The Utilities of Maryland's Future – An Agenda for Transformation[1]

I. Overview

A. The Fundamental Questions

The electric utility industry is undergoing a fundamental transformation. After a century of large, centralized, capital-intensive, and highly-polluting utility system development, the industry is poised for change. The old model delivered and expanded universal electric service to nearly every part of the United States, and the prices, if the not the costs, have been affordable. Today, the least-cost, most environmentally benign options are renewable and, increasingly, distributed. At the customer level, on-site and community-sited distributed generation that is tailored to customer needs, load management that defeats high peak prices on the demand side of the equation, storage technologies for adding dispatchability to intermittent resources, and innovative rate design that captures the full value of all these resources, are increasingly the economic option in every sense of the word.

The industry is shifting from central-station dominated structure focused on the delivery of least-price commodity electrons into a web of electrical and information connections facilitating transactions to, from, and with customers focused on delivering highest-value services. Even, and especially, where the electric utility continues to provide distribution system services as a monopoly structure, the net economic, environmental, and societal benefits of increased reliance

[1] This whitepaper was prepared in cooperation with Earthjustice on behalf of Maryland Solar United Neighborhoods (MD SUN), Chesapeake Climate Action Network, Fuel Fund of Maryland, and the Institute for Energy and Environmental Research. This whitepaper draws heavily on the work of the NY Department of Public Service Staff Whitepaper on Reforming the Energy Vision (REV). Case 14-M-0101, In the Matter of Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (May 19, 2016). The REV Whitepaper, adopted by NY PSC, forms the foundation for the full range of REV activities now underway at the NY PSC. This paper also draws on similar guidance issued in other states, most notably Hawaii.

on an integrated and diverse portfolio of distributed energy resources justify a thorough reexamination and restructuring of the distribution utility's role and function. Utilities must be empowered, encouraged, and ordered to foster the development of such portfolios.

A "transactive" electricity sector will feature many more interactions between utilities, third party service and technology providers, and customers. The range of products and services will expand as traditional electricity services are unbundled and re-bundled into novel, right-sized, and customer-focused products and services. The traditional top-down production, transmission, and delivery business model will increasingly give way to a mesh-structure of interactions in which utilities and customers are sometimes consumers, sometimes producers, and increasingly both.

In guiding and managing this transformation in Maryland, the Public Service Commission (PSC) has an opportunity and even an obligation to ensure that the resulting system is more economically efficient, more environmentally benign, and more socially equitable. This obligation stems from the duty to ensure that electric rates and services serve the "public interest,"[2] and for the regulator to serve as a substitute for the competitive market forces that would otherwise influence the business and practice of the electric distribution utility.

In undertaking an examination of electric utility transformation, the PSC must ultimately address two fundamental questions among many more subsidiary questions that will arise. These are:

1. What should the role of the distribution utilities be in achieving economic and operational efficiency, equity in services and the impacts associated with utility operations,

[2] Maryland Public Utilities Law § 7-213 – Service Quality and Reliability.

improvement in the environmental performance of the utility sector, and the acceleration in development of markets that deploy distributed energy resources?[3]

2. What changes in regulation and the role of the regulators (rates and tariffs, incentives, standards, planning requirements, and market design) guiding investment, revenues, and profits are appropriate to align utility performance with energy and societal policy objectives?

This paper sets out the many key questions that must be addressed in order to carry out a regulatory agenda of market transformation, many of which are reflected in the Maryland Public Service Commission's Notice of Public Conference 44 in the instant proceeding.[4] Attachment A provides a list of PC 44 Issues indexed to this Whitepaper. There are many questions to be answered, and the issues are interrelated, so while the larger arc of utility transformation has both direction and speed, there will be many feedback loops along the way. Customers, third party service and technology providers, utilities, and other stakeholders must be engaged for a constant stream of honest feedback in order to inform midcourse corrections. Ultimately, the work of the PSC will be evaluated by the range of products and services available in the transformed utility sector, the environmental impacts associated with electric service, and equitable access to clean, affordable, and reliable services of all kinds, across the State of Maryland.

Maryland's work will not be undertaken in a vacuum. An agenda for utility transformation in Maryland builds on a solid foundation of plans, studies, initiatives, pilots, and demonstrations.

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[3] Distributed energy resources (DER) include all technologies and services deployed within the distribution grid that meet the need for energy services. DERs include distributed generation, storage, energy management, demand response, system structures such as microgrids, and other services and technologies. DERs are enabled by rates, incentives, and enabling technologies such as smart grid technology and microgrids.

[4] Public Conference No. 44, Notice of Public Conference (September 26, 2016) (the "PC 44 Notice").

The key tasks of utility transformation are articulation of a vision and desired end-state, the crafting of an ambitious and flexible roadmap for reaching that vision, and a synthesis and integration of a wide range of on-going plans, stakeholder goals, and perspectives. Utility transformation presents another great leadership opportunity for Maryland.

B. Policy Objectives

The PSC should launch its process of utility transformation by adopting these fundamental questions as its own—in addition to the questions posed in the PC 44 Notice—and should provide ongoing visionary guidance in the form of fundamental policy objectives. Adoption of key policy objectives is absolutely essential for ensuring policy congruity as the complex proceeding and multiple ancillary proceedings that will emerge from this transformation process move forward. These policy objectives are:

- Customer empowerment through technology and information (including data) tools that enable more effective management, as individual actors or through third-party market aggregators, of energy services and bills.
- Market animation through the leverage and development power of customer data and spending on energy products and services.
- Equitable access to sustainable energy resources and services for all customers, especially low- and moderate-income customers who have been traditionally underserved in electricity choice and innovation markets.
- Affordability of clean, reliable electric service.
- System-wide economic efficiency.

- Fuel and resource diversity, including a steady transition toward clean and renewable sources of supply.
- System reliability and resiliency.
- Reduction of climate-changing carbon emissions.

C. Alignment with Statewide Energy and Environmental Policies and Plans

It is vital that the PSC ensure that the utility transformation process mesh with statewide energy and environmental plans and policies. These statewide policies provide a powerful driver for and synergistic benefits to the objectives of utility transformation. Key statewide policies and plans in Maryland include:

- Maryland Greenhouse Gas Reduction Act, 2016 and resulting plans
- EmPOWER Maryland utility energy efficiency programs and targets
- Net Energy Metering under Public Utilities Article § 7-306 and COMAR 20.50.10
- Renewable Portfolio Standard Program
- Maryland Community Solar Pilot Program[5]

The PSC should coordinate to ensure that other agencies and elements of state government with responsibility for these policies and plans participate as stakeholders in utility transformation proceedings as appropriate.

[5] COMAR 20.62 (Jun. 14, 2016).

D. Drivers of Change

The electric utility industry in Maryland traditionally has performed reasonably well in delivering affordable and reliable electric services to customers. The landscape is changing, however, posing challenges for utilities and regulators alike, in ensuring the continued reliable, efficient, and affordable delivery of energy services. A brief review of these drivers will serve to set the stage for the important regulatory agenda ahead, and to ultimately inform the evaluation of efforts undertaken to transform the utility industry for the better.

Cost Pressure – System operators and managers work with an aging supply and delivery infrastructure that is increasingly in need of repair, replacement, and enhancement. These maintenance and improvement functions will ultimately result in costs to customers. Minimizing these costs while maximizing the value of investments will require innovations in planning, advanced technologies, animation of markets, mobilization of private capital, and engagement of customers in improving the efficiency of their use of energy services.

Customer Need for Reliable and High-Quality Energy Services – Electrification of households, businesses, and industry has contributed to vast improvements in welfare, productivity, economic growth, and environmental responsibility. Information technologies and ubiquitous computing, and electric vehicles are just two major sectors that will contribute to increased demand for electricity services that are reliable and of the highest reasonable quality.

Climate Change – Reductions in greenhouse gas emissions is the policy of the State of Maryland. Moreover, Maryland’s electric infrastructure and continuity of service are increasingly threatened by increasingly severe climate events. A more climate-resilient infrastructure will be one that features greater reliance on intelligent and islandable distributed energy infrastructure that also contributes to reduce greenhouse gas emissions.

Security – Climate events are not the only threat to grid security. The interconnected electric grid is subject to both physical and cyber threats with significant potential consequences to customers and the state economy. Again, a more resilient and flexible electric grid hosting increasing amounts of distributed energy resources can contribute to improved security.

Revolution in Scale – After many decades of increasing returns to plant scale, in which larger power plants yielded lower electricity prices, the electricity system is now experiencing a reversal—a revolution in scale. As documented in hundreds of studies[6] and demonstration projects, right-sized energy resources offer economic, financial, operating, and engineering benefits in the provision of reliable and affordable electricity services. This revolution is challenging the inherently conservative electric utility industry to not only rethink the technologies deployed, but also the fundamental business model for provision of electricity services.

Energy Market Prices – Increasingly competitive electricity market prices and increased energy market volatility due to increased dependence on natural gas as generation fuel threaten the existing electricity industry. Markets are rendering traditionally solid generation assets uncompetitive. A market-wide rush to currently low-priced natural gas threatens economic and operational security if fuel prices again rise to historical highs. In a world of increasingly economic distributed energy resources, these forces increase the incentive for "economic grid defection," even if not physical separation of customers from the grid.

[6] Lovins, A., Feiler, T., Rábago, K., Datta, K., "Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size," Rocky Mountain Institute (2002).

E. An Agenda for Regulatory Processes

To face these challenges and drive an agenda of utility transformation the Maryland PSC should address several key topics in a group of related regulatory proceedings. While the subject matter of these topics supports focused efforts in separate proceedings, the Commission must be mindful to ensure effective cross-pollination between the efforts in order to ensure that progress is coordinated and efficient. These topics, many of which are already included in the PC 44 Notice, constitute a comprehensive regulatory agenda for a public proceeding and sub-proceedings:

- Technology and system requirements, especially platform technologies.
- Data access, data security, and protection of privacy.
- Market structure and the roles of utilities and other market participants. In addition, transaction models for customer decisions, including both market behaviors and utility tariffs.
- Benefit cost analysis (BCA) and its role in evaluating utility investments, third party offerings, and customer-sited resources.
- Ratemaking incentives, both explicit and implicit.
- Overcoming barriers to and enhancing customer engagement in DER markets, including for low- and moderate-income customers.
- Aligning distributed energy markets and services with wholesale markets, especially in light of recent judicial and federal regulatory decisions.
- Phasing and structuring of implementation of transformation activities.

These topic areas offer an excellent framework for initial and long-term engagement of stakeholders in the transformation process as well. Initially, the Commission should invite stakeholders to self-organize around issues that the Commission identifies. This process will be useful in identifying common ground, priorities, and areas of most significant disagreement. In moving forward, the PSC should create and manage in-depth committee efforts, on topics such as market structure, platform technology, benefit cost analysis, low- and moderate- income access to DER products and services, and value of DER topics.

F. Preparing the Field

The Commission should also map the universe of ancillary, related, and supportive activities already underway or planned in the ordinary course of business at the Commission or with the utilities. These include:

- Demand response programs at the distribution level, and coordination/cooperation with the PJM.
- Performance-based rate incentives, including negative adjustments for failure to meet required service standards.
- Revenue decoupling mechanisms or other adjustments intended to address disincentives for efficiency, distributed generation, or other DER.
- Interconnection standards and procedures for distributed generation.
- Standby rates for partial-requirements customers.
- Time of use or other dynamic pricing rates or pilot programs.
- Gas delivery rates for distributed generators, such as combined heat and power facilities.

- Energy efficiency and demand-side management programs, including electric vehicles (especially in Vehicle-to-Grid configuration).
- Customer-sited clean energy programs integrated into the renewable energy standard.
- Low- and moderate-income customer programs and services.
- Advanced energy technology and "smart grid" research and development programs.
- Green bank, resilience bank, Property-Assessed Clean Energy (PACE) or other financial initiatives aimed at increasing DER deployment.
- Net metering.
- Existing DER-related pilot programs and studies, including:
  - The Community Solar Energy Generating System Program
  - Public Conference 40 – In the Matter of the Investigation into the Technical and Financial Barriers to the Deployment of Small Distributed Energy Resources
  - Public Conference 43 – In the Matter of the Exploration into the Regulatory, Technical and Financial Barriers that Affect the Deployment of Electric Vehicles in the State

Program managers and administrators working in each of these areas should be invited to connect with the utility transformation process as appropriate to avoid unnecessary duplication of effort, and, worse, conflicting regulatory outcomes. The Commission can call upon experience gained in the Community Solar pilot and Public Conferences to guide future stakeholder engagement processes. The final section of this paper sets out a phased plan for a pathway going forward that addresses future pilots and demonstration projects.

II. The Distribution System Platform Provider – the Heart of Utility Transformation

The heart of utility transformation is the transformation of utility distribution companies into platform providers for DER development and deployment. The shift involves a move from a single provider of all electricity services to an enabling mission that includes the traditional role of electricity delivery and system maintenance and operations and adds the functions of load manager, distribution system planner, and enabler of cost-effective deployment of distributed energy resources of all kinds. Fundamental to the role of platform provider is the provision of non-discriminatory access for an enhanced range of products and services, many provided by third-party market participants, to customers connected to the grid.

Design of the new market platform for DER should be guided by fundamental principles. Together, these principles form the backbone for a vision of realized markets operating within the platform structure. These market design principles include, in no particular order:[7]

- Transparency – timely and consistent access to relevant information by market actors, as well as public visibility into market design and performance;
- Uniformity – market rules and technology standards will be uniform statewide to encourage liquidity and participation;
- Customer protection – balance market innovation and participation with customer protections;
- Customer benefit – reduce volatility and system costs and promote bill management and choice;

[7] NY PSC Case No. 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, "Order Adopting Regulatory Policy Framework and Implementation Plan," at pp. 44-45 (Feb. 26, 2015). Available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument

- Equitable access – ensuring that low- and moderate-income customers have a meaningful opportunity to participate in DER markets and obtain clean energy products and services, and not be disadvantaged by their participation;
- Minimize market power – develop DSP procurement tariffs to minimize the potential for market power;
- Large-scale utility-owned renewables versus DERs – determine the role of large-scale utility-owned generation;
- Deploy a diverse portfolio of distributed energy resources – maximize the geographic and resource-type diversity of DERs;
- "Non-wires" or "non-transmission" alternatives – require utilities to evaluate resources like demand response, storage, and other smart grid resources, as part of any assessment of proposed transmission system investments;
- Reliable service – maintain and improve service quality, including reduced frequency and duration of outages;
- Resilient system – enhance system ability to withstand unforeseen shocks—including physical-, climate-, or market-induced—without major detriment to social needs;
- 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;
- 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;

- Fair valuation of benefits and costs – include portfolio-level assessments and societal analysis with credible monitoring and verification;
- Coordination with wholesale markets – align DSP market operations and products with wholesale market operations to reflect full value of services;
- Economic and system efficiency – promote investments and market activity that provide the greatest value to society, with consideration to identified externalities;
- Avoidance or mitigation of emissions – incorporate emission regulations and PSC policy determinations regarding local impacts of distributed generation; and
- Consistency with regulatory objectives and requirements – function within regulatory jurisdiction to the maximum extent possible in order to avoid overlapping regulatory regimes and provide products consistent with any applicable regulatory requirements.

Many of the above principles were also articulated in the "utility of the future" guidance document developed by the Hawaii Public Utilities Commission (PUC) in 2014. The Commission guidance, entitled "Commission's Inclinations on the Future of Hawaii's Electric Utilities: Aligning the Utility Business Model with Customer Interests and Public Policy Goals," recognizes that the electricity system must modernize along three simultaneous tracks. That is, (1) the generation fleet must be transformed to be as efficient and renewable as possible, (2) the transmission and distribution grid must be modernized toward a primary objective of safely and reliably incorporating a significant increase in distributed generation and other distributed energy resources, and (3) utility business models and regulatory regimes must realign incentives and requirements to achieve transformation at least cost and all deliberate speed.[8] Additional guiding

[8] Hawaii Public Utilities Commission, Docket No. 2012-0036, Regarding Integrated Resource Planning. Decision and Order 32052 (April 2014), Attachment A.

principles developed by the Hawaii PUC to better align Hawaii's electric utilities' business models with customers' interests include:

- Large-scale utility-owned renewables versus DERs—determine the role of large-scale utility-owned generation;[9]
- Deploy a diverse portfolio of distributed energy resources—maximize the geographic and resource-type diversity of DERs;[10]
- "Non-wires" or "non-transmission" alternatives—require utilities to evaluate resources like demand response, storage, and other smart grid resources, as part of any assessment of proposed transmission system investments.[11]
- Stakeholder engagement in planning—integrated distribution planning process should include stakeholder participation to maximize DER integration and decrease future transmission and distribution system costs.[12]

Key to the role of distribution system platform provider (DSP) are several key functions, including planning, market enabling, energy efficiency implementation, and deployment of DSP infrastructure.

A. Planning

Planning involves many of the same activities included in integrated resource planning, coupled with systematic localized planning. Essentially, the mission of the DSP plan is to enable the least-cost mix of supply- and demand-side technologies, products, and services configured in

[9] *Id* at p. 18.
[10] *Id* at p. 5.
[11] *Id* at p. 12.
[12] *Id* at p. 14.

the most efficient mix to ensure continued reliable and affordable electric service for all customers. The utilities should be tasked to develop plans consistent with the vision and policy framework established by the Commission.[13] Key questions to be addressed in developing the new DSP plans include:

- How should existing planning functions be changed to advance and accommodate the deployment of cost-effective DER? For example, how can planning processes compare utility self-build and third-party options for meeting capacity, reliability, and service objectives?
- How can new planning processes translate identified system needs into realizable values? For example, how can DER compete to provide lower overall marginal distribution capacity cost value?
- For costs and benefits that today do not lend themselves to reliable monetization, how can risk-based or other approaches reflect and capture potential value? For example, how can planning effectively select between otherwise comparable resource choices where one choice increases equitable access to sustainable energy services or reduces risk of future environmental regulation?
- What planning metrics should be used to compare alternative options for meeting system needs? For example, should cost to ratepayers of energy to serve load be the defining

[13] PEPCO Holdings LLC ("PHI") filed a document entitled "Initial Considerations for Grid Modernization in Maryland" on Jun. 30, 2016. The *Initial Considerations* paper provides useful background information for this proceeding, but fails to fully map a path forward for utility transformation in Maryland.

metric? Or short-run marginal distribution capacity cost? Or should some combination of metrics be adopted along with a weighted scoring system?

- How should system-wide factors such as fuel diversity or system peak demand be incorporated into distribution planning, and what time horizons should govern consideration of resource alternatives? For example, should planning focus on long-term or short-term capacity requirements?
- How will customer control of siting and operations of DER affect planning? For example, should market price signals be the sole determinant, or should targeted incentives (such as for locational value) be developed and implemented?

B. DSP Markets

DSPs will play a key role in creating the market environment in which DER providers and resources can evolve. An ability to comprehensively and dynamically assess costs and benefits of DER options and operations is key to the DSP function of enabling market animation.

DSPs should play a lead role in characterizing and quantifying the benefits and costs associated with DER that are meaningful to the system. DSPs and their planning efforts must also provide transparency with respect to benefits and costs, especially as informed by value relative to the current and changing state of the system. Benefits and costs analysis is key to ultimately defining value of the products and services that can be transacted with the grid.

Any report issued as a result of the Commission's technical conference on the "Technical and Financial Barriers to Deployment of Small Distributed Energy Resources" should be reviewed for lessons that can be applied in setting the utility transformation process and stakeholder engagement going forward.

Utility transformation involves a shift from a cost-of-service mentality for non-core functions and services to a more market-friendly value based analysis of DER options. It is essential to value a wider variety of DERs than simply solar. While solar generation can provide a number of values to the distribution grid, particularly due to its typical coincidence with grid peaks, other dispatchable and responsive technologies can provide many other values including demand response, ancillary services, blackstart, capacity, and reliability. A full survey of the value of different types of DER should be undertaken through the proceeding, including other types of DG, storage, smart grid and intelligent energy management systems, demand response, energy efficiency, and other customer load management programs. Fully and fairly quantifying and reflecting value establishes the economic foundation for a utility world in which customers as well as utilities can be providers and managers of resources that support grid operations and universal electric service.

The following tables provide an initial list of benefits and costs that should be addressed in a BCA framework, and a table of currently monetizable and non-monetized benefits and costs associated with DER.

Table 1: Categories of Benefits and Costs

Categories of Benefits and Costs

Energy Load Reduction	• Energy generation • System losses
Capacity Load Reduction	• Generation capacity • Transmission and distribution capacity
Grid Support Services/Ancillary Services	• Reactive supply and voltage control • Regulation and frequency response • Energy and generator imbalance • Synchronized and supplemental operating reserves • Scheduling, forecasting, and system control and dispatch
Financial Risk	• Fuel price risk/hedge • Market price response
Security Risk	• Reliability and resilience
Transactional Platform	• Advanced Distribution System Management capital and operating expenses
Environmental	• Carbon emissions • Criteria air pollutants • Water • Land
Social	• Resilience of critical facilities • Improved housing stock • Economic development (jobs and tax revenues)
Other	• Administrative costs • Resource diversity and flexibility

Table 2: Monetizable vs. Non-Monetized Benefits and Costs

Monetizable vs. Non-Monetized Benefits and Costs

Monetizable Within Existing Market Structure	Non-Monetized
• Energy and capacity values • Some ancillary service benefits • Operational and capital system impacts • Financial credits or penalties associated with emissions or resource use • Commodity hedging values • Reliability (where a performance-based contract exists) • Tax revenues	• Some ancillary service impacts • Reliability (where performance contracts do not exist) • Resource diversity • Environmental impacts without market pricing mechanisms • Economic development (e.g., job creation, business diversification) • Community development and housing impacts

Several questions must be answered in establishing the BCA framework to accompany utility transformation and the development of DSPs. Key questions include:

- What categories of benefits and costs are relevant, and how can they be defined in ways that are meaningful to distribution planners, third-party providers, and customers?
- What is the appropriate level of analytical granularity for measuring and calculating relevant benefits and costs?
- How should the system be designed to promote rigorous and transparent accounting for benefits and costs, in order to enhance economic efficiency and minimize, as appropriate, free riders and free drivers?
- How will factors such as timing, location, and ownership/operational control impact value of DERs over time? How will valuation methods need to evolve over time?

- Do current risk-based approaches adequately support valuation of currently non-monetizable costs and benefits? Can market-based approaches, such as "willingness to pay" valuation help internalize these values?

Another major category of issues associated with the vision of DSP operations involves anticipating and facilitating the emergence and offering of new DER-based products and services. Several questions surround this new market opportunity:

- What products and services can DER owners/aggregators and the DSP offer, and at what stages of utility transformation will they be offered?
- How can BCA be used to value products and services? What non-quantified attributes should also be reflected in markets?
- To what extent and at what stages of transformation should uniformity be sought in valuing products and services across the DSPs in the state?
- How can the benefits of uniformity and commonality be balanced with the goals of creating flexibility, encouraging innovation, and in product development?
- Although the goal is market-based design and delivery of value-based products and services, what decisions are appropriately made by the regulators?
- How can the utilities develop a transparent process for applying BCA to help DER developers plan their projects and maximize DER deployment for distribution system management?[14]

[14] See also Energy Efficiency discussion in § II.D., below.

Similarly, a number of questions should be addressed relating to pricing of products and services:

- How can a desirable level of uniformity for markets and pricing be achieved among service territories and among neighboring states?
- How can system-wide benefits (including reduced peak demand and generator emissions) be integrated into market prices?
- How should DSPs recover the costs associated with performing platform functions?
- On what basis and to what extent should the Commission differentiate between products/services that can be competitively provided by the market and those that are still better provided by the residual monopoly utility?
- To the extent that the utility provides products or services, should generated revenues be treated differently than tariffed service revenues, and how should such revenues relate to regulatory incentives and earnings adjustment mechanisms?

C. Energy Storage Valuation and Classification

Energy storage must be appropriately classified and valued in this proceeding, but this classification may differ very selectively from the treatment afforded other DERs. A core principle of grid modernization is that grid services should be valued agnostically, or consistently regardless of their source. Energy storage is a vital DER for unlocking grid values related to voltage and frequency regulation, reactive power, blackstart, load flattening and balancing, resiliency, locational values, avoided transmission and distribution capacity costs, and others. These values should be credited to storage solutions through appropriate DSP markets just as distributed generation might be credited. An appropriate BCA process will undertake to quantify how different grid values can be created by different technologies, including storage, and may make distinctions between the types of markets storage may participate in, or the types of values credited to it, on this basis. For example, the environmental benefit of a storage asset should be considered in this context. While there may be carbon emissions avoided due to avoided line loss attributable to storage, storage that imports and exports system mix power would not have the same emissions impact as zero-emissions generation. These and other distinctions between the values attributable to storage as opposed to other DERs should be explored in this proceeding. In general, though, storage as well as all forms of DER that can provide a demonstrable grid service should be considered on an equal playing field in terms of eligibility for DSP markets.

D. *Energy Efficiency Programs and Products*

A key feature of utility transformation and grid modernization is enabling and increasing the deployment and adoption of energy efficiency products and services. Energy efficiency, conservation, demand response, and energy management are all aspects of this opportunity. Maryland has successfully deployed energy efficiency programs under prior electricity service market models and can build on this success to capture even greater energy and monetary savings in the future.

Utility transformation requires a structured transition from existing models to more market-based approaches, and to reduction in public costs of energy efficiency procurement where markets can better perform this function. A successful transition therefore involves two key elements: (1) monitoring and oversight to ensure no or minimal backsliding in improving efficiency of energy use and reductions in cost during the transition from utility-run programs to market-based structures, and (2) thoughtful market segmentation to ensure that the pace of transition is appropriate to the market opportunity, customer awareness, and supply- and value-chain maturity.

Energy efficiency program design and implementation are dynamic processes. This Whitepaper recognizes the Commission is currently reviewing utility programs operating pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008. Maryland Energy Efficiency Advocates submitted comments pointing to opportunities to maintain and improve on the benefits provided to Maryland customers under those programs that are appropriate for inclusion in a broader utility transformation agenda. These recommendations include allowing utilities flexibility to shift funds within residential sub-portfolios, a shift to performance-based incentives in Home Performance with ENERGYSTAR®, incorporation of the ENERGYSTAR Retail Products Platform into appliance programs, and other utility-specific program modifications.

Another major issue to be addressed in ensuring continuous improvement in energy efficiency is the synchronization of cost-effectiveness testing and metrics under existing energy efficiency program delivery approaches with the benefit-cost analysis approaches for resource procurement under transformed electricity markets. In this synchronization effort, it is vital to specifically address the challenges and opportunities as well as the costs and benefits of improved energy efficiency services to low- and moderate-income customer groups.[15]

E. DSP Infrastructure – Management Systems and Communications

The technological systems necessary to support a robust platform function must be flexible, adaptive, and supportive of increased integration of DER. Communications infrastructure must

[15] Maryland PSC Case Nos. 9153-9157, 9362.

be both secure and accessible. The utility will have a natural and understandable tendency to seek maximum security and control of both management infrastructure and communications systems. Indeed, security and reliability are necessary attributes of modern utility distribution systems. However, market participants and customers must have reasonable access to data, operating conditions, costs, and other attributes necessary to inform transactive behaviors and initiatives.

Maryland already has a robust Advanced Metering Infrastructure (AMI) program. The benefits of the AMI program to Maryland ratepayers can be maximized by ensuring that AMI technology enables the utilities' new DSP functionality; innovative rate design, including time-variant pricing (TVP); and third-party DER offerings. AMI meters can also enable third parties to identify opportunities to provide grid support as needed by the DSP, reduce DER interconnection time and cost, and increase distributed generation integration and optimization. In order to monitor the benefits of AMI to Maryland ratepayers, the Commission should develop utility metrics to track the above AMI functionalities, with frequent reporting periods to allow for course-correction as needed.

It is also essential that platform and market design elements inform infrastructure and communications systems deployment, and not the reverse.

Key questions to be addressed in reviewing utility proposed platform technology plans include:

- What investments are necessary, and in what order should they be made, in order to support the utility's load management functions in real time and over the DSP planning horizon?

- What technologies and system capabilities will be required to enable the DSP to model, dispatch, control, and interact with customer-sited DER?
- Can and should the development and deployment of advanced distribution management systems (ADMS) be accomplished in scalable phases?
- What communications functionality and systems are necessary to support the integrated grid and transactive electricity markets?
- How will the DSP protect the cyber security of the distribution system, including interconnected customer-sited DER?

F. Fundamental Regulatory Decisions Regarding the DSP

The first and foremost question that must be addressed regarding utility transformation is whether incumbent distribution utilities should become the entities performing the DSP function. In the wholesale sector, new independent system operators were created in an effort to ensure non-discriminatory access to transmission services and economic dispatch of generation. It has been argued that a similar independent distribution system operator could be created to perform the DSP function.

Allowing and encouraging the incumbent utility to become the DSP implies regulatory oversight to ensure non-discriminatory access to customers by third party providers and aggregators, and to allow customers full and fair access to value for the operation of customer-sited DER. This paper assumes that the PSC will ultimately opt to facilitate the transformation of incumbent distribution utilities into DSPs.

After reaching this key decision, a second fundamental question arises: Whether the incumbent utility transforming into a DSP should be allowed to own or control DER. The lack of well-developed DER markets may countenance both for and against utility participation in those markets; monitoring and incremental approaches may be essential. Over time, the Commission must develop metrics for characterization of emerging market competitiveness, and reexamine the role of the utility/DSP as a participant in those markets. Finally, an additional measure of granularity may be appropriate in overseeing the utility/DSP relating to the specific role it might play in DER markets. The utility could be an owner, an operator, a contracting party, and/or a financer of DER activities. The nature and degree of utility participation in emerging DER markets necessarily implies regulatory development of rules and guidelines, and the performance of a market monitoring function.

A special set of regulatory decisions will also be required relating to microgrids and community grids. The PSC's recent order denying Baltimore Gas and Electric's microgrid demonstration projects called attention to many of the features that optimally designed microgrids must incorporate, including "sophisticated integration of microgrid resources in any smart grid or grid modernization design, partnerships with third parties to provide microgrid services, integration of customer-owned generation, integration of diversified distributed generation with storage, and demand response capabilities."[16] Empowering third parties and customers to provide these types of microgrid solutions will require regulatory clarity. The Commission should evaluate whether current Maryland law allows for third party microgrid developers to own distribution assets or sell power. The Commission should provide clarity to the microgrid development community on the role of private third party microgrid developers, and, at the least, consider utility reforms that would allow third party owners of microgrid assets to make use of the utility's distribution system in order to provide microgrid service under an

[16] Maryland PSC Case No. 9416, Order 87669, at 17.

appropriately designed microgrid tariff. The Commission should evaluate whether changes in current rules, such as those relating to interconnection and standby rates, are necessary to enable microgrid and community grid development. The role of microgrids and community grids in the context of DSP planning must also be clarified. Finally, since microgrids and community grids are, by definition, interconnected to the utility grid for the vast majority of time, the role of microgrids in serving critical loads should be reviewed and potentially addressed in the pricing of utility services.

III. Customer Participation in Utility Transformation

Utility transformation is fundamentally about the adoption of a customer-facing and customer-centric view for the operation and function of the utility system. A customer-facing or customer-centric model focuses on customer value, and is distinguished from a utility-facing or utility-centric view that dominates today's industry and focuses narrowly on utility cost and efficiency, and which addresses customer benefits as a secondary concern. For example, the utility-centric model sees advanced metering infrastructure as a means for reducing meter-reading and billing system costs (including the costs of meter reading and billing errors). A customer-centric view focuses on how the systems can provide customers with usable consumption information, consumption and bill management tools, and data useful in engaging third-party-provided services. Because utility transformation is about animating markets for DER, customers have a vital role to play as users, hosts, and providers of electric services and DER, in ways not imagined when the existing system was designed and built.

The ultimate goal of utility transformation is an increasing array of opportunities for all customers to more efficiently and effectively manage their electricity bills and services, while simultaneously improving system-wide efficiency and environmental performance.

Customer engagement will be an essential part of animating and growing markets for DER. The work of building customer interest and engagement in these markets begins with the Commission's efforts to engage the public in the transformation process itself.

A. Public Engagement in the Utility Transformation Process

An agenda of utility transformation is an ambitious undertaking, rivaling any regulatory effort since the establishment of electric utility services and the current model more than 100 years ago. Even the processes of implementing retail supply choice, open-access transmission, and wholesale competition were relatively simple endeavors compared to what lies ahead in utility transformation agenda.

It is vital, therefore, that the Commission's agenda of utility transformation planning and implementation include an aggressive plan for public engagement from the very start. The Commission and staff should plan for hearings, listening sessions, and feedback processes from the proceeding's inception. Customers should have easily understandable channels for passively and actively engaging, and learning about, the utility transformation process. Feedback to the public should be frequent, honest, respectful, and meaningful. Most importantly, the Commission must craft and communicate a vision of the transformed utility industry and what it can mean for the citizens, communities, and businesses of Maryland.

B. Barriers to Customer Participation

Customer engagement in the utility transformation process and the development of DER markets is essential but not a given. Significant barriers exist that raise serious questions about whether "if you build it, they will come." These barriers include:

- Barriers to demand response

- Barriers to distributed generation
- Customer awareness and confidence
- Access to data
- Non-price economic factors
- Behavioral patterns and issues

A customer engagement strategy designed to address and overcome these barriers is a necessary component of the utility transformation process. Regulators, utilities, third party providers and others each have important roles in identifying, monitoring, and addressing customer engagement issues throughout the transformation process.

Development and delivery of an effective customer engagement strategy depends on addressing a number of questions, including:

- What factors have the greatest impact on customer engagement, and which are most amenable to modification?
- Who should take the lead in addressing factors and barriers—Regulators? Utilities? Market participants?
- How can the active participation of low- and moderate-income customers and rental customers be increased?
- What kinds of economic incentives and signals are most effective in attracting and sustaining customer participation in DER markets?

- How important a factor is customer education in driving customer engagement? Who should take the lead in conducting educational activities, and during which stages of utility transformation is each potential leader most effective?

C. Competitive Retailers

Competitive retailers can play a role in animating DER markets. Retailers can act as aggregators for delivery and acquisition of DER value from customers, leveraging existing customer management systems to expand service and product offerings. Enhanced choice and services could increase customer participation in retail choice markets, as well as create new product and service options for savings, efficiency, and renewable energy integration. The potential role of retail providers in a transformed utility sector raises important questions that should be addressed:

- What rules should govern access to customer data?
- When utilities rely on services provided by competitive retailers, is it necessary that these retailers establish and maintain certain qualifications to provide those services?
- Should utilities be barred from providing commodity supply service in order to create economies of scale for competitive retailers that can be leveraged into more rapid DER market development?
- How can DSP markets, clean energy programs, and financing innovation (e.g. through a green bank) be coordinated to enable competitive retailers to offer optimal products and services?

IV. Wholesale Markets

The jurisdictional, operational, and economic lines between wholesale markets and retail functions may be blurred by the development of DER markets and the emergence of the DSP model. In light of recent judicial decisions, the issues associated with interactions between these market segments are especially important. Questions that should be addressed include:

- What impact do recent Federal judicial and regulatory decisions have on Maryland's efforts to advance DER markets and establish DSPs?[17]
- Do PJM rules impact the ability of utilities to perform DSP functions, such as aggregation?
- Are PJM market participation requirements well-suited to supporting DER market development and growth?
- How should customer control over DERs be addressed in assessing the potential reliability impacts of such resources?

[17] Maryland may have to consider Federal Energy Regulatory Commission (FERC) Order 745 and the Clean Power Plan. FERC Order 745 requires regional transmission operators (RTOs) and independent system operators (ISOs) to pay Locational Marginal Price (LMP), or full market price, for demand response resources if: 1) the resource has the ability to balance supply and demand; and, 2) dispatch of that resource is cost-effective, as determined by a net benefits test outlined by FERC. *See* Public Service Commission of Maryland, Ten-Year Plan (2014-2023) of Electric Companies in Maryland (2014) at p. 49-51, *available at* http://webapp.psc.state.md.us/intranet/Reports/2014%20-%202023%20TYP%20Final.pdf. The Clean Power Plan (CPP) is a series of national standards for power plants and state-specific goals issued by the EPA, aimed at reducing carbon emissions. The State of Maryland may have to comply with CPP mandates, pending judicial review of CPP. *See* U.S. Environmental Protection Agency, Clean Power Plan for Existing Power Plants, https://www.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants.

V. Regulatory Rate and Revenue Reform

The heart of public interest regulation of monopolies granted a franchise to provide an essential service is the approval of rates. During the several years during which utility transformation is underway, and notwithstanding an intentional shift toward increased dependence on markets to set prices, management rates and incentives for utility services is a critical function of the transformation agenda. Rates and performance ratemaking approaches inform investment decisions, third-party offerings, and customer behavior. Utility customers ultimately bear the cost of electric service, and will also face transition costs as markets organize around new DER opportunities, even as greater reliance on DER can ultimately reduce costs for all customers.

Although traditional ratemaking has been modified, traditional principles of ratemaking still apply and will continue to apply under utility transformation. Utilities must have a reasonable opportunity to recover and earn a reasonable return on invested capital. Rates must be fair, cost-based, understandable, efficient, and easy to administer. A new vision of a transactive electric services sector adds complexity to these principles, if only because this vision anticipates an intentional reduction in the monopoly control that distribution utilities will exercise over customer choices and revenues under the DSP model.

A. Incentive and Performance Ratemaking

Rates and charges have never been solely a mechanism for recovering whatever the utility asserts are its costs of service. Allowed rates and charges send signals to consumers and producers—who may be the same entity in a transactive electricity market. Rates and charges must increasingly communicate the value of production and consumption decisions, and not just the price. The stability and predictability of rates and implicit and explicit incentives offered to market actors will be critical elements driving investment and behavioral decisions of all kinds.

A customer must see a long-term compensation opportunity associated with a durable investment that reduces the marginal distribution capacity cost of utility service in a particular location on the grid—or they will forego that investment. If a ground-source heat pump would represent the optimal investment in reducing demand on a particular grid feeder compared to capital investments in capacity improvements on that feeder, rates and incentives should send clear signals in the form of savings and return for that choice. Aggregators and third party service providers must, in turn, see an economic opportunity in developing sufficient customer adoption to offset a significant portion of those capacity investments. And the overall result of the transaction should be reduced pollution, reduced overall costs, improved system reliability and resilience, and, where possible, more jobs and a stronger Maryland economy.

Benefit-cost analysis therefore plays a vital role in ultimately informing rate design for particular services in the transformed utility DER market. Similarly, the overall approach to incentive ratemaking, with an increased reliance on performance incentives, should be based on clear measures for success, transparency, continuous monitoring, and incentives for reductions in costs of all kinds.

1. Experience from Ratemaking Innovation

Maryland is not writing on a blank slate. The Maryland PSC and other regulatory agencies have had a long history of exploration and innovation in rate design and incentive ratemaking.[18]

[18] A 2014 Maryland Public Service Commission report provides an overview of performance-based ratemaking in Maryland. Staff of the Maryland Public Service Commission, Report on Performance Based Ratemaking Principles and Methods for Maryland Electricity Distribution Utilities (July 2014), at p. 25-27.

Experience in Maryland and other states offers some key lessons in overall ratemaking that are applicable in utility transformation. These include:

- Utility rate plans should incorporate long-term and clear indicators of when the utility is spending at adequate levels to invest in and maintain the distribution system in order to avoid the rate shock associated with large catch-up investments. At the same time, indicators are necessary to ensure that utilities are not unnecessarily inflating the rate base with capital expenditures of only minimal additional value to the system.
- Performance metrics need to run for sufficiently long to allow formation of capital and business functions around them. These metrics should also include pre-established triggers for re-evaluation, especially where performance adjustments can be both upward and downward. Performance measures should be evaluated not only for year-to-year impacts, but also for long-term impacts on utility investments and operations.
- Continued monitoring of utility performance, DER markets, customer engagement, and other indicators is essential despite the level of competition and incentives in the marketplace.
- Where penalties are used, revenue adjustments should be sized to send a strong signal for performance to standards, and not just the payment of penalties for non-performance. Commission staff must have access to data and the resources to evaluate performance data for auditing purposes.
- Innovations in performance regulations and incentive structure should be developed through participation among all market providers and stakeholder voices.
- Utilities should enjoy the freedom and ability to make incremental investments that represent modest calculated risks without fear of penalty, in order to encourage

innovation and create a learning environment that will ultimately inform larger investment decisions.

The ways in which utilities will earn revenues will change under utility transformation. While cost-of-service rate regulation remains appropriate for monopoly functions that the utility continues to perform in its role as a DSP, incentive and performance regulation should inform and create incentives for reducing overall costs, increasing the vitality of DER markets, engaging customers, and improving environmental performance, among other objectives.

2. Earnings Adjustment Mechanisms and Market Based Earnings

Two major regulatory rate mechanisms should be evaluated and implemented in order to facilitate the transition of the traditional distribution utility into a DSP. First, adjustments to earnings in the form of incentives should be evaluated in order to encourage utility behavior and investments that facilitate the emergence of DER markets. These incentives should be designed both to mitigate the revenue erosion associated with the introduction of third party and customer-sited DER and to encourage utilities to create an investment and operational environment conducive to advancing cost-effective and environmentally beneficial DER. These earnings adjustment mechanisms must be carefully designed and calibrated, with reference to benefit and cost analysis, to provide sufficient incentives to motivate investments and behaviors at an overall cost that does not dramatically increase customer costs while markets organize around DER opportunities. Moreover, these earnings enhancements should be paid for primarily out of savings in business-as-usual system investments over both the long and short term. For example, where customer-sited generation provides distribution system value greater than the cost of business-as-usual infrastructure investments, incentives to utilities and compensation to customer

DER providers, in sum, should be measured against the avoided investments to ultimately produce net savings to all customers and society.

Second, distribution utilities should be encouraged to explore and develop market-based earnings opportunities of their own that can be generated through performance of their new roles as DSPs. These market-based earnings opportunities should be designed to avoid the improper exercise of market power that incumbent distribution utilities will likely enjoy for some time to come. In addition, the PSC must carefully consider whether market-based earnings come at the expense of competitive opportunities for third party providers and customers themselves. The major risk in the development of market-based earnings opportunities is the replacement of the regulated distribution monopoly with an unregulated monopoly DSP that stifles rather than facilitates competition and DER markets.

One example of the potential for market based earnings arises in the area of customer energy use data. There are likely to remain inherent economies in the utility maintenance of customer usage and billing systems even in a transformed utility environment. At the same time, data concerning customer usage patterns will be valuable for third party DER providers, especially in areas of the grid with growing capacity requirements. The DSP could develop market based products around aggregated and package data sets that could be made available to third party DER providers. Revenues from these data products could help pay to maintain and upgrade customer information systems by creating a revenue stream for the DSP.

In sum, the transition to the DSP business model implies a recognition of the need to maintain revenues necessary to ensure safe and reliable load management for the distribution system while systematically increasing the role that customer and third party DER plays in meeting the overall need for electric service.

3. *Potential Changes in the Ratemaking Paradigm*

Developing a path forward in ratemaking requires that the Commission evaluate a number of important changes in the current ratemaking paradigm. These changes include:

- Extending the term of rate plans to provide revenue certainty to distribution utilities and stable signals to all market participants.
- A shift from cost-based input driven ratemaking to an increasing reliance on profits tied to predetermined outcomes and metrics.
- The appropriate use of one-way incentives that provide only an upside opportunity for enhanced earnings, and two-way incentives that include both incentives and penalties.
- Oversight of DSP planning processes and implementation of incentives for DER adoption and deployment.
- Incentives and enhancements relating to capital and operating expenditures.

4. *Experiences from Other Jurisdictions*

Fortunately for Maryland, other states and countries have already started down the road toward utility transformation. This experience should help Maryland accomplish its objectives more quickly and efficiently. The Commission and stakeholders should particularly track proceedings in the United Kingdom,[19] New York,[20] and California.[21]

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[19] United Kingdom Office of Gas and Electricity Markets, Network Regulation—The RIIO Model, https://www.ofgem.gov.uk/network-regulation-riio-model. *See also*, RIIO: A New Way to Regulate Energy Networks—Final decision (2010), available at https://www.ofgem.gov.uk/ofgem-publications/51870/decision-doc.pdf.

[20] NY Public Service Commission, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Case No. 14-M-0101, http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101&submit=Search.

[21] California Independent System Operator, Distributed Energy Resource Provider. https://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx. *See also*,

5. Questions to Be Addressed Relating to Outcome-Based Regulation

The Commission should consider the following questions in shaping its approach to a shift from cost- and input-based ratemaking toward ratemaking based more on market and policy outcomes:

- What incentives and disincentives are currently embedded in ratemaking, and how should they be modified in order to achieve utility transformation objectives?
- How can ratemaking be revised to encourage an optimal mix of capital investments and operating expenses?
- What specific outcomes of utility transformation merit incentives or penalties?
- What fraction of utility potential earnings should be "at risk" under incentive programs and performance standards?
- What ratemaking approach should be used for investments and expenses during the transition from the status quo to the DSP model?
- How should costs and performance be benchmarked in an incentive ratemaking structure?
- Do incentives have a role to play in removing or mitigating utility bias against distributed generation and other DER that the utility does not own or control?

In considering a transition to longer-term rate plans, the Commission should additionally consider the following questions:

Distributed Energy Resource Provider Resource Checklist (2016). Available at https://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx.

- Are longer term rate plans a preferable way to enable utilities to approach transformation more strategically?
- Is there an optimal length for all utilities' rate plans? Or should rate plan length be determined on a utility-by-utility and case-by-case basis?
- How can long-term rate plans be constructed to ensure that utilities use the term to focus on long-term priorities?
- How should initial rates, such as return on equity, be determined in a long-term, outcome-based ratemaking approach?
- How should long-term rate plans incorporate reopener conditions, exogenous factors, and reconciled pass-thru items? What periodic reporting requirement should be required in long-term rate plans?
- How can long-term rate plans be designed to address utility financial stability and application of accounting standards?
- How long will it take to set the first long-term rate plan?

6. The Opportunity for Improved Cost Functionalization and Differentiated Rates of Return

Two ratemaking changes in particular offer promise for creating an earnings environment conducive to DSP development. First, the Commission should evaluate more granular unbundling in the functionalization of costs and investments. As explained by the Hawaii Public Utilities Commission, unbundled rate structures imply rates that "separate power supply, ancillary services, and energy delivery costs," and that "could more properly account for utilizing different mixes and quantities of various utility services."[22] Second, the Commission should evaluate differentiated rates of return, and incentive earnings, for specific functions performed by the DSP.

Smart metering technology offers an example for understanding these changes. Under traditional utility ratemaking, metering equipment is a classic customer cost, that is, a cost that varies solely in relation to the number of customers served. As a result, meter costs have traditionally been recovered through fixed customer charges. Smart meters and related AMI infrastructure offer an opportunity to reconsider this paradigm.

Smart metering technology performs a number of functions distinct from and additional to simple consumption metering. Smart meters enable demand response, dynamic (time-based) rates, electric vehicle deployment, distributed generation integration, and other functions. The costs associated with many of these functions are more properly allocated to energy and demand categories than the customer charge. The same is true for many grid modernization investments at the distribution edge of the system.

Once grid modernization and platform technology costs are more properly functionalized, the Commission can and should investigate the potential for allowing differentiated rates of return for the various functions.

Rate of return incentives (the premium in return allowed above the cost of capital) are conventionally set to attract capital to the utility investment requirements. Performance

[22] Hawaii Public Utilities Commission, Docket No. 2012-0036, Regarding Integrated Resource Planning. Decision and Order 32052 (April 2014), Attachment A, at p. 25.

ratemaking often offers basis point premium returns on the entire rate base for achieving specific objectives—like meeting energy efficiency targets, for example.

An opportunity for tailored incentives lies in more narrowly and precisely targeting incentive rates of return to the capital expenditures associated with functionalized investments. If the Commission wishes to accelerate the deployment of smart metering infrastructure, or increase investments in electric vehicle charging infrastructure, it can award bonus returns on just those investments. For business-as-usual investments, return incentives may not be necessary or appropriate.

The concept of fully functionalizing investments and ultimately differentiating rates of return may offer an opportunity to create a transition pathway from earnings adjustment mechanisms to market based earnings.

B. Rate Design

Rate design must change to accommodate and fairly treat DER options. As the national experience with net metering has taught, there can be a great deal of dissatisfaction with rates that accomplish only "rough justice." New rate design means taking a fresh look at pricing models and cost allocation in a world of products and services that are bought and sold by utilities or DSPs. As previously discussed, rates send price signals, not just to customers, but also upstream to service providers and sellers. New rate designs must reflect the transactive nature of operations and activities in the transformed utility grid, and be crafted with some precision in order to maximize economic efficiency. Large customer classes with heavily averaged rates will not be adequate to support value-based products and services. Even so, some traditional services and products provided through the monopoly function of the utility will remain tariff and cost-of-service based.

Because a primary role of the DSP is as load manager, orchestrating the operation and dispatch of a wide range of DERs, rates should reflect increasing degrees of temporal, locational, and operational granularity. These refinements, along with explicit accounting for ancillary services provided by DER, suggest a shift to value-based rates in order to allow the DSP to efficiently provide reliability, standby service, and power quality; as well as interact with distributed generators and act as a platform for competitive demand response and load management services.

1. *Affordable and Universal Electric Service*

Even in the context of utility transformation, safe, affordable, and reliable electric service must remain universally available. Ultimately, all customers should be able to participate in DER markets for economic, environmental, and aesthetic value. However, as experience has taught in delivering utility energy efficiency programs, some customers are harder to reach than others. Customer empowerment for some customers cannot be a basis for imposing costs without accompanying benefits on non-participating customers. Again, benefit cost analysis is fundamental to evaluating the impacts of DER market evolution.

The Commission should reexamine the definition of default electric utility service, and examine opportunities to create an environment in default service that evolves to keep pace with emerging DER market opportunities. For example, many regulatory agencies have already decided that default service means metering with advanced metering technology for all customers, and that all customers should have the opportunity to participate in green power choice programs. In the future, every customer may enjoy the right to participate in demand response programs and join a community solar project.

2. Rate Design under the DSP Model

The utility operating as a DSP will be a seller, a conduit for sales, an aggregator, a purchaser, and a conduit for purchases. The DSP will provide services to customer directly and to third party providers acting on behalf of customers. The DSP will manage interactions with the wholesale supply and transmission system, and answer service calls. As described above, DSP technologies will become more multi-functional and recovery mechanisms in rates for investments in platform technologies may require adjustments.

Rate design under utility transformation and in the presence of DER markets will draw on and modify a number of established rate design options such as time- and location-varying rates, striking a balance between fixed and variable charges, decoupling mechanisms, block structures, and others.

Time-varying rates (TVR), for example, can reduce peak demand and electricity consumption, and encourage off-peak charging of electric vehicles. Utilities can test the impact of TVRs on customer behavior through pilot programs, and should consider varying design elements, such as whether to offer an opt-in or opt-out program. A thorough pilot program should test several pricing structures, with a control group, and ensure a large enough sample size for meaningful results. In general, experience from programs across the U.S. demonstrates that TVR programs should be based on a volumetric, not demand, rate, for residential and small commercial customers, who are typically less able to understand and effectively respond to demand charges. If demand charges are used, TVR programs are best designed as opt-out, rather than opt-in, to reduce the likelihood that customers who are unable to respond to the demand-based rate are negatively impacted.

Rates may be optimized in the DSP environment to encourage load factor improvements, the siting and operation of distributed generation, the installation of controls, and the rapid dispatch of DER in response to signaling. Should the Commission decide to allow the utilities to own and operate DER on the customer premises and behind the revenue meter, rate design may require additional modifications, such as compensation for using customer property, shared savings, and provisions relating to islanded operation.

As discussed earlier, the DSP may also develop market based services and products that are offered to customers and aggregators. These could include data services, DER condition sensing, billing and collection/payment, dispatching, and others. While the growth in competitive service and product offering is an exciting potential aspect of utility transformation, it again raises the issue of ensuring that allocation of costs, and credits, to rates for basic utility services is fair to all customers, especially to low- and moderate-income customers.

3. Standby Rates

Standby rates are typically applied to customers that primarily self-generate, but on occasion must call upon the local utility for service. Along with net metering rates, standby rates bear reexamination in the utility transformation process to inform new thinking about the role of standby customers as both producers and consumers of electricity.

Historically, electric rates have been tilted in favor of all-requirements customers in order to increase the sales volume over which fixed costs could be spread. This is a legacy of the idea that the electric utility industry was one in which costs declined with power plant and infrastructure scale. With the arrival of manufacturing economies of scale and recognition of the operational, engineering, financial, and economic benefits of right-sized energy resources, the time is right to consider a value-based approach to setting standby rates.

Standby rates should ideally reflect the standby customer's actual contribution to system costs as well as their opportunity to contribute to reducing those costs through tailored operating cycles. Rather than trying to establish a single rate for an almost infinite number of operational contingencies, standby rates can incorporate incentives and penalties for operational deviations from planned operating schedules—such as incentives for demonstrated and responsive load shedding. Standby rates could be modified to incorporate incentives or requirements for the installation of load-limiting hardware, or of control equipment that allows the utility to align customer operations with real-time system conditions.

As utility experience with what is likely to be a growing population of standby generation improves, the utility should explore rates based on system-wide conditions, recognizing that with increased generation diversity, the risk of total failure of all generating units diminishes significantly. And as reliance on distributed generation increases, utilities should explore the development of rates for ancillary services, reliability, storage, and other services that might be more cost-effectively provided by the DSP.

Distributed generators may also serve as the prime mover for islandable microgrids. An islandable microgrid represents a unique block of customers to the utility in terms of assessing standby rates. The coincident demand between these customers may be substantially lower than the aggregate of individual contract demand levels, and so setting contract demand charges based on individual peaks may overestimate the cost of serving these customers. Microgrid customers are also unique in that they engage in demand management, can balance load and generation internally, and even appear to the utility as a single load under certain circumstances. Allowing microgrid customers to adjust contract demand levels in standby rates to account for their unique design and capabilities may better align cost causation to the utility. Poorly designed standby rates applied to these generators could accelerate economic defection from a wide range of utility services and exacerbate cost-shifting concerns.

4. Rate Design Questions

Rate design is a complex process under the status quo; it will become much more complicated on the road to utility transformation. Addressing a number of key issues as part of the Grid of the Future proceeding will help frame the vital issues. While rate design details could be left for a later stage in the transformation process, it is important to begin the process of consideration and stakeholder engagement early in order to reveal crucial issues. Some of the questions that the Commission should consider include:

- How is DER market development and participation impacted by customer incentives and disincentives? How are these impacts expected to evolve over time and as markets mature?
- How can tariffs reflect value? How do tariffs monetize system benefits, risk, and externalities?
- What are the most promising rate design innovations to advance public policy objectives—for example, shifts to greater reliance on volumetric rates, critical peak pricing, load factor-based rates, new approaches to decoupling such as the Value of Solar Tariff design?
- How does rate design impact inter- and intra-class equity? How much rate design change to ensure equity as DER markets emerge?
- How does rate design change to accommodate the increasing diversity in service levels, products, and other relationships that will characterize the transactive grid?

- What lessons can be learned from reexamination of standby rates? How can these rates be modified to support the development of high value distributed generation, including renewable energy generation?
- What rate design modification are appropriate to support the development of microgrids?

VI. Steps in a Pathway Forward

Utility transformation will be a complex process built on top of an already rapidly changing industry. One of the benefits that Maryland enjoys is the opportunity to learn from other states that have already started down the road. Many dozens of stakeholders must make substantial investments of time and effort into the processes established and overseen by the Commission. Utilities will accrue and pass along to customers significant costs relating to procedural engagement, regulatory affairs support, analysis, pilot and demonstration program design and execution, and rate making. In order to maximize the value of these investments, the Commission should attempt to map its regulatory utility transformation processes well in advance of execution.

Step 0. Establish a roadmap, settle on general policy goals, and mobilize public participation. Showing stakeholders how the proceeding will be structured will help stakeholders contribute constructively at each stage, understanding how each step relates to the whole. Moreover, agreeing upon at least an initial roadmap will improve management of staff resources.

Step 1. Benefit Cost Analysis. The Commission should articulate what benefits and costs will be captured and created in the transformed utility business model. This vital first step of establishing the benefit-cost analysis framework is not just about identifying categories. It also includes settling on preliminary methodologies, and scheduling future processes to adjust and refine estimation methodologies. The BCA categories set out in Tables 1 and 2 are a good starting point. For each category, the Commission should determine, based on what is reliably knowable and measurable now, how to measure the values, what cost tests and evaluation perspective should be applied for each, the relevant discount rates for long-lived impacts, and other factors. Stakeholders, including relevant DER developers, should be engaged during this process to inform discussions of the technical potential of emerging technologies, as well as market impacts from proposed valuation methodologies. This first BCA step informs the rest of the utility transformation process.

Step 2. Vision. Decide what kinds of markets and/or which new or modified rates will be established to capture BCA values. This step should start by describing, for the benefit of both planning and public engagement purposes, an idealized end state—a vision of the ultimate utility service and market model. This market vision should suggest and inform: (a) what specific functions distribution technologies can perform; (b) what kind of information market participants (customers and their agents/aggregators) will need from the utility to respond to a market signal; and (c) what the customer engagement environment will look like in the end state.

Step 3. Interaction of utility and DSP functions. This stage of the process focuses on how utility functions will inform the function of the DSP. Utilities will use planning informed by BCA to help craft markets for non-wires alternatives, customer-driven load management and distributed generation, and other alternatives to utility self-build options. The utilities should be required to produce detailed filings on how they will drive and accelerate the formation of ultimately self-sustaining markets for DER. The BCA framework from Step 1 will enable the utility to develop example cases of how DER value compares to traditional approaches, and could be tested through demonstration processes initiated in parallel to the plan development process. The market vision from Step 2 will help the utilities plan around what kinds of outputs they must deliver to allow markets to respond.

Step 4. Identify the DSP. The Commission should determine which entity will perform the DSP functions, which functions will be assigned to markets, and which will be utility functions. In addressing this step, the Commission decision will be guided by previous steps, and, importantly by an estimation of whether operations and outcomes oversight will be practical and reasonably subject to objective evaluation.

Step 5. Pilots and Demonstration Projects. Once essential tools are in place to assess DER value and compare that value to the old way of doing things, and the Commission has settled on preliminary ideas for how to build markets and who should operate them, the time is right to ask utilities and stakeholders to propose some new market pilots and demonstration projects to test and refine the concepts. Timing pilots and demonstration projects for this stage is superior to using these resource-intensive projects solely for exploratory purposes, or to test/confirm hypotheses that do not necessarily serve the broader policy agenda.

Step 6. Plan Required DSP Infrastructure. The DSP may require significant investments in advanced metering, sensors, software and information management systems, as well as targeted utility-owned DER and grid upgrades to facilitate customer-sided DER. The market design principles developed through the previous steps in this process should inform infrastructure and communications systems deployment, and not the reverse. It is appropriate to focus on these investments at this juncture.

Step 7. Incentives and Market-Based Earnings. A key element of rate design in utility transformation is the movement toward an increasingly performance- and market-based earnings environment for utilities and DSPs. Once the Commission understands what DER are worth

(BCA analysis) and what needs to get built and how to build it (vision, pilots, demonstrations, DSP infrastructure), that is the time for the Commission to commit to an earnings framework against which utilities can propose earnings adjustment mechanisms, incentives and, over time, market-based earnings opportunities.

Parallel Tracks. An active agenda for utility transformation is a complex and essential undertaking. As that agenda is developed and implemented, the Commission should monitor, or if necessary, initiate parallel proceedings with a view toward ultimately integrating these efforts into the broader utility transformation agenda. The scope and objectives of these proceedings follows from the completion of Step 2 – Vision, described above. Topics that must be addressed and that may be suitable for treatment in parallel proceedings include:

- Public engagement and education plans. Utility transformation promises to change the fundamental relationship between customers and one of the most essential services available in modern society. Experience with efforts at developing retail choice electric markets and in pilots and demonstrations across the country shows that "if you build it," they may not come. Customers have busy lives and engaging them in the opportunities presented by a transformed utility sector is essential. Moreover, engagement and education must be targeted and affirmative—the goals will not be accomplished simply through passive public hearings and listening sessions.
- Community and shared distributed energy resources rules, pilots, products, and services. The Commission has established a solid foundation for community solar development in its rules. In the context of utility transformation, a shared services proceeding would revisit those rules, and substantially expand the horizons of inquiry to address other shared resources, customer aggregation procedures and rules, community choice

aggregation, and the rules of engagement for service, product, and facility providers serving multiple customers.

- Equitable access to sustainable energy and overcoming barriers to low- and moderate-income customer participation in transformed electricity service markets are issued that must be integrated into the utility transformation agenda and at the same time addressed in a parallel proceeding where the Commission and stakeholders can engage in focused attention on the special issues impacting these customers. A politically realistic approach will recognize that low- and moderate-income customers are today underserved by electricity market innovation in products and services. Unlike retail access initiatives in the past, the Utilities of Maryland's Future and the markets operating around them must engage with and benefit these customer groups.

VII. Conclusion

A great deal of important work lies before the Commission and the public in launching and carrying out a meaningful agenda of utility transformation. Properly orchestrated, every step of the process can yield incremental benefits. These benefits include tariff and rate design improvements, improved public and customer engagement, improved equity in access to clean energy products and services, especially for low- and moderate-income customers, and an improved investment climate for both utilities and third party market entrants.

In moving forward, the Commission should consider the path of issuing two major orders, in sequence. First, the Commission should address fundamental structural issues, such as its vision for the DSP and the role of incumbent utilities in that vision. Second, the Commission should set the parameters for the provision of products and services under the new paradigm. These two major aspects of the effort should be coordinated with ancillary and supportive processes to address cost-benefit analysis, establish value-based compensation rates for DER, and map distribution system technology investment and deployment.

The Commission and the State of Maryland will be in good company, continuing Maryland's role as a leader, and joining a few others undertaking a comprehensive, proactive, and balanced approach to utility transformation.

Attachment A – PC 44 Issues Indexed to White Paper Sections

PC 44 ISSUE	WHITE PAPER SECTION
Rate Design – 1. Exploring time-varying rates for traditional electric service, DERs and EVs 2. Considering pilot programs for driving desired results through performance-based compensation	1. Section V(B)(2) 2. Section V(A)
Benefits and Costs of DERs – 1. Calculating MD-specific benefits and costs of solar 2. Other DERs?	1. Section II(B) 2. Section II(B)
AMI – Maximizing AMI's benefits for MD ratepayers	Section II(E); Section III
Energy Storage – 1. Classifying storage properly in Commission rules and policies 2. Valuing it appropriately as a distribution or customer-sited resource	1. Section II(C) 2. Section II(C)
Interconnection Process – Implementing rules and policies to promote competitive, efficient and predictable DER markets that maximize customers' choices	Section I(F); Section II(F)
Distribution System Planning – 1. Ensuring that utilities' distribution systems have the capability to handle increased DER penetration 2. Evaluating the appropriate level of utility investment in distribution assets	1. Section II(A) and (E) 2. Section II(E) and Section V(A)(1)
Limited-Income Marylanders – Assessing the effects of the evolving electric distribution system on Marylanders with limited means	Section I(B) and Section II
June 30, 2016 Pepco Holdings, Inc. Filing	*See* Pace Review of PHI Initial Considerations