution network. Moreover, a plurality of measurement devices is needed to provide meaningful, cost effective impacts. Different types of devices may require different types of interfaces for metering or other downline sensors, while meeting stringent State of New York revenue metering requirements. To support the Commission's REV vision, alternatives to traditional AMI must provide the fundamental measurement along with two-way communication ability.

In order to engage customers at a mass-scale, REV's ultimate goal, AMF will be needed. In fact, a Brattle Group study[7] estimated that the majority of societal benefits from AMF deployment would come from dynamic rates and broad adoption of DR programs. AMF will be able to ensure widespread participation of time-of-use or dynamic rate programs or behavioral demand management programs.

In addition, timely and granular usage data shared with third parties, anonymized to protect privacy, will facilitate the development of new DER products and services that in turn, will be able to reach more customers. Furthermore, broad implementation of AMF will enable the participation of low and moderate income (LMI) households in REV-supported DER projects and programs thereby helping to prevent an "energy divide." If AMF is dependent on DER provider-supplied infrastructure or limited to a smaller set of utility customers, LMI households may be less likely to participate given recognized financial barriers including lower levels of home ownership. The pricing options that AMF facilitates, including peak pricing rebates and pay-as-you-go options, can also provide substantial benefits (including reported benefits as a tool for energy efficiency) to LMI customers since the savings would constitute a larger percentage of their bill than higher income, higher use customers.

An interoperable AMI backbone can enable multiple customer-engagement applications (e.g., demand response, energy efficiency) as well as secure, timely data to support participation in near real-

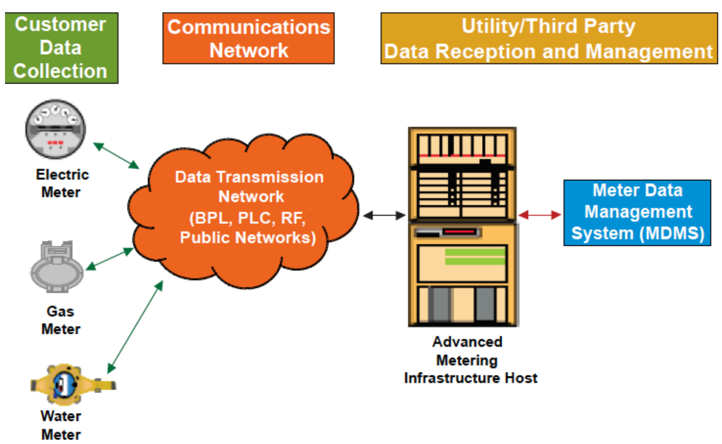
[7] Ahmed Faruqui "The Customer Side Benefits of Smart Meters," Presentation, Brattle, Nov 7 2013. Available at: http://www.brattle.com/system/publications/pdfs/000/004/953/original/The_Customer-Side_Benefits_of_Smart_Meters.pdf?1383853357

time markets. In addition, as business needs evolve beyond those needed during the early phases of REV market implementation, AMI is able to cost-effectively scale to multiple applications and territories.

Finally, the AMI system will enable numerous benefits that will positively impact all customers (those engaged and less engaged). For example, AMI, if deployed in combination with complementary customer engagement initiatives and related programs, will allow utilities to immediately engage with those customers affected by an outage and communicate with them as the outage proceeds as well as when power is restored. In addition, AMI data will allow third parties providing engagement solutions to better identify those customers with higher benefit potential.

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

AMI typically refers to the full measurement and collection system that includes meters with integrated communications at the customer site; communication networks between the customer and a service provider, such as an electric, gas, or water utility; and data reception and management IT systems that make the information available to the service provider. An AMI system has three major components as listed below and as shown in the figure below:



Source: https://www.ferc.gov/EventCalendar/Files/20070423091846-EPRI%20-%20Advanced%20Metering.pdf

1. <u>Smart meters and associated communications modules (edge devices)</u> that collect time-based data and alarm events. Meters are available that cover all three commodities: electricity, gas and water. These devices are installed at customer premises. These "edge devices" provide the primary near real-time monitoring, metering and control connections to the customer premises as well as the utility's measurement and automation devices controlling the integrity of the overall distribution network. In many

cases, edge devices can also serve as connectivity nodes to downstream Field Area Networks (FAN), local Home Area Networks (HAN) and in-home appliances. Edge devices include:

- Meters
- Distribution controls and intelligent electronic devices (IEDs) such as switches, capacitor banks, regulators, reclosers, load tap changers, water and gas pumps, regulators, level monitors and miscellaneous sensors.

2. Communication networks that have the ability to transmit collected data from smart meters typically include two levels: a local area network (LAN) for communications to a nearby concentrator and then from the concentrator, via a wide area network, back to the head end of the system. Local area networks are typically through commonly available fixed networks such as Fixed Radio Frequency (RF) and Power Line Communications (PLC). Wide area networks (WANs) are typically public networks such as cellular. WANs provide the long-range connectivity between concentrators and head end or intermediate command, control and analytic enterprise data management systems. Note that smart meters can also connect to wide area networks directly, though this is typically more costly and, in practice, tends to be limited to large commercial customers. The network communication will often comprise a variety of technologies that are aligned to a utility's unique characteristics and performance requirements. Whereas a mix of various technologies is necessary and prudent, it is important that they be proven and tightly integrated to provide a cohesive and manageable infrastructure in order to maximize the benefits to both the utility and consumer. Examples of network communication technology include:

- Powerline communications (PLC)
- Fixed RF (radio frequency) wireless communication
    - Mesh technology
    - Point to multi-point technology
    - Public Carrier or cellular technology
- Fiber Optic
- IP/Public Infrastructure (Internet)

AMI communications networks support continuous interaction between utilities and customer premises. The devices that help form the communications networks (typically known as concentrators) reside on utility property.

3. AMI back office information technology (IT) system (including the "head-end" and enterprise management and control applications) receives the stream of meter and sensor data brought back by the communications network. Enterprise systems comprise a variety of critical functions and provide a platform to integrate data for multiple system types. They are also crucial for maintaining network security and providing important alternatives for closed network functionality or cloud based data access. Head-end systems make the data available for other systems (such as meter data management systems) by request or pushing the data out. The IT systems support data management functions for activities such as on-demand reads, remote service switch and outage detection. These systems can reside either in the utility's data center or at the AMI vendor's center, depending on whether the utility buys this component as a license or as a Software-as-a-Service (SaaS). Some elements can also be deployed at consumer locations or within edge devices to provide management, control and analytics necessary to achieve REV objectives. Examples of Enterprise Management and Control applications are:

- Communication network management
- Meter Data Management systems
- DMS (Distribution Management System)
- OMS (Outage Management System)
- EA (Engineering Analysis)
- GIS (Geospatial Information System)
- DRMS (Demand Response Management System)
- Market transaction software (e.g., to deliver data to authorized third parties or to the NY-ISO for settlement)

In addition to these three basic components, Communication Protocols are critical. Communication between edge devices such as meters or distribution automation equipment and enterprise systems and applications relies on standards-based communication protocols to provide simplicity in system-wide integration and predictable network performance during both normal operation and in congested conditions associated with upsets or outages. Standards-based protocols support the interoperation of devices and systems.

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

Experience globally (about 500 million AMI meters[8]) and in the United States (with approximately 50 million AMI meters[9]) has shown utility ownership to be most cost-effective in the vast majority of cases. In the UK, the government created a regulated communications monopoly such that though the utilities do not own the system, the model is similar. There are examples that reliance on the competitive metering market to deliver AMI has not been successful, including in Australia and Germany.

In the UK and Germany, original regulations provided for competitive metering, with advanced metering to be delivered via voluntary operation of the market. Due to the investment risk, loss of scale economies, and loss of benefits, advanced metering was deployed to only large commercial and industrial customers, less than one percent of all customers.[10] Accordingly, the governments reversed the policy and adopted policies where advanced metering would be provided via utility distribution companies (or, in the UK, a mandate on competitive retailers for full-scale deployment).[11]

On the customer side of the meter, we support an active role for third-party providers to help with customer engagement and DER deployment, either on behalf of the utility or on their own, enabled by AMF. This is consistent with the Commission's Track 1 Order.

Although utility ownership has been the most common option to date, utility ownership of AMI components depends on a few criteria:

- Overall total cost of ownership
- Regulatory incentives (e.g., utilities earn returns on capital investment, third-party ownership of specific components may be mandated)
- Capabilities (e.g., third parties may have greater expertise or scale to own and operate)
- Risk (e.g., shifting ownership to another party may lower overall implementation risk for the utility)
- Regulatory alignment (revenue grade measurement devices, management of data)

There are variations in ownership models depending on the component:

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[8] - Siemens global research. "AMI" is the FERC definition: "Meters that measure and record usage data at hourly intervals or more frequently, and provide usage data to both consumers and energy companies at least once daily."
[9] FERC, *Assessment of Demand Response and Advanced Metering,* Staff Report, December 2014.
[10] King, Chris, "How Competitive Metering Has Failed," Public Utilities Fortnightly, November 15, 2001.
[11] In Germany, the policy change is in the form of proposed legislation expected to be adopted in early 2016. The government has already determined that the competitive market approach has not achieved the goal of broader advanced metering deployment.

- Data Collection Management: This may be the most common variation to the traditional AMI ownership model. Head-end systems are comprised of hardware, software as well as utility personnel to manage the AMI data collection. Utilities can buy and host the hardware at their data center and employ dedicated personnel to manage their back-office. For example, Con Edison expects to employ one FTE for every 100,000-200,000 meters, which in their case would translate to 26-52 FTEs.[12] Alternatively, a utility can decide to contract their back-office as a service from a third party. This ownership model aims at leveraging the scale efficiencies and in-house knowledge of third parties. In this case, the third parties shoulder the burden of owning and managing hardware servers and smart grid software at their facilities, while providing guaranteed levels of service to the utility.
- Communications Network: Utilities can either own and operate their network or seek a Network-as-a-Service (NaaS) solution that aims to reduce the risk of network deployments. Utilities under this model pay a recurring fee to a third party in order to access the network. This approach can be more beneficial in territories with more challenging, uncertain network topologies as it reduces the implementation risk to the utility, but may introduce technological obsolescence risk. Other variations of this model could potentially have one third party own the network, with the goal of ensuring open access to the communications network by all utilities as well as other third parties that may be able to leverage the communication infrastructure for additional applications.
- Endpoint Devices, Communication Network and Data Collection Management: Another alternative ownership option would be where an entity other than the utility manages the endpoint, communications infrastructure and the data collection management system. For example, in a new rule in Australia,[13] a retailer appoints a Metering Coordinator (MC) – this can be the utility or a third party – to provide metering and data services such as provisioning the meter and providing access to devices. In turn, energy retailers will facilitate deployment of smart meters to their customers based on their choice of products and services. If a customer decides to switch their electricity retailer in the future, the MC will either have systems to manage the meter as-is and will receive a transfer from the previous MC or will field pair the meter to replace it with a system which it currently supports.

[12] ConEdison, *Advanced Metering Infrastructure Benchmarking Report*, October 15, 2015, page 31. Filed in case 15-E-0050.
[13] http://www.aemc.gov.au/getattachment/ed88c96e-da1f-42c7-9f2a-51a411e83574/Final-determination.aspx

4. *Utilities should describe in detail what type of communications technology and infrastructure would be proposed for AMI deployment in your service territory? Explain why this communications strategy was selected versus other potential means of communications such as (mesh/point-to-point/fiber/internet/etc.). What are the pros/cons of the proposed communications system versus other potential means described above? Does the communication system proposed have the capacity to handle the large amount of data needed to support REV goals/initiatives? If not, is the communications system scalable to eventually meet the REV goals/initiatives?*

Each Utility should consider a broad range of factors when choosing the AMI technologies that align best with their goals and performance requirements. Utilities may find that no single technology will meet all criteria in all circumstances. The best suited solutions will be those that can successfully integrate a range of technologies into a cohesive end-to-end infrastructure with key considerations being cost-of-ownership, performance and Opex vs. Capex tradeoffs. The selection of an AMI system is unique to each utility's circumstances and is dependent on a number of factors including:

- Geography: flat vs. mountainous; urban vs. rural; forested vs. farmland. Each type will drive variations in the infrastructure and deployment costs associated with any single technology.
- Density: The number of consumers/assets vs. the geographic distribution of the network. This will also apply to the projected number of distributed energy resources and their relative location within the network area.
- Scalability and Growth: As the NY market expands the AMI system must continue to meet performance requirements.
- Utility use case requirements (e.g., address system losses, reduce energy/capacity or reduce labor costs). For example:
    - If the utility plans to use the network for multiple smart grid applications, then they will need a communication network that is interoperable so as to permit a broad choice of devices and functionality.
    - If the utility intends to use the network for advanced applications (e.g., load disaggregation) then it is important for the utility to select a network that meets the needed bandwidth and latency requirements. Adequate free capacity is important for future applications.
    - If the utility plans to use the network for system control, billing, or other critical applications then appropriate security and reliability will be critical.

a. Explain why this communications strategy was selected versus other potential means of communications such as (mesh/point-to-point/fiber/internet/etc.). What are the pros/cons of the proposed communications system versus other potential means described above?

There are multiple FAN technologies that can be utilized or could be deployed as a combination of cellular, mesh or point-to-multipoint depending on the use case, each with pros and cons, as shown in the table below:

Communication Technology	Pros	Cons
RF Mesh	• High coverage rates • High resiliency and self-managing • High bandwidth • No license cost • Fast Multicast • Supports battery powered devices	• Performance depends on contiguous network build-out • Hops can add latency • Un-licensed interference
RF Point-to-multipoint	• Longer range • High bandwidth • Cost effectively supports sparse deployments • Ownership of frequency/ interference protection • Fast broadcast • Supports battery powered devices	• Limited support for peer-to-peer applications • License costs • Terrain dependent
Power Line Communications (Ultra Narrow band)	• Leverages existing infrastructure • Reaches all electric connected endpoints, i.e., rural • Supports phase balancing	• Low bandwidth • Does not support battery powered operation • Limited peer-to-peer due to grid wiring topology • Urban density • Performance may be affected by power line noise
RF Cellular	• High bandwidth, low latency • Re-use existing cellular carrier infrastructure • Surgical deployments • Supports battery powered devices	• Higher cost per end point • Reliance on public infrastructure • Not primary market
Fiber	• Highest bandwidth, lowest latency	• High cost per endpoint • Not extensively proven for smart grid • Peer-to-peer limited to network design • Does not support battery powered operation

b. **Does the communication system proposed have the capacity to handle the large amount of data needed to support REV goals/initiatives? If not, is the communications system scalable to eventually meet the REV goals/initiatives?**

Any of the RF-based or fiber-based communication systems have or can be scaled to support the REV goals/initiatives. Selection criteria should account for the cost for each system to meet REV goals/initiatives. Power line communications deployed in hybrid configurations with RF technologies can be scaled to eventually meet the REV goals/initiatives.

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

Key AMI benefits for further deployment of renewables and DER include:

1. Records usage/production hourly (or commonly down to each 30, 15 or five minutes with capability of each 1 minute or each 5 second[14] depending on technology) so that customers can visualize their performance in near real time and the market can charge/pay the appropriate value based on actual usage/production at any given time, for which value varies significantly throughout the day and year.
2. Voltage data from AMI meters, in combination with Smart Inverters or coordination of LTCs, capacitors and regulators, can be used to manage voltage fluctuations and prevent voltage problems that can result from high DER penetration.
3. Aggregation of data by circuit, transformer, etc., enables utilities to accurately measure loading on specific distribution equipment so DER can be compensated (or charged) appropriately for adding/relieving stress on the system.
4. AMI enabled end devices (generation sources and loads) can be switched on and off much more quickly (including through the enablement of smart inverters) than standard generation and can offset the need for traditional sources of ramping capacity to balance the fluctuating supply of DER with local AMI responsive loads.

[14] For example, some utilities are bringing back 5 second data for large C&I customers via cellular technology.

5. As DER penetration rises, the data collected from AMF can be integrated into distribution system planning and administration within the DSP. This will further enable the ongoing deployment and management of DER.
6. Using AMI data to identify load shape patterns among customers and enabling personalized DER offerings based on their specific energy usage profile.

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

In order to achieve the vision of the REV initiative, communications to a plurality of devices within a targeted geographic area is important to enable all components to function as a system. The incorporation of new power 'sources', whether purchased or generated; demand management; or added storage capability can improve the utility's ability to maintain a healthy margin between load and capability. But to provide scalability and reliability, all devices require integration to a unifying network and control system. Scale economies can be achieved in the following areas:

- Central software, operations, and project management, as well as the communications network, which are shared by the number of meters such that more meters = less cost per meter.
- Installation is cheaper when every premise is visited vs. piecemeal; personnel travel costs between installation sites for piecemeal installations is substantial.
- Operating costs and operational efficiencies, such as meter reading – manual labor must be maintained if only a portion of meters is automated. In addition, analytic applications such as transformer or circuit load monitoring and detection of non-technical losses are impractical with partial data. Outage restoration and voltage optimization work far better with higher penetration of advanced meters.
- As the penetration rate of DER increases across the DSP region, visibility to the customer delivery point becomes more critical to operating the grid and recommending additional deployment of DER.

As a stepping stone to ubiquitous communications, high-value applications can be provided with surgical deployments of communication systems to provide for immediate benefits. An example of high-value applications includes distributed generation or storage provided by public or private, third-party entities generating energy through renewable resources or electric vehicle fleets. Wind and solar farms are being constructed by independent producers who offer competitive pricing and the opportunity for today's new energy consumer to purchase their energy from an environmentally friendly source. Electric vehicle charging requires careful load balancing but the vehicles' batteries can also act as sources of generation during peak hours. This vehicle-to-grid (V2G) connection has the potential to reduce the need for new power plants when electric vehicles are used during high peak periods as an energy source.

Concentrated and coordinated participation in demand management programs by commercial, industrial or residential consumers create virtual power plants and also represent an opportunity to surgically deploy and integrate devices to monitor, control and measure results of load shedding. However, data and control of these generation, storage and load-shedding devices need to support standards based protocols such that their integration into future systems is assured. To only 'connect' the resources without integration is neither a sustainable nor a scalable operations model.

Even in these point solutions, a critical mass is important to derive meaningful system impacts and to offset program costs. Integration is required to produce the greatest value of controlling distributed resources and must be designed based on a cohesive strategy to address challenges such as intermittent and variable supply of power for both distributed and large-scale generation and storage, regardless of ownership of these assets (i.e., whether private or utility owned). One possible approach is that AMI investments are approved sequentially, as deployment of areas demonstrates benefits. In the current ConEd plan, for example, deployment is tranched by region already. Penetration can reach 100% in those areas first and demonstrate full AMF before moving to other areas.

Locational or regional deployments most closely overlay with geographically-based distribution constraints and can be used as a way to get early benefits and provide the foundation for more complete deployment in the future, but they still require broadly designed and deployed communications infrastructures to allow the integration of evolving programs and technologies over time.

With all that said, cost-effectiveness of alternative scenarios should be examined, as the DSIP Guidance has asked utilities to do. For example, in California, utilities submitted business cases for 10%, 100%, and various utility-selected "in-between" --- the 100% cases were most cost effective (100% refers to a geographic area).[15]

7. *Over what timeframe is the deployment anticipated to take place? If market-driven, what will be the key determinants of uptake in the market? How will the deployment schedule affect overall costs?*

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[15] See, for example, "Preliminary AMI Business Case Analysis of Pacific Gas and Electric Company," Proceeding R-02-06-001, October 15, 2004.

The ideal timeframe to deploy the anticipated AMF strategy is 18 to 24 months ahead of the anticipated DER adoption to a geographic portion of the utility territory. Fundamental to the proper placement of DER is granular and timely information, providing distribution system planning with dynamic information, thereby increasing system reliability and affordability. The longer it takes to install and implement advanced metering infrastructure elements, the longer it will take utilities to benefit from AMF-centric features. Short-term benefits can be realized through energy efficiencies such as better customer engagement, Volt/VAR optimization, Conservation Voltage Reduction (CVR) optimization (in combination with smart inverter capabilities enablement), and reduction of system losses. Additional DER resources will evolve and be adopted over time. Aside from the loss of early benefits, a protracted deployment methodology will generally escalate costs from a variety of issues including cost of money, inflation, and having to support two different meter data acquisition methodologies. In broad terms we would suggest that an optimal timeframe is to begin planning in the first year of the DSP market followed by one year of ramp up, 3-5 years of rollout, and one year of ramp down, all of which depend on the size of the utility (smaller utilities could do this in less time).

If the deployment were market driven, key determinants of market uptake will be driven by an inclusive, transparent market framework and the proactive communication of both the tangible benefits and how the market can participate. Deployment would ultimately depend on uptake of offerings, e.g., TVR for consumption or market prices paid for DER (as customers “raise their hand”, AMF would be deployed). Uptake will be determined by various other factors such as wholesale prices, products and services being offered, and customer awareness and education. Unless the market is well educated, has easy ways to participate, and can see a clear business case for participation, under the market-only scenario, uptake is likely to be in the range of a few percent of potential total customers per year. For example, to address peak demand, markets and edge devices will need easy access to near real-time prices and straight-forward mechanisms to participate in the markets at the device level. Another example is market mechanisms for consumers to purchase and contribute VAR control to the grid via smart solar inverters.

8. *What are the characteristics of the utility service territory that impact economics of AMI deployment? For example, if a utility has fully deployed automatic meter reading or only reads meters bimonthly, this may limit the operational savings available from AMI deployment.*

Communications networks can be more expensive in rural areas, and more generally, AMI economics are affected by geography (terrain constraints, building construction), meter density (the number of meters per mile of distribution line), system losses, load capacity, and labor costs.

AMI business cases typically have 20 or more categories of benefits, with some large and some small. Meter reading is typically a significant benefit (i.e., if switching from manual to automated) but is typically less than half of total benefits. These benefits accrue from the labor savings associated from eliminating manual meter readings. Benefits and costs are utility specific and a full business case should be performed for each utility to assess specific economics.

The true value of AMF includes "day 2" benefits of improved services, planning, etc., that are often omitted. It is important for Staff to thoroughly evaluate all submitted benefits to ensure that all potential benefits are being properly considered, and if certain benefits have been omitted, that they be included.

9. *Filings should examine the issue of AMI deployment from the perspective of three alternative scenarios: (a) full AMI implementation by the utility, (b) utility implementation of AMI to 20% of customers, with remaining customers receiving AMR (automated meter reading) meters, and (c) AMR implementation by the utility, with AMI deployed to individual customers by ESCOs and/or competitive DER providers. In each scenario, assume the utility will maintain the communications network, and meter data management systems. Compare the costs and risks of each alternative scenario, including flexibility, scalability, and level of ratepayer investment, as well as overall net benefits.*

Although this question is directed at the utilities, we offer the following observations and comments:

First, with respect to the phrase, "examine the issue", we assume this to mean performing a detailed benefit-cost analysis, in addition to the flexibility and scalability analyses mentioned in the question. The Commission should clarify this in the final DSIP Guidance.

Experience shows that the full implementation of an AMI system and infrastructure provides the highest chances for success in achieving REV objectives primarily because the utility is in the best position to support the plurality of devices that are needed to realize the multiple accretive benefits as well as take advantage of the economies of scale. With a full utility implementation the following benefits, among others, are realized:

- Immediate benefits from new timely data flow:
    - Consumer engagement with feedback to enhance energy efficiency and conservation
    - Sufficient data for one-call response to customer queries to drive increased customer satisfaction and reduced operational costs

- Reduce labor costs
    - Automated meter reading versus by-route or drive-by with improved, off-season, off-cycle management
    - Remote diagnostics for individual customers
    - Remote connect/disconnect of service
    - Optimized outage response and restoration

- Greater emissions reductions
    - CO_2 and criteria pollutant reductions from reduced truck rolls and meter reading, as well as consumption reductions associated with energy information feedback

In the scenario of a 20% implementation of AMI by the utility with the remaining customers receiving AMR services the result is expected to be a smaller, more fragmented deployment and a reduction in the benefit-cost ratio. The selection criteria for AMR customers must also ensure that the AMR investment is not prematurely stranded in the event that DER deployment by those customers requires an increase in AMI meters or if the customer elects to participate in a Time Varying Rate with granular data. Moreover, there would seem to be a distinct disparity in the benefits realized between regions deploying AMI and those that do not. Additional obstacles to achieving the goals of REV are:

- Market confusion within a utility's service territory between those that have AMI and those that do not (e.g., AMR customers may think they are eligible for certain services that are only possible with AMI).
    - Disparity in utility process costs due to the different service capabilities between customers with and without AMI.
    - Differences in services available to similarly situated customers; for example, AMI customers would have automatic outage reporting, while other customers would still have to call the utility.
    - The inability of AMR-only customers to leverage the customer portal or digital marketplace to the fullest.

In the final scenario where AMR (monthly drive-by remote meter reading with no interval data) is deployed by the utility and AMI is deployed to individual customers by ESCOs or competitive DER providers, the benefits sought by REV are likely to be limited, assuming that the deployment by ESCOs or DER providers is more limited, resulting in a reduced number of participants. While it is also possible that those customers served by AMI via the competitive market may received benefits equal to or perhaps even greater than customers served by a saturation deployment of AMI, those customers with only AMR services would not gain any of the potential direct benefits of REV, such as he ability to participate in TVR programs. Under this scenario the AMI meter would be a New York state approved meter owned by the customer and managed by the ESCO or DER provider. Additionally in this model it would be necessary to have market rules to address churn of customers that elect to change ESCOs. For example, would the AMI meter remain and be subsequently managed by the DSP or would the new ESCO be required to support the meter? This scenario as described would also appear to leave the LMI group with an entry barrier. With multiple ESCOs per utility territory there could be multiple AMI technology selections with an overall larger total cost of ownership to the state than when a DSP provides the AMI technology to the customer clearinghouse for all of the market participants. However, should this deployment scenario be adopted, it is imperative that the technologies selected and any incremental AMI deployment be capable of being integrated into a subsequent full AMI deployment.

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

AMI networks provide real-time or near real-time metrics of the distribution network. Transmission and distribution constraints that have been difficult to address tend to be very localized and time variant. The key objectives of REV require the effective use of current assets in addressing the utility needs of the market. AMI networks with a plurality of devices provide the locational and time critical metrics required to drive both market based and utility optimization of resources. Many network types can be used for controlling distribution and market edge devices. However, without the real-time or near real-time locational and time specific metrics provided by an AMI system, the efficient optimized control to meet the objectives of REV will be difficult to achieve. Today, the AMI network is the only economical means of providing the granular data required by the REV market to meet the policy objectives and metering regulations within NY. AMI networks also provide a communication backbone to allow customers that otherwise could not participate in the REV market to participate. This could include viewing granular data on the consumer portal to participating in market-based pricing programs.

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

Yes, AMI can support demand rates for mass-market customers; data is recorded at the necessary market interval (usually every 5 or 15 minutes) with granular time stamps to support the time varying cost of DSP delivery throughout the year. Pricing/behavior signals can also be cost-effectively sent via alternative channels (i.e.: telemetry, openADR, SEP 2.0, revenue grade (ANSI certified) meters, including via third parties.

Stand-alone electronic meters, which do not require a communications network, could also be used, but because you cannot achieve the granular time stamp data necessary to meet the fluctuating system conditions it is impracticable to use them with anything but the most basic of demand rates (e.g., a monthly peak demand), which would not provide the desired benefits of moving to demand rates.

12. *Describe the anticipated costs associated with the strategy? Provide detail according to capital versus operating expenses, including break—down of costs to specific components including labor costs for installation and operational requirements. Who would bear the costs of the metering strategy?*

Costs will vary by implementation strategy and AMI technology selected. Numerous case studies and business cases including the recently filed AMI business case by ConEd break out the costs and benefits of an AMI solution. This approach has been seen by other utilities, states, and countries as a basic feature of the distribution infrastructure and charged out accordingly. In a rollout – and just as with a distribution grid – benefits accrue to all customers, though not to all equally; and costs are associated with all customers, though not with all equally. Regulators universally have determined that the costs of the distribution grid should be socialized across all customers for a variety of reasons, including benefits to society. We believe it is important for the Commission to consider the merits of all benefits submitted within the DSIP filing to determine where the proposed benefits flow. There have been numerous case studies released by the U.S Department of Energy (US DOE) within the past five years that discuss the value of previously considered hard-to-quantify benefits. The ultimate cost of the proposed metering strategy, based upon careful review of the AMI business case, could be applied appropriately to consumers and utilities.

13. *What additional system infrastructure (e.g., backbone communication infrastructure) does considered advanced metering system require? What protocols or standards would be required for interoperability? In the case that metering devices and other assets are provided by a third-party service provider, how would ownership and transfer of assets be managed if the customer opts to change service providers? How will ownership and transfer of customer data be managed?*

a. What additional system infrastructure (e.g., backbone communication infrastructure) does considered advanced metering system require?

Advanced metering will require backhaul connectivity. Most AMI networks use a mixture of utility backhaul and public backhaul networks. All AMI systems rely on a backhaul methodology to transfer collected meter data to a head-end system. Different types of commonly used backhaul methods include privately-owned RF systems (such as microwave point-to-point), public cellular communications (utilizing virtual private networks or VPNs), fiber optics, or leased telephone lines. Each DSIP should discuss how the backhaul method or technology selected can provide sufficient bandwidth for current applications as well as future ones. Traditionally, backhaul infrastructure owned by the utility itself has been a preferred solution, although secured and encrypted VPNs have caused utilities to frequently consider other publicly utilized systems including cellular communications.

Additionally, if the utility intends to run head-end software on their own application infrastructure, then hardware servers and hosting services will be required. An alternative back-office approach would be to leverage a Software-as-a-Service (SaaS) model where a third party would manage delivery of the software application, possibly with lower risks and costs for the utility. Alternative API channels can also be established over which to send data, such as the emerging SEP 2.0 standard.

b. What protocols or standards would be required for interoperability?

Driving standards across all layers of the smart grid solution is critical. There are a variety of protocols for both the transport and application layers that should be considered for system interoperability. One option is an IP-based network platform (consistent with the recommended standards set forth in the NIST framework and roadmap for Smart Gird Interoperability Standards, Release 3.0) that is capable of supporting several device and applications across a common infrastructure. Key transport protocols could include IPv4 and IPv6 for networking as well as Modbus and DNP3 for serial communications. Key application layers could include IEC 61968 and IEC 61970 for distribution management, IEC 61850 for substation control as well as other protocols developed and supported by the IEC, NASBE, IEEE, and ANSI groups. Additionally, network protocol standards that are widely being adopted such as IEEE 802.15.4g/e, Wi-SUN and ZigBee for Home Area Networking create interoperable platforms as they harmonize proprietary technologies, provide end-to-end connectivity and support the needed data rates.

Interoperability is needed for exchanging data between back-office IT systems (today, most interconnections of back-office systems still require custom interfaces, though the cost is very small in an

AMI rollout), for exchanging data with authorized third parties (e.g., the EDI standards already used in the competitive market or Green Button and GBC for emerging applications), allowing a plurality of devices on to the network platform to provide flexibility and choice for the utility and for exchanging data between devices (meters and in-home devices, etc.). The emerging SEP 2.0 standard should be explored as well. DSP functions in the future should ensure that interoperability with new technologies remain cost effective to implement into the REV marketplace.

c. In the case that metering devices and other assets are provided by a third-party service provider, how would ownership and transfer of assets be managed if the customer opts to change service providers? How will ownership and transfer of customer data be managed?

We discussed in our response to Question 3 some alternative ownership options for elements of an AMI system. Third-party meter ownership poses challenges due to the long life and payback period of investment, as well as the fact that some benefits flow to the utility and others flow to the customer. In the case of third party meter ownership, the Commission will need to consider issues such as:

- How to deliver benefits to the utility if a third party owns the meter, e.g., outage data, voltage data.
- How to conduct settlement. For example, when LMP+D is implemented in the future, there will need to be a central clearinghouse (the DSP is likely to be the most appropriate entity for this).
- Whether or not third parties need to follow all current New York State standards for revenue metering.
- Who is ultimately responsible for all assets and transfer of assets should the third party cease operations.
- How to draw clear lines of responsibility between the regulated utility/DSP and the unregulated third party provider.
- How customer Personally Identifiable Information (PII) is handled.

Nevertheless, a few models exist with regards to ownership and transfer of assets if the customer opts to change service providers. We offer two examples of how this is being/has been implemented:

- At Singapore Power, a network platform (paid for and deployed by the utility) allows customers to seamlessly switch between retail providers and buy electricity at wholesale market prices, lowering energy prices through increased competition. Customers that have opted-in for retail flexibility pay retailers for their meter through a fee. If the customer changes retailers, the fee continues to be charged by the new retailer.

- In Australia's competitive metering services market, beginning in 2017, the plan is to have the energy retailer, who owns and pays for the advanced meter, appoint a Metering Coordinator (MC) to coordinate metering and data services on behalf of them. If the customer changes retail providers, then the new retailers' MC will assume responsibility for the new customer. The new MC will either have systems to manage the meter as-is and transfer from the previous MC or field pair communications with the existing meter so that it can support it with its existing systems. Note this approach requires communications to be modular in meters so that a field pair can be done without replacing (or disconnecting) the supply. As mentioned earlier in our comments, this approach to the market has resulted in only minimal deployment of advanced meters, the examples being Texas, Germany, and the UK.

Customer data transfer can be handled, as a starting point, through existing rules governing data transfer between retailers when a customer switches retailers. Additionally, because interval usage data will be available, third party service providers can offer customized services and improved billing procedures. For example, should a customer choose to switch providers, interval data enables easy bill reconciliation at any point in a billing cycle. Our view is that customers have a right to access data about themselves. Customers must have the ability to transfer their personally identified information to new suppliers or service providers via Green Button or other mechanisms. It is likely that that majority of customers will need the utility or service providers to assist them with this, although there are other avenues that are emerging. For example, companies are beginning to emerge in the market to facilitate such data transfer, leveraging Green Button but adding further functionality – going beyond usage data to add rates and billing information that is helpful in a more comprehensive analysis of consumer benefits of DER. Utilities could also make non-customer identifiable data available to third-parties via standard protocols.

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

Grid services supported include: outage notification, restoration verification, Volt/VAR optimization, transformer/circuit overload prevention, asset load monitoring, losses identification and management.

Customer services supported include: real-time reads for assisting with customer queries; connect/disconnect for customer moves and changes; improved accuracy and timeliness of billing; consumer information options such as online usage details, usage disaggregation, high bill and other alerts, email subscriptions with usage updates; bill to date and projected month end; time-varying pricing options; pre-payment service; home energy management; personalized energy efficiency recommendations; rate recommendation/optimization.

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

Market programs or rate structures that could be supported include:

- Demand response (DR)
- Behavioral demand management
- Time varying rates (TVR), including Time of Use (TOU), Critical Peak Pricing (CPP), Variable Peak Pricing (VPP), Peak Time Rebate (PTR), demand charges, and hourly pricing
- Customer Prepayment

AMI systems are capable of supplying granular interval data for participation in and measurement and verification of ancillary market transactions. AMI in conjunction with other networks such as Home Area Networks can provide the automation required for participation by mass market customers.

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

The feedback from large numbers of local devices provides the ability to address locational constraints and distribution optimization. Key areas that AMF greatly enhance are:

- Conservation Voltage Reduction can be optimized along the entire feeder while maintaining service standards.
- Volt/VAR management through optimized placement and control of capacitors

- Coordination of smart inverters
- Provides needed data for consumer engagement through real-time or near real-time feedback to drive understanding and behavior change
- Ramping power options to complement DER via real-time or near real-time demand response
- Management of electric vehicle charging
- Management local distribution operation constraints

Societal benefits are also provided, including:

- Improved customer satisfaction and engagement
- Reduced environmental impact
- Increased economic output
- Increased fairness
- Improved service quality

Additional intangible benefits for the utility include:

- Increased safety for utility workers and customers
- Enhanced visibility into the grid
- Improved integration of new generation sources
- More effective rate design
- Reduced planning efforts

Realization of the broad range of benefits will be maximized when ESCOs and DER providers can access timely, granular data associated with their customers.

17. *What data will be collected, and for what purposes will it be used? Who will own the collected data, and how will access to data be managed? Will the system be able to control end—use devices within the consumer's premise? How will information about controlled events be communicated to customers?*

Data access, uses, and privacy and security are key topics in the implementation of the Commission's REV vision. The California PUC issued a detailed rule regarding these topics in its Decision 11-07-056,[16] some of which may be useful in adopting related rules in New York.

What data will be collected: REV implicates three types of data. The first is customer consumption information, including more detailed usage information to enable various time-varying rates, demand charges, or other pricing options. The second is power quality data from advanced meters, such as voltage and outage alarms. The third is DER data, such as energy production, voltage or other power quality characteristics, and DER equipment information, such as capacity, battery charge state, and others. The metering provider, normally the utility, collects the first and second types and limited information about DERs, such as installed capacity (via interconnection applications). Other data about DERs is typically collected by the DER provider, usually a third party.

Purpose: Consumption data is used for billing, as well as providing feedback to customers for use in managing consumption, including when and how DER is used on premises. Advanced metering data enables pricing options and energy information services that can be offered to consumers by utilities, retailers, and third parties. Utilities use power quality to operate the grid, maintain reliability, and ensure that voltage and other electricity characteristics remain within required limits. Another purpose is to manage the grid more efficiently or enable efficiency options, such as managing line losses or enabling conservation voltage control (CVR).

Data ownership: Few jurisdictions have specifically determined data ownership for advanced metering data. For DERs, data ownership depends on the agreement between the DER provider and the customer. In general, jurisdictions have focused on control of who may receive and use the data. Utilities typically have access to data needed for billing and grid operations but may not share it with third parties without customer consent. Third parties have access to metering data only with customer consent. Data about DERs is provided to utilities in accordance with regulations regarding interconnection, generally with the same restrictions as metering data (can use for grid operations and planning only, no sharing with third parties without consent).

Data access management: Entities receiving customer-specific data – consumption, DER characteristics or operations – must have secure systems in place to secure the data and protect customer privacy. Data can be shared through automated, standards-based interfaces, such as Green Button and Green Button Connect. The data can be protected by requiring a customer login for access to data, including self-downloading and authorization of transfers to third parties. Third parties receiving data

[16] CPUC, "Decision Adopting Rules to Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company," July 28, 2011.

from utilities should have contracts in place to guarantee data privacy and security. As a general consideration, we suggest consideration of the Fair Information Practices (FIP) principles developed as a result of the federal Privacy Act of 1974: Transparency, Individual Participation, Purpose Specification, Use Limitation, and Data Security.

System control capabilities: In the REV context, utility and third-party systems have the potential to control DERs, devices such as smart thermostats, smart appliances, and other equipment. Which party has the right to control a device is governed by the customer's consent.

Event communications: Control events can be communicated via numerous means, including email, texts, alerts on apps, automated phone calls, and messages sent to devices, home energy management systems, and building energy management systems. The communications are an inherent part of the service offering.

18. How should cyber-security concerns be addressed on the system and how will customer data be protected?

We recommend that all service providers have end-to-end cyber-security strategies and technologies for REV-related services including but not limited to cyber security requirements contained within the current NY State minimum AMI requirements. Customer data should be protected the same way as today: in utility systems behind firewalls or in secure cloud environments, shared only with customer's consent. Again, we suggest consideration of the FIP principles in defining data protection (e.g., who has access to the data, how is access granted, how are protections enforced).

It will also be important that the responsibilities of all the different parties be clearly spelled out by the Commission.

19. How will privacy concerns be addressed on the system described?

See response to Question 18.

20. How will individual customer load data be shared with third parties such as energy service providers (ESCOs), demand response providers, and energy service providers?

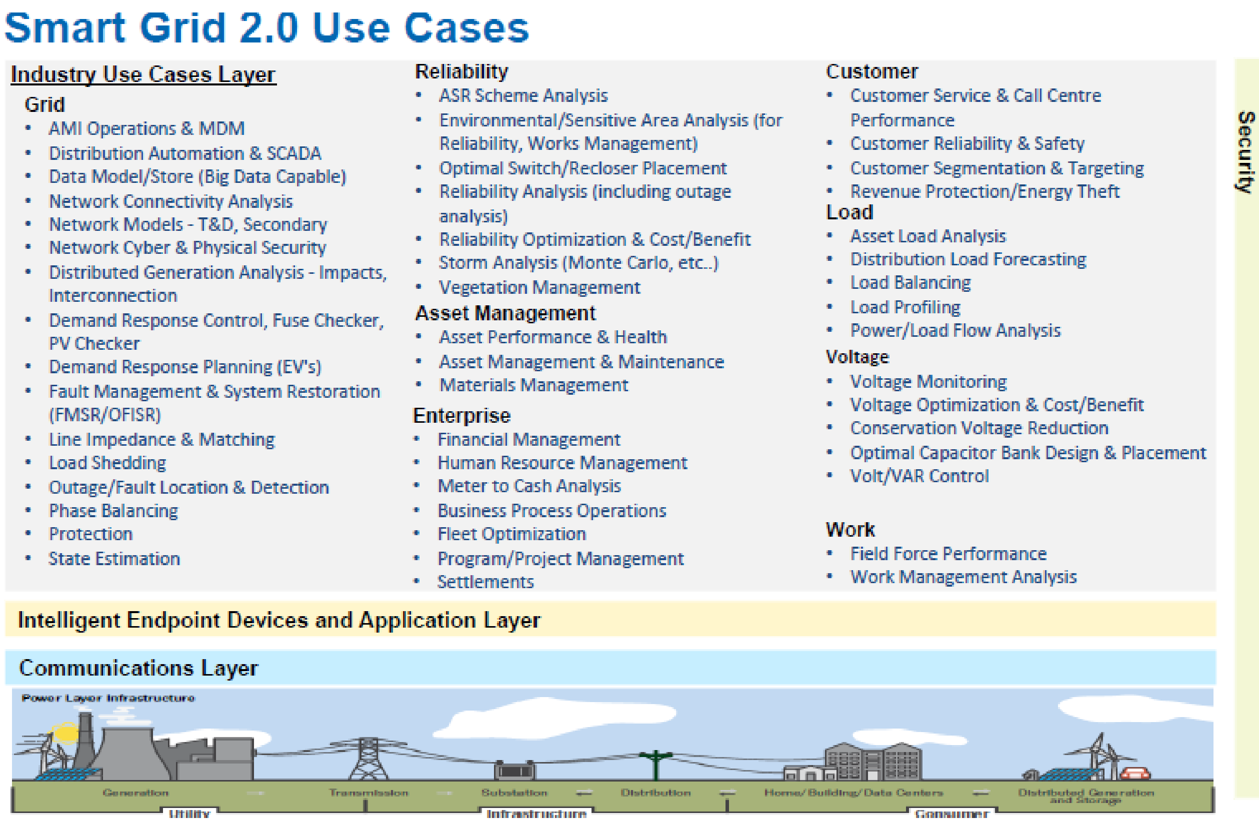
We suggest individual customer load data be shared with third parties only with the customer's consent, via a standard protocol such as Green Button Connect, and in accordance with the FIP principles discussed above.

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

In order to achieve the REV goals, customer load data must be provided to ESCOs and the NYISO in a way that allows the NYISO to settle ESCOs' load in a timely manner based on actual usage instead of class load shapes of their customers. Today, customers are billed based on class load shapes, so there is no incentive – and no benefit to the customer – to change their usage pattern in a way that would lower system costs. By using less energy on peak or aligning their consumption with, say, rooftop solar production, a consumer would cause system costs to go down – but the consumers would pay the same bill. Providing price signals – financial incentives – requires both time-varying rates and the corresponding settlement based on actual data. Good examples for doing so today are Ontario, Canada, where over four million residential customers are on TOU prices; and Texas, where the major competitive retailers offer TOU as an option to all their customers. In these examples, and many others, actual interval data is used for settlement. Interval data is collected daily, processed, and made available for settlement within one or two days. The settlement calendar varies, but initial settlement typically occurs within a few days of actual consumption. In Ontario, initial settlement occurs two days after consumption, with final settlement occurring eight days after consumption.[17]

Other attributes of the system: the AMF data and system support multiple analytics use cases as illustrated by this example from PEPCO below.

[17] See: http://www.ieso.ca/Pages/Participate/Calendars/2015-Financial-Market-SSPC.aspx



Citation: Karen Lefkowitz, Gregg Edeson "Creating a Smart Grid Analytics Road Map: Experience from PEPCO Holdings," PHI and PA Consulting Group, Presentation at Distributech 2015, February 2015.

22. *Does a scenario exist where utilities or third parties could offer a customer advanced services without a full-scale deployment of advanced meters and what is the rationale behind the response? If not, what limitations would be required to change the response?*

Yes, advanced services can be offered to customers prior to a full-scale deployment. In a coordinated deployment, once systems are in place to support customers, services could be offered. Full-scale deployments best offer the mix of communicating devices to enable the vision of REV in both immediate benefits and as the framework for DER and other more advanced applications. Evidence from large-scale AMI deployments has shown that deliberate deployment plans generate more robust cost-benefit analysis due to expedited delivery of operational benefits. Nevertheless, there are surgical high-value scenarios that can be justified, as an example, due to the utility's ability to isolate and control participants in programs such as Volt-VAR, demand response/management, or scenarios where larger distributed energy resources are integrated into the utility's grid:

- Volt-VAR & IVVC - The practice of optimizing the distribution network using methods such as Volt-VAR has been used by utilities for over 30 years. More recently, Integrated Volt-

VAR control (IVVC) has presented more opportunities for utilities to manage and optimize the distribution grid.

  - The successful implementation of IVVC on a distribution feeder requires the synchronous monitoring and operation of several devices, from load tap changers in the substation to capacitor banks to meters or other smart grid devices that measure secondary voltage at the end of the feeder where voltage will be the lowest. IVVC is a relatively new opportunity in the sense that new smart grid technologies, communications infrastructure, and applications have been developed to manage and operate distribution grid devices in a coordinated fashion through a unifying software platform.
  - Distribution operations need to be able to monitor voltages from the substation (where voltage is the highest) to the end of a feeder (where voltages may be the lowest). Initially, utilities assumed that voltage information from smart meters could provide the voltage information. However, due to the specific requirements of the IVVC application (frequent intervals, near-real-time monitoring), utilities have begun investigating installations of "bellwether" meters at strategic locations along the grid. The Node can actually provide all the information required, along with other benefits such on demand reconfiguration to perform different functions, produce analytics, and capture data at various intervals or be turned on and off.

- Demand Response and Demand Management - In the past few years, demand response has evolved into demand management where load is called upon more often -- both for economic and capacity (reliability) reasons.
  - More than load shedding, demand management is a combination of capacity demand response, economic demand response and constant commissioning for energy efficiency. Companies are not just dropping load when the cost of energy increases – they are also shedding more load for economic reasons as payments to shed have increased. Automation has encouraged new participants into demand management programs since critical operations can continue to process while still shedding load.
- Energy Storage and Distributed Generation - Energy storage and distributed generation technologies are attracting increasing interest from utilities and regulators as localized flexible grid assets.
  - Storage can act as a buffer between electricity supply and demand, increasing the flexibility of the grid and allowing greater accommodation of variable renewable

> resources. Both storage and DG may provide temporary solutions for regional and local capacity shortages, and may provide relief to localized transmission and distribution congestion. But to make distributed generation and storage economically and technologically feasible, new investments controlling devices, understanding load performance, systems integration and grid planning are all required and can only occur through an integrated approach.

Stand-alone interval meters can support some of this but are far less cost-effective. Illinois used them for residential hourly pricing program but is replacing those meters with AMI. In Arizona, Salt River Project and Arizona Public Service used stand-alone TOU meters but replaced them with AMI. Using AMI from the start avoids redundancy and write-offs associated with two-step approach of stand-alone then AMI.

Other Considerations related to AMF

In addition to the above answers, we offer the following considerations for the Commission.

There is an important role for Staff and the Commission to play in moving deployment along. Regulatory rules and processes will need to be streamlined, e.g., as the marketplace changes, it should be easy to incorporate new types of devices and services, especially if behind-the-meter activities become part of the clearinghouse for settlement. Examples could include standards for submetering and whether or not customer revenue-grade meters should interface with the utility. With the expected proliferation of DER devices used for the purpose of revenue grade metering, the product qualification process, test data, interoperability testing etc. will all need to be done in a manner that does not inhibit market development yet supports a single consistent marketplace. As the role of third parties expands, the overall system cannot become a deterrent to DER.

IV. Supplemental DSIP Filing

As stated above, the advanced energy community supports the concept of a Supplemental DSIP filing in that it is designed to ensure coordination and commonality between utilities, but we have no additional specific comments at this time.

Conclusions

The advanced energy community appreciates the opportunity to provide these Initial Comments on the SIP Guidance. The advanced energy community strongly supports the efforts of the Commission in this proceeding and is committed to playing its part to create a high-performing electricity system in New York State. We recognize the complexity of what is being undertaken and look forward to our continued involvement in this proceeding and working with other parties during the reply comment period.