



# 1                   **The Utilities of Maryland’s Future – An Agenda for Transformation**<sup>1</sup>

## 2    ***I. Overview***

### 3        ***A. The Fundamental Questions***

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

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

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<sup>1</sup> 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.

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

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

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

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

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

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<sup>2</sup> Maryland Public Utilities Law § 7-213 – Service Quality and Reliability.

1 improvement in the environmental performance of the utility sector, and the acceleration  
2 in development of markets that deploy distributed energy resources?<sup>3</sup>

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

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

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

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<sup>3</sup> 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.

<sup>4</sup> Public Conference No. 44, Notice of Public Conference (September 26, 2016) (the “PC 44 Notice”).

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

5 *B. Policy Objectives*

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

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

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

5 *C. Alignment with Statewide Energy and Environmental Policies and Plans*

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

- 10 • Maryland Greenhouse Gas Reduction Act, 2016 and resulting plans
- 11 • EmPOWER Maryland utility energy efficiency programs and targets
- 12 • Net Energy Metering under Public Utilities Article § 7-306 and COMAR 20.50.10
- 13 • Renewable Portfolio Standard Program
- 14 • Maryland Community Solar Pilot Program<sup>5</sup>

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

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<sup>5</sup> COMAR 20.62 (Jun. 14, 2016).

1        *D. Drivers of Change*

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

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

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

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

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

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

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

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<sup>6</sup> 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).



1        *E. An Agenda for Regulatory Processes*

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

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

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

8        *F. Preparing the Field*

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

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

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

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

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

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

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

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

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<sup>7</sup> 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>

- 1 • Equitable access – ensuring that low- and moderate-income customers have a meaningful  
2 opportunity to participate in DER markets and obtain clean energy products and services,  
3 and not be disadvantaged by their participation;
- 4 • Minimize market power – develop DSP procurement tariffs to minimize the potential for  
5 market power;
- 6 • Large-scale utility-owned renewables versus DERs – determine the role of large-scale  
7 utility-owned generation;
- 8 • Deploy a diverse portfolio of distributed energy resources – maximize the geographic and  
9 resource-type diversity of DERs;
- 10 • “Non-wires” or “non-transmission” alternatives – require utilities to evaluate resources  
11 like demand response, storage, and other smart grid resources, as part of any assessment  
12 of proposed transmission system investments;
- 13 • Reliable service – maintain and improve service quality, including reduced frequency and  
14 duration of outages;
- 15 • Resilient system – enhance system ability to withstand unforeseen shocks—including  
16 physical-, climate-, or market-induced—without major detriment to social needs;
- 17 • Fair and open competition – design “level playing field” incentives and access policies to  
18 promote fair and open competition;
- 19 • Minimum barriers to entry – reduce data, physical, financial, and regulatory barriers to  
20 participation;
- 21 • Flexibility, diversity of choice, and innovation – promote diverse product and program  
22 options in a competitive market including financing mechanisms to increase the value of  
23 those options;

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

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

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

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

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

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

16 *A. Planning*

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

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<sup>9</sup> *Id* at p. 18.

<sup>10</sup> *Id* at p. 5.

<sup>11</sup> *Id* at p. 12.

<sup>12</sup> *Id* at p. 14.

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

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

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<sup>13</sup> 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.



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

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

#### 10 *B. DSP Markets*

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

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

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

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

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

1 *Table 1: Categories of Benefits and Costs*

**Categories of Benefits and Costs**

<b>Energy Load Reduction</b>	<ul style="list-style-type: none"> <li>• Energy generation</li> <li>• System losses</li> </ul>
<b>Capacity Load Reduction</b>	<ul style="list-style-type: none"> <li>• Generation capacity</li> <li>• Transmission and distribution capacity</li> </ul>
<b>Grid Support Services/Ancillary Services</b>	<ul style="list-style-type: none"> <li>• Reactive supply and voltage control</li> <li>• Regulation and frequency response</li> <li>• Energy and generator imbalance</li> <li>• Synchronized and supplemental operating reserves</li> <li>• Scheduling, forecasting, and system control and dispatch</li> </ul>
<b>Financial Risk</b>	<ul style="list-style-type: none"> <li>• Fuel price risk/hedge</li> <li>• Market price response</li> </ul>
<b>Security Risk</b>	<ul style="list-style-type: none"> <li>• Reliability and resilience</li> </ul>
<b>Transactional Platform</b>	<ul style="list-style-type: none"> <li>• Advanced Distribution System Management capital and operating expenses</li> </ul>
<b>Environmental</b>	<ul style="list-style-type: none"> <li>• Carbon emissions</li> <li>• Criteria air pollutants</li> <li>• Water</li> <li>• Land</li> </ul>
<b>Social</b>	<ul style="list-style-type: none"> <li>• Resilience of critical facilities</li> <li>• Improved housing stock</li> <li>• Economic development (jobs and tax revenues)</li> </ul>
<b>Other</b>	<ul style="list-style-type: none"> <li>• Administrative costs</li> <li>• Resource diversity and flexibility</li> </ul>

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3

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

**Monetizable vs. Non-Monetized Benefits and Costs**

Monetizable Within Existing Market Structure	Non-Monetized
<ul style="list-style-type: none"> <li>• Energy and capacity values</li> <li>• Some ancillary service benefits</li> <li>• Operational and capital system impacts</li> <li>• Financial credits or penalties associated with emissions or resource use</li> <li>• Commodity hedging values</li> <li>• Reliability (where a performance-based contract exists)</li> <li>• Tax revenues</li> </ul>	<ul style="list-style-type: none"> <li>• Some ancillary service impacts</li> <li>• Reliability (where performance contracts do not exist)</li> <li>• Resource diversity</li> <li>• Environmental impacts without market pricing mechanisms</li> <li>• Economic development (e.g., job creation, business diversification)</li> <li>• Community development and housing impacts</li> </ul>

2

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

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

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

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

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

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<sup>14</sup> See also Energy Efficiency discussion in § II.D., below.

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

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

#### 14 *C. Energy Storage Valuation and Classification*

15 Energy storage must be appropriately classified and valued in this proceeding, but this  
16 classification may differ very selectively from the treatment afforded other DERs. A core  
17 principle of grid modernization is that grid services should be valued agnostically, or consistently  
18 regardless of their source. Energy storage is a vital DER for unlocking grid values related to  
19 voltage and frequency regulation, reactive power, blackstart, load flattening and balancing,  
20 resiliency, locational values, avoided transmission and distribution capacity costs, and others.  
21 These values should be credited to storage solutions through appropriate DSP markets just as  
22 distributed generation might be credited. An appropriate BCA process will undertake to quantify

1 how different grid values can be created by different technologies, including storage, and may  
2 make distinctions between the types of markets storage may participate in, or the types of values  
3 credited to it, on this basis. For example, the environmental benefit of a storage asset should be  
4 considered in this context. While there may be carbon emissions avoided due to avoided line loss  
5 attributable to storage, storage that imports and exports system mix power would not have the  
6 same emissions impact as zero-emissions generation. These and other distinctions between the  
7 values attributable to storage as opposed to other DERs should be explored in this proceeding. In  
8 general, though, storage as well as all forms of DER that can provide a demonstrable grid service  
9 should be considered on an equal playing field in terms of eligibility for DSP markets.

10 *D. Energy Efficiency Programs and Products*

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

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

1 transition is appropriate to the market opportunity, customer awareness, and supply- and value-  
2 chain maturity.

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

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

19 *E. DSP Infrastructure – Management Systems and Communications*

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

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<sup>15</sup> Maryland PSC Case Nos. 9153-9157, 9362.



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

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

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

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

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

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

9 *F. Fundamental Regulatory Decisions Regarding the DSP*

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

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

21 After reaching this key decision, a second fundamental question arises: Whether the  
22 incumbent utility transforming into a DSP should be allowed to own or control DER. The lack of

1 well-developed DER markets may countenance both for and against utility participation in those  
2 markets; monitoring and incremental approaches may be essential. Over time, the Commission  
3 must develop metrics for characterization of emerging market competitiveness, and reexamine  
4 the role of the utility/DSP as a participant in those markets. Finally, an additional measure of  
5 granularity may be appropriate in overseeing the utility/DSP relating to the specific role it might  
6 play in DER markets. The utility could be an owner, an operator, a contracting party, and/or a  
7 financier of DER activities. The nature and degree of utility participation in emerging DER  
8 markets necessarily implies regulatory development of rules and guidelines, and the performance  
9 of a market monitoring function.

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

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<sup>16</sup> Maryland PSC Case No. 9416, Order 87669, at 17.

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

### 8 ***III. Customer Participation in Utility Transformation***

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

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

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

4 *A. Public Engagement in the Utility Transformation Process*

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

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

18 *B. Barriers to Customer Participation*

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

- 22 • Barriers to demand response

- 1 • Barriers to distributed generation
- 2 • Customer awareness and confidence
- 3 • Access to data
- 4 • Non-price economic factors
- 5 • Behavioral patterns and issues

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

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

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

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

#### 4 *C. Competitive Retailers*

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

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

1        ***IV. Wholesale Markets***

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

- 6        • What impact do recent Federal judicial and regulatory decisions have on Maryland’s  
7        efforts to advance DER markets and establish DSPs?<sup>17</sup>
- 8        • Do PJM rules impact the ability of utilities to perform DSP functions, such as  
9        aggregation?
- 10       • Are PJM market participation requirements well-suited to supporting DER market  
11       development and growth?
- 12       • How should customer control over DERs be addressed in assessing the potential  
13       reliability impacts of such resources?

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<sup>17</sup> 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>.



1        ***V. Regulatory Rate and Revenue Reform***

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

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

18        ***A. Incentive and Performance Ratemaking***

19        Rates and charges have never been solely a mechanism for recovering whatever the utility  
20 asserts are its costs of service. Allowed rates and charges send signals to consumers and  
21 producers—who may be the same entity in a transactive electricity market. Rates and charges  
22 must increasingly communicate the value of production and consumption decisions, and not just

1 the price. The stability and predictability of rates and implicit and explicit incentives offered to  
2 market actors will be critical elements driving investment and behavioral decisions of all kinds.

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

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

### 18 *1. Experience from Ratemaking Innovation*

19 Maryland is not writing on a blank slate. The Maryland PSC and other regulatory agencies  
20 have had a long history of exploration and innovation in rate design and incentive ratemaking.<sup>18</sup>

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<sup>18</sup> 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.

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

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

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

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

8 *2. Earnings Adjustment Mechanisms and Market Based Earnings*

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

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

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

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

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

1                   3. *Potential Changes in the Ratemaking Paradigm*

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

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

13                   4. *Experiences from Other Jurisdictions*

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

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<sup>19</sup> 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>.

<sup>20</sup> 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>.

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

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

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

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

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

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

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

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

17 Two ratemaking changes in particular offer promise for creating an earnings environment  
18 conducive to DSP development. First, the Commission should evaluate more granular  
19 unbundling in the functionalization of costs and investments. As explained by the Hawaii Public  
20 Utilities Commission, unbundled rate structures imply rates that “separate power supply,  
21 ancillary services, and energy delivery costs,” and that “could more properly account for



1 utilizing different mixes and quantities of various utility services.”<sup>22</sup> Second, the Commission  
2 should evaluate differentiated rates of return, and incentive earnings, for specific functions  
3 performed by the DSP.

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

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

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

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

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

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

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

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

## 12 *B. Rate Design*

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

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

8                    *1. Affordable and Universal Electric Service*

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

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

1        2. *Rate Design under the DSP Model*

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

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

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

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

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

### 13 *3. Standby Rates*

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

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

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

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

15 Distributed generators may also serve as the prime mover for islandable microgrids. An  
16 islandable microgrid represents a unique block of customers to the utility in terms of assessing  
17 standby rates. The coincident demand between these customers may be substantially lower than  
18 the aggregate of individual contract demand levels, and so setting contract demand charges based  
19 on individual peaks may overestimate the cost of serving these customers. Microgrid customers  
20 are also unique in that they engage in demand management, can balance load and generation  
21 internally, and even appear to the utility as a single load under certain circumstances. Allowing  
22 microgrid customers to adjust contract demand levels in standby rates to account for their unique  
23 design and capabilities may better align cost causation to the utility. Poorly designed standby

1 rates applied to these generators could accelerate economic defection from a wide range of utility  
2 services and exacerbate cost-shifting concerns.

#### 3 *4. Rate Design Questions*

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

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

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

5 ***VI. Steps in a Pathway Forward***

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

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

19 Step 1. Benefit Cost Analysis. The Commission should articulate what benefits and costs will  
20 be captured and created in the transformed utility business model. This vital first step of  
21 establishing the benefit-cost analysis framework is not just about identifying categories. It also  
22 includes settling on preliminary methodologies, and scheduling future processes to adjust and  
23 refine estimation methodologies. The BCA categories set out in Tables 1 and 2 are a good



1 starting point. For each category, the Commission should determine, based on what is reliably  
2 knowable and measurable now, how to measure the values, what cost tests and evaluation  
3 perspective should be applied for each, the relevant discount rates for long-lived impacts, and  
4 other factors. Stakeholders, including relevant DER developers, should be engaged during this  
5 process to inform discussions of the technical potential of emerging technologies, as well as  
6 market impacts from proposed valuation methodologies. This first BCA step informs the rest of  
7 the utility transformation process.

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

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

1 process. The market vision from Step 2 will help the utilities plan around what kinds of outputs  
2 they must deliver to allow markets to respond.

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

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

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

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

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

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

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

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

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

## 12 ***VII. Conclusion***

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

19 In moving forward, the Commission should consider the path of issuing two major orders, in  
20 sequence. First, the Commission should address fundamental structural issues, such as its vision  
21 for the DSP and the role of incumbent utilities in that vision. Second, the Commission should set  
22 the parameters for the provision of products and services under the new paradigm. These two  
23 major aspects of the effort should be coordinated with ancillary and supportive processes to

1 address cost-benefit analysis, establish value-based compensation rates for DER, and map  
2 distribution system technology investment and deployment.

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

6

1 Attachment A – PC 44 Issues Indexed to White Paper Sections

<b>PC 44 ISSUE</b>	<b>WHITE PAPER SECTION</b>
<p><b>Rate Design –</b></p> <ol style="list-style-type: none"> <li>1. Exploring time-varying rates for traditional electric service, DERs and EVs</li> <li>2. Considering pilot programs for driving desired results through performance-based compensation</li> </ol>	<ol style="list-style-type: none"> <li>1. Section V(B)(2)</li> <li>2. Section V(A)</li> </ol>
<p><b>Benefits and Costs of DERs –</b></p> <ol style="list-style-type: none"> <li>1. Calculating MD-specific benefits and costs of solar</li> <li>2. Other DERs?</li> </ol>	<ol style="list-style-type: none"> <li>1. Section II(B)</li> <li>2. Section II(B)</li> </ol>
<p><b>AMI –</b></p> <p>Maximizing AMI’s benefits for MD ratepayers</p>	<p>Section II(E); Section III</p>
<p><b>Energy Storage –</b></p> <ol style="list-style-type: none"> <li>1. Classifying storage properly in Commission rules and policies</li> <li>2. Valuing it appropriately as a distribution or customer-sited resource</li> </ol>	<ol style="list-style-type: none"> <li>1. Section II(C)</li> <li>2. Section II(C)</li> </ol>
<p><b>Interconnection Process –</b></p> <p>Implementing rules and policies to promote competitive, efficient and predictable DER markets that maximize customers’ choices</p>	<p>Section I(F); Section II(F)</p>
<p><b>Distribution System Planning –</b></p> <ol style="list-style-type: none"> <li>1. Ensuring that utilities’ distribution systems have the capability to handle increased DER penetration</li> <li>2. Evaluating the appropriate level of utility investment in distribution assets</li> </ol>	<ol style="list-style-type: none"> <li>1. Section II(A) and (E)</li> <li>2. Section II(E) and Section V(A)(1)</li> </ol>
<p><b>Limited-Income Marylanders –</b></p> <p>Assessing the effects of the evolving electric distribution system on Marylanders with limited means</p>	<p>Section I(B) and Section II</p>
<p><b>June 30, 2016 Pepco Holdings, Inc. Filing</b></p>	<p>See Pace Review of PHI Initial Considerations</p>