BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

-------In the Matter of-------	)	
	)	
PUBLIC UTILITIES COMMISSION	)	DOCKET NO. 2014-0183
	)	
Instituting a Proceeding to	)	
Review the Power Supply	)	
Improvement Plans for Hawaiian	)	
Electric Company, Inc., Hawaii	)	
Electric Light Company, Inc., and	)	
Maui Electric Company, Limited.	)	
	)	

DECISION AND ORDER NO. 34696

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PUBLIC UTILITIES COMMISSION	)	Docket No. 2014-0183
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Instituting a Proceeding to Review the Power Supply Improvement Plans for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited.	)	Order No. 34696

DECISION AND ORDER

By this Decision and Order, and subject to the conditions set forth herein, the State of Hawaii Public Utilities Commission ("commission") accepts the Hawaiian Electric Companies' PSIPs Update Report ("Report"),[1] provides guidance regarding implementation and future planning activities, and closes this docket.[2]

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[1]"The Hawaiian Electric Companies' PSIPs Update Report, Filed December 23, 2016, Books 1-4," filed on December 23, 2016 in the instant docket.

[2]The Parties to this docket are: (1) Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO"), (collectively, the "HECO Companies" or the "Companies"); (2) the Consumer Advocate, an ex officio party to this proceeding, pursuant to Hawaii Revised Statutes ("HRS") § 269-51 and Hawaii Administrative Rules ("HAR") § 6-61-62(a); the Intervenors, pursuant to

I.

INTRODUCTION

On August 7, 2014, the commission instituted this proceeding to review the power supply improvement plans ("PSIPs") filed by Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO") (collectively, the "HECO Companies" or "Companies"). By this order, the commission accepts the Report and provides guidance for implementing the near-term actions identified in the PSIPs.

The Companies' near-term action plans and long-range analysis provide useful context for evaluating pending and future operational decisions and resource acquisition alternatives.

Order No. 33320 at 175: (3) the County of Maui ("COM"); (4) the Department of Business, Economic Development, and Tourism ("DBEDT"); and (5) the County of Hawai'i ("COH"); the Participants, pursuant to Order No. 33320 at 175: (6) Renewable Energy Action Coalition of Hawaii, Inc. ("REACH"); (7) Life of the Land ("LOL"); (8) Hawaii Solar Energy Association ("HSEA"); (9) Puna Pono Alliance ("Puna Pono"); (10) The Alliance for Solar Choice ("TASC"); (11) Hawaii Renewable Energy Alliance ("HREA"); (12) The Gas Company, LLC, dba Hawaii Gas ("Hawaii Gas"); (13) AES Hawaii, Inc. ("AES"); (14) Blue Planet Foundation ("Blue Planet"); (15) Ulupono Initiative LLC ("Ulupono"); (16) Hawaii PV Coalition ("HPVC"); (17) Sierra Club; (18) Tawhiri Power LLC ("Tawhiri"); (19) SunPower Corporation ("SunPower"); (20) Paniolo Power Company, LLC ("Paniolo"); (21) Eurus Energy America Corporation; (22) First Wind Holdings, LLC; and (23) the Distributed Energy Resources Council of Hawaii ("DERC") (admitted as a Participant in Order No. 33388, filed on December 11, 2015 in this docket). Except as specifically otherwise noted, the use of the term "Parties" in this Order refers, collectively, to the Parties and the Participants.

The commission is confident that many of the Companies' proposed near-term actions pertaining to renewable energy development are supported by sound analysis and are consistent with State energy policy and prior commission orders.

These proposed actions include company-wide plans for competitive procurement of grid scale renewable resources; successful implementation of the community-based renewable energy program ("CBRE"), demand response ("DR"), and distributed energy resource ("DER") programs; and certain utility actions to improve the reliability of each island grid. The commission now expects the Companies to advance these elements of the near-term action plans, and offers further guidance on these elements in Section V.B., below.

The commission also finds that certain projects in the near-term action plans are not sufficiently justified by the analysis in the Report. These projects include certain proposed conventional generation plants, utility-owned battery energy storage systems ("BESS"), proposed synchronous condensers, and certain proposed transmission projects. The commission will require further analysis, including thorough analysis of alternatives, during review of capital expenditures and any applications for these projects. Section V.C., below, contains further guidance related to these proposed projects. The commission expects the Companies to continuously improve and

refine their resource planning tools and methods, and employ these tools to support appropriate competitive procurement processes and project applications in the near term.

Overall, the commission finds significant improvements in the Report over the previous PSIPs filed in this docket. The Companies have expanded the scope of their analysis, and engaged new planning tools to better address the substantial planning challenges they face. Compared to prior filings, the Report is more transparent, incorporates additional stakeholder input, and addresses several of the commission's previously stated concerns regarding analysis.

In addition, the high-quality stakeholder input throughout this proceeding has improved both the planning process and the resulting plans. The commission appreciates the significant effort expended by all Parties, whose continued engagement and respectful dialogue have markedly improved the results.

Subject to the conditions and guidance set forth in this Order, the commission accepts the Report, including the near-term action plans, and directs the Companies to focus their efforts on implementing these plans. The commission will use the Report to provide context for further consideration and analysis in the review of subsequent competitive procurement processes and applications

for approval of specific resources, projects, and contracts, as appropriate.[3]

II.

BACKGROUND AND PROCEDURAL HISTORY[4]

On April 28, 2014, the commission issued four Orders[5] that collectively provided broad guidance on electric utility planning and operations, including instructions to the HECO Companies to develop and file PSIPs, and the initial requirements that the PSIPs should address.[6] In addition, the commission made clear that the PSIPs should incorporate the guidance set forth in the *Commission's Inclinations on the Future of Hawaii's Electric Utilities*

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[3]See Order No. 33877 at 14; Order No. 33320 at 2.

[4]A more exhaustive procedural history of this docket is provided in Order No. 33877 at 6-9.

[5]See In re Public Util. Comm'n, Docket No. 2012-0036, Decision and Order No. 32052, filed April 28, 2014 ("Order No. 32052"); In re Public Util. Comm'n, Docket No. 2011-0206, Decision and Order No. 32053, filed on April 28, 2014 ("Order No. 32053"); In re Public Util. Comm'n, Docket No. 2007-0341, Order No. 32054 "Policy Statement and Order Regarding Demand Response Programs," filed on April 28, 2014 ("Order No. 32054"); and In re Public Util. Comm'n, Docket No. 2011-0092, Decision and Order No. 32055, filed on April 28, 2014 ("Order No. 32055").

[6]Order No. 32055 at 87-93; In re Hawaii Elec. Light Co., Docket No. 2012-0212, Decision and Order No. 31758, filed on December 20, 2013, at 113-121; and Order No. 32053, at 68-69.

("Commission's Inclinations"),[7] which detailed the commission's broader perspectives on aligning the HECO Companies' investments and business model with customer needs and the State's public policy goals.

On August 7, 2014, the commission opened this docket to consolidate the review of the PSIPs filed by the HECO Companies.[8] In describing the purpose of the PSIPs, the commission stated:

> The PSIPs are to include actionable strategies and implementation plans to expeditiously retire older, less-efficient fossil generation, reduce must-run generation, increase generation flexibility, and adopt new technologies such as demand response and energy storage for ancillary services, and institute operational practice changes, as appropriate, to enable integration of a diverse portfolio of additional low cost renewable energy resources, reduction of energy costs and improvements in generation operational efficiencies.[9]

On November 4, 2015, the commission issued Order No. 33320, in response to the PSIPs filed by the HECO Companies on August 26, 2014. The commission identified eight observations and concerns ("Observations and Concerns")[10] regarding those PSIPs and provided the following initial statement

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[7]Order No. 32052, Exhibit A.

[8]In re Public Util. Comm'n, Docket No. 2014-0183, Decision and Order No. 32257 ("Order No. 32257"), filed on August 7, 2014, at 1.

[9]Order No. 32052 at 72-73.

[10]Order No. 33320 at 3-7.

of issues ("Initial Statement of Issues") for the review, supplementation, amendment, and update of the PSIPs:

1. Whether the PSIPs, as amended and updated in this proceeding, provide useful context and meaningful analysis to inform major resource acquisition and system operation decisions and identify well-reasoned and adequately-supported plans and actions that will result in reliable energy services, meeting State clean energy requirements, while ensuring that costs and rates will be reasonable.

2. Whether the PSIP for each of the HECO Companies, as amended and updated in this proceeding, includes reasonable plan components as required for HECO in Order No. 32053, including:

   a. a Fossil Generation Retirement Plan;

   b. a Generation Flexibility Plan;

   c. a Must-Run Generation Reduction Plan;

   d. an Environmental Compliance Plan;

   e. a Key Generator Utilization Plan;

   f. an Optimal Renewable Energy Portfolio Plan; and

   g. a Generation Commitment and Economic Dispatch Review.

3. Whether the PSIPs, as amended and updated, adequately address the Observations and Concerns . . . .[11]

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[11]Order No. 33320 at 138-139.

In response to Order No. 33320, on April 1, 2016, the HECO Companies filed their PSIP Update with the commission.[12] On June 3, 2016, the commission solicited comments on the PSIP Update.[13] The commission particularly sought comments regarding the Initial Statement of Issues, and "specific procedural steps the commission should consider to ensure constructive further progress in this docket."[14]

Order No. 33877 established the procedural schedule for the remainder of this docket. On August 26, 2016, the Companies filed a motion for clarification of Order No. 33877.[15] Notwithstanding the Companies' motion, pursuant to Order No. 33877: (1) on September 7, 2016 the Companies filed a work plan detailing their analytical approach and the necessary steps to finalize their

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[12]The HECO Companies hosted public meetings to discuss the PSIP Update with interested stakeholders on May 17, 2016, and June 29, 2016.

[13]In re Public Util. Comm'n, Docket No. 2014-0183, Order No. 33740 ("Order No. 33740"), filed June 3, 2016, at 4-5.

[14]Order No. 33740 at 4.

[15]"Hawaiian Electric Companies Motion for Clarification of Order No. 33877" ("Motion for Clarification"), filed on August 26, 2016. By their Motion for Clarification, the Companies seek clarification regarding the focus and scope of the plans, the analysis the commission requires, and confirmation that its proposed approach to completing its work in this docket is consistent with the commission's prior orders. Because the commission is accepting the Report and is closing this docket, the Motion for Clarification is now moot.

PSIPs; (2) on September 21, 2016 and again on October 3, 2016, the commission held technical conferences, prior to each of which, the Parties submitted questions to be asked at the technical conferences; (3) on December 23, 2016, the Companies filed the Report; (4) the Parties filed their information requests ("IRs") and responses thereto; and (5) the Parties filed their statements of positions ("SOPs").[16]

III.

THE REPORT

The Report includes an executive summary, seven chapters, and seventeen appendices.[17] According to the Companies, the Report outlines "a detailed plan charting the specific actions for the years 2017 through 2021 to accelerate the achievement of Hawaii's 100 percent Renewable Portfolio Standard ("RPS") by 2045."[18] The Report details the analyses and procedures the Companies used to determine several alternative long range resource plans and, ultimately, the specific actions in the near-term action plans.

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[16]Order No. 33877 at 6-9.

[17]The Companies also provided additional voluminous supporting data on an internet site accessible to the commission and Parties.

[18]Report at ES-1.

The Report explains how the Companies developed their candidate long-range plans, utilizing several optimization models, including four candidate plans for the Island of Oahu, and two plans each for the Islands of Maui and Hawaii.[19] The Companies refined these candidate plans based on more detailed production cost modeling analysis, by further considering DER, including DR resources,[20] and by analyzing system security requirements.[21] Based on these analyses and several "planning and analysis considerations," the Companies developed the near-term action plans.[22] Chapter 7 of the Report presents the Companies' near-term action plans, which identify "a set of actions that must be taken to continue on the path of reaching our 100% renewable energy goal."[23] The near-term action plans include "company-wide action

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[19]These plans are identified in Chapter 4 of the Report. The Companies identified and developed two additional long-range plans for each of the Islands of Lanai and Molokai without using optimization modeling.

[20]See Report at 3-6 to 3-17. In addition to the plans developed by the optimization modeling, the Companies analyzed a previously developed "Post-April PSIP Plan" for the Islands of Oahu, Maui, and Hawaii.

[21]See Report at 3-17 to 3-18 and Appendix O: System Security Analysis.

[22]See Report, Chapter 6.

[23]Report at 7-1.

plans" and an action plan for each of the five island utility systems, for the years 2017-2021.[24]

The near-term action plans contain elements including acquisition of new renewable generation resources, grid modernization, development of DER policies, achievement of environmental compliance, and system level improvement projects.[25]

IV.

STATEMENTS OF POSITION

On February 13, 2017, the Parties filed their SOPs on the Report. The commission appreciates the Parties' in-depth review of the Report, detailed comments on the plans, and suggestions for future planning efforts.

The commission notes several common themes among the SOPs. Many Parties state that the revised PSIPs show major improvement from prior efforts, and that the Report should be accepted. Several Parties provide recommended next steps to establish a methodology for procurement decisions. Although there is general agreement that the PSIPs are substantively improved, many Parties remain concerned about how certain assumptions were forced into the models, and how this may have biased the modeling results to

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[24]Report, Chapter 7.

[25]Report, Chapter 7.

disproportionately favor utility-owned assets. Nevertheless, the Parties generally agree that the PSIPs provide enough information to move forward with project procurement.

Below, the commission summarizes several common themes expressed throughout the Parties' SOPs, including: (a) improvements over prior PSIP filings; (b) future resource procurement; (c) recommendations for future planning; (d) proposed new fossil fuel generation; (e) modeling processes and assumptions; (f) DER; and (g) customer bill impacts.

A.

Improvements Over Prior PSIP Filings

Several Parties acknowledge the significant improvements to the planning process. The Consumer Advocate points out that the Report utilized several modeling tools to compare and validate various resource plan options, incorporated stakeholder input, and re-evaluated inputs and assumptions. The Consumer Advocate states that the revised PSIPs "show a reasonable integration of various resource considerations."[26]

DBEDT commends the HECO Companies for making the planning process more transparent:

[26]"Division of Consumer Advocacy's February 14, 2017 Statement of Position in Response to Order No. 34103; and Certificate of

> As compared to two years ago, DBEDT today has a more transparent vantage point with respect to the HECO Companies' development of their resource plans, in particular regarding the exchange of data and analysis. The ability to participate in the HECO Companies' internal planning meetings is evidence of this transparency and has proved valuable to DBEDT in developing its positions.[27]

Blue Planet states that the transparent optimization modeling utilized in the Report is effective and beneficial. To illustrate the value that this process has provided, Blue Planet notes that "[t]he total forecasted revenue requirement forecasted for the Companies combined in the E3 Plan is $2.4 billion less than the non-optimized Post-April 2016 Plan."[28]

Although Ulupono states that it cannot draw the conclusion that the entire near-term action plan is the least-cost or best mix of resources, Ulupono maintains that the Report provides enough information to take "meaningful near-term actions now, and resolve

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Service" ("Consumer Advocate SOP"), filed on February 14, 2017, at 11.

[27]"The Department of Business, Economic Development, and Tourism's Statement of Position on the Hawaiian Electric Companies' Revised and Supplemented Power Supply Improvement Plans, and Certificate of Service" ("DBEDT SOP"), filed on February 14, 2017, at 6.

[28]"Blue Planet Foundation's Statement of Position on the December 23, 2016 Power Supply Improvement Plan Update; and Certificate of Service" ("Blue Planet SOP"), filed on February 14, 2017, at 3.

the strategic uncertainties that remain in a matter of months, not years."[29]

B.

Future Resource Procurement

The HECO Companies, DBEDT, Blue Planet, and Ulupono all emphasize that there is an urgent need to quickly procure renewable generation while there are still federal tax credits available and to take advantage of current low interest rates. Ulupono more explicitly states that the commission "should approve the issuance of an all-source RFP for utility-scale firm and non-firm renewable power on all counties in 2017, 2020, and 2022."[30]

Although DBEDT generally supports procuring renewables, DBEDT has concerns about the Companies' proposed procurement approach and methodology. DBEDT states:

> There is a lack of sufficient evidentiary support or explanation in the PSIPs to demonstrate that the metrics and criteria the HECO Companies will apply in comparing proposals will result in procurement decisions that are consistent with the PSIPs and State energy policies.[31]

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[29]"Ulupono Initiative LLC's Statement of Position; Exhibit A; and Certificate of Service" ("Ulupono SOP"), filed on February 14, 2017, at 24.

[30]Ulupono SOP at 14.

[31]DBEDT SOP at 7.

DBEDT further questions the HECO Companies' methodology for establishing separate blocks for the evaluation of firm and variable generation, and how the Companies will compare and adjust the blocks of energy between the two. Finally, DBEDT doubts the Companies' methodology for analyzing each resource separately to determine cost savings, and the Companies' proposal to use criteria based on a net present value methodology to determine benefits.

Tawhiri recommends that all new renewable resources "must be procured in a manner that is totally agnostic with respect to both technology and the resources involved."[32] Paniolo emphasizes that all new generating resources should be competitively bid and not assumed to be owned by the utility. Paniolo suggests that the HECO Companies issue an energy storage request for proposals ("RFP") that is technology neutral for the Big Island, so that both BESS and pumped storage hydroelectric power ("PSH") are considered.

C.

Recommendations for Future Planning

Many of the Parties provide similar suggestions for future planning processes. The Consumer Advocate maintains that the PSIPs

[32]"Tawhiri Power LLC's State of Position on the Revised and Supplemented Power Supply Improvement Plans of Hawaiian Electic [sic] Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company Limited; and Certificate of Service," ("Tawhiri SOP"), filed on February 14, 2017, at 5.

should be a "*working* plan to be periodically updated and revisited[,]"[33] and that "HECO and stakeholders need to continuously seek improvements to the planning process."[34]

The HECO Companies propose that the next cycle of updating the PSIPs should begin in 2019, pursuant to which updated plans would be submitted in 2020. The Companies state that "[s]uch timing would allow the Companies to focus on executing the Near-Term Action Plan, and draw upon the Companies' experiences and findings from RFPs and developments in DER and DR, which could be used as inputs for the next PSIP effort."[35]

DBEDT recommends that future planning processes should be refined "to ensure resulting plans are resilient to uncertainty."[36] DBEDT further recommends more transparent analysis on siting, sizing, and selection of proposed resources, with respect to security during emergencies.[37]

Ulupono proposes the following steps for the next planning process: (1) define the strategic issues; (2) agree on transparent

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[33]Consumer Advocate SOP at 18 (emphasis in original).

[34]Consumer Advocate SOP at 13.

[35]"Hawaiian Electric Companies' Statement of Position; and Certificate of Service" ("Companies' SOP"), filed on February 14, 2017, at 3.

[36]DBEDT SOP at 19.

[37]DBEDT SOP at 21.

methodology; (3) agree on model inputs with all stakeholders, the Consumer Advocate, and commission staff; (4) create an interim report with stakeholder input and inquiry; (5) have the HECO Companies subsequently conduct the detailed engineering and planning; and (6) ensure the action plan is based on the planning process, not the Companies' business decisions.[38]

Blue Planet maintains that future planning analyses should continue to use objective optimization via capacity expansion modeling.[39] Blue Planet recommends that the commission immediately commence the next planning cycle, issue guidelines on the roles of the Companies, consultants, and stakeholders in that planning cycle, and set appropriate milestones and timelines.[40]

D.

Proposed New Fossil Fuel Generation

Many Parties stated concerns with the Companies' proposed new fossil fuel generation resources -- the 100 MW Joint Base Pearl Harbor-Hickam ("JBPHH") plant and the 54 MW Kaneohe Marine Corps Base Hawaii ("KMCBH") plant. Specifically, Parties opposed how the Companies manually selected the JBPHH and KMCBH plants,

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[38]See Ulupono SOP at 30.

[39]See Blue Planet SOP at 3-4.

[40]Blue Planet SOP at 20.

and forced them into the optimization models. The Consumer Advocate believes that additional data and analyses are necessary to assess if the JBPHH and KMBCH projects are in the public interest. DBEDT is concerned that the manual selection of these plants "will box out/influence the renewable options chosen in the future" and "whether the HECO Companies will be responsible for the costs if the manually selected resources are retired."[41]

The Joint Parties state that Companies also treated the JBPHH plant, the KMCBH plant, and the 18 MW combustion engine power plant proposed to be installed in South Maui in 2022, "as 'fixed assumptions,' 'must build' resources . . . effectively circumventing and nullifying the planning process."[42] Ulupono argues that the Companies' analysis demonstrates that the proposed JBPHH and KMCBH plants are not the least cost choices and should not be justified as waiver projects.[43] Ulupono also indicates that "[w]hen RESOLVE was allowed to optimize the construction plan for these projects,

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[41]DBEDT SOP at 22.

[42]"Sierra Club's Distributed Energy Resources Council of Hawaii's Hawaii Solar Energy Association's, and SunPower Corporation's Statement of Position RE Hawaiian Electric Companies' PSIP Update Report, filed on December 23, 2016; and Certificate of Service" ("Joint Parties SOP"), filed on February 14, 2017, at 14 (Sierra Club, DERC, HSEA, and SunPower are collectively referred to as the "Joint Parties" in this Order).

[43]Ulupono SOP at 3.

total resource costs were lowered by postponing these investments until 2045."[44]

E.

Modeling Process and Assumptions

Several Parties provided detailed feedback about other constraints and assumptions that the Companies applied to their analyses, particularly with respect to the HELCO system. Tawhiri expressed concern that there is a "lack of consistency and possible bias in the evaluation of wind energy investment in Hawaii County."[45] With respect to the wind generation on the HELCO system, Paniolo states "[t]he fact that the entire 70 MW was not procured in 2020 appears to be the result of an artificial 20 MW transmission constraint on wind generation for the year 2020 that was forced into the E3 RESOLVE modeling by the HECO Companies."[46] Paniolo states that the "Near-Term Action Plans should reflect the more optimal, earlier procurement of 70 MW of wind in 2020, even if project is installed in phases."[47]

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[44]Ulupono SOP at 16.

[45]Tawhiri SOP at 2.

[46]"Paniolo Power Company, LLC's Statement of Position; and Certificate of Service" ("Paniolo SOP"), filed on February 14, 2017, at 13 (internal citations omitted).

[47]Paniolo SOP at 14.

Tawhiri calls attention to HELCO's use of a single wind generation profile in all simulations of wind energy investments, and suggests that the "proper approach is to use multiple wind generation profiles with each profile representing a specific geographic location among the alternative wind energy resources (farms) under evaluation for each plan."[48]

Paniolo states that the Report does not disclose tradeoffs between alternative resource options, particularly regarding storage.[49] Paniolo questions why BESS was selected over PSH without identifying the tradeoffs between the two resources.[50] Paniolo states that it is unclear why the HECO Companies opted to assume a low-end useful life figure for PSH, while opting to use a high-end useful life assumption for BESS, and maintains that the figures used for the useful life assumptions should be equal.[51]

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[48]Tawhiri SOP at 5.

[49]See Paniolo SOP at 7.

[50]See Paniolo SOP at 7.

[51]See Paniolo SOP at 8.

F.

DER

Blue Planet suggests that the role of DER is a main issue that remains "unresolved" in the Report.[52] Blue Planet recommends that future planning efforts should develop methods to evaluate and incorporate energy efficiency in relation to other resource options.[53] The Joint Parties state that the modeling analyses did not pair distributed solar with distributed energy storage, but rather modeled storage as an independent resource.[54] The Joint Parties further state that "this may have resulted in the selection of separate utility-scale battery resources, but ignored the benefits of 'smart' DER systems combining solar and batteries."[55]

Ulupono commends "the HECO Companies for the extensive circuit by circuit grid-side planning in PSIP Section N, as well as for the transparency of the methodology and analysis."[56] Ulupono affirms that the HECO Companies have performed extensive system security analysis, but notes that "long and mid-term system security requirements would change if 'smart export'"

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[52]Blue Planet SOP at 2.

[53]Blue Planet SOP at 16.

[54]Joint Parties SOP at 10.

[55]Joint Parties SOP at 9.

[56]Ulupono SOP at 19.

was evaluated.[57] Ulupono expresses concern that the Report does not analyze how the potential for smart export could lower ancillary service demands and the need for "extensive utility sided batteries and grid upgrades."[58]

G.

Customer Bill Impacts

Several Parties are concerned about the projected long-term increase in electric rates. COH is especially concerned about the impact increases will have on ratepayers on the Island of Hawaii and recommends that future planning efforts include an "over-arching cost-control process . . . ."[59] Paniolo is concerned with the "detrimental impacts of prolonged high electricity rates outlined in the PSIPs . . . ."[60] The HECO Companies discuss how the rate projections resulting from the PLEXOS outputs "should not be used as precise long-term projections of customer rates."[61] The Companies explain that the value of these projections "is not

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[57]Ulupono SOP at 27.

[58]Ulupono SOP at 27.

[59]"County of Hawai'i's Statement of Position; and Certificate of Service" ("COH SOP"), filed on February 14, 2017, at 15.

[60]See Paniolo SOP at 3.

[61]Companies' SOP at 14.

in the precise values but in the relative results of planning to provide context to inform important pending and future resource acquisition and system operation decisions."[62]

V.

DISCUSSION

A.

Overview

As the commission observed at the outset of this proceeding, each electric utility's power supply system is becoming more complex and operationally challenging as greater quantities of diverse renewable energy resources are integrated with older, relatively inflexible base load fossil-fuel generation resources.[63] In the more than two and a half years since this proceeding began, complexities in the islands' electric systems have only increased, in large part because of continuing developments in DER, such as rooftop PV.

Given the length of time that has passed since the commission and Parties first began this docket, it is useful to

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[62]Companies' SOP at 14.

[63]Order No. 32257 at 1 (citations omitted).

revisit the intended purpose and expectations of the Companies' PSIPs. As the commission has previously stated:

> [t]he ultimate purpose of this proceeding is to determine a reasonable power supply plan for each of the HECO Companies that can serve as a strategic basis and provide context to inform important pending and future resource acquisition and system operation decisions.[64]

The commission has repeatedly stressed that the development of well-vetted, credible, comprehensive system analysis[65] is "essential to the HECO Companies fulfilling their role to provide a platform to meet the diverse service requirements of their customers by integrating a variety of generation sources and customer-sited resources in an economically and operationally efficient manner."[66]

The commission acknowledges the challenges inherent in long-term forecasting and analysis, particularly where, as here, the underlying inputs and assumptions are dynamic and subject to significant uncertainty over the next decade or more. Accordingly, the commission has stated its expectation that the PSIPs "should place particular emphasis on identifying and supporting the near-term actions, applications, and decisions necessary

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[64]Order No. 33320 at 2.

[65]See Order No. 33320 at 40-41.

[66]Order No. 33320 at 137.

to effectively meet identified challenges, policy goals, and planning objectives."[67] .

Although the instant proceeding has proven to be an extensive undertaking, the commission can now affirm that the objectives outlined above have largely been met, subject to the concerns articulated herein. The PSIPs in the Report reflect significant improvements over the previous PSIPs filed in this docket. The Companies have expanded the scope of their analysis, and engaged new planning tools to better address the substantial planning challenges they face. The Companies have made their filings more transparent, incorporated additional stakeholder input, and addressed many of the commission's previously stated concerns. The result is a set of plans that provides useful context for making informed decisions regarding the near-term path forward.

The commission appreciates the significant effort expended in this proceeding by the HECO Companies, the Consumer Advocate, and all Parties, whose continued engagement and respectful dialogue have helped develop an extensive record in this docket. After review, commission has reasonable assurance that many of the actions identified in the near-term action plans are credible, supported by sound judgment and analysis, informed by stakeholder input, and consistent with State energy policy and prior

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[67]Order No. 33877 at 15.

commission orders. Thus, the commission believes that the Companies' analyses are sufficient to provide context and inform near-term procurement and resource acquisition.[68] As a result, the commission expects that the Companies will continue implementing the valid aspects of the PSIPs.

Notwithstanding the urgent need to prudently implement the near-term action plans, the commission has concerns with several aspects of the PSIPs. The commission has identified areas that require additional improvements, analyses, or justification to address remaining questions or concerns. These are not "fatal flaws," but rather are areas the commission expects all Parties will continue to address either in parallel proceedings (e.g., Docket No. 2014-0192), through the Companies' submission of discrete project applications, or as part of the next planning cycle. The PSIPs that resulted from this proceeding should not be viewed as a prescriptive plan for future, but a useful snapshot of the Companies' dynamic and ongoing planning efforts.

In sum, by this Decision and Order, subject to the conditions set forth in herein, the commission accepts the Report, and directs the Companies to continue implementing the near-term action plans, particularly those elements described in Section V.B., below.

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[68]See Order No. 33320 at 2.

The following sections of this Order discuss high priority near-term actions in the Companies' resource plans, describe the commission's concerns with certain aspects of the plans, identify topics for further analysis, and offer guidance regarding the Companies' future efforts to continuously refine and improve their planning approach.

B.

High Priority Near-Term Actions

The commission is encouraged by the Companies' commitments to competitively procure new grid-scale renewable resources, to continue to work with stakeholders to develop CBRE and DER programs, and to implement system-level reliability improvements for each island grid. These high-priority near-term actions are discussed in detail, below.

1.

Competitive Procurement of Grid-Scale Renewable Resources

The Companies' resource plans include procurement of nearly 400 MW of new renewable resources across all service territories by 2021.[69] Collectively, this represents the largest new generation procurement ever undertaken in the State. There is

[69]See Report, Chapter 7.

broad stakeholder support for acquiring new renewable resources, as well as significant developer interest in meeting Hawaii's needs. Furthermore, the Companies must move quickly to enable customers to benefit from available tax credits, such as the federal investment tax credit ("ITC"), which is set to expire within the near-term action plan period. As such, the commission expects the Companies to devote attention and resources to ensure a transparent, timely, and successful procurement process.

The commission intends to open a series of new dockets to serve as repositories for filings related to the planned upcoming procurements. As part of the development of the procurement process, the Companies should carefully consider the design of each RFP, including the quantity of energy and grid services requested, eligible technologies, the interconnection study process, the complexity and risks associated with model power purchase agreements ("PPAs"), the timeline to complete the procurement process, the availability of incentives (e.g., the federal ITC), and the sequencing of future procurements at known intervals to provide greater transparency to market participants and reduce costs to customers.[70] The Companies must learn from and improve upon prior

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[70]As the commission recently stated, it expects that the Companies will fully consider energy storage systems in proposing any new generation projects. In re Hawaiian Elec. Co., Docket No. 2016-0342, Decision and Order No. 34676, ("Order No. 34676") filed on June 30, 2017, at 79. The commission

procurement attempts, including the recent energy storage and waiver project solicitations.

There are benefits and drawbacks to every procurement approach; thus, the commission expects the Companies to solicit and incorporate feedback from stakeholders where appropriate, as well as the Independent Observer,[71] during the drafting of future requests for proposals and model PPAs. In sum, the commission encourages the Companies to use upcoming procurements as opportunities to continue to collaborate with stakeholders to ensure a high-quality approach that fairly considers alternatives and promotes the timely and successful deployment of cost-effective renewable resources for customers' benefit.

2.

Actions Related to CBRE and DER Integration

The commission views the ongoing development of CBRE and DER programs as high priorities for near-term action by the HECO Companies. These efforts are currently the subject of

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views energy storage, such as battery storage or PSH, as an essential element in achieving the State's goals to integrate increasing levels of renewable energy generation into the State's island grids and "a viable option for supporting the integration of low cost renewables into the grid, with the capacity to provide fully dispatchable renewable energy." Order No. 34676 at 79-80.

[71]See In re Public Util. Comm'n, Docket No.03-0372, Decision and Order No. 23121, Exhibit A, Section III.C, at 13-16.

Docket Nos. 2015-0389, 2014-0192, and 2015-0412, among others. The commission supports many of the actions identified by the Companies, including procurement of diverse CBRE projects; further development of DER programs (e.g., "smart export" tariffs), activation of advanced inverter functions for DER, further improvements to the interconnection process (e.g., offering an online application portal), development of a DR portfolio that provides valuable grid services from customers, and continued investment by the Companies in research, development, and demonstration projects. The commission remains very supportive of the use of energy efficiency and cost effective DR resources to resolve operating needs, meet system reserve requirements, defer the need for future capacity additions, provide ancillary services and assist with the integration of additional renewable energy resources, and promote the reliable and economical operation of the electrical grid.[72]

These proposed actions are consistent with the State's energy policy and prior commission orders. Thus, the Companies should accelerate their efforts to make meaningful near-term progress on these topics in relevant parallel proceedings.

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[72]See In re Public Util. Comm'n, Docket No. 2007-0341, Order No. 32054 "Policy Statement and Order Regarding Demand Response Programs," filed on April 28, 2014, at 1-2.

3.

System-Level Grid Reliability Projects

In the Report, the Companies propose to make several system-level grid reliability improvements, including upgrades to the under-frequency load shedding ("UFLS") scheme and projects to reduce fault clearing time. The HECO Companies have discussed these improvements for many years, and appear to have only partially implemented them.[73] Increasing the dynamic flexibility of the UFLS scheme for each island and improving fault detection and clearing times are worthwhile objectives that the Companies should pursue, especially given the high proportion of non-synchronous generation expected on most islands in the near future.[74] The Companies should evaluate such options to enhance grid reliability, in conjunction with procurements for new renewable resources, development of DR and other DER programs, and the implementation of the Companies' grid modernization strategy.

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[73]See Report at 7-29 to 7-30.

[74]While the commission encourages the Companies to pursue these projects, the commission is not providing regulatory "pre-approval" of any investments at this time. Such decisions will be made in the context of future applications for cost-recovery (e.g., general rate case), as appropriate.

C.

Commission Concerns with the Report

While there are many well-supported proposals in the Report, the commission has concerns with some aspects of the Report, including the anticipated increases in customer rates, proposed conventional generation projects,[75] proposed BESS and synchronous condenser projects;[76] and certain proposed transmission projects.[77]

As stated generally above, the commission expects the Companies to rigorously examine the prudence, timing, cost effectiveness, affordability, and reasonably available alternatives in individual applications for future projects. Thus, many of the resources identified in the Report will be subject to further scrutiny in future proceedings. To the extent that the Companies choose to propose these resources and projects in the future, the Companies must address these concerns prior to or as part of the review of any necessary applications or approvals by the commission. At this time, the commission provides the following discussion of concerns to provide broad guidance with respect to several specific resources and projects included with the Report.

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[75]See Report at 7-18 and 7-24.

[76]See Report at 7-9.

[77]See Report at 7-22 to 7-23 (MECO), 7-29 to 7-30 (HELCO).

1.

Customer Rate and Bill Impacts

The commission continues to be concerned with the affordability of the Companies' plans. Most recently, the commission directed the Companies to address affordability and the risks associated with customer exit in Order No. 33877.[78]

The rates associated with the Companies' near-term action plans are projected to increase substantially (between 18% and 25%) during the near-term action plan period, and even more in the subsequent five years on Oahu and the Island of Hawaii.[79]

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[78]Order No. 33877 at 28-30 (citations omitted).

[79]Figure 1 and Table 1 are based on "PSIP Rates and Bill Impact with CAGR - Consolidated Final.xlsx," filed in support of the Report, Chapter 5.

Figure 1
Average Residential Rates (Real $/kWh)

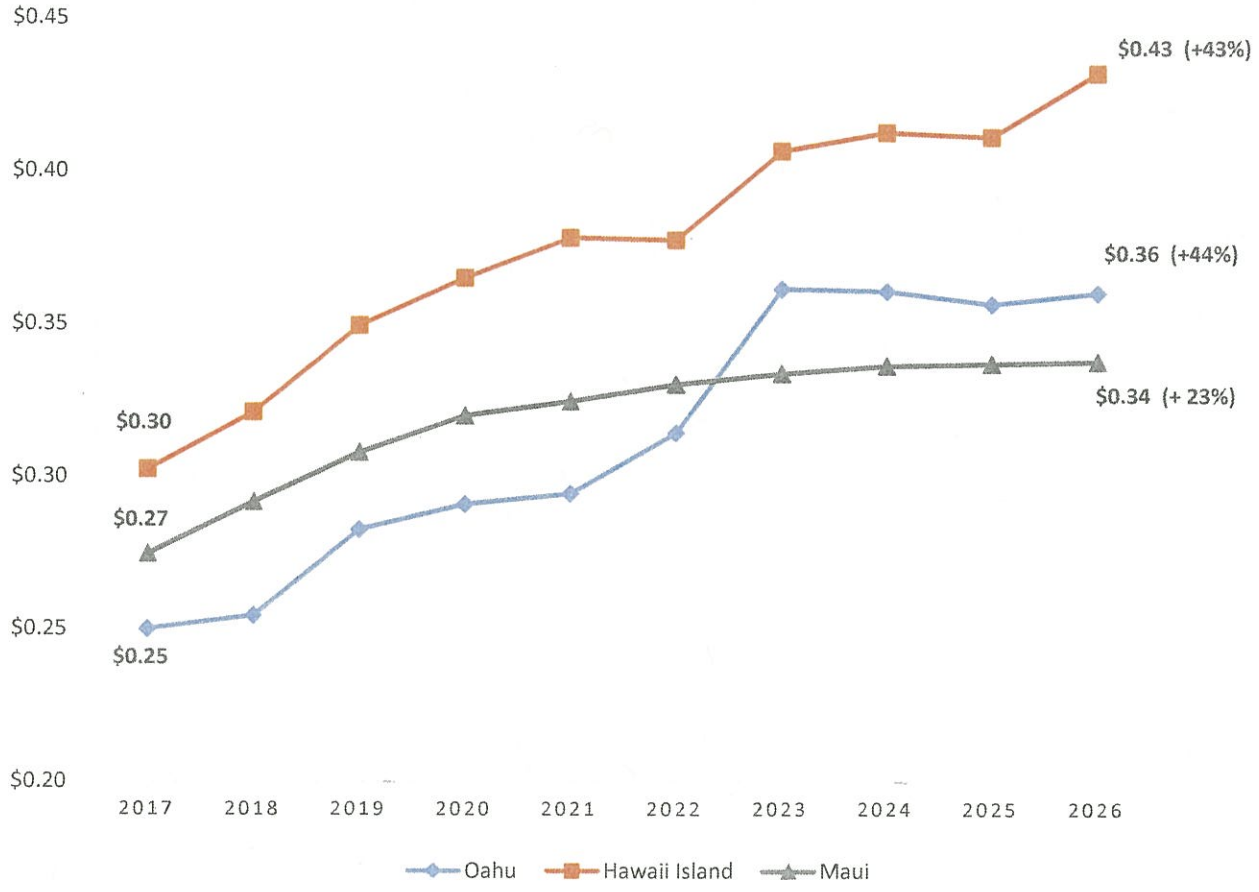

Table 1		
Average Residential Rates (Real $/kWh)		
	% Increase for the near-term action plans (2017-2021)	% Increase for 2017-2026
HECO	17.8%	44.1%
HELCO	25.1%	42.9%
MECO	18.2%	23.0%

Given the substantial increase in rates forecasted in the Report, the commission is concerned that the Companies have not fully considered the affordability of their plans. The Companies have provided only limited responses to the commission's instruction

to analyze customer and implementation risks.[80] The Companies do not appear to have evaluated the capital investments, financial commitments, and the resulting increasing rates, in the context of affordability to customers and the risk of stranded assets.

It is the Companies' responsibility to diligently examine and fully consider the possibilities and risks that their plans pose to customers. The impacts of increasing customer rates and the prospect of uneconomic customer exit can be reasonably anticipated and could be forestalled or exacerbated by the Companies' investment, procurement, and operational decisions. Thus, the risks associated with such decisions rest with the Companies.

2.

New Conventional Generation Resources

The Oahu Action Plan includes a proposal for HECO to install and operate a reciprocating engine at Marine Corps Base Hawaii ("MCBH"), that the Companies envision acquiring via a waiver from the competitive bidding framework and a G.O. 7

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[80]See, e.g., HECO's Response to PUC-IR-97. Although the Companies state that Appendix Q contains "preliminary analysis of . . . the comparative economics of a customer remaining connected to the utility grid versus disconnecting from the grid," the commission notes that the information and analysis presented in Appendix Q is minimal and incomplete.

application.[81] The Companies also seek to install an additional "100 MW of firm, dispatchable, flexible generation," likely through an RFP, but possibly through a waiver process.[82]

Similarly, the Maui near-term action plan proposes new generation to be installed in 2022.[83] The Maui near-term action plan does not specify the type and size of the new generation resources to be added, presumably because the proposed installation date falls outside of the near-term action plan period of 2017 - 2021. However, in the longer-term supporting optimization and economic analyses for MECO, the Companies specify the addition of two 9 MW internal combustion generation units for the year 2022, with an additional 20 to 40 MW of biomass generation.[84]

The commission's primary concern with these proposed projects is the apparent lack of thorough analysis in the Report to justify the resources. Without this analysis, it appears that the Companies simply presumed that these generation resources would be included in each resource plan.[85] As discussed extensively in prior commission orders, such an approach is not sufficient.

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[81]Report at 7-18.

[82]Report at 7-18.

[83]Report at 7-24.

[84]See Report at 4-12.

[85]See Ulupono SOP at 16 (citations omitted).

The Companies should not assume the commission will waive the competitive bidding process for any of these proposed projects. If the Companies choose to pursue these resources, the Companies should incorporate the need for the competitive bidding process in planning the timing of its procurements.[86] Prior to initiating any such procurement, the Companies must evaluate and demonstrate the merits of the selection, sizing and timing of these resources, including evaluation of available alternatives (including generation, storage, and distributed resources such as energy efficiency and DR).

3.

BESS and Synchronous Condensers

The long-range resource plans and near-term action plans for each of the five island utility systems include new BESS and synchronous condenser resources.[87] The proposed BESS resources are designed to provide several utility system functions, including meeting "fast frequency response contingency,"[88]

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[86]See HECO's Response to PUC-HECO-IR-88.

[87]See Report at 7-9.

[88]See Report at 7-8.

"load-shift,"[89] and "regulating/ramping" requirements.[90] The Companies also state that they "will continue to evaluate and pursue distributed energy storage systems (DESS) to benefit DER integration."[91]

In the Report, the Companies analyzed the system security that each island grid needs to support diligent efforts to improve grid reliability.[92] However, it is not clear if the Companies have considered a full range of alternative options, including PSH, thermal, and electrical storage technologies, or fully explored demand-side, as well as utility storage options. PSH resources, in particular, may help provide cost-effective long-duration storage, complementing distributed resources like DR.

The Companies should continue their efforts to improve reliability and ensure system security, taking into account the magnitude and duration of ancillary services needs, as well as expected changes in ancillary services needs over time. Further, the Companies should propose appropriately sized resources to meet those needs. Proposed resources should be co-optimized to provide multiple ancillary services if possible, and the Companies should

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[89]See Report, Chapter 4, all tables.

[90]See Report at 7-17 to 7-18.

[91]Report at 7-14. See also Report at 3-17 to 3-20, and Appendix O.

[92]Report, Appendix O.

evaluate options to lower costs to customers, such as pairing with renewable energy projects to enable storage resources to benefit from available tax credits. As stated above, the commission expects the Companies to consider the full range of available options, including DR resources, as well as various technologies and combinations of technologies.

Similarly, the Companies' analysis of synchronous condenser resources does not appear to be complete. If the Companies decide to pursue these resources, the Companies must support their proposals with thorough and sound supporting analyses, prior to, and/or in the context of, procurement proceedings and review for necessary approvals by the commission.

4.

Transmission System Projects

The Maui and Hawaii Island near-term action plans both identify several transmission system upgrade projects.[93] Regarding the Maui Island transmission upgrades, the Companies state that "[n]on-transmission alternatives were considered as options to the transmission upgrades," including DG, BESS, DR, and synchronous

[93]Report at 7-22 to 7-23, 7-29.

condensers.[94] In addition, the Companies state that MECO will further explore the potential of aggregated DR resources as a "non-transmission" alternative.[95] However, the Report does not sufficiently evaluate the possibility of non-transmission alternatives to the transmission upgrades identified in the Maui or Hawaii Island near-term action plans.

The commission supports the ongoing consideration of non-transmission alternatives for the Maui and Hawaii Island systems as mentioned in the Report, along with procedures to solicit competitive proposals that consider a full spectrum of transmission and non-transmission options. If MECO or HELCO decides to pursue such resources, the commission expects any application for transmission system upgrades to ensure that non-transmission alternatives and competitively solicited alternatives are appropriately considered.

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[94]Report at 7-22.

[95]Report at 7-23.

D.

Topics Requiring Further Analysis

1.

Achieving RPS Goals

As requested by the commission, the Report places greatest emphasis "on the near-term actions that allow [the Companies] to make strong progress on achieving our clean energy goals."[96] Although the primary purpose of the Report is to provide context for near-term decisions, the Companies also assert that their resource analyses support a reasonable course to ultimately attain the State's 2045 RPS requirement of 100% by the year 2040, and a goal of 100% renewable generation (i.e., no fossil fuel powered generation, exceeding the 100% RPS) by the year 2045.[97]

Beyond serving as aspirational goals, the long term RPS and renewable generation targets are important planning and design criteria. The commission commends the Companies' commitment to achieving the RPS ahead of schedule. Nevertheless, the commission has some concerns regarding the technical feasibility and economics of the long-term resource plan for each island. It appears that certain technology options, such as PSH resources, may have been excluded from the analysis. It also appears that certain costs

[96]Report at ES-2.

[97]Report at 1-1.

may not be fully incorporated into the rate and bill impact analysis and several of the underlying analyses in the Report suggest that negative reliability impacts could result from implementing the long-term resource plan.[98] The commission expects future planning cycles will more fully address the capital costs, operating costs, and reliability concerns associated with long-term achievement of the RPS goals.

2.

Molokai and Lanai Advanced 100% Renewable Energy Plans

MECO intends to solicit proposals for the procurement of biofuels in 2018,[99] followed by an application with the commission for approval of a biofuel contract in 2020.[100] The Lanai near-term action plan indicates that MECO will pursue a process to procure cost-effective renewable resources to achieve 100% renewable energy in 2030 or possibly sooner.[101]

As noted above, the commission supports MECO's efforts to achieve 100% renewable energy for the islands of Molokai and Lanai ahead of the timeline established in the RPS. MECO should

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[98]See e.g., Report, Appendix P at P-16 to P-18.

[99]Report at 7-25.

[100]Response to PUC-IR-88.

[101]Report at 7-27.

coordinate future procurement efforts with its upcoming RFP for new grid scale resources. This should include an opportunity for competitive bidding for resources that can provide comparable services as biofuel powered, utility-owned generation. Such resources could include combinations of energy efficiency, renewable generation, DR, and various storage options, in addition to or instead of larger-scale thermal generation. The Companies should also pursue transparent, competitive and community-engaged efforts[102] for the Islands of Molokai and Lanai, for procuring resources and further considering the costs and benefits of early attainment of 100% renewable generation, consistent with the needs and goals of these communities.

3.

System Security Requirements

In Order No. 33877, the commission noted that the Companies had not adequately supported their system security analysis, reiterating guidance from Order No. 33320.[103] Specifically, the commission, stated:

> In Order No. 33320, the commission identified significant concerns in the following areas related to system security analysis:

[102]See Report at 7-27.

[103]See Order No. 33877 at 25-26 (citations omitted).

1. The HECO Companies have not clearly established the technical basis for the proposed requirements and defined them in technology-neutral terms;

2. The HECO Companies have not adequately demonstrated how the proposed requirements balance cost with system reliability and risk; and

3. System security requirements appear to unreasonably limit utilization of and increase costs to integrate renewables.[104]

After reviewing the Report, the commission notes significant improvement in several aspects of the system security analysis. Some of these improvements enabled the Companies to identify ways to reduce costs and develop innovative solutions to meet customer needs.[105] For example, the Companies have developed an analytical approach to unbundle various ancillary services from conventional generation resources. This analysis has allowed the Companies to define specific ancillary services needs as part of the DR portfolio in Docket No. 2015-0412. In addition, the Companies' system security analysis now appears to more realistically consider the characteristics and capabilities of DER.

Nevertheless, within the limited time provided for the final Report, the Companies have not fully performed the system

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[104]Order No. 33877 at 25-26, citing Order No. 33320, at 112 (citations and quotations omitted).

[105]See, e.g., Docket Nos. 2014-0192 and 2015-0412.

security analysis required by the commission in Order No. 33320, and again in Order No. 33877. The commission expects that the Companies will continue building upon their efforts to date by diligently refining their system security analysis.

E.

Expectations for Implementation

By this Decision and Order, the commission accepts the Report, and intends to use the PSIPs "in conjunction with the evaluation of specific filings for approval of capital and other projects."[106] Although the commission supports many aspects of the Report, given the uncertainty about future conditions, and because planning is a continuous and ongoing activity, the commission encourages flexibility and anticipates variation and modification of the plans, as time goes on. Future applications "will be evaluated on [their] own merits pursuant to applicable statutory and regulatory standards, as well as [their] relationship to the final PSIPs."[107]

As such, in subsequent applications for approval or cost-recovery, the utility will bear the burden of supporting the merits of each proposed resource or action. The commission's

[106]Order No. 33877 at 2.

[107]Order No. 33877 at 2.

acceptance of the Report should not be construed as regulatory pre-approval for any specific element identified in the Report. The inclusion of a specific resource or action in the Report or near-term action plans does not mean the commission will presume that resource or action is necessary, properly timed, or prudent. Furthermore, the commission expects the Companies to consider and propose the most efficient and cost-effective resource alternatives, including resources not specifically included in the Report or near-term action plans, as applicable. The commission expects the Companies to procure resources that, both individually and collectively, continue to drive down customer costs compared to the costs estimated in the Report.

In addition, the revenue adjustment mechanism cap ("RAM Cap"), that was implemented pending "approval" of the Companies' PSIPs, remains in effect, unless otherwise ordered by the commission. Any proposed changes to the RAM Cap will be addressed in pending or future rate cases for each of the HECO Companies.[108]

In subsequent applications, the Companies must fully support the merits of each resource or proposed action. The commission expects the procurement activities identified in the

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[108]See In re Public Util. Comm'n, Docket No. 2013-0141, Order No. 34514 ("Order No. 34514"), filed on April 27, 2017.

PSIPs and near-term action plans to result in the acquisition and development of the most cost-effective resources for customers, and to include consideration of resources not necessarily identified in the PSIPs or near-term action plans. The commission expects the Companies to strive to procure resources at the lowest costs possible, and at costs lower than estimated in the near-term action plans.

In addition, although the commission supports the Companies' ambitious plan to achieve the State's RPS ahead of schedule, it is most important for the Companies to focus their efforts on designing and executing sound procurement and application processes that address the commission's concerns, as described in this and prior Orders.

Therefore, the commission directs the Companies to take the following actions, at a minimum, as a part of efforts to implement the near-term action plans: (1) include a fair and transparent evaluation of alternatives, including consideration of alternatives that could result in lower cost and/or lower risk for customers, (2) consider all appropriate technologies, including combinations of technologies, to address system, capacity, and energy needs, rather than specifying a single resource option, (3) sufficiently justify how each resource is the best choice in conjunction with the near-term action plans identified in

the Report, and (4) include performance measures to evaluate implementation of the proposed action.

F.

Future Planning Activities

The conclusion of this docket does not mean the end of the Companies' planning efforts. The Companies have repeatedly stated that planning is a continuous process, and the commission agrees.[109] As such, the Companies must work diligently to continuously improve their planning tools and methods, and timely revise their estimates and forecasts as part of an ongoing, cyclical planning process.[110] The commission also agrees that even as the Companies' continually update their work, now is the time to focus on implementing the Companies' near-term action plans, consistent with the guidance provided herein.[111]

The Companies' future planning efforts must coordinate with and learn from other ongoing activities and pertinent proceedings and activities, including programs such as DER, DR, CBRE, and proposed grid modernization projects. Future planning

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[109]See, e.g., Report at ES-7, 2-15, 2-18, and 7-28.

[110]Consumer Advocate SOP at 18.

[111]See, e.g., Companies' SOP at 3, DBEDT SOP at 6, and Blue Planet SOP at 2.

efforts must also include and build upon the new set of tools used in the last round of PSIPs, particularly the use of advanced resource optimization models.[112] Finally, future planning efforts must continue to actively engage stakeholders, and incorporate their constructive input.

The commission observes that in the Companies' June 2017 Draft Report, "Modernizing Hawaii's Grid for Our Customers," the Companies propose a planning process that integrates bulk system resource planning with transmission and distribution planning to assess total resource net benefits.[113] The Companies state that the process would engage customers and stakeholders at key junctures in the integrated planning effort. The commission is supportive of the Companies' proposal to more effectively integrate resource, transmission, and distribution planning going forward.

Therefore, the commission directs the Companies to file with the commission, outside of this docket, a report that details the Companies' planning approach and schedule for the next round of

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[112]Blue Planet SOP at 3-4.

[113]See "HECO Companies' Grid Modernization Strategy (Draft) for Stakeholder Review and Comment," filed on June 30, 2017, at 22-23 ("Draft Grid Modernization Strategy"), available online at https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/grid_modernization_strategy_draft.pdf.

integrated planning. The Companies shall file this report with the commission no later than March 1, 2018.

VI.

ORDERS

THE COMMISSION ORDERS:

1. The Report is accepted, for the purposes stated and subject to the conditions set forth in this Order.

2. By March 1, 2018, the Companies shall file with the commission, outside of this docket, a report that details their planning approach and schedule for the next round of resource planning.

3. The Companies' Motion for Clarification of Order No. 33877, filed on August 26, 2016, is dismissed as moot.

4. This docket is closed unless determined otherwise by the commission.

DONE at Honolulu, Hawaii JUL 14 2017.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By _____
Randall Y. Iwase, Chair

By _____
Lorraine H. Akiba, Commissioner

By _____
James P. Griffin, Commissioner

APPROVED AS TO FORM:

_____
Mike S. Wallerstein
Commission Counsel

2014-0183.ljk

CERTIFICATE OF SERVICE

The foregoing order was served on the date of filing by mail, postage prepaid, and properly addressed to the following parties:

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OAH 80-2500-31888
MPUC E-999/CI-14-643

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3

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STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3	**FINDINGS OF FACT, CONCLUSIONS, AND RECOMMENDATIONS: CARBON DIOXIDE VALUES**

This matter is pending before Administrative Law Judge LauraSue Schlatter pursuant to a Notice and Order for Hearing filed by the Public Utilities Commission (Commission) on October 15, 2014.[1]

On September 24 – 30, 2015, the evidentiary hearing for the carbon dioxide (CO_2) portion of this matter took place at the Commission's office in Saint Paul, Minnesota.

Appearances:[2]

Kevin Reuther, Leigh Currie, and Hudson Kingston, attorneys with the Minnesota Center for Environmental Advocacy, appeared on behalf of the Minnesota Center for Environmental Advocacy, Fresh Energy, and Sierra Club, collectively the Clean Energy Organizations (CEOs).

Tristan L. Duncan, attorney with Shook, Hardy & Bacon L.L.P., and Jonathan Massey, Attorney at Law, appeared on behalf of Peabody Energy Corporation (Peabody).

Linda Jensen, Assistant Attorney General, appeared on behalf of the Minnesota Department of Commerce, Division of Energy Resources (Department), and the Minnesota Pollution Control Agency (MPCA) (collectively the Agencies).

Eric F. Swanson, attorney with Winthrop & Weinstine P.A., appeared on behalf of the Lignite Energy Council (Lignite).

B. Andrew Brown, attorney with Dorsey & Whitney L.L.P., appeared on behalf of Great River Energy (GRE), Minnesota Power Company (MP), and Otter Tail Power Company (OTP) (collectively the Utilities).

David Moeller, attorney with Minnesota Power Company, appeared on behalf of Minnesota Power Company (MP).

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[1] NOTICE AND ORDER FOR HEARING (Oct. 15, 2014) (eDocket No. 201410-103872-02).
[2] A list of the parties and their expert witnesses is attached as Appendix A.

James R. Denniston, Assistant General Counsel, appeared on behalf of Northern States Power Company, d/b/a Xcel Energy (Xcel).

Marc Al and Andrew P. Moratzka, attorneys with Stoel Rives L.L.P., appeared on behalf of Minnesota Large Industrial Group (MLIG).

Benjamin L. Gerber, Attorney at Law, appeared on behalf of the Minnesota Chamber of Commerce (MCC).

Kevin P. Lee, Attorney at Law, appeared on behalf of Doctors for a Healthy Environment (DHE).

Bradley Klein and Jessica Dexter, attorneys with the Environmental Law & Policy Center, appeared on behalf of the Clean Energy Business Coalition (CEBC).

Tricia DeBleeckere, Energy Analyst, and Sean Stalpes, Energy Analyst, were present at the hearing on behalf of the staff of the Commission.

I. Procedural History

1. In 1993, the Minnesota Legislature enacted Minnesota Statute section 216B.2422, subdivision 3, which requires the Commission to "quantify and establish a range of environmental costs associated with each method of electricity generation." In addition, the statute requires utilities to use the costs "when evaluating and selecting resource options in all proceedings before the [C]ommission, including resource planning and certificate of need proceedings."[3]

2. In 1994, the Commission established interim cost values, and in 1997, the Commission established final values, after a contested case proceeding (first Externalities case).[4] The Commission's 1997 decision establishing final values was affirmed by the Minnesota Court of Appeals.[5]

3. On October 9, 2013, several environmental advocacy organizations filed a motion requesting that the Commission update the cost values for carbon dioxide (CO_2) and nitrogen oxide (NO_x) emissions, establish a cost value for particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), and re-establish a value for sulfur dioxide (SO_2). In the

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[3] 1993 Minn. Laws ch. 356, § 3 at 2523.

[4] *In the Matter of the Quantification of Envtl Costs Pursuant to Laws of Minn. 1993, Chap. 356, Sec. 3,* PUC Docket No. E-999/CI-93-583, ORDER ESTABLISHING ENVIRONMENTAL COST VALUES at 1, 33 (Jan. 3, 1997) (*see also* eDocket No. 20148-102561-01) (93-583 PUC ORDER 1); *In the Matter of the Quantification of Envtl Costs Pursuant to Laws of Minn. 1993, Chap. 356, Sec. 3,* PUC Docket No. E-999/CI-93-583, ORDER AFFIRMING IN PART AND MODIFYING IN PART ORDER ESTABLISHING ENVIRONMENTAL COST VALUES at 8 (July 2, 1997) (*see also* eDocket No. 201410-103872-02) (93-583 PUC ORDER 2).

[5] *In re Quantification of Envtl Costs*, 578 N.W.2d 794 (Minn. Ct. App. 1998), *review denied* (Minn. Aug. 18, 1998).

motion, the environmental organizations recommended that the Commission adopt the federal government's Social Cost of Carbon as the cost value for CO_2.[6]

4. On February 10, 2014, the Commission issued an order reopening its investigation into "the appropriate range of externality [cost] values for $PM_{2.5}$, SO_2, NO_x, and CO_2."[7] The Commission ordered the Agencies to convene a stakeholder group to provide recommendations on the scope of the reopened Externalities investigation.[8]

5. On June 10, 2014, the Agencies filed a report stating that there was little stakeholder consensus. The Agencies recommended that the Commission adopt the federal Social Cost of Carbon midpoint values for CO_2,[9] and also made recommendations about the scope and process of the Commission investigation and retention of an expert.[10]

6. On October 15, 2014, the Commission issued the Notice and Order for Hearing for this matter, which set the scope of the reopened Externalities investigation as follows:

> The Commission will investigate the appropriate cost values for $PM_{2.5}$, SO_2, NO_x, and CO_2. The Commission will not further investigate at this time the environmental costs of other greenhouse gasses such as methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Because CO_2 represents 99% of greenhouse gas emissions, an accurate environmental cost value for CO_2 will account for almost all greenhouse gas costs. This will result in a more manageable proceeding and allow the parties to focus their resources.
>
> It would be premature at this stage to adopt the federal SCC values for CO_2 as the Agencies recommend. The Commission still believes that a contested case proceeding is necessary to fully consider the Agencies' proposed CO_2 cost values. The Commission will therefore not act at this time on the Agencies' proposal to adopt the federal SCC values immediately. But, in light of the record so far, the

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[6] *In the Matter of the Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subd. 3,* PUC Docket No. E-999/CI-00-1636, MEMORANDUM IN SUPPORT OF CLEAN ENERGY ORGANIZATIONS' MOTION TO UPDATE EXTERNALITY VALUES FOR USE IN RESOURCE DECISIONS at 1-2, 18-19 (Oct. 9, 2013).

[7] *In the Matter of the Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subd. 3,* PUC Docket No. E-999/CI-00-1636, ORDER REOPENING INVESTIGATION AND CONVENING STAKEHOLDER GROUP TO PROVIDE RECOMMENDATIONS FOR CONTESTED CASE PROCEEDING at 3 (Feb. 10, 2014).

[8] *Id.*

[9] *In the Matter of the Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subd. 3,* PUC Docket No. E-999/CI-00-1636, COMMENTS BY DOC-DER AND MPCA at 9-10 (June 10, 2014).

[10] *Id.* at 16-17.

> Commission will ask the Administrative Law Judge to determine whether the Federal Social Cost of Carbon is reasonable and the best available measure to determine the environmental cost of CO_2 and, if not, what measure is better supported by the evidence.
>
> The Commission will require parties in the contested case proceeding to evaluate the costs using a damage cost approach, as opposed to (for example), market-based or cost-of-control values. When last faced with the question of the preferred approach to estimate environmental cost values, the Commission stated that, as between estimates based on damage or based on cost-of-control, the damage-cost approach is superior because it appropriately focuses on actual damages from uncontrolled emissions.
>
> Nothing in this proceeding justifies reaching a different conclusion now. Where a damage cost can be reasonably estimated, it represents a superior method of valuing an emission's environmental cost. The Commission is persuaded that a damage-cost approach can be used for the emissions under investigation, and will therefore require it.[11]

7. The Commission referred the matter to the Office of Administrative Hearings to address the following issues:

a. Whether the Federal Social Cost of Carbon is reasonable and the best available measure to determine the environmental cost of CO_2 under Minn. Stat. § 216B.2422 and, if not, what measure is better supported by the evidence; and

b. The appropriate values for $PM_{2.5}$, SO_2, and NO_x [the criteria pollutants] under Minn. Stat. § 216B.2422, subd. 3.[12]

8. Following a prehearing conference on November 14, 2014, the Administrative Law Judge issued an order granting intervention to OTP, MP, Lignite, Xcel, MLIG, GRE, and the MCC as full parties in this matter.[13] In addition, the Administrative Law Judge ordered the proceedings to be bifurcated. Testimony regarding CO_2 and the criteria pollutants would be prefiled according to separate schedules, with separate evidentiary hearings scheduled.[14]

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[11] NOTICE AND ORDER FOR HEARING at 4-5 (Oct. 15, 2014) (eDocket No. 201410-103872-02).
[12] *Id.*
[13] FIRST PREHEARING ORDER at 3 (Dec. 9, 2014) (eDocket No. 201412-105272-01). In addition to the Department, the CEOs and Peabody were the only parties named in the Commission's Notice and Order for Hearing issued on October 15, 2014.
[14] FIRST PREHEARING ORDER at 4 (Dec. 9, 2014) (eDocket No. 201412-105272-01).

9. On March 19, 2015, the Administrative Law Judge granted intervention to the MPCA as a full party in this matter.[15]

10. On March 27, 2015, the Administrative Law Judge issued an order addressing the evidentiary burdens of proof for this matter. After considering the parties' arguments, the Administrative Law Judge set forth the following parameters for the evidentiary burdens of proof:

a. A party or parties proposing that the Commission adopt a new environmental cost value for CO_2, including the Federal Social Cost of Carbon, bears the burden of showing, by a preponderance of the evidence, that the value being proposed is reasonable and the best available measure of the environmental cost of CO_2.

b. A party or parties proposing that the Commission adopt a new environmental cost value for one or more of the criteria pollutants – SO_2, NOx, and/or $PM_{2.5}$ – bears the burden of showing, by a preponderance of the evidence, that the cost value being proposed is reasonable, practicable, and the best available measure of the criteria pollutant's cost.

c. A party or parties proposing that the Commission retain any environmental cost value as currently assigned by the Commission bears the burden of showing, by a preponderance of the evidence, that the current value is reasonable and the best available measure to determine the applicable environmental cost.

d. An environmental cost value currently being applied by the Commission is presumed to be practicable, as required by Minn. Stat. § 216B.2422, subd. 3. A party challenging an existing cost value on the grounds that it is not practicable bears the burden of demonstrating impracticability by a preponderance of the evidence.

e. A party or parties, opposing a proposed environmental cost value must demonstrate, at a minimum, that the evidence offered in support of the proposed values is insufficient to amount to a preponderance of the evidence. This requirement does not apply to a party challenging an existing cost value based on its alleged impracticability, as described in paragraph 4, above.

[15] ORDER GRANTING INTERVENTION TO MINNESOTA POLLUTION CONTROL AGENCY (Mar. 20, 2015) (eDocket No. 20153-108414-01).

f. Any proponent of an environmental cost value, including existing environmental cost values, shall file direct testimony in support of its proposal according to the schedule set forth in the Second Prehearing Order in this matter.

g. A party advocating for retention of an existing cost value may not refer by reference to evidence or testimony from the Commission's CI-93-583 docket or related dockets, but must introduce any evidence on which it intends to rely in this docket, whether the evidence is drawn from an older docket or is new evidence.

h. A party may propose an environmental cost value not proposed in direct testimony in the party's rebuttal testimony only if the new cost value is offered in response to a cost value proposed in direct testimony.[16]

11. On April 16, 2015, the Administrative Law Judge issued an order concluding that testimony regarding the efficacy of renewable energy or renewable energy policy was presumed to be irrelevant and would be excluded from this matter unless its relevance was specifically demonstrated.[17] The Administrative Law Judge also granted intervention to DHE, the CBEC, and Interstate Power and Light Company as full parties in this matter.[18]

12. On May 27, 2015, the Commission issued an order requiring one public hearing to be held for this matter.[19] The Commission's order also required that members of the public be allowed to submit written comments regarding this matter via mail or the Commission's SpeakUp website.[20] The Commission's plan for providing the public notice of the public hearing and written comment period included publishing notice in the Environmental Quality Board Monitor and the MPCA's electronic newsletter, posting notice on state agency websites, issuing a press release, and directly providing the notice to all county administrators.[21]

13. On June 2, 2015, the Commission issued a notice for the public hearing and of the written comment period.[22]

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[16] ORDER REGARDING BURDENS OF PROOF at 2-3 (Mar. 27, 2015) (eDocket 20153-108636-01).
[17] THIRD PREHEARING ORDER at 2 (Apr. 16, 2015) (eDocket No. 20154-109385-01).
[18] ORDER GRANTING INTERVENTION TO DOCTORS FOR A HEALTHY ENVIRONMENT, CLEAN ENERGY BUSINESS COALITION, AND INTERSTATE POWER AND LIGHT COMPANY (Apr. 16, 2015) (eDocket No. 20154-109386-01). Interstate Power and Light Company later withdrew from the proceeding. *See* Interstate Power and Light Company Letter Withdrawing (Aug. 13, 2015) (eDocket No. 20158-113202-01).
[19] ORDER REQUIRING PUBLIC HEARING at 2 (May 27, 2015) (eDocket 20155-110744-01).
[20] Public Hearing and Comment Period Notice Plan (May 29, 2015) (eDocket 20155-110942-01).
[21] *Id.*
[22] Notice of Public Hearing and Comment Period (June 2, 2015) (eDocket No. 20156-111067-01).

14. On June 1, 2015, the parties filed direct testimony in the CO_2 portion of this matter.

15. On August 5, 2015, parties filed direct testimony in the criteria pollutants portion of this matter.

16. On August 12, 2015, parties filed rebuttal testimony in the CO_2 portion of this matter.

17. On August 26, 2015, the public hearing was held at the Commission's office in Saint Paul.[23]

18. On September 10, 2015, parties filed surrebuttal testimony in the CO_2 portion of this matter.

19. On September 15, 2015, the Administrative Law Judge filed two orders deciding several different motions to strike and exclude testimony. The Administrative Law Judge denied motions to strike all or portions of the testimony of Dr. Michael Hanemann, Dr. Stephen Polasky, Mr. Nicholas Martin, Mr. Shawn Rumery, and Mr. Christopher Kunkle.[24] The Administrative Law Judge granted a motion to strike a portion of the testimony of Dr. William Happer.[25]

20. On September 21, 2015, the Administrative Law Judge issued an order deciding additional motions to strike and exclude testimony. The Administrative Law Judge denied motions to strike portions of the testimony of Dr. John Abraham, Dr. Andrew Dessler, and Dr. Kevin Gurney.[26] The Administrative Law Judge granted a motion to strike a portion of the testimony of Dr. Peter Reich.[27]

21. On September 24 – 30, 2015, the evidentiary hearing for the CO_2 portion of this matter took place at the Commission's office in Saint Paul.

22. On October 30, 2015, the parties filed rebuttal testimony in the criteria pollutants ($PM_{2.5}$, SO_2, NO_x) portion of this matter.

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[23] A summary of the public hearing testimony, exhibits, and written public comments is attached as Appendix B.

[24] ORDER ON MOTIONS BY MINNESOTA LARGE INDUSTRIAL GROUP AND PEABODY ENERGY CORPORATION TO EXCLUDE AND STRIKE TESTIMONY at 2 (Sept. 15, 2015) (eDocket No. 20159-113992-01); ORDER ON MOTIONS BY PEABODY ENERGY CORPORATION, MINNESOTA DEPARTMENT OF COMMERCE, AND POLLUTION CONTROL AGENCY TO EXCLUDE AND STRIKE TESTIMONY at 2 (Sept. 15, 2015) (eDocket No. 20159-113998-01).

[25] ORDER ON MOTIONS BY PEABODY ENERGY CORPORATION, MINNESOTA DEPARTMENT OF COMMERCE, AND POLLUTION CONTROL AGENCY TO EXCLUDE AND STRIKE TESTIMONY at 2 (Sept. 15, 2015) (eDocket No. 20159-113998-01). The Administrative Law Judge excluded a single photograph of a weather thermometer hanging on a house above a charcoal grill, finding the photograph's probative value was outweighed by its prejudicial effect.

[26] ORDER ON MOTIONS BY MINNESOTA LARGE INDUSTRIAL GROUP AND PEABODY ENERGY CORPORATION TO EXCLUDE AND STRIKE TESTIMONY at 2-3 (Sept. 21, 2015) (eDocket No. 20159-114135-01).

[27] *Id.* A single sentence of Dr. Reich's surrebuttal testimony was excluded as irrelevant because it addressed the impact climate change might have on the needs of wildlife in particular types of habitat.

23. On November 12, 2015, the issues matrix for the CO_2 portion of this matter was filed.[28]

24. On November 24, 2015, parties filed initial briefs in the CO_2 portion of this matter. On the same date, the Administrative Law Judge issued an order denying motions to strike and exclude the testimony of Mr. Richard Rosvold and Dr. Roger McClellan in the criteria pollutants portion of this matter.[29]

25. On December 4, 2015, the parties filed surrebuttal testimony in the criteria pollutants portion of this matter.

26. On December 15, 2015, parties filed reply briefs and proposed findings in the CO_2 portion of this matter.

27. On January 12-14, 2016, the evidentiary hearing for the criteria pollutants portion of this matter took place at the Commission's office in Saint Paul.

28. On March 1, 2016, the issues matrix for the criteria pollutants portion of this matter was filed.[30]

29. On March 15, 2016, the parties filed initial briefs in the criteria pollutants portion of this matter.

30. On April 15, 2016, the parties filed reply briefs and proposed findings in the criteria pollutants portion of this matter.

31. The Administrative Law Judge is scheduled to issue her Report in the criteria pollutants portion of this matter on June 15, 2016.

II. Organization of this Report

32. In order to best accommodate all of the parties and their arguments in this proceeding, this Report is organized as described in the following paragraphs.

33. Section I provides introductory substantive background regarding the proceeding and the Report.

34. Section II sets forth Peabody's arguments regarding the existence, cause, and benefits of climate change, followed by the various parties' responses to Peabody's arguments and a section of Additional Findings of Fact. This section includes

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[28] $C0_2$ Issues Matrix (Nov. 12, 2015) (eDocket No. 201511-115671-01).
[29] ORDER ON MOTIONS BY DEPARTMENT OF COMMERCE, POLLUTION CONTROL AGENCY AND CLEAN ENERGY ORGANIZATIONS TO EXCLUDE AND STRIKE TESTIMONY at 2 (Nov. 24, 2015) (eDocket No. 201511-115904-01).
[30] Criteria Pollutants Issues Matrix (Mar. 1, 2016) (eDocket No. 20163-118846-01).

Conclusions of Law by the Administrative Law Judge regarding Peabody's climate change arguments.

35. Section III provides a detailed description of the background, development, modeling, and implementation of the process used to calculate the federal social cost of carbon (FSCC). Section IV includes the various parties' criticisms of specific aspects of the FSCC and processes related to its development. The responses to each set of criticisms follow immediately after the recitation of those criticisms. Section V presents the conclusions and recommendations of the Utilities, MLIG and Peabody regarding methodologies and costs for the social cost of carbon (SCC).

36. Section VI provides a description of Xcel's proposal for calculating the SCC. Section VII presents other parties' criticisms, and Xcel's responses, to its SCC proposal.

37. The Administrative Law Judge's Conclusions of Law and Recommendations are followed by a Memorandum. Appendix A provides a brief description of each witness who provided testimony in this proceeding, by party. Appendix B summarizes public comments.

FINDINGS OF FACT

I. Background

1. The task of the Administrative Law Judge in the CO_2 portion of this matter is to review and synthesize information related to the complex issues of climate change science, economics, and public policy in order to recommend an updated externality or cost value for carbon dioxide emissions produced by electricity generation in Minnesota.

2. When an economic activity imposes a cost or benefit on an unrelated third party, the cost or benefit is known as an economic external cost or "externality."[31] Externalities can be viewed as positive or negative depending on their impact.[32] This portion of this proceeding focuses on the externalities created as a result of CO_2 emissions produced while generating electricity.

3. Environmental economics, as used in this proceeding, focuses on the costs of externalities from electricity generation in order to develop and implement public policies, such as government regulations and tax remedies aimed at reducing environmental damages.[33] The results of this proceeding will affect how utilities in Minnesota select, allocate, and build resources for the future.

4. When it set final cost values pursuant to Minn. Stat. § 216B.2422, subd. 3 in the January 1997 Order in the first Externalities case, the Commission established several principles to guide its quantification of those values. These principles, as applicable to CO_2 cost values, included a) a preference that a damage-cost approach be

[31] Ex. 800 at 7-8 (Hanemann Direct).
[32] *Id.*
[33] Ex. 800 at 10, 12-13 (Hanemann Direct).

used; b) establishment of a range of values to appropriately take into consideration a level of uncertainty; and c) use of a global basis to establish damages for CO_2 values.[34]

5. In its July 1997 Order in the first Externalities case, the Commission found "that CO_2 is markedly different from the other pollutants for which it has established ranges of environmental costs."[35] Specifically, the Commission acknowledged that the uncertainties inherent in the assumptions necessary to provide a meaningful estimate of potential costs from CO_2 emissions, as well as those uncertainties connected to discounting to present value "the significant damage costs assumed to occur many years into the future," made quantifying externality cost values for CO_2 complex.[36] Despite the complexity of these uncertainties, the Commission concluded that it was "practicable to establish an environmental cost range for carbon dioxide."[37]

6. The Commission's concern in 1997 with the complexity of calculating the environmental cost value of CO_2 arises from the nature of CO_2 itself. Emissions of CO_2 mix into the atmosphere when they are released. They travel around the Earth and remain in the atmosphere for hundreds of years. Thus, their impacts are felt around the globe for several hundred years.[38]

7. Because of the extended time period involved, it is not possible to develop a methodology to estimate the externality value for CO_2 based solely on empirical evidence in the record. Many modeling assumptions about the future – such as population, income, gross domestic product (GDP), emissions, damage functions, equilibrium climate sensitivity (ECS), technological change, adaptation, and mitigation – rely on estimates about the future based on current experience and evidence.[39] Thus, one of the primary questions in this proceeding is which of the approaches or combinations of approaches, proposed by the parties, best accounts for the future uncertainties.

II. Climate Change

8. Peabody asserted that significant climate change is not occurring or, to the extent climate change is occurring, it is not due to anthropogenic causes. Furthermore, Peabody insisted that any current warming and increased CO_2 in the Earth's atmosphere are beneficial. Based on its position on climate change, Peabody maintained that the

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[34] 93-583 PUC ORDER 1 at 14-15. The Commission's January 1997 Order in the 1997 Externalities docket required the CO_2 cost values to be applied to facilities built within a 200-mile radius outside of Minnesota's borders. The reasoning behind this decision was an attempt to be consistent with the Commission's approach to the criteria pollutants. On reconsideration, in July 1997, the Commission declined to use its authority to apply the CO_2 values to facilities beyond Minnesota's border. 93-583 PUC ORDER 2 at 3-5.
[35] 93-583 PUC ORDER 2 at 4.
[36] 93-583 PUC ORDER 2 at 4.
[37] *Id.*
[38] Ex. 805 at 2 (Hanemann Opening Statement).
[39] Ex. 600 at 5-6 (Martin Direct).

externality value of CO_2 would most accurately be set at or below zero.[40] Peabody made several arguments in support of its position, which are discussed below.

A. Peabody Criticism of Climate Change: Natural Variability of the Earth's Climate

9. Peabody argued that only half of the CO_2 in the atmosphere is due to fossil fuel emissions. The remainder comes from natural processes.[41] According to Peabody, the claim that all increases in atmospheric CO_2 are from human causes is simply unfounded.[42]

10. Peabody maintained that CO_2 emissions are not directly related to increasing concentrations of CO_2 in the atmosphere. While CO_2 emission rates roughly tripled between 1995 and 2002, Peabody pointed out that atmospheric CO_2 concentrations "remained essentially unchanged during that time."[43] Thus, Peabody claimed "we are currently unable to relate atmospheric CO_2 levels to temperature and still less to regional changes."[44]

11. Peabody highlighted that climate change is not a new concept because the Earth's temperature and the CO_2 concentration in its atmosphere have varied quite significantly over time. According to Peabody, in earlier epochs, the Earth's climate was significantly warmer and the atmosphere's CO_2 content was much higher.[45] Peabody maintained there "is no indication that the Earth's climate is 'changing' in any manner that is not otherwise naturally-occurring and consistent with climate change patterns that occurred long before the recent concern over anthropogenic emissions."[46] Peabody argued that the Earth has experienced much higher CO_2 levels over most of the 550 million year history of multicellular living organisms without the higher CO_2 levels inducing catastrophic climate change.[47]

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[40] Peabody Initial Brief (Br.) at 98 (Nov. 30, 2015).
[41] Ex. 207 at 6 (Lindzen Direct).
[42] Ex. 207 at 6 (Lindzen Direct); Ex. 213 at 29 (Lindzen Surrebuttal).
[43] Ex. 207 at 6 (Lindzen Direct).
[44] *Id.*
[45] Ex. 207 at 2, 4, 11 (Lindzen Direct). The Earth has experienced the following warm periods: "the Medieval Warm period, the Holocene Optimum, several interglacial periods, and the Eocene (which was much warmer than the present)." *Id*. at 4; s*ee also* Ex. 228 at 2 (Bezdek Direct); Ex. 204 at 4 (Happer Rebuttal).
[46] Ex. 207 at 2 (Lindzen Direct).
[47] Ex. 204 at 4 (Happer Rebuttal Ex. 1).

12. According to Peabody, climate change concerns focused on CO_2 are not viable unless it is first proven that global warming caused by CO_2 emissions is greater than warming caused by natural variability.[48] Peabody argued that the Intergovernmental Panel on Climate Change (IPCC)[49] simply assumed global warming caused by carbon dioxide emissions is greater than warming caused by natural variability, and therefore attributes the warming observed since the 1970s to anthropogenic causes.[50] According to Peabody, the Earth's climate record shows that global temperatures rose from 1895 to 1946 in a manner essentially indistinguishable from the warming that occurred between 1957 and 2008.[51] Thus, Peabody took issue with the IPCC attributing all of the warming in the later period solely to human activity.[52]

13. To support its argument that the IPCC's climate models greatly overestimate global warming, Peabody pointed to evidence that the United States was warmer during the Dust Bowl years of the 1930s than it has been since, and cited a study of United States data from 2005 to 2014 that suggests the climate is cooling.[53]

B. Peabody Criticism of Climate Change: Global Temperature Changes

14. According to Peabody, global atmospheric temperatures are measured by surface thermometers, weather balloons (radiosondes), and satellites.[54] Peabody claimed all three methods of measuring atmospheric temperatures show no warming since 1998.[55]

15. Peabody stated that the IPCC's climate models may generate warming that roughly fits the observational data of atmospheric temperatures from the 1970s into the 1990s, but Peabody determined that global average temperatures have failed to increase after 1998, as the models predicted. Peabody is not certain why the models failed.[56] Peabody insisted that the climate models predicted much more atmospheric warming than has occurred, even as CO_2 emissions have been at their highest levels.[57]

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[48] Ex. 209 at 3 (Lindzen Direct Ex. 2).
[49] In 1988, the United Nations established the Intergovernmental Panel on Climate Change (IPCC), which is a scientific organization charged with producing reports supporting the United Nations Convention on Climate Change, an international treaty. The IPCC has published five climate science assessment reports in 1990, 1995, 2001, 2007, and 2014. The Commission and the Minnesota Court of Appeals recognize the IPCC as a source of expertise on climate change. *See In the Matter of the Quantification of Envtl Costs Pursuant to Laws of Minn. 1993, Chap. 356, Sec. 3,* PUC Docket No. E-999/CI-93-583, ORDER ESTABLISHING ENVIRONMENTAL COST VALUES at 24 (Jan. 3, 1997); *In re Quantification of Envtl Costs*, 578 N.W.2d 794, 800-01 (Minn. Ct. App. 1998), *review denied* (Minn. Aug. 18, 1998).
[50] Ex. 207 at 2-3 (Lindzen Direct).
[51] *Id.* at 4.
[52] *Id.*
[53] Ex. 233 at 9-10 (Bezdek Rebuttal Ex. 1).
[54] Ex. 221 at 5-6 (Spencer Direct).
[55] *Id.*
[56] Ex. 200 at 4, 8 (Happer Direct); Ex. 207 at 3 (Lindzen Direct); Ex. 227 at 2-4 (Spencer Surrebuttal).
[57] Ex. 207 at 3 (Lindzen Direct); Ex. 221 at 3-5 (Spencer Direct); Ex. 233 at 5 (Bezdek Rebuttal Ex. 1).

16. In addition to overestimating atmospheric warming, Peabody alleged the IPCC's climate models overestimated the amount of oceanic warming that has occurred.[58]

17. Peabody's experts referred to the period after 1998 as the "hiatus" because, in contrast to the rising temperature trend observed beginning in the 1970s, the observational data after 1998 shows a flat or even declining trend in atmospheric temperatures.[59]

18. Peabody placed significant weight on the failure of the IPCC's climate models to explain the hiatus in warming after 1998 except by the introduction of *ad hoc* mechanisms, such as aerosols.[60] Peabody contended the IPCC's climate models have no utility if they cannot reliably predict temperature change from CO_2 emissions.[61] The Integrated Assessment Models (IAMs) used to calculate the FSCC "make little sense today since they are based on climate models that clearly overestimate the warming from more CO_2 by hundreds of per cents [sic]."[62] Because the IPCC models failed to account for the hiatus in warming, Peabody argued the models are not reliable.[63]

C. Peabody Criticism of Climate Change: Extreme Weather Events

19. Peabody disputed that extreme weather events are becoming more severe or more frequent than in the past.[64] Peabody noted that, even more certainly than climate change, increased populations and wealth have been found to be major causes of economic damages from extreme weather events.[65] "Concerns arising from the potential impact of global warming on drought, flooding, storminess, sea ice, and similar issues are largely unproven. There is no evidence that these matters are increasing due to warming (or in most cases increasing at all)."[66] Moreover, Peabody claimed there is no evidence of increased hurricanes, tornadoes, wildfires, or droughts despite increases in atmospheric CO_2 levels.[67]

20. Furthermore, despite alarms over recent reports of rising sea levels, Peabody maintained that sea levels have been rising for a very long time.[68] Peabody

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[58] Ex. 206 at 7 (Happer Surrebuttal).
[59] Ex. 200 at 8 (Happer Direct); Ex. 221 at 6 (Spencer Direct).
[60] Ex. 207 at 3 (Lindzen Direct); Ex. 202 at 6 (Happer Direct Ex. 2). "Aerosols" in the climate change context refer to "so-called sulfates," which primarily "act as reflectors of visible light" and have a cooling effect because they reflect sunlight. Evidentiary Hearing Transcript Volume (Tr. Vol.) 2A at 37 (Lindzen).
[61] Ex. 223 at 4 (Spencer Direct Ex. 2).
[62] Ex. 200 at 4 (Happer Direct).
[63] *Id.* at 9.
[64] Ex. 228 at 32 (Bezdek Direct); Ex. 207 at 6-7 (Lindzen Direct); Ex. 200 at 9 (Happer Direct).
[65] Ex. 213 at 38 (Lindzen Surrebuttal).
[66] Ex. 207 at 6-7 (Lindzen Direct).
[67] Ex. 228 at 32 (Bezdek Direct).
[68] Ex. 207 at 7 (Lindzen Direct); Ex. 213 at 36-37 (Lindzen Surrebuttal).

stated the rate of sea level rise was faster during the period from 1904 to 1953 than it has been since that time.[69]

21. Peabody highlighted that even the IPCC has retreated from claims concerning the connection between global warming and extreme weather. The IPCC's most recent report, *Climate Change 2013: The Physical Science Basis,* Fifth Assessment Report (IPCC AR5),[70] found the causal connection less certain than did the IPCC's last version of the report published in 2007 (Fourth Assessment Report (IPCC AR4)).[71]

22. Peabody predicted that the actual impact of global warming will be to reduce extreme weather events.[72] "The primary driving force for storm development is the temperature difference between the tropics and the poles, a difference that should be decreasing if there is global warming, which is supposed to be greater at the poles."[73]

D. Peabody Criticism of Climate Change: Benefits from Increased CO_2 Concentrations and Warmer Temperatures

23. Peabody asserted that the IAMs virtually ignore the benefits from rising CO_2 levels.[74]

24. Peabody said there are direct and indirect benefits from CO_2 emissions created by burning fossil fuels for energy, including increased agricultural productivity.[75] According to Peabody, increased levels of atmospheric CO_2 are highly beneficial for most plants "as has been demonstrated in literally thousands of laboratory and field experiments."[76] Most plants benefit from higher CO_2 concentrations because higher concentrations facilitate the photosynthetic process by increasing plants' ability to absorb CO_2, and plants lose less water through transpiration, which means plants grow more readily in drier climates.[77] Peabody maintained that doubling the CO_2 in the atmosphere will increase the productivity of most herbaceous plants by about one-third.[78]

25. Peabody claimed the economic benefits of increased agricultural productivity are large. From 1961 to 2012, the economic value of the increased output of 45 crops due to increased atmospheric CO_2 levels cumulatively totaled $3.2 trillion.[79] Peabody estimated that the economic value will triple from 2012 to 2050.[80] By driving current global GDP with carbon emissions, Peabody calculated that "at present, each ton

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[69] Ex. 233 at 11-12 (Bezdek Rebuttal Ex. 1); Ex. 213 at 36 (Lindzen Surrebuttal) (the sea level increases from 1930 to 1950 "are as large or larger than the increases documented since 1979.").
[70] Ex. 405 (IPCC AR5).
[71] Ex. 213 at 38-39 (Lindzen Surrebuttal).
[72] *Id.*
[73] Ex. 207 at 10-11 (Lindzen Direct).
[74] Ex. 228 at 9-10 (Bezdek Direct).
[75] *Id.* at 8-9.
[76] *Id.* at 2.
[77] *Id.*
[78] *Id.* at 3.
[79] *Id.*
[80] *Id.* at 10-11.

of carbon used produces about $6,700 of global GDP."[81] Overall, Peabody estimated that the "current benefits [from CO_2 emissions] clearly outweigh any hypothesized costs by, literally, orders of magnitude."[82]

26. Peabody maintained that fossil fuels are the only fuels that can assure future economic growth.[83] Furthermore, Peabody argued that renewable sources of energy cannot sustain economic growth because "they are unreliable, intermittent, expensive and are not scalable."[84]

27. Peabody claimed that excessive cold caused twice as many deaths in the United States as excessive heat.[85] Citing a study concluding that warmer weather is associated with fewer hospital admissions for asthma than colder weather, Peabody alleged that DHE's "claim that global warming will lead to more asthma and respiratory illness is backwards; it will actually reduce them." [86] Two other studies cited by Peabody concluded that a wider variety of pollens and microbes resulting from increased CO_2 in a slightly warmer world could decrease the incidence and severity of asthma and respiratory complications by increasing resistance.[87]

28. The principal indirect benefit from CO_2 emissions is the modern industrial world, according to Peabody.[88]

E. Response to Peabody Criticism of Climate Change: Natural Variability of the Earth's Climate

29. The Agencies responded to Peabody's denial that carbon dioxide emissions are the driving force behind climate change by asserting that the increase in atmospheric CO_2 is largely due to the increase in the combustion of fossil fuels and the alteration of vegetation at large scales (e.g. tropical deforestation).[89] Explaining that the form of atmospheric carbon dioxide, known as $^{14}CO_2$, is a CO_2 molecule with a slightly heavier carbon atom, the Agencies claimed fossil-fuel-derived CO_2 is distinguishable and does not contain any of the rare form $^{14}CO_2$ molecules because of $^{14}CO_2$'s short-lived natural radioactive decay, which is far less than the time it takes for carbon to transition to fossilized form.[90] According to the Agencies, the atmosphere has a well-measured amount of CO_2 in the $^{14}CO_2$ form. The dilution of $^{14}CO_2$ can be quantitatively tied to the emissions of fossil fuel CO_2 into the Earth's atmosphere at levels consistent with the

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[81] *Id.* at 14.
[82] *Id.* at 28.
[83] *Id.* at 14.
[84] *Id.* at 15.
[85] *Id.* at 6.
[86] Ex. 206 at 22 (Happer Surrebuttal).
[87] Ex. 206 at 23 (Happer Surrebuttal).
[88] Ex. 228 at 11 (Bezdek Direct).
[89] Ex. 803 at 8 (Gurney Rebuttal).
[90] *Id.*

records of coal, oil, and natural gas consumption worldwide.[91] This is known as the "Suess" effect and, the Agencies claimed, is well-established.[92]

30. The Agencies further explained that roughly one-half of the emissions due to fossil fuel combustion and deforestation are removed from the atmosphere on an average basis, and the removal processes in the ocean and land biosphere are relatively well quantified.[93] The short-term (year-to-year) modulation of global emissions remains an area of active research.[94]

F. Response to Peabody Criticism of Climate Change: Global Temperature Changes

31. In response to Peabody's claim that no significant global warming has occurred since 1998, the Agencies argued that Peabody's statement, "satellite measurements indicate that the lower atmosphere has had no warming for at least 20 years," appears to be based upon information published on a website rather than a peer-reviewed scientific paper.[95]

32. The Agencies observed that 1998 was a very large El Niño year with an unusually high global mean temperature.[96] According to the Agencies, this time period in the observed-temperature record has been discussed regularly in the peer-reviewed literature as well as in the IPCC AR5.[97] During the time period cited by Peabody, the global mean surface temperature record shows a decadal trend of 0.04 degrees centigrade (°C) increase per decade. However, over a longer climatological span, from 1951 – 2012, a larger trend estimate of 0.106 ± 0.027 °C per decade is estimated.[98]

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[91] *Id.*
[92] *Id.*
[93] *Id.*
[94] *Id.*
[95] Ex. 803 at 10 (Gurney Rebuttal).
[96] *Id.* at 11.
[97] Ex. 803 at 11 (Gurney Rebuttal). Because of the timing of the production and review process involved in all IPCC reports, the period is described in the most recent IPCC AR5 as a 15-year timespan (1998 – 2012). *Id.*
[98] Ex. 803 at 11 (Gurney Rebuttal).

33. The Agencies pointed to the IPCC AR5's presentation of the global mean surface temperature trends from three different temperature databases[99]:

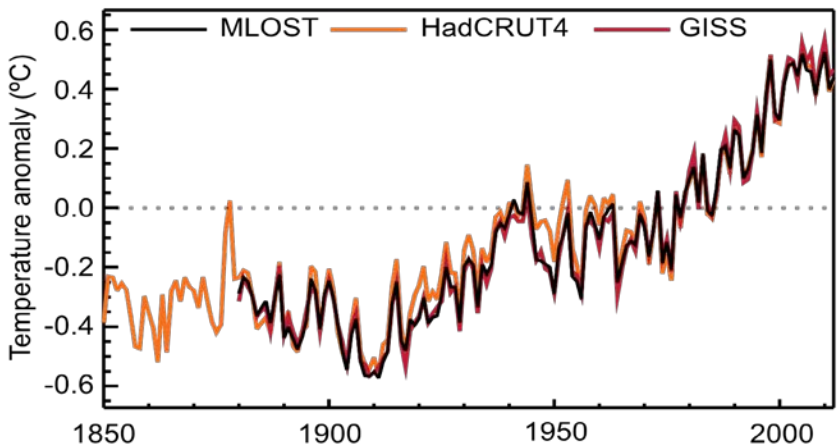

Figure 2.20 | Annual global mean surface temperature (GMST) anomalies relative to a 1961–1990 climatology from the latest version of the three combined land-surface air temperature (LSAT) and sea surface temperature (SST) data sets (HadCRUT4, GISS and NCDC MLOST). Published data set uncertainties are not included for reasons discussed in Box 2.1.

34. According to the Agencies, the temperature trend records shown in the graph represent statistically significant trends greater than the short, recent warming "hiatus."[100] The short time period emphasized by Peabody is only the very end portion of the 162-year record, for which the general trend behavior slows.[101] The Agencies maintained that trends over periods as short as 15 years are neither reliable nor a reflection of long-term change in climate.[102] Further, the Agencies pointed to the IPCC AR5 explanation:[103]

> Owing to natural variability, trends based on short records are very sensitive to the beginning and end dates and do not in general reflect long-term climate trends. As one example, the rate of warming over the past 15 years (1998 – 2012; 0.05 [–0.05 to +0.15] °C per decade), which begins with a strong El Niño, is smaller than the rate calculated since 1951 (1951 – 2012; 0.12 [0.08 to 0.14] °C per decade). Trends for 15-year periods starting in 1995, 1996, and 1997 are 0.13 [0.02 to 0.24], 0.14 [0.03 to 0.24] and 0.07 [–0.02 to 0.18], respectively.

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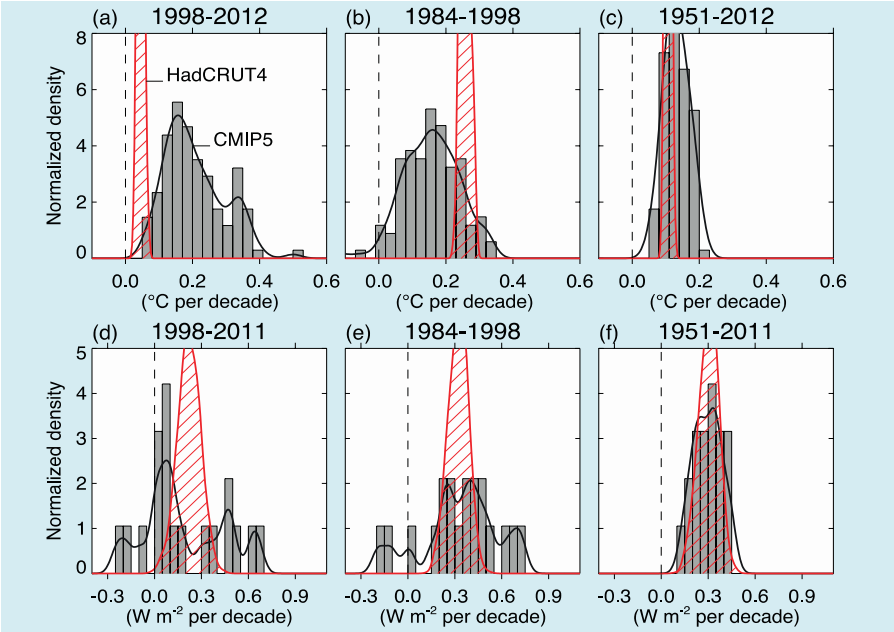
[99] Ex. 803 at 12 (Gurney Rebuttal); Ex. 405 at 193 (IPCC AR5).
[100] Ex. 803 at 12 (Gurney Rebuttal).
[101] *Id.*
[102] Ex. 803 at 13 (Gurney Rebuttal).
[103] Ex. 405 at 194 (IPCC AR5). The numbers from the IPCC AR5 trends are slightly different from those provided by the Agencies. The Agencies did not explain the discrepancy.

35. The Agencies provided a more complete view of the topic by showing the following figure from the IPCC AR5. The figure shows there is little discrepancy between the model and observed temperature trends when a comparison is performed over long time periods such as in panel c: the 1951-2012 time period, as opposed to shorter time periods such as in panels a and b: 1998-2012 and 1984-1998, respectively.[104]



ded: from Forster et al., 2013). Black lines are smoothed versions of the histograms. Each histogram is normalized so that its area sums up to one.

36. The Agencies criticized Peabody for its failure to acknowledge panel c.[105] The Agencies explained that the figure in panel c demonstrates the importance of considering sufficiently long periods of time in order to establish climate trends and/or the ability of models to simulate long-term climate trends.[106] The Agencies stressed that periods of less than three decades are not long enough to assess climate trends or model veracity.[107]

37. Overall, the Agencies argued that Peabody's reference to trends in the short "hiatus" time period is not relevant to an assessment of the observational evidence for

[104] Ex. 803 at 15 (Gurney Rebuttal). Panels a, b, and c in this figure illustrate temperature trends, which are the subject of the discussion between the Agencies and Peabody. Panels d, e, and f illustrate forcing, a concept not relevant to the discussion. However, for purposes of completeness, the entire figure is included.
[105] Ex. 803 at 16 (Gurney Rebuttal).
[106] *Id.*
[107] *Id.*

anthropogenic climate change, nor is it sufficient grounds upon which to make a statement regarding the long-term trend of the climate in one direction or another.[108]

38. The Agencies disputed the statement of Peabody witness Dr. Bezdek, who claimed to quote a study by Steinkamp and Hickler, stating that the study is "further evidence that 'global warming has ceased.'"[109] The Agencies maintained that their expert examined this paper, and found that it neither contains the statement nor implies such a conclusion. Instead, the Agencies asserted that the paper concerns dry forests, the reasons for their mortality, and the failure of modeling to adequately represent this kind of mortality.[110]

G. Response to Peabody Criticism of Climate Change: Extreme Weather Events

39. In response to Peabody's claimed lack of evidence of increasing frequency and severity of extreme weather events, the CEOs argued that Peabody's claim "conflicts with the scientific literature," which demonstrates "increasing frequency and intensity of extreme weather events."[111] According to the CEOs, there has been a substantial global increase in droughts, heatwaves, and extreme precipitation events.[112] The CEOs also pointed to "a wide array of peer-reviewed analyses [indicating] that humans are playing an increasingly important role in extreme temperature and precipitation events."[113]

H. Response to Peabody Criticism of Climate Change: Benefits from Increased CO_2 Concentrations and Warmer Temperatures

40. In response to Peabody's assertion that agriculture will benefit from increased CO_2 and warming temperatures, the Agencies conceded that the climate science community does not deny the CO_2 fertilization effect.[114] Instead, the Agencies insisted the relevant question is whether the impacts (positive or negative) of climate change on vegetation, particularly food crops, have been incorporated into the modeling efforts. According to the Agencies, the research suggests the net effect of climate change on food crops is negative.[115]

41. The CEOs cautioned that the effects of climate change on vegetation include many simultaneous kinds of changes. These impacts include not only changes in CO_2 concentrations and warmer temperatures, but also changes in soil and water availability, changes in insects, diseases, invasive species and fire.[116] Climate change also means that the regions in which certain species of vegetation now grow will change. For example, some trees, such as spruce and fir, which are adapted to the cool climate

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[108] *Id.* at 13.
[109] Ex. 804 at 18 (Gurney Surrebuttal).
[110] *Id.*
[111] Ex. 102 at 19 (Abraham Rebuttal).
[112] Ex. 105 at 23 (Abraham Surrebuttal).
[113] Ex. 103 at 26 (Dessler Rebuttal).
[114] Ex. 804 at 11-12 (Gurney Surrebuttal).
[115] *Id.*
[116] Ex. 107 at 4 (Reich Surrebuttal).

of northern Minnesota and Canada, will not do well because of warming temperatures, even if other growth factors are ideal.[117]

42. The CEOs explained that recent research from Canada and Minnesota is suggesting that increased periods of limited water availability are occurring due to climate change. The CEOs maintained that this is because climate change brings fewer, heavier rainfalls, with more water running off into streams and rivers and less soaking into the soil. Moreover, the CEOs asserted, warmer plants and soil will evaporate more water.[118]

43. In addition, the CEOs observed that "the same processes that increase the CO_2 concentrations in our atmosphere . . . also contribute to the formation of increased ozone concentrations . . . ."[119] Not only does ozone damage lungs of people and other animals, it "also damages the membranes of any plant cells it encounters." Increased ozone will likely offset most or all of the benefits that CO_2 or warming might bring.[120] The CEOs concluded that the risks to crop production from climate change are greater than the potential benefits.[121]

44. DHE challenged Peabody's claims regarding health benefits from increased CO_2. DHE asserted that Peabody's claim that cold is a greater danger to human health than heat "is directly contradicted by the National Climate Assessment, which states that 'heat stress . . . has been the leading weather-related cause of death in the United States since 1986, when record-keeping began.'"[122]

45. DHE explained that, while there might be fewer deaths from cold, the increased number of deaths from warmer temperatures would result in a net increase in mortality rates.[123] DHE maintained that health professionals are in "nearly unanimous" agreement that climate change is the "biggest global health threat of the 21st century."[124]

46. Responding to Peabody's claim that only fossil fuels can assure future economic growth, CEBC asserted that wind power costs have dropped 90 percent since the 1980s[125] and the cost to install a residential solar photovoltaic (PV) system dropped 43 percent from the end of 2011 to the end of 2014, reaching a cost of $3.54 per watt at the end of 2014. During the same time span, the price to install a utility-scale system decreased by 50 percent, to $1.61 per watt at the end of 2014, according to CEBC.[126]

47. CEBC rebutted Peabody's arguments that renewable energy sources are unreliable, declaring that wind energy has become increasingly reliable, with downtime for utility-scale wind turbines decreasing 47 percent from 2007 to 2012 and states such

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[117] *Id.* at 4-5.
[118] Ex. 107 at 6 (Reich Surrebuttal).
[119] *Id.* at 13.
[120] *Id.* at 14.
[121] *Id.*
[122] Ex. 500 at 4 (Rom Rebuttal).
[123] *Id.*
[124] *Id.* at 6.
[125] Ex. 701 at 6 (Kunkle Rebuttal).
[126] Ex. 700 at 3 (Rumery Rebuttal).

as Iowa and South Dakota providing more than 25 percent of in-state generation from wind.[127] According to CEBC, solar energy is increasingly being integrated into the electricity grid without impacting reliability or stability.[128]

48. Finally, CEBC maintained that renewable energy now comprises a significant portion of the new generating capacity added to the grid in the United States. For example, CEBC said that, since 2006, "at least 21% of electric capacity added every year has been from renewable resources," with that contribution increasing to 50 percent or above from 2012-2014.[129]

I. Additional Findings Regarding Climate Change

49. The Commission and the Minnesota Court of Appeals recognize the IPCC as a source of expertise on climate change.[130] On appeal of the first Externalities case, the Minnesota Court of Appeals concluded that "the commission properly relied on . . . expert testimony and the IPCC report."[131]

50. The Court of Appeals further found "the commission's determination that [carbon dioxide] negatively affects the environment was proper."[132]

51. In 2007, the United States Supreme Court observed that "[t]he harms associated with climate change are serious and well recognized. The Government's own objective assessment of the relevant science and a strong consensus among qualified experts indicate that global warming threatens, inter alia, a precipitate rise in sea levels, severe and irreversible changes to natural ecosystems, a significant reduction in winter snowpack with direct and important economic consequences, and increases in the spread of disease and the ferocity of weather events."[133] The United States Supreme Court found that greenhouse gases "fit well within" the Clean Air Act's definition of "air pollutant,"[134] further noted the "EPA's failure to dispute the existence of a causal connection between manmade greenhouse gas emissions and global warming" and attached "considerable significance to EPA's espoused belief that global climate change must be addressed."[135] In making its observations regarding climate change, the United States Supreme Court favorably cited the IPCC.[136]

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[127] Ex. 701 at 12 (Kunkle Rebuttal).
[128] Ex. 700 at 9 (Rumery Rebuttal).
[129] Ex. 700 at 7 (Rumery Rebuttal).
[130] *In the Matter of the Quantification of Envtl Costs Pursuant to Laws of Minn. 1993, Chap. 356, Sec. 3,* PUC Docket No. E-999/CI-93-583, ORDER ESTABLISHING ENVIRONMENTAL COST VALUES at 24 (Jan. 3, 1997); *In re Quantification of Envtl Costs*, 578 N.W.2d 794, 800-01 (Minn. Ct. App. 1998), *review denied* (Minn. Aug. 18, 1998).
[131] *In re Quantification of Envtl Costs*, 578 N.W.2d 794, 800 (Minn. Ct. App. 1998), *review denied* (Minn. Aug. 18, 1998).
[132] *Id.*
[133] *Mass. v. EPA*, 127 S. Ct. 1438, 1442, 549 U.S. 497, 499 (2007).
[134] *Id.*
[135] *Id.* at 1443, 549 U.S. at 500.
[136] *Id.* at 1448-49, 549 U.S. at 508-10.

52. The IPCC AR5 "presents clear and robust conclusions in a global assessment of climate change science — not the least of which is that the science now shows with 95 percent certainty that human activity is the dominant cause of observed warming since the mid-20th century."[137]

53. According to the IPCC AR5, "[w]arming of the climate system is unequivocal, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of greenhouse gases have increased . . . ."[138] Data from the IPCC Report shows that "[e]ach of the last three decades has been successively warmer at the Earth's surface than any preceding decade since 1850 . . . . In the Northern Hemisphere, 1983-2012 was *likely* the warmest 30-year period of the last 1400 years (*medium confidence*)."[139] In addition, "[t]he rate of sea level rise since the mid-19th century has been larger than the mean rate during the previous two millennia (*high confidence*). Over the period 1901 to 2010, global mean sea level rose by 0.19 [0.17 to 0.21] m[eters] . . . ."[140]

54. The IPCC AR5 predicts that "[g]lobal surface temperature change for the end of the 21st century is likely to exceed 1.5°C relative to 1850 to 1900 for all Representative Concentration Pathways (RCP)[141] scenarios except RCP2.6. It is *likely*-to exceed 2°C for RCP6.0 and RCP8.5, and *more likely than not* to exceed 2°C for RCP4.5. Warming will continue beyond 2100 under all RCP scenarios except RCP2.6. Warming will continue to exhibit interannual-to-decadal variability and will not be regionally uniform . . . ."[142]

55. Data from the IPCC AR5 also shows that "[t]he atmospheric concentrations of carbon dioxide, methane, and nitrous oxide have increased to levels unprecedented in at least the last 800,000 years. Carbon dioxide concentrations have increased by 40% since pre-industrial times, primarily from fossil fuel emissions and secondarily from net land use change emissions. The ocean has absorbed about 30% of the emitted anthropogenic carbon dioxide, causing ocean acidification . . . ."[143] Therefore, "[m]ost aspects of climate change will persist for many centuries even if emissions of CO_2 are stopped. This represents a substantial multi-century climate change commitment created by past, present and future emissions of CO_2."[144] Moreover, "[c]ontinued emissions of greenhouse gases will cause further warming and changes in all components of the

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[137] Ex. 405 at v (IPCC AR5).
[138] Ex. 405 at 4 (IPCC AR5).
[139] *Id.* at 5.
[140] *Id.* at 11. (emphasis in original).
[141] RCPs, or Representative Concentration Pathways, are four new scenarios defined by the scientific community that are identified by their approximate total radiative forcing in year 2100 relative to 1750. Ex. 405 at 29 (IPCC AR5).
[142] Ex. 405 at 20 (IPCC AR5). (emphasis in original).
[143] *Id.* at 11.
[144] *Id.* at 27.

climate system. Limiting climate change will require substantial and sustained reductions of greenhouse gas emissions."[145]

56. Ultimately, the IPCC AR5 concludes, "[h]uman influence on the climate system is clear. This is evident from the increasing greenhouse gas concentrations in the atmosphere, positive radiative forcing, observed warming, and understanding of the climate system."[146] "Human influence has been detected in warming of the atmosphere and the ocean, in changes in the global water cycle, in reductions in snow and ice, in global mean sea level rise, and in changes in some climate extremes . . . . This evidence for human influence has grown since the [AR4]. It is *extremely likely* that human influence has been the dominant cause of the observed warming since the mid-20th century."[147]

J. Administrative Law Judge's Conclusions Regarding Climate Change

57. Peabody must demonstrate, by a preponderance of the evidence, that its claims that climate change is not occurring or, to the extent it is occurring, the warming and increased CO_2 in the Earth's atmosphere are not anthropogenically caused and are beneficial. [148] This burden of proof is appropriate because Peabody presented the testimony regarding the existence and benefits of climate change and warming in support of its proposed values for the SCC in this proceeding. In its Post-Hearing Brief in this matter, Peabody states that the most appropriate SCC value is zero.[149] Alternative values proposed by Peabody are set forth in section V.C. of this Report.

58. The Administrative Law Judge concludes that Peabody Energy has failed to demonstrate, by a preponderance of the evidence, that climate change is not occurring or, to the extent climate change is occurring, the warming and increased CO_2 in the Earth's atmosphere are beneficial.

III. The Federal Social Cost of Carbon

A. Federal Social Cost of Carbon Background

59. Executive Order 12866[150], issued in 1993, requires federal agencies conducting rulemakings to assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating. Costs and benefits shall be understood to include both quantifiable measures (to the fullest extent that these can be usefully estimated) and qualitative measures of costs and benefits that are difficult to quantify, but nevertheless essential to consider.[151]

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[145] *Id.* at 19.
[146] *Id.* at 15.
[147] Ex. 405 at 17 (IPCC AR5) (emphasis in original).
[148] Minn. R. 1400.7300, subp. 5 (2015); ORDER REGARDING BURDENS OF PROOF at 2-3 (Mar. 27, 2015) (eDocket 20153-108636-01).
[149] Peabody Initial Br. at 98 (Nov. 30, 2015).
[150] Exec. Order No. 12866, 58 Fed. Reg. 190 (Oct. 4, 1993).
[151] *Id.*

60. Concerned that natural and anthropogenic activities were generating heat-trapping greenhouse gasses (GHG), federal regulatory officials determined that Executive Order 12866 required federal agencies conducting rulemakings to consider as part of a prospective rule's costs and benefits the potential effects the rule would have on GHG emissions.[152]

61. In 2009, the United States' Council of Economic Advisers and the federal Office of Management and Budget (OMB) convened a working group of federal agencies to develop estimates of the FSCC.[153] The interagency group included scientific and economic experts from the White House and federal agencies, including the Council of Economic Advisers, Council on Environmental Quality, National Economic Council, Office of Energy and Climate Change, Office of Science and Technology Policy, Office of Management and Budget, Environmental Protection Agency, and Departments of Agriculture, Commerce, Energy, Transportation, and Treasury.[154]

62. Known as the Interagency Working Group (IWG), this group of federal agency representatives was charged with estimating the social cost of carbon so that federal agencies regulating activities affecting carbon emissions could incorporate the benefits of reducing CO_2 emissions, or the costs of increasing CO_2 emissions, into the "cost-benefit analyses of regulatory actions that have small, or 'marginal,' impacts on cumulative global emissions."[155]

63. The FSCC is defined as "an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year" developed by the IWG.[156]

64. In 2010, the IWG produced its first estimates of the FSCC. The IWG cautioned that its estimates were based on many uncertainties and "should be updated over time to reflect increasing knowledge of the science and economics of climate impacts."[157]

65. The IWG updated the FSCC in May and November of 2013 and again in July of 2015.[158]

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[152] Ex. 800, WMH-2 at 2 (Hanemann Direct).
[153] Ex. 100, Schedule 4 at 2 (Polasky Direct); Ex. 800, WMH-2 at 4 (Hanemann Direct).
[154] Ex. 100, Schedule 2 at cover page (Polasky Direct).
[155] Ex. 100, Schedule 2 at 1 (Polasky Direct). The reference to "carbon" in the FSCC reflects three things: (1) the dominance of carbon dioxide among the current greenhouse gasses; (2) the translation of non-CO_2 GHGs into CO_2-equivalent units, and (3) the use of "carbon" as shorthand for carbon dioxide and its equivalents. Ex. 800 at 22 (Hanemann Direct).
[156] Ex. 100, Schedule 2 at 1 (Polasky Direct). The "incremental Increase" is an additional metric ton of CO2 emissions. This report uses the term Federal Social Cost of Carbon (FSCC) when discussing the specific analysis and cost values determined by the IWG. It uses the term Social Cost of Carbon (SCC) when referring more generally to processes designed to arrive at cost values for future damages caused by CO_2, or by CO_2 damage cost values determined by entities other than the IWG.
[157] Ex. 100, Schedule 2 at 1 (Polaksy Direct).
[158] *See* Ex. 800, WMH-3 (Hanemann Direct); Ex. 600, NFM-1, Schedule 2 (Martin Direct).

66. The FSCC is used in federal regulatory impact analyses (RIA) involving GHG emissions. The FSCC is a tool for evaluating the benefits and costs of proposed federal rules by accounting for the impact of GHG emissions.[159]

67. The process the IWG used to develop the FSCC was evaluated by the United States Government Accountability Office (GAO) at the request of members of Congress.[160]

68. The GAO report, dated July, 2014, concluded that the IWG process reflected the following principles:[161]

a. The working group used a consensus-based approach for making key decisions in developing the 2010 and 2013 estimates.

b. The working group relied largely on existing academic literature and models to develop its estimates.

c. The Technical Support Document disclosed several limitations of the estimates and areas that the working group identified as being in need of additional research.

B. The IWG FSCC Development Process: Overview

69. The CEOs, the Agencies, DHE, and CEBC[162] advocate the adoption of the IWG's FSCC as "reasonable and the best available measure to determine the environmental cost of CO_2 under Minn. Stat. § 216B.2422 . . . . "[163] The CEOs and the Agencies presented the IWG's process and the resulting FSCC as described in the remainder of this section of the Report.

70. From a conceptual standpoint, the Agencies explained that, in order to estimate the marginal external cost associated with an incremental increase in carbon emissions, the following information must be considered: (1) how an additional carbon emission changes the existing accumulation of GHGs in the atmosphere via the carbon cycle; (2) how that change, in turn, changes the amount of energy stored in the Earth's system (known as the change in radiative forcing); (3) how the change in radiative forcing leads to changes in the climate worldwide; (4) how those changes in climate affect things that matter to humans, such as water supply and drought, crop production, disease and

[159] Ex. 800 at 61 (Hanemann Direct).
[160] Ex. 100 at 6 (Polasky Direct).
[161] *Id.* at 7.
[162] *See* Ex. 500 at 9 (Rom Rebuttal); CEBC Initial Br. (November 24, 2015). In its post-hearing brief, MLIG argued for the first time that neither DHE nor CEBC introduced "admissible foundational evidence to support adoption of the FSCC." MLIG Initial Br. at 11-17 (November 24, 2015). The Administrative Law Judge addresses these objections in her Memorandum at the end this Report.
[163] NOTICE AND ORDER FOR HEARING at 5 (Oct. 15, 2014) (eDocket No. 201410-103872-02).

human health, outbreaks of wildfire, coastal flooding, ecosystem functioning and the like; and (5) how humans value the changes in those things.[164]

71. According to the Agencies, the IWG determined that the task of estimating the SCC was best accomplished through the use of integrated assessment models (IAMs). An IAM is a mathematical computer model that accounts for the five estimates identified in the preceding paragraph required to calculate the SCC. The IAMs combine climate processes with economic growth scenarios and attempt to quantify their effects on each other.[165]

72. The Agencies described IAMs as mathematical models based upon explicit assumptions about the behavior of a modeled system. They attempt to incorporate information from physical and social sciences that considers economic, political, and demographic variables in addition to the climate system, to provide a synthesis of information available for use by decision-makers.[166]

73. The Agencies further stated that, for purposes of estimating the SCC, an IAM combines (1) a reduced-form[167] representation of the carbon cycle and the climate system together with (2) a reduced-form representation of the economy, economic growth and the generation of GHG emissions and (3) a reduced-form representation of the impacts of climate change and how those impacts are valued (the external cost generated).[168] An IAM combines these three components in one integrated model – the representation of how economic activity generates emissions, the representation of how the emissions lead to climate change, and the representation of the economic cost of the resulting impacts.[169] The numerical computations are conducted period by period, starting in a base year (e.g., 2010) and continuing at least through 2100.[170]

C. Modeling Relationships: the Global Economy, Emissions, Warming and Damages

74. Fossil fuel combustion and other human activities such as deforestation release CO_2 emissions that add to the CO_2 already present in the atmosphere, according to the Agencies.[171] Natural processes also release CO_2.[172] Over time, some of the CO_2 emissions have remained in the atmosphere, changing its energy balance. The Agencies

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[164] Ex. 800 at 22-23 (Hanemann Direct).
[165] *Id.* at 23-24.
[166] *Id.*
[167] In climate science, "reduced-form" models involve a simplified version of a larger model. The larger model ("the structural model") has equations characterizing physical or behavioral relationship ("structural equations") which, in the reduced-form model, are simplified into a smaller number of equations that summarize the outcome of interactions among the structural equations after variables have been solved out of them. Ex. 800 at 24 (Hanemann Direct).
[168] Ex. 800 at 23 (Hanemann Direct).
[169] *Id.* at 24.
[170] Ex. 800 at 25-26 (Hanemann Direct). As discussed *infra*, the IAMs, in their original forms, ended their computations in different years.
[171] Ex. 800 at 6-7 (Hanemann Direct).
[172] *Id.*

stated that changes in the earth's energy balance lead to changes in the climate worldwide, including changes in temperature, precipitation, melting of sea ice, sea-level rise, ocean acidification and other effects.[173]

75. The Agencies stated that climate warming imposes economic costs (e.g. sea levels rise because polar ice caps contract with global warming and because water expands as it warms imposing costs on coastal populations to relocate or build protective structures), while Peabody focused on the economic benefits of warming (e.g. higher concentrations of atmospheric carbon promote plant growth while warmer temperatures result in longer growing seasons thereby increasing agricultural productivity and output).[174]

76. Given the persistence of CO_2 emissions in the climate system for hundreds of years, the CEOs reported that the IWG calculated the damages from an emission in a given year to include the damages (the sum of benefits and costs) the emission causes in that year, plus the damages that emission will cause each subsequent year into the year 2300.[175]

77. The IAMs attempt to capture the physical effects of warming due to CO_2 emissions, monetize the market and non-market effects, and aggregate the monetary impacts, both positive and negative, into a single value. That value is the net present value of all of the costs and benefits resulting from an emission of CO_2 at a given point in time.[176]

78. Because the costs continue into the future, the FSCC measures the discounted present value of the stream of additional external costs occurring as a result of an incremental unit of carbon emitted now, according to the Agencies. To the extent that any changes in climate associated with the emissions are beneficial, the external cost is negative. To the extent that the effect is harmful, the value of the FSCC is a positive number.[177]

79. The IWG used three IAMs to model damages. All three IAMs were developed in the early 1990s and have been updated several times since then.[178]

80. The main benefit of each of the IAMs is that they combine climate processes, economic growth, and feedbacks in a single model. However, all three IAMs function at the "expense of a more detailed representation of the underlying climatic and economic systems."[179] With the IAMs' reduced-form approach, each endogenous (i.e. determined inside the model) variable is expressed as a function of exogenous (determined outside the model) variables. This approach permits the calculation of how

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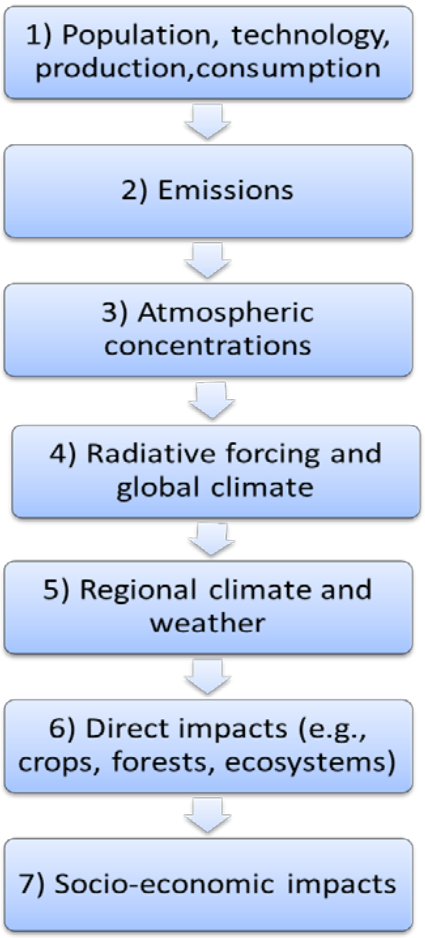
[173] Ex. 800 at 6-7 (Hanemann Direct).
[174] Ex. 228 at 12-14 (Bezdek Direct); Ex. 800 at 7 (Hanemann Direct).
[175] Ex. 800 at 11, fn 3 (Hanemann Direct); Ex. 101 at 15 (Polasky Rebuttal).
[176] Ex. 100, Schedule 2 at 2 (Polaksy Direct); Ex. 800, MWH-2 at 6-8 (Hanemann Direct).
[177] Ex. 800 at 21 (Hanemann Direct).
[178] Ex. 800, WMH-2 at 5, fn 2 (Hanemann Direct).
[179] Ex. 100, Schedule 2 at 5 (Polaskly Direct).

much an endogenous variable changes as a result of a change or changes in one or more exogenous variables.[180]

81. The aggregated costs the models generate are estimates. The IWG acknowledges that there is uncertainty stemming from the physical complexity of the climate system as well as the imprecision of valuing nonmarket damages over an almost 300 year time span. The Agencies explained it is important to understand that the IAMs, like all models, involve simplifying assumptions. Some assumptions reflect the limitations of the modeler's knowledge. Others are made for practical reasons such as the availability of computational capacity.[181] In this complex project, some assumptions have a stronger grounding in empirical observation or stronger theoretical foundation than others.[182]

82. The following chart, provided by the Agencies, depicts the functional elements of an IAM:[183]



[180] Ex. 800, WMH-2 at 5 (Hanemann Direct).
[181] Ex. 800 at 42-44 (Hanemann Direct).
[182] Ex. 800, WMH-2 at 5, 25, 33 (Hanemann Direct).
[183] Ex. 800 at 25 (Hanemann Direct).

D. The Three IAMs Chosen by the IWG

83. Xcel reported that the three IAMs chosen by the IWG are the Dynamic Integrated Climate and Economy (DICE) model developed by Dr. William Nordhaus, the Policy Analysis of the Greenhouse Effect (PAGE) model developed by Dr. Chris Hope, and the Climate Framework for Uncertainty, Negotiation and Distribution (FUND) model developed by Dr. Richard Tol.[184]

84. Xcel explained that the IWG chose these models because they have long histories and have produced most of the SCC estimates in the recent scientific literature.[185] The IPCC's AR4 and AR5 cited the results of the DICE, PAGE, and FUND models, according to the Agencies.[186]

1. The DICE Model

85. The Agencies stated that DICE is an optimization model.[187] "Optimization," the Agencies explained, "denotes the maximization or minimization of some objective or criterion."[188] In the DICE model, optimization takes the form of a standard economic growth model which has been modified to account for GHGs, a stock externality.[189]

86. The Agencies further described an optimization model as one where a linkage is created between the determinations of variables made for one period and those made for the other periods. The linkage reflects the optimization being conducted.[190]

87. The optimization in the economic growth model is that investment, consumption, and output spanning all time periods are chosen in a way that maximizes the discounted present value of well-being (or output) aggregated over the span of all the periods considered, according to the Agencies. This maximization across all periods determines the optimal values of the variables for the individual periods.[191]

88. In each time period, the Agencies explained, well-being benefits from consumption but is harmed by damage from warming in that period. Output from production is adjusted downwards to account for damage from warming in that period. The remaining output can either be consumed to increase well-being (or utility); it can be invested in productive capital, raising output in future periods but not current well-being; or it can be used to reduce GHGs, which reduces future warming but does not increase current well-being.[192]

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[184] Ex. 600 at 17 (Martin Direct).
[185] Ex. 600, NFM-1, Schedule 5 at viii (Martin Direct).
[186] Ex. 800 at 34 (Hanemann Direct).
[187] *Id.* at 35.
[188] *Id.* at 37.
[189] *Id.*
[190] *Id.*
[191] *Id.* at 37-38.
[192] *Id.* at 38.

89. Over time, economic growth has led to higher levels of atmospheric CO_2 concentrations, despite technological advancements that have decreased the quantity of CO_2 generated per unit of output. As global average temperatures increase with rising CO_2 concentrations, the IAMs model damages using a damage function. DICE uses a quadratic damage function, meaning that damages are a function of the square of the change in temperature. This functional form causes damages to increase at an increasing rate as temperature increases.[193] The Utilities and MLIG cautioned that the damage function in DICE does not allow any beneficial effects to be associated with even the smallest amounts of temperature increase.[194]

90. As the IWG explains, the DICE model incorporates impacts on agriculture, coastal areas (due to sea level rise) and "other vulnerable market sectors" (based primarily on changes in energy use), human health (based on climate-related diseases such as malaria and dengue fever, and pollution), non-market amenities (based on outdoor recreation), and human settlements and ecosystems. DICE implicitly allows for some adaptation to global warming. The agricultural impact studies the model relies upon allow for farmers to adjust land uses. The health impact studies assume improvements in healthcare over time.[195] The DICE damage function also includes an estimate of the expected value of damages associated with sudden and dramatic climate changes which have a low probability of occurring, but are likely to have huge impacts if they do occur.[196]

91. DICE derives emissions from socioeconomic development (changes in land use and fossil fuel energy generation),[197] derives income from an assumed trajectory for global population, and computes an optimal growth path, according to the Agencies.[198] But, Xcel stated, as the IWG employs the model, global income, global population, the global stock of fossil fuels, and the pace of technical change are all made into exogenous variables which are input into the model to calculate CO_2 emissions and concentrations, global temperature change, and aggregate damages from climate change.[199]

92. DICE's time span of several centuries includes generations of people, according to the Agencies. DICE adopts a common approach to this problem, which is to represent the generations as though there were a single person representing the entire population, across time and space, controlling each time period's variables, such as output, investment, consumption, and generation of emissions. The representative person benefits from consumption but is harmed by warming. Each period's output

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[193] Ex. 800, WMH-2 at 6-7 (Hanemann Direct). DICE assumes that damages are proportional to GDP. If GDP doubles, damages also double. DICE assumes that 2° of warming will cause damage equal to 1% of GDP. 4° of warming causes damages equal to 4% of GDP. *Id.*

[194] Ex. 302, AES-D-2 at 27 (Smith Direct). Because economic growth proceeds at a much slower pace than rising temperatures, increases in temperatures could cause damages to exceed total global income. To avoid this outcome, the IAMs must temper the rate of increase or cap damages after a certain level of temperature increase is passed so that they do not exceed 100% of GDP. Ex. 300 at 17-18 (Smith Direct).

[195] Ex. 800, WMH-2 at 6-7 (Hanemann Direct).

[196] *Id.*

[197] Ex. 800 at 35-36 (Hanemann Direct).

[198] *Id.*

[199] Ex. 600, NFM-1, Schedule 5 at 4-2 (Martin Direct).

available from production can be used to increase current well-being (utility), to invest in productive capital, or to reduce GHGs, mitigating future warming.[200]

2. The PAGE Model

93. As described by the Agencies, PAGE was developed as a simulation model to permit users to study the implications of varying input assumptions on damage estimates. PAGE models the impacts of climate change across three sectors: economic impacts, non-economic impacts[201], and discontinuity impacts which result from abrupt changes to the climate system. PAGE assumes a time path trajectory for economic growth. Where DICE produces an estimate of global damages, PAGE divides the globe into eight geographic regions and analyzes each separately.[202]

94. In PAGE, as temperatures rise, damages rise exponentially, but at varying rates to account for uncertainty with regard to the damage function.[203] PAGE models the impact of catastrophic events probabilistically, with the probability of a particular event increasing when the temperature crosses a specified threshold. PAGE explicitly attempts to model adaptation to global warming. Economic impacts occur when temperatures increase by more than 2° C in developed countries, and by any amount of temperature increase in undeveloped countries. Non-economic impacts occur when temperatures increase by any amount. Adaptation is assumed to reduce damages significantly – 25% of non-economic impacts, and higher percentages for economic impacts.[204] The time horizon of PAGE is every 10 years from 2000 to 2060 and then 20-year intervals from 2060 to 2100.[205]

95. The Agencies described why the PAGE and FUND models, which are simulation models, are different from the DICE model. A simulation model moves through time period by period. Inputs to the calculations for each period consist of endogenous variables from preceding periods' computations, added to exogenous inputs. Each period's computations are completed sequentially, with some of the results stored for use in future periods' computations.[206] Because they are simulation models, PAGE and FUND do not demonstrate the optimization characteristics that DICE does.[207]

3. The FUND Model

96. FUND is a simulation model and assumes a trajectory for economic growth. FUND examines how a set of exogenous scenarios concerning economic and population

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[200] Ex. 800 at 37-38 (Hanemann Direct).
[201] Non-economic or non-market damages are damages to items that people value but do not obtain through the economy or the market – for example, environmental amenities such as scenery, wildlife, or aquatic recreation. Ex. 800 at 14-15 (Hanemann Direct).
[202] Ex. 800 at 34-38 (Hanemann Direct). Figure 2 incorrectly shows that FUND divides the globe into 8 regions and PAGE into 16. *See* Ex. 800 at 36 (Hanemann Direct). These should be reversed.
[203] Ex. 800, WMH-2 at 7 (Hanemann Direct).
[204] *Id.*
[205] Ex. 800 at 35 (Hanemann Direct).
[206] *Id.* at 37.
[207] *Id.* at 37-38.

growth, improvements in energy efficiency, reductions in the carbon intensity of energy use, and GHG emissions affect the concentration of atmospheric CO_2, global mean temperature, and the impacts of temperature change.[208]

97. FUND calculates damage impacts separately for agriculture, forestry, water, energy, sea level rise, ecosystems, human health, and extreme weather.[209] Each damage impact is calculated for 16 geographic regions. Damage impacts increase with increases in temperature and in some cases, with increases in the rate of temperature change. Some damage impacts also depend on the level of regional income. Agricultural and forestry impacts also increase with increases in CO_2 concentrations.[210]

98. FUND does not incorporate the possibility of catastrophic events but it does implicitly and explicitly allow for adaptation. Both agricultural and forestry impacts are reduced by adaptation explicitly. Implicit adaptation is included in energy and human health impacts as wealthier regions are assumed to be less vulnerable to climate change.[211] FUND models agricultural impacts as the sum of: 1) damages due to the rate of temperature change – higher rates of temperature change generate higher damages; 2) damages (or benefits) due to the level of temperature – in some regions, warming at lower levels leads to increased agricultural output i.e. benefits (negative damages), and in other regions warming reduces agricultural output; and 3) benefits from CO_2 fertilization which eventually decline to zero at some concentration level. Slower rates of temperature increase result in lower damages in FUND in an effort to incorporate the effect of adaptation. Unlike DICE and PAGE which only generate positive damage estimates for any increase in temperature and CO_2 concentrations, FUND generates negative damage estimates for relatively small increases in temperature and CO_2 concentrations. [212]

99. As a simulation model, FUND assumes trajectories for income and population, according to the Agencies.[213] Xcel noted that FUND derives emissions from socioeconomic development and energy and emissions intensity assumptions.[214] According to the IWG, FUND tends to produce the lowest damage estimates of the three IAMs because its damage function generates increases to global GDP (i.e. negative external costs), until warming exceeds 2 to 2.5 degrees centigrade. Beyond that, damages do not increase by more than about 1 percent even for large temperature increases. FUND calculates the SCC every year through the year 2200. In comparison, damages for DICE and PAGE increase at an accelerating rate with temperature increases until the models hypothesize very large increases in temperature.[215]

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[208] Ex. 800, WMH-2 at 8 (Hanemann Direct).
[209] Ex. 800 at 41; WMH-2 at 7-8 (Hanemann Direct).
[210] Ex. 800, WMH-2 at 8-9 (Hanemann Direct).
[211] *Id.*
[212] *Id.* DICE assumes damages are proportional to GDP. Ex. 800, WMH-2 at 6 (Hanemann Direct). If GDP doubles, damages also double.
[213] Ex. 800 at 39 (Hanemann Direct).
[214] Ex. 600, NFM-1, Schedule 5 at 4-2 (Martin Direct).
[215] Ex. 800, WMH-2 at 8-9 (Hanemann Direct).

E. Implementation of the IAMs

100. Having chosen the three IAMs, the IWG took several steps to produce the FSCC. The steps included standardizing the IAMs in certain respects, choosing values for exogenous variables, developing discount rates, operating the IAMs to produce estimates, then synthesizing the results to arrive at a single FSCC range.

1. The IWG's Modifications of the IAMs: Standardization

101. The Agencies explained that the three IAMs estimate the damages from climate change based on the global population's estimated willingness to pay (WTP) to avoid the harm(s) that climate change may bring.[216]

102. While the models all generate estimates of the SCC, they do so in different ways. When different models share the same input variables and yield comparable outputs, the models can be compared. However, DICE, PAGE, and FUND do not share identical modeling structures. That is, they do not employ the same exogenous and endogenous variables. Therefore, in order to generate comparable damages estimates from the three IAMs, the IWG had to standardize the models in certain respects. It did so by making the model alterations necessary so that each model could be run with the same socioeconomic emissions assumptions, equilibrium climate sensitivity and discount rate assumptions.[217] According to the CEOs, for each of these standardized inputs the IWG selected a range of values, instead of just one value, to account for the uncertainty of the inputs.[218]

103. To standardize DICE, the Agencies reported the IWG had to change it from an optimization model to a simulation model.[219]

104. According to the Agencies, the IWG substituted a commonly held population projection for all three models to replace their three slightly differing projections.[220]

105. All three models derive the quantity of CO_2 emissions in a given year from the level of global income (or output) for that year. Instead of allowing DICE to determine the optimal level of global GNP, the IWG altered it to make GNP exogenous for DICE as it is for PAGE and FUND. The IWG could then run all three models with the same assumptions for the time paths of population and global GNP growth.[221]

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[216] Ex. 800 at 18-21 (Hanemann Direct). An alternative concept is willingness to accept (WTA), which is the estimate of what the global population would be willing to accept to surrender a benefit. WTA is generally assumed to be somewhat higher than WTP. Dr. Hanemann suggests WTP has been adopted by the climate economics literature because it is somewhat simpler to measure than WTA. *Id.*
[217] Ex. 800 at 46-47; WMH-2 at 43-44 (Hanemann Direct).
[218] Ex. 100 at 8 (Polasky Direct).
[219] Ex. 800 at 47 (Hanemann Direct).
[220] Ex. 800 at 48 (Hanemann Direct). It is not clear from Dr. Hanemann's testimony whether the IWG chose the replacement population projections from the EMF (Standford Energy Modeling Forum) scenarios, but it is clear that he believes the population projection choice was a sensible one. Tr. Vol. 2B at 121-123 (Hanemann).
[221] Ex. 800 at 47-48; WMH-2 at 24-25 (Hanemann Direct).

2. Socioeconomic Scenarios

106. Having decided how to standardize the models, the IWG needed to develop or adopt values for the exogenous variables. The selection of the sets of socioeconomic inputs is significant because the quantity of emissions depends upon the presumed size and wealth of the global population. Larger and wealthier populations are assumed to generate greater amounts of CO_2. They are also assumed to be more willing to pay to avoid deleterious climate impacts.[222] Because of this, the IWG considered how to model the following input parameters together: gross domestic product (GDP); population; CO_2 emissions; and non-radiative forcing. The IWG looked for the most plausible range of outcomes for these variables as it decided which scenarios to include.[223]

107. The IWG adopted scenarios from the Stanford Energy Modeling Forum (EMF) exercise, EMF-22. EMF-22 uses ten well-recognized scenarios to evaluate global action to meet specific global stabilization targets. The EMF-22 scenarios provide GDP, population, and GHG emission trajectories that are internally consistent for each model. The EMF-22 scenarios have been peer-reviewed, published, and are publically available.[224]

108. The IWG selected four scenarios from EMF-22 and derived a fifth from the other four.[225] Four scenarios represent business-as-usual (BAU) growth in population, wealth, and emissions and, by the year 2100, result in CO_2 concentration levels greater than 600 parts per million (ppm).[226] Xcel commented that BAU means that no climate policy is implemented and economic and population growth continue to result in rising emissions. According to Xcel, the fifth scenario represents the implementation of climate policies across the globe such that atmospheric CO_2 concentration stabilizes at 550 ppm in the year 2100.[227] 550 ppm is twice the concentration of CO_2 at its pre-industrial level.[228] The IWG derived the fifth scenario by running each of the other four scenarios with the restriction that CO_2 concentration stabilizes at 550 ppm in 2100 and then averaging the results. The four BAU scenarios are their modelers' judgments of the most likely trajectories assuming no effective mitigation policies occur.[229]

109. Because CO_2 persists in the atmosphere for hundreds of years, CO_2 emitted in 2020 will continue to generate damages well past 2100, the terminal year for the EMF-22 scenarios. The IWG sought to capture substantially all of the damages from emissions in a given year. To do so, the IWG chose to estimate damages through the year 2300,

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[222] Ex. 800, WMH-2 at 15 (Hanemann Direct).
[223] *Id.*
[224] *Id.*
[225] Four of the forecasts were taken directly from the baselines of the IMAGE, MERGE, MESSAGE, and MiniCAM models. *Id.* at 15-16.
[226] *Id.* at 15-17.
[227] Ex. 600, NFM-1, Schedule 5 at 4-3 (Martin Direct).
[228] Ex. 800, WMH-2 at 12 (Hanemann Direct).
[229] *Id.* at 16-17.

which in turn required the IWG to extrapolate the five EMF-22 scenarios over an additional 200 years.[230] The required inputs were extrapolated as follows:[231]

- Population growth rate declines linearly, reaching zero in the year 2200.
- GDP/per capita growth rate declines linearly, reaching zero in the year 2300.
- The decline in the fossil and industrial carbon intensity (CO_2/GDP) growth rate over 2090-2100 is maintained from 2100 through 2300.
- Net land use CO_2 emissions decline linearly, reaching zero in the year 2200.
- Non-CO_2 radiative forcing remains constant after 2100.

110. The IAMs have varying default time horizons. For PAGE, the default time horizon was 2200, for DICE it was 2595, and the most recent version of FUND had a default time horizon of 3000. Having chosen 2300 as an appropriate time horizon to best capture damages, the IWG only had to make a small adjustment to the PAGE model to accommodate the additional 100 years to its time horizon.[232]

3. Equilibrium Climate Sensitivity

111. Another exogenous variable for the standardized IAMs is the equilibrium climate sensitivity (ECS). The ECS is the "long-term increase in the annual global-average surface temperature resulting from a doubling of atmospheric CO_2 concentration relative to preindustrial levels (or stabilization at a concentration of approximately 550 ppm)."[233] In other words, the ECS is the relationship between emissions and warming. This parameter is important, but subject to considerable uncertainty.[234] The Utilities and MLIG noted that empirical observations about ECS, particularly in the higher temperature ranges, are very limited.[235] Peabody explained that an ECS of 2 means that a doubling of the atmospheric concentration of CO_2 from preindustrial levels results in an equilibrium temperature increase of 2°C. An ECS of 1 implies that a doubling of CO_2 concentration ultimately leads to an increase in temperature of 1°C.[236]

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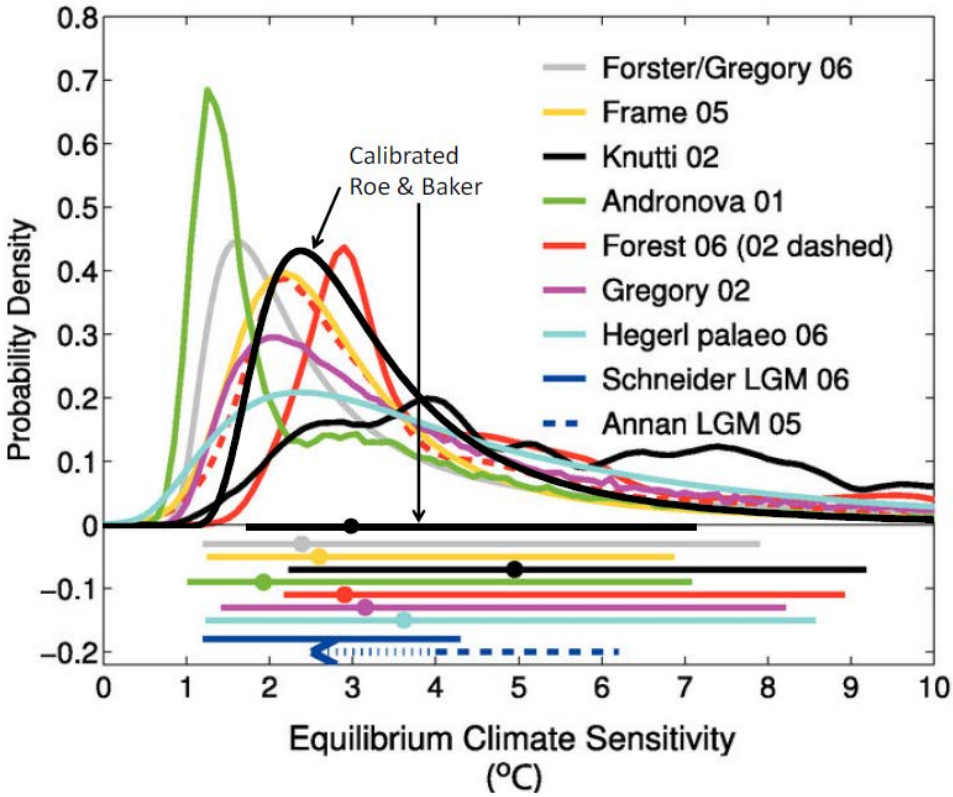
[230] To produce these extrapolations, the IWG made assumptions about population and income growth, the energy intensity of production, CO_2 emitted due to changes in land use (e.g. deforestation), and non-CO_2 sources of greenhouse gasses. *Id.* at 43-47.
[231] *Id.* at 43.
[232] *Id.* at 25.
[233] Ex. 800, WMH-2 at 12 (Hanemann Direct).
[234] *Id.*
[235] Ex. 302, AES-D-2 at 28-29 (Smith Direct).
[236] Ex. 200 at 6-7 (Happer Direct).

112. According to the Agencies, the IPCC AR4 concluded the likely range of values for the ECS was in the range of 2 to 4.5 °C. The IPCC AR4 found a most likely ECS value of 3 °C and stated that ECS was very likely larger than 1.5 °C.[237] The chart below graphs the various estimates the IPCC considered for the probability density function for the ECS:[238]



113. To incorporate the uncertainty as to the actual value of the ECS, the IWG used the Roe & Baker distribution, a probability distribution calibrated according to the IPCC's conclusions about the range of possible ECS values.[239] The IWG used the Roe & Baker distribution for three reasons. First, because the distribution is based on "a theoretical understanding of the response of the climate system to increased greenhouse gas concentrations."[240] Second, because the distribution includes the possibility of very high values in accord with the IPCC's judgment that high values cannot be excluded. Third, because the distribution is not inconsistent with the IPCC's conclusion that the ECS is very likely larger than 1.5 °C. The Roe & Baker distribution sets the probability that the ECS is higher than 1.5 °C at 99 percent.[241] Xcel explained that the IWG made the ECS

[237] Ex. 800, WMH-2 at 12-13 (Hanemann Direct).
[238] *Id.* at 14.
[239] Ex. 800, WMH-2 at 13-14 (Hanemann Direct).
[240] *Id.*
[241] *Id.*

a random variable for all three IAMs, using the Monte Carlo method to run the IAMs many times with random draws for the ECS and other input parameters.[242]

4. The Discount Rate for Converting Future Damages into Present Values

114. The final exogenous variable for which the IWG had to develop values, according to the Agencies, is the discount rate. The discount rate is used to determine the value today of damages that occur in the future.[243] Because CO_2 emitted today remains in the atmosphere for many years, determining the social cost of a ton of CO_2 emitted today involves estimating the damages it causes over the following decades and cumulating those damages into a present value.[244]

115. Economists generally assume that people have a preference for present consumption. That is, the value people derive from consuming X today is greater than the value to them today of consuming X some years in the future. Similarly, economists assume the value of avoiding a harm today is greater than the value today of avoiding the same harm some years in the future.[245]

116. The discount rate used to convert future damages into present values exerts a powerful effect on the IAMs' estimates of the social cost of carbon. A high discount rate reduces the present value of future damages more than a low discount rate, according to the Agencies.[246]

117. OMB Circular A-4 directs agencies to use discount rates of 3 and 7 percent, where 3 is the consumption discount rate and 7 is the discount rate appropriate for private capital.[247] That is, when a regulation is anticipated to affect primarily private consumption "for instance, via higher prices for goods and services," OMB Circular A-4 advises the use of a 3 percent discount rate "to reflect how private individuals trade-off current and future consumption."[248] When a regulation is expected to primarily affect how capital is allocated in the private sector, the higher rate of 7 percent is appropriate as it better reflects the opportunity cost of capital.[249] Observed returns on invested capital are much higher than the 3 percent consumption rate of time preference (also called the risk free interest rate), at least in part because investments involve risk for which investors must be compensated; and investors pay taxes on income from their investments.[250]

118. The IWG concluded that "the consumption rate of interest is the correct discounting concept to use when future damages from elevated temperatures are

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[242] Ex. 600 at 18 (Martin Direct).
[243] Ex. 800 at 53 (Hanemann Direct).
[244] Ex. 800, WMH-2 at 17-18 (Hanemann Direct).
[245] *Id.* at 20, fn 20.
[246] *Id.* at 17.
[247] *Id.* at 17-19.
[248] Ex. 800, WMH-2 at 19 (Hanemann Direct).
[249] *Id.* at 19-20.
[250] *Id.*

estimated in consumption-equivalent units."[251] The IWG justified the use of the 5 percent discount rate by explaining that climate damages are positively correlated with market returns and individuals are willing to pay relatively high rates of interest to shift consumption into the present.[252]

119. The time frame for the IAMs discount rate extends over many generations.[253] There is no consensus among economists, asserted the Agencies, as to what is the correct rate to use, or whether it is appropriate at all in cost benefit analysis to discount the welfare of future generations.[254] An extra dollar's worth of benefits to society in 2300 will be worth less than an extra dollar today because society will have many more dollars.[255] OMB Circular A-4 states that, for intergenerational cost/benefit analysis, agencies "should consider a further sensitivity analysis using a lower but positive discount rate in addition to calculating net benefits using discount rates of 3 and 7 percent."[256]

120. The Agencies reported that the IWG chose to use three alternative values for the annual discount rate, 2.5 percent, 3 percent and 5 percent,[257] and that this was a policy judgment by the IWG.[258] The IWG selected the 3 percent value for the central estimate.[259]

5. The Damage Functions

121. The three IAMs share the assumptions that damages increase with the size of the global economy and that the fraction of global GDP lost is a function of temperature increase, according to the Agencies. The nature of that relationship, represented in the IAMs by the damage function, is critically important for the FSCC. If damages increase linearly, a one degree increase in temperature always causes the same percentage increase in climate damages. If the damage function is quadratic, damages caused by a 3 degree increase in temperature will be 8 times as large as the damages from an increase of 1 degree.[260]

122. In DICE and PAGE, the damage functions are power functions, the Agencies stated. While DICE uses a quadratic damage function, PAGE damages are a function of the increase in temperature raised to a power that is randomly chosen within a range from 1.5 to 3.[261] In both DICE and PAGE, the use of the power function relationship between damages and warming temperatures means that damages increase at an accelerating rate as the temperature rises. FUND is constructed with a separate formula for each category of damages. Because it includes such positive externalities as

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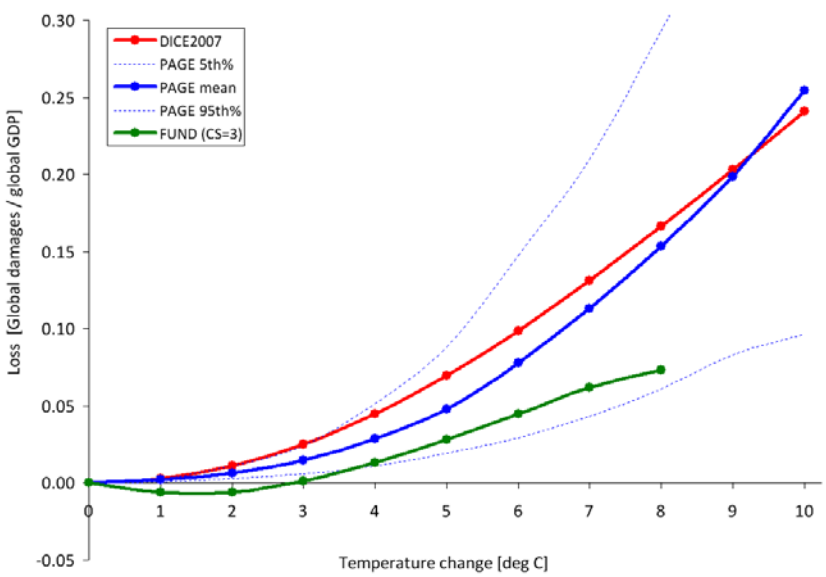
[251] *Id.* at 23.
[252] *Id.*
[253] *Id.* at 18.
[254] Ex. 801 at 71-88 (Hanemann Rebuttal).
[255] Ex. 101, Schedule 1 at 20-22 (Polasky Rebuttal).
[256] *Id.*
[257] Ex. 800 at 54 (Hanemann Direct).
[258] Ex. 800, WMH-2 at 23 (Hanemann Direct).
[259] Ex. 800 at 68 (Hanemann Direct).
[260] Ex. 800 at 27-29 (Hanemann Direct).
[261] *Id.* at 29.

carbon fertilization and benefits in agricultural productivity in northerly latitudes accompanying low levels of temperature increase, FUND is the one model that can generate net benefits from low levels of warming, as Peabody noted.[262]

123. In estimating the value of damages associated with increases in global mean temperature, the DICE, PAGE and FUND models use differing levels and kinds of detail, according to the CEOs. DICE does not list damages for separate categories, but uses a single function calibrated to represent impacts to the various market and non-market sectors for which it has inputs. PAGE uses separate damage functions for economic impacts, non-economic impacts, and catastrophic climate-change impacts. FUND calculates eight separate damage functions for 16 regions of the world. FUND's damage functions include several of the same categories as DICE, but also includes forestry, water resources, and extreme weather events.[263]

124. According to the IWG, damages estimated as a result of extreme increases in temperature are far more uncertain than the estimates of damages from more moderate temperature changes.[264] There may be a very low probability of very high temperature increases, but the damages from a low probability catastrophic event could be so enormous as to raise damage estimates well above the most likely values.[265]

125. The following figure illustrates annual consumption loss as a fraction of global GDP in 2100 due to an increase in annual global temperature as calculated by the DICE, FUND, and PAGE models:[266]



[262] Ex. 214 at 6-7 (Mendelsohn Direct); Ex. 800, MWH-2 at 9 (Hanemann Direct).
[263] Ex. 100 at 13-14 (Polasky Direct).
[264] Ex. 800, WMH-2 at 30 (Hanemann Direct).
[265] *Id.* at 31-32.
[266] *Id.* at 9. The x-axis represents increases in annual, rather than equilibrium, temperature. The y-axis represents the annual stream of benefits as a share of global GDP. These damage functions are the outcome of default assumptions. Under alternative assumptions, the damages from FUND, for example, may cross from negative to positive at less than or greater than 3˚C. *Id.* at 9, fn 5.

6. Running the IAMs to Produce the FSCC

126. To estimate the FSCC, the IWG used the following inputs in running each of the IAMs:

- A Roe and Baker distribution for the climate sensitivity parameter bounded between 0 and 10 with a median of 3 °C and a cumulative probability between 2 and 4.5 °C of two-thirds.
- Five sets of GDP, population and carbon emissions trajectories based on EMF-22 scenarios.
- Constant annual discount rates of 2.5, 3, and 5 percent.[267]

127. The inclusion of multiple uncertain variables for the ECS and other specific parameters meant that results varied with each model run.[268] The Agencies commented that this required the models to be run many times to obtain the true range of possible outcomes.[269]

128. For each socioeconomic scenario, the IWG decided to run each IAM 10,000 times for a given year, each time with a randomly chosen ECS and randomly chosen values for other uncertain parameters, according to the Agencies.[270] This process yielded estimates of damages from projected emissions for each year through the year 2300.[271]

129. Running each IAM 10,000 times for each of the five socioeconomic scenarios yielded 50,000 estimates for the damages for each given year.[272]

130. To calculate the damages from an incremental emission of CO_2 in a given year, the IWG then re-did all of the calculations described above, adding one additional unit of CO_2 for the given year.[273] Then the marginal damages resulting from the additional unit of CO_2 for every year were calculated by subtracting the baseline values for each year from the values resulting from the incremental CO_2.[274] This resulted in a string of incremental damages beginning in the year the incremental unit of CO_2 [275] was introduced and extending to the year 2300.[276]

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[267] Ex. 800, WMH-2 at 24 (Hanemann Direct).
[268] Ex. 800 at 52-55, 67-68; WMH-2 at 24-25 (Hanemann Direct); Ex. 100 at 8, 15-16 (Polasky Direct).
[269] Ex. 800 at 23-55 (Hanemann Direct).
[270] Ex. 800 at 53-54 (Hanemann Direct).
[271] Ex. 800, WMH-2 at 43 (Hanemann Direct).
[272] Ex. 800 at 54; WMH-2 at 24-25 (Hanemann Direct).
[273] Ex. 800 at 54-55 (Hanemann Direct).
[274] Ex. 800, WMH-2 at 24 (Hanemann Direct).
[275] *Id.*
[276] Ex. 800 at 54; WMH-2 at 24 (Hanemann Direct).

131. Next, the IWG calculated the present value of the incremental or marginal damages by applying a discount rate to each of the marginal damages to determine their present value.[277]

132. From each IAM, the IWG obtained 150,000 estimates (data points) of the SCC, as illustrated below:[278]

	2.5% Discount Rate	3.0% Discount Rate	5.0% Discount Rate
EMF-22 Scenario 1	10,000	10,000	10,000
EMF-22 Scenario 2	10,000	10,000	10,000
EMF-22 Scenario 3	10,000	10,000	10,000
EMF-22 Scenario 4	10,000	10,000	10,000
EMF-22 Scenario 5	10,000	10,000	10,000

133. When this process was repeated for all three IAMs, it resulted in a total of 45 separate distributions of the SCC for a given year - the product of 3 models, 5 socioeconomic scenarios, and three discount rates.[279]

134. The IWG determined that the 45 distributions presented too many separate distributions for it to consider in a regulatory impact analysis. Therefore, the IWG weighted the distributions equally and calculated the simple average of the FSCC for all three IAMs, across all five scenarios for each discount rate.[280] Because the discount rate plays a large role in determining the FSCC and because there is no consensus on the correct discount rate, the IWG chose to present the FSCC as "based on the average values across models and socioeconomic scenarios for each discount rate.[281]

135. In other words, the IWG averaged the 150,000 estimates of the FSCC for a given year at a particular discount rate to produce its final estimate of the FSCC for that year and discount rate. Rather than perform these calculations for each and every year, the IWG calculated the FSCC in this way for the years 2010, 2020, 2030, 2040, and 2050. To obtain values for the FSCC years in between, the IWG used a simple linear interpolation.[282]

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[277] Ex. 800, WMH-2 at 24 (Hanemann Direct).
[278] Ex. 800 at 52-55 (Hanemann Direct).
[279] Ex. 800, WMH-2 at 25 (Hanemann Direct). The IWG explains that DICE is run in 10 year time steps, FUND in annual steps, and PAGE with varying time steps. *Id.* at 24.
[280] *Id.* at 25.
[281] *Id.*
[282] *Id.* at 28. For example, if the SCC value for 2020 is $100, and for 2030 the SCC value is $200, a linear interpolation yields a value of $150 for the year 2025.

136. The IWG presented four values of the FSCC for each given year. The IWG presented the average FSCC across all scenarios and models discounted at 2.5 percent, again at 3 percent, and again at 5 percent. The IWG used three discount rates because the cost estimates are highly dependent on the discount rate applied and the appropriate rate to be used is controversial.[283] The IWG's fourth value is calculated by taking the SCC values at the 95 percentile of the FSCC distribution for each model at the 3 percent discount rate. This is intended "to represent the higher-than-expected economic impacts from climate change further out in the tails of the SCC distribution."[284]

137. The following table shows the IWG's FSCC numbers for the years 2010-2050, in 2007 dollars:[285]

Discount Rate Year	**5% Avg**	**3% Avg**	**2.5% Avg**	**3% 95th**
2010	4.7	21.4	35.1	64.9
2015	5.7	23.8	38.4	72.8
2020	6.8	26.3	41.7	80.7
2025	8.2	29.6	45.9	90.4
2030	9.7	32.8	50.0	100.0
2035	11.2	36.0	54.2	109.7
2040	12.7	39.2	58.4	119.3
2045	14.2	42.1	61.7	127.8
2050	15.7	44.9	65.0	136.2

138. The IWG revised its FSCC estimates in 2013, using updated versions of the IAMs but keeping the same methodology it used in 2010 and the same socioeconomic scenarios, ECS, and discount rates. The IWG's 2013 results increase the FSCC by 50 to 100 percent depending upon discount rate and year.[286] The 2010 FSCC used the 2007 version of DICE, the 3.5 version of FUND, and the 2002 version of PAGE. The 2013 FSCC used the 2010 version of DICE, the 3.8 version of FUND, and the 2009 version of PAGE.[287]

[283] Ex. 800, WMH-2 at 23.
[284] *Id.* at 25.
[285] *Id.* at 28.
[286] Ex. 600, NFM-1, Schedule 2 at 1-2 (Martin Direct).
[287] *Id.* at 5.

139. The following table illustrates the November 2013 revised FSCC, in 2007 dollars per metric ton of CO_2. Included for comparison are the estimates for the year 2020 reported in the 2010 IWG FSCC estimates:[288]

Discount Rate	5.0%	3.0%	2.5%	3.0%				
Year	Avg	Avg	Avg	95th				
2010	11	32	51	89				
2015	12	37	57	109	2010 Results			
2020	12	43	64	128	7	26	42	81
2025	14	47	69	143				
2030	16	52	75	159				
2035	19	56	80	175				
2040	21	61	86	191				
2045	24	66	92	206				
2050	26	71	97	220				

140. The 2013 version of DICE had an updated calibration of the carbon cycle, which decreased the absorption of carbon from the atmosphere by the ocean. All else being equal, this results in more rapid warming and hence higher damages.[289] DICE was also revised to explicitly model sea level rise to comport with the results of the IPCC AR4.[290] These modifications tended to reduce damages in the near term but increase them in more distant years, reducing the FSCC slightly.[291]

141. PAGE also added an explicit treatment of sea level rise damages, updated adaptation assumptions, and a revised treatment of potential abrupt damages.[292] The more recent version of PAGE is less optimistic about the extent to which adaptation can reduce damages. These "less optimistic assumptions regarding the ability to offset

[288] *Id.* at 3. The IWG released an initial update in May 2013 (*see* Ex. 800, WMH-3 at 3 (Hanemann Direct)), but revised the update in November 2013.
[289] Ex. 600, NFM-1, Schedule 2 at 5-6 (Martin Direct).
[290] *Id.* at 6.
[291] *Id.* at 7.
[292] *Id.* at 10-11.

impacts of temperature and sea level rise via adaption increase the SCC by approximately 30 percent."[293]

142. Changes to FUND included updated damage functions.[294] The revised model reduces the benefit from reductions in space heating as temperatures warm, thereby tending to increase FSCC estimates.[295] Alterations to FUND's treatment of sea level rise tended to lower the FSCC by assuming coastal areas become steeper as sea levels rise.[296] While FUND's modeling of the agricultural sector was updated, the net effect on FSCC estimates was difficult to predict.[297] Another change to the model was to reduce the sensitivity of the rate of temperature response to the level of the ECS, a change likely to increase the FSCC as higher temperatures and correspondingly higher damages are experienced earlier and are subjected to fewer years of discounting.[298] A change to FUND's treatment of methane also tended to increase FSCC estimates.[299]

F. IWG's Acknowledgement of Limitations

143. The IWG acknowledged that its methodology for calculating the FSCC is subject to a number of significant limitations. Among them are that the IAMs "do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature . . . because of lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research."[300] Another limitation involves the possibility of catastrophic damages occurring.[301] A third limitation is that the IAMs do not provide compelling treatments of adaptation and technological change. The higher the damages resulting from CO_2 emissions, the greater the incentives to adapt and develop technologies better suited to a warming climate.[302] The IWG also recognized that its assumption of risk neutrality may be incorrect and individuals (or society) might very well prefer high probability, low damage outcomes to low probability, high damage outcomes.[303] The IWG further acknowledged that the effects of climate damages in one region of the world on another region are incompletely treated by the IAMs. For example, drought in one region may lead to migration which affects other regions.[304]

IV. Criticisms of the Federal Social Cost of Carbon

144. The Utilities, MLIG, Peabody, and Xcel each criticized various aspects of the IWG's FSCC. The various parties' criticisms ranged from critiques of the IWG's

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[293] *Id.* at 11.
[294] *Id.* at 7-8.
[295] *Id.* at 8.
[296] *Id.*
[297] *Id.* at 9.
[298] *Id.*
[299] *Id.*
[300] Ex. 800, WMH-2 at 29 (Hanemann Direct).
[301] *Id.*
[302] *Id.* at 30.
[303] *Id.*
[304] *Id.* at 32.

process, to commentaries regarding the models by which the IWG chose to calculate the data on which the FSCC was based, including modifications the IWG made to those models. Other criticisms of the FSCC included the IWG's choice of inputs to the models it used and the parameters it chose when running the models, as well as the much broader questions of whether the IWG's underlying assumptions about warming and its effects are correct. Finally, the Utilities, MLIG, Xcel, and Peabody questioned whether it is appropriate to use the FSCC for the purposes required by Minn. Stat. § 216B.2422. The various parties' arguments concerning all of these issues, and the responsive discussions, are set forth in the remainder of this section.

A. The IWG's Use of the IAMs as Damage Cost Models

1. Criticisms

145. According to the Utilities and MLIG, one consequence of the reduced-form modeling approach is that the models do not produce descriptively realistic, spatially disaggregated responses of climate impact and damage variables.[305] This is because the IAMs do not provide damage estimates for each physical change. Instead, the Utilities and MLIG assert, the IAMs combine the effects of certain central stylized facts about response to climate change within mathematical formulae that yield a value for the FSCC.[306]

146. The Utilities and MLIG contended that the IAMs do not follow a traditional "damage cost approach."[307] A traditional damage cost approach, in the Utilities' and MLIG's view, uses what is known traditionally as "damage functions" in IAMs. The "damage function approach" is what the federal government has long used in its benefits analyses, according to the Utilities and MLIG.[308] The damage function method, as the Utilities and MLIG described it, is a "bottom-up method of calculating benefits from regulations . . . ."[309] In the context of estimating the "benefits of pollutant regulation," the Utilities and MLIG stated the "damage function approach" examines the benefits as "an effect-by-effect logical chain," applying the economic valuation after specific forms of adverse physical effects have been quantified.[310]

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[305] *See* Ex. 302, AES-D-2 at 4-5 (Smith Direct).

[306] Dr. Smith notes that, while PAGE and DICE project the physical extent of sea level rise and value those changes separately, all other components of damages are derived from temperature changes and not from "calculation of the amount of physical change in the resources being valued." Ex. 302, AES-D-2 at 5, fn 8 (Smith Direct). FUND utilizes eight damage functions and so produces eight separate components of the SCC. Nonetheless, Dr. Smith notes that most of FUND's separate damage functions do not have "an explicit estimate of the physical change that is being assigned monetized value." *Id*.

[307] *Id.* at 21.

[308] *Id.*

[309] *Id.*

[310] *Id.* The Utilities and MLIG relied on a 1983 Environmental Protection Agency document for this analysis, which described the analytical chain to be followed: "*(1) the release of pollutants by industry, households, agriculture, and municipal sources to (2) the impact of these releases on ambient quality to (3) exposures of people, plants, animals, and materials through various media (air, water, etc.) to (4) the adverse effects to (5), when feasible, what people would pay to avoid these effects*." *Id.*

147. The Utilities and MLIG noted that Commission staff briefing papers from the 1993 Externalities docket described a damage cost approach to criteria pollutants analysis that the Utilities and MLIG asserted was similar to the "damage function approach" that the Utilities and MLIG were urging here.[311] The Utilities and MLIG criticized the IWG IAM damage functions, describing them as "simplified formulas that largely circumvent a key attribute of the damage function approach."

148. According to the Utilities and MLIG, the damage function method requires scientific and economic research to be separated. Quoting 1983 EPA Guidelines regarding a damage function approach, the Utilities and MLIG stated that this method is based on a dose-response function, relating "changes in a pollutant to physical changes in receptor organisms or materials." Then, the value of the physical changes is estimated.[312] Specifically, the Utilities and MLIG faulted the IWG IAMs because they fail to use "dose-response" relationships "between climate outcomes and physical measures of resource changes that can then be assigned monetary values . . . ." Instead, the Utilities and MLIG maintained that the IWG IAMs calculate society's economic losses directly from changes in temperature levels.[313]

149. This kind of aggregation of damages is contrary to the principal of separating physical damage estimates from the economic valuation of society's willingness to pay to avoid the damages, which is "considered a defining characteristic of the damage function approach" argued the Utilities and MLIG. Because of the aggregation of damages, the Utilities and MLIG asserted that it is difficult to know precisely what types of damages are included in an FSCC estimate.[314]

150. The Utilities and MLIG advised the Commission to consider approaches other than the damage cost estimates of the IAMs to produce an SCC value. If the Commission chooses to continue with the damage cost approach, however, the Utilities and MLIG recommended that it "adopt a range of values calculated using assumptions that are less speculative and more appropriate for Minnesota."[315]

151. The Utilities and MLIG warned that a fundamental limitation on the reliability of the IAM-generated estimates is the IAMs' damage functions. They are all based on a very limited number of studies "of the economic impact of warming of 3 degrees Celsius" or less but "are used to predict the damage to the economy of much greater changes in temperature."[316] The Utilities and MLIG concluded that the IAMs' predictions of damages at high levels of temperature change are based on their developers' speculative extrapolations.[317]

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[311] *Id.* at 22.
[312] *Id.*
[313] Ex. 302, AES-D-2 at 23 (Smith Direct).
[314] *Id.*
[315] Ex. 300 at 33 (Smith Direct).
[316] *Id.* at 18-19.
[317] *Id.* at 19-20. "The primary basis for the IAMs' estimates of the monetary value of damages from temperature changes exceeding about 3° C remains the professional opinion of certain researchers…." Ex. 302, AES-D-2 at 6-7 (Smith Direct).

152. Xcel asserted that important variables in the IAMs "suffer from a lack of empirical basis" and the IAMs themselves depend "on assumptions that cannot easily be verified."[318] Xcel specified that the IAMs lack an empirical basis in the areas of predicting ECS, creating damage functions, modeling future populations' abilities to adapt to climate change, and "modeling possible discontinuous 'tipping point' behavior in the climate system that could occur at temperature increases greater than the . . . increases for which the IAMs have been calibrated."[319]

153. Peabody alleged the IAMs' "descriptions of the impact of climate change are completely ad hoc, with no theoretical or empirical foundation" and provide no information about "the most important driver of the SCC."[320] Peabody alleged that the IAMs provide a false perception of knowledge and precision.[321] In addition, Peabody claimed that the IAMs are too sensitive to the modelers' assumptions to be used for regulatory policies.[322]

154. Peabody argued that DICE, PAGE, and FUND all assume "short-term natural climate variability is irrelevant in that it averages out, and that there is no long-term natural climate variability."[323] Peabody contended that the existence of natural climate variability should be disaggregated from the impacts of human-induced warming but "work on that issue is just in its infancy."[324]

155. Peabody pointed out that PAGE is a simulation model that reflects the uncertainty of important parameters and was built to allow investigators to explore the effects of changing assumptions. Because of the purpose for which it was intended, Peabody claimed, PAGE was not designed "as a model capable of yielding a determinate value."[325] Peabody asserted that PAGE is "less careful" than DICE or FUND in "grounding assumptions in empirical evidence," and Peabody has little confidence in its results.[326]

156. Peabody and Xcel both noted that PAGE's damages are based on European Union calculations, then scaled to other regions of the world based on length of coastline in proportion to the European Union.[327]

157. Peabody alleged that the damage functions in the IAMs merely guess at the relationship between temperature changes and GDP.[328] Peabody also raised conceptual complications of linking damages to carbon emissions, arguing that damages from

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[318] Ex. 600 at 47 (Martin Direct).
[319] *Id.* at 47-48.
[320] Ex. 228 at 7 (Bezdek Direct). Dr. Bezdek does not specify the "most important driver."
[321] *Id.*
[322] Ex. 233 at 22, 36-40 (Bezdek Rebuttal Ex. 1).
[323] Ex. 238 at 9 (Tol Rebuttal Ex. 2).
[324] *Id.*
[325] Ex. 233 at 38 (Bezdek Rebuttal Ex. 1).
[326] Ex. 214 at 7 (Mendelsohn Direct).
[327] Ex. 233 at 39 (Bezdek Rebuttal Ex. 1); Ex. 600 at 40 (Martin Direct).
[328] Ex. 228 at 26 (Bezdek Direct).

warming may be greater or lesser depending upon many human factors.[329] Peabody posited that risks such as the development of malaria in more northern countries are dependent on "the state of roofs and pavements, on the availability of pesticide-impregnated bed nets, and on the affordability of malaria medicine."[330] Similarly, Peabody speculated that risks from coastal flooding cannot be adequately calculated for the purpose of understanding the SCC because, if a poor and poorly-governed country such as Bangladesh is at risk of increased coastal flooding, measurement of the risk depends on whether the subject countries have caring and competent governments.[331]

158. Peabody concluded that "the chain of causation from carbon dioxide emission to damages is long, complex and contingent on human decisions that are at least partly unrelated to climate policy. The social cost of carbon is, at least in part, also the social cost of underinvestment in infectious disease, the social cost of institutional failure in coastal countries, and so on."[332]

159. Peabody recommended the point at which the marginal damage caused by an additional emission of CO_2 is just equal to the marginal cost of abating that damage. This abatement equated estimate would be much lower than the FSCC because the latter does not take abatement into account. According to Peabody, the purpose of the SCC is to "get the prices right." Therefore, said Peabody, the SCC must be at the optimal mitigation level.[333]

160. Peabody ran the DICE model but altered its damage function so that damage would not begin until temperatures reached 1.5°C - 2°C above preindustrial levels (or 0.7°C – 1.2°C warmer than today). Peabody's reasoning was that warming is generally more beneficial than harmful and the IAMs assume damages before temperatures have increased sufficiently.[334]

161. Peabody questioned the significant increases of the IWG's estimates of the SCC between 2010 and 2013, as indicated below.[335] Over roughly the same time period, the estimates generated by FUND's creators decreased from $8 to $6.6 per ton, according to Peabody.[336] Peabody stated that the differences between the estimates using FUND as it was designed, compared to the estimates generated by the IWG's modifications to FUND, raises "serious questions as to whether the IWG's estimates lack economic and scientific reliability."[337]

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[329] Ex. 238 at 10-13 (Tol Rebuttal).
[330] *Id.* at 11.
[331] *Id.* at 12.
[332] Ex. 238 at 12-13 (Tol Rebuttal).
[333] Tr. Vol. 3B at 35-37, 52-54 (Mendelsohn); Ex. 261 at 2 (Mendelsohn Opening Statement); Ex. 220 at 22-23 (Mendelsohn Surrebuttal).
[334] Ex. 216 at 14 (Mendelsohn Direct Ex. 2).
[335] Ex. 238 at 6-7 (Tol Rebuttal Ex. 2); Ex. 800, WMH-2 at 1; WMH-3 at 3 (Hanemann Direct).
[336] Ex. 238 at 6-7 (Tol Rebuttal Ex. 2).
[337] *Id.* Note: The IWG's discussion of the 2013 increase is discussed at paragraphs 138-142 supra.

	5%	3%	2.5%
IWG 2010 estimates for the SCC in 2020	6.8	26.3	41.7
IWG 2013 estimates for the SCC in 2020	12.0	43.0	65.0

2. Responses

162. The Agencies supported the FSCC and the IWG's use of the damage cost approach. As stated in paragraphs 70-73 above, the Agencies provided testimony demonstrating the IAMs are computable, numerical models that account for the five estimates of impacts needed to calculate the SCC.[338] These five estimates are:

- how emissions change the existing accumulation of GHGs in the atmosphere via the carbon cycle;
- how, in turn, those changes alter the amount of energy stored in earth's system (the change in radiative forcing);
- how the change in radiative forcing leads to changes in the climate worldwide;
- how those changes in climate affect things that matter to humans, such as water supply and drought, crop production, disease and human health, outbreaks of wildfire, coastal flooding, and ecosystem functioning etc.; and
- how humans value the changes in those things that matter to them.[339]

163. The CEOs concluded the FSCC is the best available damage cost measure for carbon dioxide emissions, in part because IWG used a transparent process.[340] In addition, the IWG members thoroughly reviewed the literature and chose to base their estimate on results from the three most widely-used integrated economic-climate change assessment models.[341] Additionally, the IWG has committed to updating estimates as new information arises.[342]

[338] Ex. 800 at 22-23 (Hanemann Direct).
[339] *Id.*
[340] Ex. 100 at 24 (Polasky Direct).
[341] Ex. 100 at 24-25 (Polasky Direct).
[342] *Id.*

164. The Agencies disagreed with the Utilities' and MLIG's assertion that IAM damage functions are invalid because they are not dose-response functions.[343] The Agencies explained that dose-response functions are typically formulated for narrowly defined outcomes of impacts. For example, dose-response functions would apply to examination of a mosquito-infested swamp and nearby inhabitants' rate of malaria infection, but not to the concept of waterborne diseases in general. The Agencies stated they were not aware of the existence of dose-response functions for the number of outcomes likely to be associated with climate change given the broad spatial and temporal scales required.[344] The Agencies maintained that the damage function of an IAM is the economic value associated with particular groups of impacts at a specific point in time as a function of the increase in global temperature occurring at that time.[345] The formula for a damage function is represented through an algebraic equation.[346] In this case, an IAM is a reduced form model, which is a simplified version of a larger model.[347]

165. The Agencies asserted that modifying the damage function to make it less damaging, as Peabody's witness, Professor Mendelsohn proposed, has two effects: 1) it lowers the SCC; and 2) it reduces the incentive to reduce emissions, so that atmospheric CO_2 reaches higher levels and there is more warming before – under optimization – abatement efforts kick in. The Agencies noted that Peabody's analysis using DICE's default damage function generated an SCC of $18.60 in 2015, and Peabody's changes to that damage function lowered the SCC by two-thirds or more, to $6.90 or $4.45.[348] The Agencies asserted that this was a very large alteration to the specifications of DICE based on very little evidence to show that such alteration is reasonable.[349]

166. The Agencies also observed the wide differential between Peabody's values and those of DICE's author, Dr. Nordhaus. Peabody utilized DICE2013, the most recent version of DICE, which was also used in Dr. Nordhaus', *Climate Casino.*[350] The Agencies pointed out that the value Dr. Nordhaus gave in the book for the social cost of carbon is "about $25" for 2015.[351] Dr. Nordhaus referred to the IWG's 2010 estimate of the FSCC, calling the IWG's $25 estimate the "best estimate" for 2015.[352]

167. The Agencies responded to Xcel's statement that the designers of IAMs lacked an empirical basis on which to base the damage function, asserting that a more accurate statement is that the IAM designers drew on empirical literature mainly from the

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[343] Ex. 801 at 39 (Hanemann Rebuttal).
[344] *Id.*
[345] Ex. 800 at 27 (Hanemann Direct).
[346] *Id.* at 27-28.
[347] *Id.* at 23-24. Reduced-form models involve a simplified version of a larger model with a smaller number of equations that summarize the outcome of interactions among the structural equations in the larger model after variables have been solved out of them. *Id.* at 24.
[348] Ex. 801 at 45 (Hanemann Rebuttal).
[349] *Id.*
[350] *Y*ale Univ. Press, 2013. *Id.* at 45, fn 27.
[351] *Id.*
[352] *Id.*

1990s for their damage functions. Citing a 2014 report from the Energy Power Research Institute (EPRI 2014), the Agencies observed:[353]

> [T]he models draw directly and indirectly on older literature, some dating back to the 1990s. Scientific impacts knowledge has progressed since, as summarized in synthesis products like IPCC (2007, 2014). However this knowledge is not reflected in the current SCC model damage formulations.

168. The Agencies acknowledged that fewer than 50 studies form the information base on which these IAMs draw.[354] The Agencies stated that this number represents a small fraction of the information now available in the economic literature on climate change impacts, and a minuscule fraction of what is available in the larger impact literature.[355] The Agencies asserted that the literature, while still highly incomplete, is not non-existent as suggested by Xcel.[356]

169. The Agencies explained that, not only is there a much larger volume of studies than existed fifteen years ago, the studies are qualitatively different. An important feature of the newer studies is that, on temporal and spatial scales, they assess impacts of climate change at a more granular level than previous studies.[357]

170. The Agencies stated there are more severe damage estimates in newer literature. Those estimates are partly due to the increased detail of the General Circulation Models (GCMs) used to make projections of climate change on a global scale, as well as to the GCM analyses increasingly being supplemented by what is known as "spatial downscaling." The Agencies stated that spatial downscaling (or spatial disaggregation) translates the GCM projections from the relatively coarse native spatial grid scale of the GCMs to a finer spatial scale.[358]

171. In addition, the Agencies explained that the damage functions are "convex," meaning the marginal damage increases as the temperature increases, and the marginal damage is larger when it is warmer.[359] The more sharply the marginal damage increases as temperature increases, the more convex the damage function. Because of the convex nature of the damage functions, the development of a more detailed analysis is likely to

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[353] Ex. 801 at 47 (Hanemann Rebuttal).
[354] *Id.* In the case of DICE, the last detailed accounting of impacts on individual sectors based on specific impact studies was used with DICE2000. In the case of FUND, EPRI 2014 identifies thirty-two studies which form the information base for FUND's damage functions, but only four appeared after 2002. EPRI 2014 identifies eight studies that form the information base for the damage functions in PAGE, seven of which date from the period 2006-2009. Ex. 801 at 47; Schedule 5 at Table 6-2 (Hanemann Rebuttal).
[355] Ex. 801 at 47 (Hanemann Rebuttal).
[356] *Id.*
[357] *Id.* at 48.
[358] *Id.* at 48-49.
[359] *Id.* at 49-51.

generate higher estimates of damages. According to the Agencies, this is an important reason why the new literature tends to come up with higher estimates of damages.[360]

172. The Agencies asserted that a similar effect occurs with temporal averaging, for example when using the warming of annual temperature rather than the warming of seasonal temperatures taken separately. Due to the convexity of the damage function, disaggregating temperature change by seasons, or even more finely, would raise the estimate of aggregate damage.[361] The Agencies provided illustrations showing how disaggregation and the convexity of the damage function influences the damage estimate.[362]

173. The Agencies determined that, contrary to the testimony of Peabody, MLIG, the Utilities, and Xcel, the damage functions in DICE, FUND, and PAGE likely understate the actual SCC because they do not include all damages, do not account for climate tipping points, and reflect the level of GDP in a given year rather than the year's growth rate.[363] Furthermore, the Agencies added, the IAM damage functions understate the effects of climate change because the IAMs exclude all aspects of changes in climate apart from average annual temperature. They do not account for precipitation, which is an important factor for flooding, water-borne disease, impacts on vegetation and ecosystems, and other types of impacts. To the extent those impacts do not co-vary (i.e. tend to move in the same direction) with average annual temperature, they are not accounted for by the IAM damage functions. While the damage functions in DICE, FUND, and PAGE fairly accurately reflected the economic literature on climate impacts as of about 2001, the Agencies stressed that the damage functions in DICE, FUND, and PAGE are the only damage functions available for use in a model inter-comparison exercise.[364]

174. DHE argued that the FUND model arbitrarily limits public health impacts in its damage function to urban areas, although rural areas will be impacted as well.[365] The FUND damage function also limits the change in mortality to five percent of baseline mortality. DHE asserted that mortality increases may be much higher than five percent.[366]

175. In addition, the DHE maintained that the FSCC does not account for increased health harms from ozone and small particulate matter as a result of CO_2-induced climate change.[367] Both of these threats are worsened as temperatures increase, according to the DHE, but the FSCC does not account for these damages.[368]

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[360] Ex. 801 at 49 (Hanemann Rebuttal).
[361] *Id.* at 53.
[362] *Id.* at 50-52.
[363] *Id.* at 55-63.
[364] *Id.* at 63.
[365] Ex. 500 at 9 (Rom Rebuttal).
[366] *Id.* at 18.
[367] *Id.* at 8.
[368] *Id.* at 14-17. DHE cited the Environmental Protection Agency's Clean Power Plan Analysis, estimating reductions in GHGs would prevent 13,000 premature deaths in 2050 and 57,000 premature deaths in 2100, based solely on air quality improvements. *Id.* at 18.

176. The Agencies' expert, Dr. Hanemann, stated that the decision by the IWG to use the DICE, FUND, and PAGE models was reasonable at the time the IWG made it, and is still reasonable today.[369] His opinion that the damage functions in the IAMs likely understate the actual SCC does not change his recommendation.

177. While also supporting the FSCC, the CEOs agreed that it is a conservative value that errs on the side of underestimating damages, because: 1) the IAMs give insufficient weight to potential catastrophic consequences of climate changes; 2) the IWG used relatively high discount rates; 3) the IAMS may inadequately account for the impacts of climate change on economic growth; and 4) the IAMs fail to include several potentially important kinds of damages from climate change.[370]

178. Some of the areas of impact the CEOs identified which are excluded from IAMs damage functions are "biodiversity losses, impacts on long-term economic growth, increased political instability, increased migration, extreme weather events, irreversible climate change and increases in wildfire."[371]

179. In response to Peabody's assertion that the SCC is different from traditional damage cost methodologies, the CEOs stated the IAMs use standard models of resource allocation over time, integrated with simple climate science, which is similar to other disciplines in the natural sciences.[372]

180. The CEOs disagreed with Peabody's criticisms of IAMs, which relied on the opinions in a 2013 article by Dr. Pindyck.[373] The CEOs pointed out Peabody's failure to mention that, despite Dr. Pindyck's strong opinion regarding the deficiencies of IAMs in climate change analysis, he ultimately supported the IWG's FSCC as the best available estimate of the SCC.[374]

181. DICE, PAGE, and FUND, as well as the EMF scenarios, are all published in peer-reviewed literature, according to Xcel.[375] In addition, the Utilities and MLIG acknowledged that the three models "have been used and repeatedly revised since [they were first used], with results of analyses that have been done using them described in peer-reviewed articles."[376]

B. Discount Rates

1. Criticisms

182. The IWG presented the FSCC valued at three different discount rates: 2.5, 3, and 5 percent. The Utilities and MLIG agreed that it was reasonable for the IWG to

[369] Ex. 801 at 63 (Hanemann Rebuttal).
[370] Ex. 100 at 18 (Polasky Direct).
[371] *Id.* at 23.
[372] Ex. 104 at 18 (Polasky Surrebuttal).
[373] Ex. 101 at 55 (Polasky Rebuttal).
[374] *Id.*
[375] Ex. 600 at 48 (Martin Direct).
[376] Ex. 302, AES-2 at 20 (Smith Direct).

base its discount rates on the "consumption rate of interest" and supported the 3 and 5 percent discount rates.[377] The "consumption rate of interest," according to the Utilities and MLIG, is the same as what OMB calls the "social rate of time preference," with both terms in contrast to the "opportunity cost of capital."[378] The Utilities and MLIG agreed that the consumption rate of interest was appropriate for the IWG to use because the IAMs model damages in "consumption-equivalent" units. Therefore, it was sensible to utilize the consumption rate of interest to discount damages to their present value.[379]

183. The Utilities and MLIG alleged that the IWG erred by using a 2.5 percent discount rate.[380] The Utilities and MLIG argued that a 2.5 percent rate for the FSCC was adopted to "acknowledge a subjective and prescriptive view among some policy analysts that people living today should not discount the consumption of future generations in the manner in which they discount their own within-generation consumption choices."[381] The Utilities and MLIG concluded that the IWG's use of a 2.5 percent discount rate "lacks a meaningful connection to empirical evidence" and therefore fails to conform to the evidentiary standards required for establishing Minnesota's environmental cost values, using conservative assumptions in the face of great uncertainty.[382]

184. The Utilities and MLIG also argued that a 5 percent discount rate should not be the upper bound used for the SCC. The Utilities and MLIG raised the concern that, once the damages are stated as a present value, they "will be compared to a cost of emissions control that will be paid for with private capital," that is, compared to utility resource investment costs.[383] The Utilities and MLIG objected that the FSCC fails to account for the opportunity costs of utility resource investments in its discounting. If the IWG accounted for the opportunity costs of utility resource investments, it would include discount rates higher than 5 percent, which would lower the FSCC. The IWG's discount rates have overstated the cost by only using consumption rates of interest.[384] The Utilities and MLIG acknowledged that it would be impracticable to incorporate the opportunity cost of emissions reductions in the IWG's IAMs, but instead suggested increasing the upper end of the discount range. The Utilities and MLIG hinted that the OMB's suggested discount rate of 7 percent would be "a reasonable estimate of the before-tax market rate of interest" as an appropriate upper bound, but ultimately did not endorse a specific percentage for the upper limit.[385]

185. Peabody argued that the FSCC is unreliable because the discount rates are arbitrary, but have significant impacts.[386] Peabody's witness, Dr. Tol, who developed the FUND model, stated the Ramsey rule is a more appropriate choice for the IWG to use to

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[377] Ex. 300 at 23 (Smith Direct).
[378] *Id.*
[379] *Id.* at 25.
[380] *Id.* at 24.
[381] *Id.*
[382] *Id.*
[383] *Id.* at 25.
[384] *Id.*
[385] Ex. 304 at 26-27 (Smith Surrebuttal).
[386] Ex. 228 at 7 (Bezdek Direct).

develop discount rates.[387] According to the Ramsey rule, the discount rate should vary with economic growth, rising as economic growth increases and falling as economic growth slows.[388] The discount rate should also differ between countries growing at different rates.[389]

186. Peabody described the underlying logic of the Ramsey rule, stating it "makes sense because it relates the money discount rate to parameters underlying the 'time value' of money – i.e. the reasons that receiving money today is preferred over receiving it in the future."[390]

187. Peabody argued that by using the 2.5, 3, and 5 percent discount rates, rather than the Ramsey rule's slowing rates of growth, the IWG's estimates of the FSCC are too high.[391] Further, Peabody pointed out that some countries that have high rates of growth also have low incomes, and the appropriate discount rate for them should be higher than the discount rate for slower growing but wealthier countries. By applying a constant discount rate globally, Peabody argued, the IWG in effect weights damages in high growth, low income countries more than damages in low growth, high income countries.[392]

188. Peabody's discussion of the discount rate was based in part on its underlying presumption that "the initial impacts of climate change are positive, due to carbon dioxide fertilization, reduced winter heating, and few cold-related deaths . . . ."[393] As a result, Peabody asserted, CO_2 emissions should be subsidized and the SCC "is negative for the highest discount rates."[394]

189. To illustrate the effect of inserting a constant discount rate into FUND, Peabody compared the results of using the Ramsey rule versus using a constant discount rate with respect to United States. and China damages. As a slow- growing, high-income economy, the United States has a lower Ramsey discount rate than fast-growing but lower-income China.[395] Thus, using the FUND scenario as the IWG used it, without the Ramsey rule, Peabody calculated impacts in China are weighted 46 to 87 percent more heavily than impacts in the United States. Damages valued at one dollar in the United States are valued at $1.46 to $1.87 in China, according to Peabody. The result, argues Peabody, is to place a greater value on damages in China than in the United States.[396]

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[387] Ex. 238 at 4 (Tol Rebuttal Ex. 2).
[388] Ex. 238 at 4 (Tol Rebuttal Ex. 2).
[389] *Id.*
[390] *Id.*
[391] *Id.*
[392] *Id.* at 5-6. FUND develops estimates for 16 geographic regions. Ex. 800, WMH-2 at 8-9 (Hanemann Direct).
[393] Ex. 238 at 4-5 (Tol Rebuttal Ex. 2).
[394] *Id.*
[395] Ex. 238 at 6 (Tol Rebuttal Ex. 2). Peabody does not explicitly state that the U.S. is a wealthier but slower-growing country than China, but use of the example implies it.
[396] *Id.*

190. At least one additional Peabody expert criticized the IWG for failing to use the 7 percent discount rate in accordance with OMB's Circular A-4. Peabody quoted a White House guide on Circular A-4 instructing agencies to use the 7 percent discount rate, in addition to a lower but positive rate ranging from 1 to 3 percent, where important intergenerational costs or benefits are at stake.[397]

191. Another Peabody witness recommended the DICE model, in its optimized form, with discount rates that are "calculated internally to be consistent with the growth in GDP per capita."[398] At a 2 percent GDP growth rate, the interest rate is 5 percent, according to Peabody. If the growth rate slows, which is what DICE assumes, the interest rate will also fall "to slightly lower levels."[399]

192. Peabody reported that the DICE model predicted, with slowing GDP over time, the discount rate would fall to approximately 3.5 percent in 2100 and 2.7 percent in 2200.[400] Peabody maintained that, by maintaining a steady interest rate, the IWG "divorces the interest rate from the path of GDP," an approach inconsistent with economic theory.[401]

193. Peabody asserted that, by choosing "whatever discount rate pleases them," the IWG is choosing a unique discount rate for GHGs, distinct from "every other public investment," and thus implicitly arguing that climate change "should have a different 'price of time.'" Peabody maintained that there is no theoretical support for this idea and no explanation as to why it is socially desirable for GHG mitigation to have a lower rate of return than public investments in national security, health, education, safety, and infrastructure.[402]

2. Responses

a. Xcel's Public Policy Approach

194. Xcel maintained that the choice of a discount rate is a public policy decision, and there is no agreement in the economic literature on the appropriate discount rate(s) for a proceeding such as this one. Xcel observed that the IWG recognized the selection of a discount rate over long periods of time "raises highly contested and exceedingly difficult questions of science, economics, philosophy, and law."[403]

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[397] Ex. 233 at 28, 34 (Bezdek Rebuttal Ex. 1).
[398] Ex. 214 at 12 (Mendelsohn Direct). This is an iteration of the Ramsey formula and consistent, in principle, with Peabody's other expert testimony. *See* Ex. 220 at 29-30 (Mendelsohn Surrebuttal).
[399] Ex. 214 at 12 (Mendelsohn Direct).
[400] Ex. 216 at 16 (Mendelsohn Direct Ex. 2).
[401] *Id.*
[402] *Id.* at 17.
[403] Ex. 600, NFM-1, Schedule 6 at 17 (Martin Direct).

195. Xcel also noted that the economic literature suggests both lower discount rates than the IWG used (e.g. 1.5 percent) and higher discount rates than the IWG used (e.g. the 7 percent discount rate consistent with OMB guidance).[404]

196. Because there is no empirical evidence of the preferences of distant future generations, Xcel maintained that the decision on discount rates is a public policy judgment that must be made without comprehensive empirical evidence.[405]

197. Xcel Energy agreed that the 2.5, 3, and 5 percent discount rates used by the IWG were appropriate. Therefore, Xcel chose to retain and equally weight all three IWG discount rates in its model as described at paragraphs 395 to 396 below.[406]

b. The Agencies' Consumption Rate of Discount Response

198. Peabody stated that the IWG's use of a 2.5 percent discount rate does not meet the evidentiary criteria required to establish environmental cost values under Minnesota law. The Agencies disagreed with Peabody and asserted that the FSCC's consumption rate of discount of 2.5 percent is compatible with calculations based on reasonable economic assumptions.[407]

199. The Agencies disagreed with Peabody's characterization of the IWG's discount rates as "arbitrary," pointing to the well-developed economic theory of the discount rate. The Agencies observed that, technically, when environmental economists speak of using a 5 percent discount rate to compute the SCC, what is actually being referred to is the "consumption rate of discount" which is derived from the "utility rate of discount."[408]

200. The Agencies explained that the concepts of consumption rate of discount and utility rate of discount show why the IWG's discount rate is neither "arbitrary" nor inappropriate.[409] The Agencies defined the utility rate of discount as the rate at which individuals are willing to trade off an amount of current well-being – or utility - in exchange for an increase of well-being of the same magnitude in the future.[410]

201. In economic theory, the Agencies elaborated, the resolution of this choice requires a comparison between changes in one's well-being at two points in time – now and in the future. Two sets of factors influence the comparison: (i) the magnitude of the change in well-being, and (ii) how the person feels about future versus present well-being. The latter factor is measured by what is called the person's "rate of time preference" or "utility rate of discount" (represented by δ). This rate of time preference is a subjective decision by the decision-maker. It measures the decision-maker's willingness to make an investment (thus, deferring consumption) that entails a cost now but improves the

[404] Ex. 600 at 44-47 (Martin Direct); Ex. 602 at 20-21 (Martin Surrebuttal).
[405] Ex. 602 at 29-30 (Martin Surrebuttal).
[406] Ex. 600 at 59-60 (Martin Direct).
[407] Ex. 801 at 72 (Hanemann Rebuttal).
[408] *Id.* at 71.
[409] *Id.*
[410] *Id.* at 72.

decision-maker's future welfare.[411] In a highly simplified form, the Agencies observed, this discussion of the utility rate of discount symbolizes the choice being faced with regard to regulating the emission of GHGs.[412]

202. The Agencies described the consumption rate of discount and how it relates to this discussion. The tradeoff in the rate of time preference has been framed in terms of utility or well-being – giving up some well-being now in exchange for more well-being later. The same tradeoff can also be framed in monetary terms: giving up some income (or consumption) now in exchange for more income (or consumption) later. That tradeoff depends on how the person values a unit of consumption now versus a unit of consumption later. The factor involved in this trade-off is known as the consumption rate of discount.[413] The Agencies maintained that it is the consumption rate of discount that should be used when calculating the FSCC.[414]

203. According to the Agencies, when the DICE model is run in its optimization mode, with a δ value of 1.5 percent and a marginal utility factor of 4 percent, as Dr. Nordhaus would do, it yields a consumption rate of discount amounting to 5.5 percent. On the other hand, the Agencies maintained, when the assumed δ value is 0.1 percent and the marginal utility factor is 1.3 percent, as Dr. Stern assumed, the consumption rate of discount is 1.4 percent.[415]

c. The Agencies' Response to the Ramsey Rule

204. The Agencies explained that the British economist Frank Ramsey first clarified the relationship between the consumption rate of discount and the utility rate of discount.[416] Ramsey demonstrated that the consumption rate of discount depends on two factors: (i) the utility rate of discount, and (ii) the extent to which the person's income (or consumption) will be different in the future compared to today. If a person expects her income to be the same in the future as it is today, the consumption rate of discount exactly equals the utility rate of discount. If a person expects her income to be larger in the future than today, that introduces a correction factor which needs to be added to δ. Conversely, if she expects her income to be smaller in the future than it is today, that introduces a correction factor which needs to be subtracted from δ (lowering the consumption rate of discount to a value less than δ). The "marginal utility factor" is the correction factor added to or subtracted from δ, yielding a total consumption rate of discount.[417]

205. Two groups of assumptions which the Agencies found questionable generated the 5.5 percent consumption rate of discount: (i) the assumption of a value of 1.5 percent for δ, and (ii) a set of assumptions resulting in a 4 percent value for the marginal utility factor. The Agencies cautioned that, since the consumption rate of

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[411] *Id.* at 72-73.
[412] *Id.* at 73.
[413] *Id.* at 74.
[414] *Id.*
[415] Ex. 801 at 75 (Hanemann Rebuttal).
[416] *Id.* at 74.
[417] *Id.* at 74-75.

discount is what is used for estimating the FSCC, these assumptions have an impact on the estimate of the FSCC.[418]

206. The Agencies described the assumptions underlying the marginal utility factor that arises with Ramsey Rule discounting as applied in DICE's optimization mode, and why they believe the assumptions are not reasonable in the context of calculating the FSCC:[419]

- The assumption that climate policy can be viewed through the metaphor of a single, infinitely-lived individual arranging his consumption over the course of his (infinite) lifetime.

- The assumption that the individual has constant preferences and constant expectations regarding what gives him well-being throughout the course of his lifetime.

- The assumption that everything the individual cares about can be boiled down to one item – the amount of money that he has – and all impacts of climate change can be reduced to the equivalent of a change in the money that he has.

207. The Agencies contended that, if any of the assumptions is judged unreasonable, it would change the formula for the marginal utility factor and, therefore, the value of the consumption rate of discount. The Agencies do not consider the assumptions reasonable.[420]

208. The notion of a single, infinitely-lived decision-maker determining the world's GHG emissions from now to beyond 2300 is a fiction, which the Agencies acknowledged provides a mathematically convenient framework for conducting the IAM analysis. The Agencies emphasized that the approach sidesteps the ethical issues associated with inter-generational and intra-generational equity.[421] The Agencies argued that Ramsey discounting is not useful if one takes seriously an obligation to preserve the planet for future generations.[422]

209. Further, the Agencies disputed the notion that human preferences will remain unchanged over three centuries, and what people expect out of life will stay unchanged over three centuries, labelling such theories "wildly implausible."[423] The Agencies alleged that this assumption underlies the argument made by the Utilities and MLIG that "future generations will be far wealthier and have far higher consumption than is the case in the present."[424] The Agencies noted that the Utilities and MLIG made this

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[418] *Id.* at 75, 78.
[419] *Id.* at 76.
[420] Ex. 801 at 76 (Hanemann Rebuttal).
[421] *Id.*
[422] *Id.* at 77.
[423] *Id.*
[424] *Id.*

argument in the context of arguing for a high discount rate. However, the Agencies reasoned, "[t]he mathematical basis for the argument regarding the increase in future wealth" relies on the decreasing marginal utility effect, and "assumes that future generations will have exactly the same expectations out of life as we do today." This means that, despite incomes that are many times higher in real terms than incomes are today, the expectations of people in the future "will be completely unchanged by the passage of time and the rise in their standard of living."[425]

210. The Agencies maintained that, if people's expectations change over time, the decreasing marginal utility effect is undercut. Moreover, the Agencies said, depending on how much peoples' preferences and expectations change, some amount of alignment between increased wealth and consumption with increased expectations would reduce or eliminate the decreasing marginal utility effect, thereby lowering the consumption rate of discount.[426]

211. In addition, the Agencies stated that if people care separately for both things money can buy and also for other, non-market things, such as preserving the natural environment, and if they do not see those two types of items as perfect substitutes for one another, this adds an additional, third term to the Ramsey Rule formula for the consumption rate of discount. If one makes the assumption – which the Agencies considered plausible – that people care for an unimpaired natural environment but the unimpaired natural environment is increasingly threatened and declines in scale with economic growth and with climate change, then the mathematical effect is to reduce the value of the consumption rate of discount.[427] Thus, the Agencies rejected the 4 percent marginal utility factor and use of the Ramsey Rule as recommended by Peabody.[428]

d. The Agencies' Response to the Rate of Time Preference

212. With regard to the other component of the consumption rate of discount, namely the rate of time preference (the utility rate of discount), which Professor Nordhaus, the creator of the DICE IAM, set at the relatively high value of 1.4 percent in DICE, the Agencies argued that this is not a matter of economic theory but an ethical judgment. The Agencies maintained that the rate of time preference has economic implications, but economic theory *per se* cannot prescribe the numerical value to employ. The Agencies pointed to Professor Pindyck's statement that the numerical value for the rate of time preference is a policy judgment.[429]

213. The Agencies further claimed that a consumption rate of discount of 2.5 percent is compatible with calculations based on reasonable economic assumptions. The Agencies explained that making realistic assumptions about people's preferences over time could plausibly generate values of the marginal utility factor in the range from 1.3 to

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[425] *Id.*
[426] *Id.*
[427] Ex. 801 at 78 (Hanemann Rebuttal).
[428] *Id.* at 75, 78.
[429] *Id.* at 78-79.

2, and the Agencies believe a pure rate of time preference of $\delta = 0.5$ is ethically defensible.[430]

e. The Agencies' Response to Recommendations Regarding the Market Rate of Interest

214. The Agencies also rejected the criticisms, promoted by the Utilities and MLIG, that a FSCC calculation based solely on estimates of the consumption rate of discount is too low. The Agencies explained that, rather than the consumption rate of discount, the Utilities and MLIG were arguing for using something closer to the market rate of interest ("the opportunity cost of capital") when calculating the SCC. The Agencies maintained that the market rate of interest and the consumption rate of capital are two different concepts. They are different in the same way that the worth of an item to a person is a different concept than the price the person has to pay to acquire the item.[431] The Agencies defined the consumption rate of discount measures how much consumption (income) a decision-maker would be willing to give up today in exchange for an extra unit of consumption (income) a year from now. The Agencies defined the market rate of interest as the price that measures how much it would cost that decision-maker in terms of today's consumption (income) in order to acquire an extra unit of consumption (income) a year from now.[432]

215. The Agencies explained that what an item is worth to a person is conceptually different than what it costs: the former reflects factors affecting demand, while the latter reflects factors affecting supply. The Agencies observed that there exist circumstances where what an item is worth is equal to its price. That outcome occurs, the Agencies noted, in a competitive market where the intent of the decision-maker is to optimize the quantity of the item in question. This condition applies also to the market rate of interest and the consumption rate of discount; the two are equated, the Agencies said, when the decision-maker in a competitive market is making optimal choices over points in time when choices at one time influence the possibilities available at other points in time. However, the Agencies contended this condition does not characterize how global emissions of GHGs are determined in the real world.[433]

216. The Agencies reiterated that the assumption of optimality is the crux of the analysis when DICE is being run in its native optimization format. According to the Agencies, that depicts what would happen to global GHG emissions if they were controlled by a single, infinitely-lived decision-maker optimizing his well-being over many centuries. The Agencies said such an individual would choose levels of consumption and investment in each period so as to ensure that the marginal return on investment just equaled the marginal value of consumption or, equivalently, that the market rate of interest just equaled the consumption rate of discount.[434] But the Agencies rejected this result, stating it has no practical relevance for climate policy, or for the FSCC because in

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[430] *Id.* at 79.
[431] Ex. 800 at 15-17 (Hanemann Direct); Ex. 801 at 83 (Hanemann Rebuttal).
[432] Ex. 801 at 83-84 (Hanemann Rebuttal).
[433] *Id.* at 84.
[434] *Id.*

the real world there is no single, infinitely-lived decision-maker controlling the trajectories of global consumption, investment and GHG emissions, and those trajectories are not being determined optimally. In the absence of this optimality, argued the Agencies, there is no presumption that the observed market rate of interest measures the consumption rate of discount. The market rate of interest, the Agencies concluded, is an incorrect basis for calculating the SCC.[435]

f. The Agencies' and CEOs' Responses to the Seven Percent Discount Rate

217. The Agencies recognized the argument, raised by the Utilities and MLIG, that: "Federal guidance required use of a seven percent rate when a regulation will affect private sector spending because seven percent approximates the opportunity cost of displaced private sector investment."[436] The CEOs observed that Peabody also relied on OMB Circular A-4 to argue that the IWG should have used a seven percent discount rate.[437] In response, the Agencies quoted from the IWG's July, 2015 *Response to Comments*:[438]

> While most regulatory impact analysis is conducted over a time frame in the range of 20 to 50 years, OMB guidance in Circular A-4 recognizes that special ethical considerations arise when comparing benefits and costs across generations. Although most people demonstrate time preference in their own consumption behavior, it may not be appropriate for society to demonstrate a similar preference when deciding between the well-being of current and future generations. Future citizens who are affected by such choices cannot take part in making them, and today's society must act with some consideration of their interest. Even in an intergenerational context, however, it would still be correct to discount future costs and benefits generally (though perhaps at a lower rate than for intragenerational analysis), due to the expectation that future generations will be wealthier and thus will value a marginal dollar of benefits or costs less than the current generation. Therefore, it is appropriate to discount future benefits and costs relative to current benefits and costs, even if the welfare of future generations is not being discounted. Estimates of the discount rate appropriate in this case, from the 1990s, ranged from 1 to 3 percent. After reviewing those considerations, Circular A-4 states that if a rule will have important intergenerational benefits or costs, agencies should consider a further sensitivity analysis using a lower but positive discount rate in addition to calculating net benefits using discount rates of 3 and 7 percent.

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[435] Ex. 801 at 84-85 (Hanemann Rebuttal).
[436] *Id.* at 85.
[437] Ex. 104 at 8 (Polasky Surrebuttal).
[438] Ex. 801 at 85-86 (Hanemann Rebuttal).

218. The CEOs claimed that OMB played a key oversight role in the interagency review process, pointing out that OMB is listed as a participant in the IWG on the title page of the IWG's Technical Update.[439] The CEOs alleged that the OMB "agreed on using discount rates of 2.5 percent, 3 percent, and 5 percent, and not using 7 percent."[440]

219. The CEOs pointed out that the language of OMB Circular A-4 characterizes the discount rates as "suggestions 'designed to assist analysts' and offer guidance" but the OMB document does not establish a required approach.[441]

220. The Agencies explained that the IWG examined the economics literature and concluded that the consumption rate of interest is the correct concept to use in evaluating the net social costs of a marginal change in CO_2 emissions, because the impacts of climate change are measured in consumption-equivalent units in the three IAMs used to estimate the SCC. The Agencies agreed that this is consistent with OMB guidance in Circular A-4, which states that when a regulation is expected to primarily affect private consumption, for instance, via higher prices for goods and services, it is appropriate to use the consumption rate of interest to reflect how private individuals trade off current and future consumption.[442]

221. The CEOs asserted that Peabody's analysis of published research on climate change showed that only two papers used a discount rate above five percent while ten studies used a discount rate below three percent. The CEOs concluded that a seven percent discount rate is outside the range of discount rates used by climate change researchers.[443]

g. The Agencies' and CEOs' Discount Rate Conclusions

222. According to the Agencies, it was appropriate for the IWG to use the three discount values it chose, and to consider the 3 percent value the central estimate. The Agencies stated that these values are consistent with the values used in the existing literature on the economics of climate change and of GHG mitigation. The Agencies explained that a major study, the Stern (2006) Review, conducted for the United Kingdom, used a discount rate of 1.4 percent and that Dr. Nordhaus uses a 5.5 percent discount rate for DICE. The Agencies are not aware of any values higher than 5.5 percent or lower than 1.4 percent being used in the existing literature on the economics of climate change.[444]

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[439] Ex. 104 at 9 (Polasky Surrebuttal). OMB is listed on the cover pages of the IWG FSCC 2010 Technical Support Document, the May 2013, November 2013, and July 2015 Updates to the Technical Support Document, as well as on the cover page of the July 2015 IWG Response to Comments on the IWG's FSCC. *See* Ex. 600, NFM-1, Schedules 2, 6, 7 (Martin Direct); Ex. 601, NFM-2, Schedule 1 (Martin Rebuttal); Ex. 101, Schedule 1 (Polasky Rebuttal).
[440] Ex. 104 at 9 (Polasky Surrebuttal).
[441] *Id.*
[442] Ex. 801 at 86 (Hanemann Rebuttal).
[443] Ex. 104 at 8-9 (Polasky Surrebuttal).
[444] Ex. 800 at 68-69, 73 (Hanemann Direct).

223. The Agencies and the CEOs agreed with the IWG policy judgments to: (a) use discount rates of 2.5 percent, 3 percent and 5 percent in developing results for the FSCC, and (b) select the 3 percent value of the FSCC as the central estimate. The Agencies and the CEOs accepted these judgments and found them to be reasonable. [445]

C. 95th Percentile Value at 3 Percent Discount Rate

1. Criticisms

224. MLIG asserted that using the 95th percentile at the 3 percent discount rate would give excessive weight to uncertain high-cost catastrophic risks relative to the more certain, lower-cost risks. MLIG claimed this would distort policies and regulations.[446] In keeping with the Agencies' insurance metaphor, MLIG claimed that the 95th percentile/3 percent discount rate would amount to over-insurance, putting too many resources into the wrong potential problem.[447]

225. Xcel noted that the IWG included its 95th percentile value to "represent the higher-than-expected economic impacts from climate change further out in the tails of the SCC distribution."[448] Xcel acknowledged that the IWG used this value to account for the IWG's concern that the three IAMs fail to fully model damages under extreme climate change scenarios.[449] However, Xcel expressed concern that the IAMs also fail to account fully for adaptation to climate change, which could lead to over-estimation of damages.[450] Noting the factors that could cause both over-and under-estimation of damages, Xcel argued that there was no rationale for the IWG to present a 95th percentile value without its corresponding 5th percentile value. In addition to maintaining that the 95th percentile at a 3 percent discount rate would be statistically indefensible, Xcel asserted that the IWG proposal would "privilege a single discount rate."[451]

226. Peabody stated that a cost-benefit analysis demonstrates that the benefits of carbon emissions are such that, using the FSCC for 2010 at the 95th percentile with a 3 percent discount, results in the benefits of CO_2 emissions exceeding the costs by a ratio ranging between 30-to-1 and 40-to-1.[452] Peabody reached this conclusion based on its conclusion that increased carbon emissions will result in a net economic benefit rather than a net cost.[453]

2. Responses

227. In response to criticisms of the 95th percentile, 3 percent discount rate, the CEOs responded that the high end of the damages range is not well-represented by the

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[445] Ex. 801 at 85 (Hanemann Rebuttal); Ex. 101 at 21 (Polasky Rebuttal).
[446] Ex. 401 at 13-17 (Gayer Surrebuttal).
[447] *Id.*
[448] Ex. 600 at 29 (Martin Direct).
[449] *Id.*
[450] *Id.*
[451] *Id.* at 28.
[452] Ex. 230 at 78 (Bezdek Direct Ex. 2).
[453] *Id.* at 76-78.

three mean values at the 2.5, 3.0 and 5.0 percent discount rates.[454] The CEO's reported that the IWG included the 95th percentile value because the IWG determined that the FSCC likely underestimated the true damages of CO_2. In its 2015 Response to Comments, the IWG said:[455]

> The IPCC Fourth Assessment Report, which was the most current IPCC assessment available at the time of the IWG's 2009-2010 review, discussed these limitations and concluded that it was "very likely that [SCC] underestimates" climate change damages. Based on the current scientific understanding of climate change and its impacts, and on the limitations of the IAMs in quantifying and monetizing the full array of potential "catastrophic" and non-catastrophic damages, the IWG concluded that the distribution of SCC estimates may be biased downwards. Since then, the peer-reviewed literature has continued to support this conclusion. For example, the IPCC Fifth Assessment report observed that SCC estimates continue to omit various impacts that would likely increase damages. The 95th percentile estimate was included in the recommended range for regulatory impact analysis to address these concerns.

228. The CEOs supported adopting the 95th percentile value of the FSCC because it represents very useful information contained in the long tail of the high side of the FSCC distribution about the small probability for very high damages. The CEOs noted that there is no equivalent long tail on the low side of the FSCC distribution.[456]

229. The Agencies agreed that the 95th percentile value is a "relevant consideration" if the question of the SCC is being viewed "through the lens of risk management."[457] Referring to an analogy that a person would not likely board an airplane if there were a 5 percent chance that it would crash, the Agencies stated that the 95th percentile value does not represent an unreasonably low level of risk tolerance.[458]

D. Equilibrium Climate Sensitivity

1. Criticisms

230. Peabody called ECS "the most important variable" used to predict the level of global warming in response to carbon dioxide emissions, or other climate forcing.[459] However, Peabody said, there is no proven ECS value, both "because of the uncertainties of past temperature change events and knowledge of the magnitude of the forcing that

[454] Ex. 101 at 35 (Polasky Rebuttal).
[455] Ex. 101 at 35-36 (Polasky Rebuttal).
[456] Ex. 104 at 24 (Polasky Surrebuttal).
[457] Ex. 801 at 88 (Hanemann Rebuttal).
[458] Ex. 802 at 40 (Hanemann Surrebuttal).
[459] Ex. 221 at 7 (Spencer Direct).

caused those events."[460] It is difficult to measure the climate's sensitivity to CO_2 by experimental observations, Peabody stated, because "many factors besides atmospheric CO_2 affect the Earth's temperature. These factors . . . include solar influences, clouds, aerosols, volcanos, massive ocean instabilities like El Niños, etc.," which may amplify or diminish the effects of CO_2.[461]

231. Peabody claimed the IPCC's assumed climate sensitivity is overstated.[462] Peabody alleged that observed warming has been much less than predicted by the climate models.[463] One of Peabody's witnesses contended that climate sensitivity is 1, indicating that there are no physical processes that amplify the effects of increasing CO_2 concentrations.[464] Another Peabody witness concluded that climate sensitivity falls in the range from .85C to 1.5C "and is very likely less than 2° C."[465]

232. Peabody maintained that the CEOs and others who predict an ECS value of 3 or higher can only do so by finding "some sort of positive feedback mechanism (principally water vapor) . . . ."[466] But, Peabody asserted, no one has yet validated a strong feedback mechanism "despite vigorous attempts by global warming proponents to do so. If there were a strong positive feedback, Peabody argued, the Earth would not have experienced a lack of surface warming for the past 15 or more years."[467]

233. One Peabody witness maintained that, because the relationship between CO_2 concentration and temperature is logarithmic, "the more you increase CO_2, the less sensitive the climate will be to additional increases."[468]

234. Peabody pointed out that there have been at least 14 new studies and 20 experiments, "each lowering the best estimate and tightening the error distribution about that estimate" since January 1, 2011, yet the IWG continues to use the IPCC's distribution from the 2007 4th Assessment Report.[469] Based on the 2010 IWG TSD, Peabody contended that the IWG's current ECS is higher than the IPCC's 2007 estimate of the probability distribution of the ECS. Peabody reasoned that this is because the IPCC found it "very likely" (greater than 90% probable) that the ECS is greater than 1.5 degrees centigrade. But, Peabody noted, the FSCC ECS distribution uses a 99% probability that the ECS is greater than 1.5 centigrade.[470]

235. Peabody criticized the IWG for failing to re-evaluate its ECS number of 3, despite the IPCC AR5 which no longer offers 3 as a "best guess."[471] The IPCC's AR4

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[460] *Id.* at 8.
[461] Ex. 200 at 6-7 (Happer Direct); Ex. 207 at 2, 8 (Lindzen Direct).
[462] Ex. 216 at 2, 13-14 (Mendelsohn Direct Ex. 2).
[463] Ex. 223 at 1 (Spencer Direct Ex. 2); *see also* Ex. 207 at 3 (Lindzen Direct).
[464] Ex. 200 at 7 (Happer Direct).
[465] Ex. 207 at 5 (Lindzen Direct).
[466] Ex. 206 at 2 (Happer Surrebuttal).
[467] *Id.*
[468] Ex. 200 at 6 (Happer Direct).
[469] Ex. 233 at 23 (Bezdek Rebuttal Ex. 1).
[470] *Id.* at 26.
[471] Ex. 206 at 6 (Happer Surrebuttal).

stated with high confidence that the ECS was 'very unlikely' to be less than 1.5 degrees centigrade as the low end of the likely range. Peabody pointed out that AR5 declined to determine any best estimate because of the substantial discrepancy between observation-based estimates of ECS, which were lower, versus climate-model estimates, which were higher.[472]

236. Peabody concluded that an ECS value of 1 or 1.5 degrees centigrade is correct; and that an ECS of more than 2 degrees centigrade is "extremely unlikely."[473]

2. Responses

237. The Agencies noted the observation that, while a decrease in the minimum possible climate sensitivity "is undoubtedly good news for the planet," it also implied a widening of the range of uncertainty.[474] The Agencies explained that, as the uncertainty surrounding damages related to climate change increases, one is willing to pay a higher premium to avoid exposure to that increasingly uncertain risk. The Agencies also asserted that Freeman *et al*. demonstrated that reducing the "peakedness" of the climate sensitivity distribution by eliminating the "best estimate" for climate sensitivity increased the willingness to pay value for avoiding climate change.[475] Therefore, the Agencies concluded, the economic implication of the increase in the uncertainty regarding climate sensitivity is that it raises the SCC in the Pindyck economic model of climate change.[476]

238. A second critique raised regarding ECS was Peabody's assertion that the models reviewed by the IPCC AR5 have ECS values that are too large.[477] Peabody's opinion was that a mean value of S = 1 K is the correct value. Peabody relied on the assertion that the ECS is most accurately assessed without any climate feedbacks.[478]

239. The Agencies rebutted this assertion, noting that the IPCC consists of a group of scientists who volunteer to review, synthesize, and summarize existing peer-reviewed research.[479] The Agencies contended that the doubling ECS range reported in the IPCC AR5 (1.5 °C – 4.5 °C) is a range of values representative of the large body of peer-reviewed scientific literature on the topic.[480] The IPCC AR5 includes a comprehensive review of this metric of the climate system; different aspects are discussed in at least three different chapters.[481] The reported range of ECS values are based on multiple lines of evidence, including paleoclimate, model simulations, and

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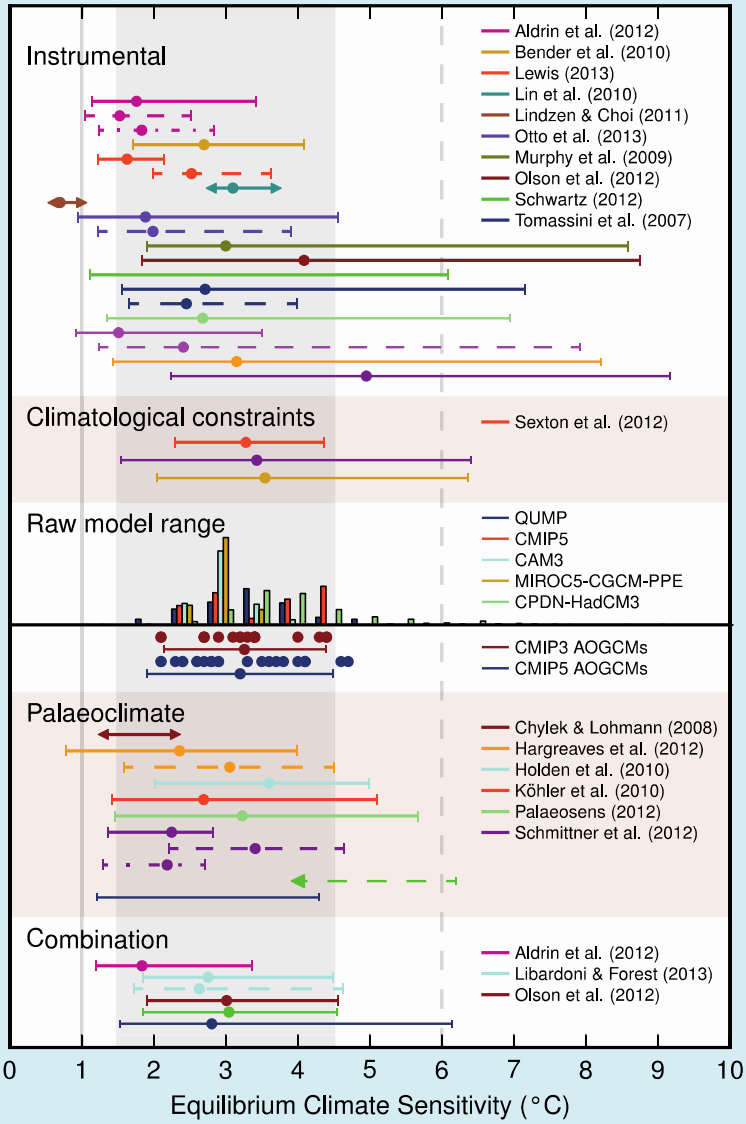
[472] Ex. 213 at 16 (Lindzen Surrebuttal).
[473] Ex. 211 at 2 (Lindzen Rebuttal Ex. 1).
[474] Ex. 801 at 33 (Hanemann Rebuttal).
[475] *Id.* at 32-33.
[476] Ex. 801 at 33 (Hanemann Rebuttal).
[477] Ex. 202 at 8 (Happer Direct Ex. 2).
[478] *Id.* at 7.
[479] Ex. 803 at 17 (Gurney Rebuttal).
[480] *Id.*
[481] *Id.*

instrumental measurements, as demonstrated in the following figure from the IPCC AR5:[482]



Box 12.2, Figure 1 | Probability density functions, distributions and ranges for equilibrium climate sensitivity, based on Figure 10.20b plus climatological constraints shown in IPCC AR4 (Meehl et al., 2007b; Box 10.2, Figure 1), and results from CMIP5 (Table 9.5). The grey shaded range marks the *likely* 1.5°C to 4.5°C range, and the grey solid line the *extremely unlikely* less than 1°C, the grey dashed line the *very unlikely* greater than 6°C. See Figure 10.20b and Chapter 10 Supplementary Material for full caption and details. Labels refer to studies since AR4. Full references are given in Section 10.8.

[482] *Id.*; *see also* Tr. Vol. 3B at 18- 22 (Dessler).

240. Pointing to the annotation in the above figure, the Agencies noted that the gray shaded area represents the likely 1.5 to 4.5ºC range of ECS and the gray solid line represents the extremely unlikely ECS of less than 1ºC. The Agencies concluded that the available evidence, as represented by the IPCC AR5, does not support Peabody's assertions regarding ECS. [483]

241. The CEOs addressed the question of why the IWG chose not to adopt the IPCC's updated ECS values in the 2013 FSCC updates, quoting from the IWG's 2015 Response to Comments:[484]

> The IWG is aware that this is an active area of research and remains committed to updating the SCC estimates to incorporate new scientific information and accurately reflect the current state of scientific uncertainty regarding the ECS. While we agree with commenters that the ECS distribution, along with other climate modeling inputs to the SCC calculation, should be updated periodically to reflect the latest scientific consensus, care must be exercised in selecting an appropriate range of estimates for this important parameter. Many studies estimating climate sensitivity have been published, based on a variety of approaches (instrumental record, paleoclimate observations, models, etc.). These individual studies report differing values and provide different information. Picking a single study from the high or low end of the range, or even in the middle, will exclude relevant information. A valid representation of uncertainty regarding climate sensitivity should be obtained from a synthesis exercise such as that done by the IPCC that considers the full range of relevant studies.
>
> At the time the 2013 SCC update was released, the most authoritative statement about ECS appeared in the IPCC's AR4. Since that time, as several commenters noted, the IPCC issued a Fifth Assessment Report that updated its discussion of the likely range of climate sensitivity compared to AR4. The new assessment reduced the low end of the assessed likely range (high confidence) from 2°C to 1.5°C, but retained the high end of the range at 4.5°C. Unlike in AR4, the new assessment refrained from indicating a central estimate of ECS. This assessment is based on a comprehensive review of the scientific literature and reflects improved understanding, the extended temperature record for the atmosphere and oceans, and new estimates of radiative forcing.

[483] Ex. 803 at 18 (Gurney Rebuttal).
[484] Ex. 101 at 45-46 (Polasky Rebuttal).

> Several of the post-AR4 studies highlighted by some commenters were cited in the AR5 assessment. In particular, both Aldrin et al. (2012) and Otto et al. (2013) were cited in both Chapter 10 and Chapter 12 of the AR5 Working Group I assessment. Eight of the authors of Otto et al. (2013), including the lead author, were authors of Chapter 12 for AR5's Working Group I and one was a lead author for the chapter. Hence it is clear that the IPCC considered Otto et al. (2013) in its synthesis of literature on the ECS. More broadly, the AR5 climate sensitivity distribution likely incorporates much of the literature identified by the commenters. The IWG will continue to follow and evaluate the latest science on the equilibrium climate sensitivity and seek external expert advice on the technical merits and challenges of potential approaches prior to updating the ECS distribution in future revisions to the SCC estimates, including (but not limited to) using the AR5 climate sensitivity distribution for the next update of the SCC.

242. The CEOs' witness, Dr. Dessler, stated that the IPCC AR5 relied heavily on 20th Century observational records. Many of the world's experts in climate sensitivity have since agreed that the 20th Century observational estimates have previously unrecognized methodological problems which result in incorrect ECS estimates. As a result, Dr. Dessler asserted that if the IPCC ECS estimate were to be reassessed today, the lower bound would likely again be 2 degrees instead of the 1.5 degrees published in the AR5.[485]

243. The CEOs concluded that the IWG's approach to climate sensitivity is a reasonable one.[486]

E. Marginal Ton: last unit of CO_2 emitted

1. Criticisms

244. The Agencies explained that the IAMs' damage functions are generally convex until temperature increases grow quite substantial. Consequently, every additional unit of CO_2 emitted causes more damage than its predecessors. Damages are caused by the total quantity of CO_2 in the atmosphere.[487] The Utilities and MLIG contended that the IWG's decision to value more recent CO_2 emissions as though they are more damaging than earlier CO_2 emissions is inappropriate.[488] Rather, the Utilities and MLIG argued that the damages caused by CO_2 in 2020 will consist of damages caused that year plus damages in all future years.[489] The Utilities and MLIG explained:

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[485] Tr. Vol. 3A at 111-112 (Dessler).
[486] Ex. 101 at 46 (Polasky Rebuttal).
[487] Ex. 801 at 49-51 (Hanemann Rebuttal).
[488] Ex. 300 at 15 (Smith Direct).
[489] *Id.* at 20.

> [M]any of the tons emitted that contribute to the SCC will not be emitted until much later than the Minnesota tons in question. For example, the SCC value for 2020 depends on the concentration of greenhouse gasses projected to already exist by 2020, all emissions produced in 2020, and all emissions produced from 2020 into the far future.[490]

245. The Utilities and MLIG explained "the 'marginal' damage of an incremental amount of emissions reduction should be equal to the 'marginal' or incremental societal cost to accomplish that reduction."[491] That is why economists focus on marginal damages when they estimate the value of environmental externalities. How much of a pollutant is emitted is key to establishing the marginal damage. With GHGs, the marginal damage estimate depends on the baseline underlying the projected emissions. The marginal damage will be higher if the baseline reflects a world with no established GHG control policies, as opposed to a world with global GHG controls.[492]

246. The IWG's methodology for calculating the FSCC is to use the socioeconomic scenarios to establish a baseline of damages and then subtract the baseline from the damages resulting from an additional unit of CO_2. The IWG's marginal damage estimate thus depends on the baseline scenarios. The Utilities' and MLIG's concerns were heightened because, they claimed, "the IWG has assumed no reductions in greenhouse gases other than the ton in question . . . ."[493] This caused marginal damages to be higher than they would be if policies to restrict emissions were in place.[494]

247. The Utilities and MLIG disagreed with this result because an actual change in climate risk requires global action to achieve large reductions. Therefore, the Utilities and MLIG maintained, all emitters' tons "that would remain under a global reduction plan should be valued like every other emitter's tons, which suggests either a marginal damage estimate assuming the emissions are on the globally-controlled target trajectory, or an average damage of all the tons emitted."[495] The Utilities and MLIG also observed that, in the prior proceeding, the Commission adopted an average cost per ton approach.[496]

248. The Utilities and MLIG recommended two alternative marginal cost estimates, either of which, they asserted, would be preferable to the IWG's marginal cost definition: (1) an estimate of the marginal cost halfway between the first and last tons, which the Utilities and MLIG called the average marginal cost value;[497] or (2) baselines

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[490] *Id.*
[491] Ex. 300 at 21 (Smith Direct).
[492] *Id.*
[493] *Id.* at 21-22.
[494] *Id.*
[495] Ex. 302, AES-D-2 at 7-8 (Smith Direct).
[496] *Id.* at 8.
[497] Ex. 308 at 3 (Smith Opening Statement); Tr. Vol. 2A at 58-60, 82-85 (Smith); *see also* Ex. 302, AES-D-2 at 8 (Smith Direct).

in which there are no additional emissions of CO2 after the incremental emission. Either approach would lower the damage estimates compared to the IWG's approach.[498]

249. Xcel agreed with the Utilities and MLIG that the IWG's "last-ton" approach likely overstates damages from Minnesota emissions, and would similarly overstate the benefits that would accrue from an incremental reduction in emissions in Minnesota.[499] Xcel supported the idea of the average ton approach in theory, but did not recommend it because it would not be practicable to implement.[500]

2. Responses

250. The Agencies criticized the first ton approach taken by the Utilities and MLIG because the first ton approach assumes that no anthropogenic emissions will occur after the year 2020.[501] The year 2020 is the baseline scenario for the first ton approach, with an "emission blip on that baseline . . . ." which is then compared to damages with and without the 2020 blip.[502] According to the Agencies, this is not a reasonable foundation on which to base an SCC.[503] The Agencies argued that warming in any future year depends on emissions that occurred before the present as well as emissions that occur between now and the future date for which emissions and damages are being estimated.[504]

251. The CEOs contended the Utilities and MLIG's discussion of what is meant by "marginal" damage is confusing and inconsistent with the way economists discuss marginal damage. They asserted that introductory economics instructs that the "efficient decision occurs where marginal cost equals marginal benefit, not where average costs equals average benefits, and certainly not where the cost of the first unit is equal to some measure of benefits."[505]

252. The actual argument that the Utilities and MLIG have is not with the marginal ton or marginal damage, according to the CEOs, but "with the emissions projections from which marginal damage is calculated."[506]

253. The CEOs distinguished between damages, which are the result of particular levels of emissions over time, and assumptions about emissions, which the Utilities and MLIG were making. Those assumptions were, with the "first ton" approach, that there would be no further emissions after 2020 because there is a global climate policy in place equating the marginal cost of reducing emissions with the SCC and determining the quantity of emissions resulting from this policy; or with the "average ton"

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[498] Ex. 300 at 48 (Smith Direct).
[499] Ex. 601 at 46 (Martin Rebuttal).
[500] *Id.* at 47.
[501] Ex. 801 at 28 (Hanemann Rebuttal).
[502] *Id.*
[503] *Id.* at 29.
[504] *Id.* at 28.
[505] Ex. 101 at 10 (Polasky Rebuttal).
[506] *Id.*

approach, that an "average" amount of emissions could be predicted between zero and the IWG's projections.[507]

254. The IWG stated "[t]here is a limited amount of research linking climate impacts to economic damages" making the IAMs' analysis of that relationship difficult.[508] Nonetheless, the CEOs emphasized that the IWG's approach to calculating damages, based on a range of projections of emissions given likely future conditions, including future technology, economic and political circumstances, is the better approach and based on a current understanding of the likely potential trajectories of future emissions.[509]

F. Modeling Time Horizon: Estimates of damages after 2100

1. Criticisms

255. The Utilities and MLIG criticized the IWG for extending the IAMs' time horizon to the year 2300.[510] The EMF-22 scenarios were not constructed to allow calculations beyond the year 2100.[511] The Utilities and MLIG asserted that the extension of the scenarios to 2300 required the IWG to make assumptions so speculative and uncertain that they are inconsistent with the Commission's standard established in the 1993 Externalities docket.[512]

256. Up to about 3 degrees centigrade, the Utilities and MLIG acknowledged there is some limited empirical evidence about how climate change will impact the economy.[513] By extending the time horizon of the scenarios, significant numbers of the IAMs' runs project very high temperature increases. Because there is no data to support the amount of damages that will result from temperature increases over about 4 degrees centigrade, the Utilities and MLIG contended that much of the FSCC estimate is speculative.[514]

257. With decreasing discount rates, increasing portions of the FSCC values came from the post-2100 time period, according to the Utilities' and MLIG's calculations. For example, at a 5 percent discount rate, about one-quarter of the FSCC estimates come from the post-2100 era range. At a 3 percent discount rate, the Utilities and MLIG estimated that about one half of the FSCC consisted of damages incurred after 2100.[515] The Utilities and MLIG found these values highly speculative.[516]

258. The Utilities and MLIG compared the IWG's effort to predict the socioeconomic state of affairs in 2300 to that of a projection by someone in 1715 of

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[507] *Id.* at 10-11.
[508] Ex. 100, Schedule 2 at 5 (Polasky Direct).
[509] Ex. 101 at 12 (Polasky Rebuttal).
[510] Ex. 300 at 15, 22-23 (Smith Direct).
[511] Tr. Vol. 2A at 80-81 (Smith).
[512] Ex. 300 at 15 (Smith Direct); 93-583 PUC ORDER 2 at 8.
[513] Ex. 308 at 2 (Smith Opening Statement).
[514] Ex. 302, AES-D-2 at 70-72 (Smith Direct).
[515] *Id.* at 75-79.
[516] *Id.* at 75-76.

conditions today.[517] In particular, the Utilities and MLIG criticized the IWG's assumption that "future generations will passively endure temperature changes as high as 10° C above pre-industrial levels, without taking any steps whatsoever to address the causes of such temperature changes."[518] The Utilities and MLIG stated it is unreasonable for the IWG to assume that future generations will not develop new or improve existing technologies that would alter the relationships between population and GDP growth and CO_2 emissions.[519] The Utilities and MLIG noted there are numerous ways societies can undertake to reduce emissions as well as to promote carbon sequestration such as encouraging the planting of trees. The Utilities and MLIG noted that some of these reductions are incorporated into the PAGE and FUND models.[520]

259. The Utilities and MLIG pointed out the Commission adopted an estimate based on a time horizon of 100 years when it determined the social cost of carbon in 1997.[521]

260. Xcel expressed concerns about the great uncertainty in the EMF scenarios as they were extrapolated to the year 2300, asserting that the IWG inserted largely arbitrary assumptions into the scenarios in the years past 2100. In addition, Xcel contended that, even if the modeling assumptions were correct, predicting emissions required yet another layer of assumptions which were not based on evidence. Like the Utilities and MLIG, Xcel found the lack of endogenous modeling of societal response to emissions troubling. [522]

2. Responses

261. The CEOs maintained that the impact of a unit of emission of CO_2 should be taken into account for as long into the future as that CO_2 is likely to remain in the atmosphere, causing damages.[523] Because some estimates state that a unit of CO_2, along with its associated warming effects, will remain in the atmosphere for up to 200 years, the CEOs asserted that it would be arbitrary to exclude some time period in the future where damages are likely to occur.[524]

262. Acknowledging that eventually the combination of a low probability that the unit of CO_2 will remain in the atmosphere and the impact of discounting will make the value of future damages negligible, the CEOs agreed that the IWG appropriately determined that the year 2300 was the proper end point in time for purposes of calculating the FSCC.[525]

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[517] Ex. 300 at 22 (Smith Direct).
[518] *Id.*
[519] Ex. 302, AES-D-2 at 72-73 (Smith Direct).
[520] PAGE and FUND "explicitly incorporate some assumptions regarding how adaptation may mitigate climate change impacts." Ex. 302, AES-D-2 at 20 (Smith Direct).
[521] *Id.* at 69.
[522] Ex. 600 at 31-35 (Martin Direct).
[523] Ex. 101 at 15 (Polasky Rebuttal).
[524] Ex. 101 at 15; Schedule 1 at 29 (Polasky Rebuttal).
[525] Ex. 101 at 15 (Polasky Rebuttal); s*ee also* Ex. 405 at 545 (IPCC AR5).

263. The CEOs admitted that it is not possible to predict with great accuracy what will happen between now and 2300. But the CEOs alleged that it is also not possible to predict with great accuracy what will happen between now and 2140, 2100 or even 2050.[526]

264. The CEOs agreed with the Utilities and MLIG that making predictions to the year 2300 is filled with uncertainty. But the CEOs disagreed with the solution offered by the Utilities and MLIG, which was to assume that there would be zero damages after the year 2100 or 2140. The CEOs claimed such an approach "has no bearing in reality" and is not viable.[527]

265. The Agencies responded to the Utilities' and MLIG's concerns that the EMF-22 scenarios only go through 2100. The Agencies explained that the purpose of the EMF-22 scenarios, unlike the IWG's purpose, was not a cost-benefit analysis of climate mitigation policies. Rather, the EMF-22 scenarios were focused on cost minimization in reducing emissions to meet targets being considered in current climate policy debates and focused on abatement costs to meet a specific goal in the year 2100. Damages were not considered in any other year, either before or after 2100.[528]

266. The Agencies maintained that the EMF-22 scenarios are projections and that the nature of projections is that they cannot be based on evidence or facts. They can only be based on reasonable assumptions. For that reason, the Agencies did not recognize a significant distinction between the EMF-22 scenarios as they were originally designed to project to the year 2100 and as the IWG extrapolated them to go to the year 2300. The Agencies understood both uses of the EMF-22 scenarios to be fairly similarly speculative.[529]

267. The Agencies pointed out that Xcel's description of the IWG's emissions scenarios projections was misleading because Xcel's illustration of the IWG's emissions scenarios ends at approximately 2100, leaving the impression that, with the exception of the fifth scenario, emissions will continue to rise.[530] But, the Agencies observed, the IWG's emissions scenarios projections level off and decline between 2150 and 2200.[531] The Agencies noted that the IWG did not assume that emissions would continue to grow from 2100-2300. Instead, the IWG provided for societal response to climate change by placing a 20 percent weight on the fifth scenario emission projection that hypothesizes a global climate stabilization plan at 550 ppm of CO_2.[532]

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[526] Ex. 101 at 16 (Polasky Rebuttal).
[527] Ex. 101 at 16 (Polasky Rebuttal).
[528] Ex. 801 at 24-25 (Hanemann Rebuttal).
[529] *Id.* at 25.
[530] *Id.* at 18-23.
[531] *Id.*
[532] *Id.* at 23. Dr. Hanemann explained that the goal of 550 ppm originated in the 1990s to define the concentration of CO_2 that would cause roughly a doubling of the pre-industrial concentration and avoid more than a 2°C warming. According to Dr. Hanemann, by 2007 it had become clear that a concentration of less than 550 ppm would be required to avoid warming beyond 2°C. *Id.* at 23-24.

G. Geographic Scope

1. Criticisms

268. The Utilities and MLIG argued that using a FSCC based on global damages rather than damages incurred by Minnesotans is inappropriate.[533] They reasoned that Minnesota's application of the FSCC in its resource planning efforts will not bind other states or nations to doing the same, and will have no significant impact on climate change.[534]

269. The Utilities and MLIG stated that Minnesota should not impose costs upon its residents that will be much greater than the benefits they will receive as a result of any emissions reductions.[535] The Utilities and MLIG ran the FUND and PAGE models, limiting damages to those that will be experienced in the United States.[536] The result "reduces the SCC by 81% to 84% from its value when global damages are considered."[537] Assuming that Minnesota's damages are proportionate to its share of the United States' GDP, the Utilities and MLIG alleged that Minnesota's domestic-only SCC estimate would be lower by a factor of more than 50.[538]

270. MLIG argued that the CEOs failed to properly consider the definition of "society" when the CEOs defined the term "externality value" to "include[] the total external costs inflicted on society from the emission of pollution." [539]

271. MLIG framed the question of who should be counted in calculating "the external costs of pollution, or equivalently, the external benefits of reducing pollution" as a question of "economic standing."[540] In reviewing this cost-benefit analysis, MLIG discussed the issue in terms of who pays the costs of the policy of reducing pollution and who receives the benefits.[541]

272. MLIG advised that "standard benefit-cost analysis applied to a policy paid for by the residents of a state would evaluate the benefits to residents of the state rather than of neighboring states."[542]

273. MLIG recognized that there are justifications for considering the benefits of residents outside the jurisdiction that would incur costs under the policy being considered.

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[533] Ex. 300 at 15 (Smith Direct).
[534] Ex. 300 at 15, 27 (Smith Direct).
[535] *Id.* at 36-37.
[536] Ex. 302, AES-D-2 at 98 (Smith Direct). Dr. Smith did not include the DICE model in this analysis because it has no regional detail. *Id.*
[537] *Id.*
[538] *Id.* at 99.
[539] Ex. 400, Appendix 2 at 3 (Gayer Direct).
[540] Ex. 400, Appendix 2 at 3 (Gayer Direct).
[541] *Id.* at 4.
[542] *Id.*

Those justifications include intergovernmental grants, an explicit recognition or expectation of reciprocity, or altruistic motivations, according to MLIG.[543]

274. MLIG advocated the use of a Minnesota, rather than a global, scope of damage calculation in the absence of express reciprocity. Alternatively, taking into account demonstrative feelings of altruism even in the absence of reciprocity, MLIG recommended a much narrower damages scope, such as United States damages.[544]

275. MLIG acknowledged that the IWG provided some estimates of the national domestic benefits of reducing CO_2, but added that there was no effort to estimate the state-specific benefits of reducing CO_2."[545]

276. MLIG asserted that if the global approach to measuring the SCC were applied more broadly as a state policy, it "would demand a dramatic shift in all state policies, including state poverty programs."[546] MLIG suggested it would be important to consider what this "practice of granting benefits to non-residents equally to benefits of residents across the world would suggest if applied to all policies." MLIG projected that the end result could mean that poor people all over the world would have equal standing to receive low-income assistance from Minnesota.[547]

277. Peabody distinguished the American Cost of Carbon from the global SCC. The American Cost of Carbon measures only the damages experienced in the United States and is about 5% of the global SCC.[548] Peabody opined that Minnesota is "currently a net beneficiary of warming" because sea level rise and tropical cyclones do not affect Minnesota and "[a] warmer, wetter, CO_2-enriched world would be a clear gain for Minnesota agriculture."[549]

2. Responses

278. In response to the parties who urged the Commission to limit the scope of damages to the United States or to Minnesota, the Agencies reiterated their claim that GHGs are different from criteria pollutants in the spatial scale of their impacts.[550] Because GHGs emitted in one location on earth mix with GHGs emitted from all other locations on the planet, each GHG molecule emitted contributes to climate change experienced everywhere. Consequently, the Agencies asserted, damages are experienced globally.[551]

279. The CEOs argued that a Minnesota electric power generating emitter must incorporate into the generator's production decision process the damages its emissions

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[543] *Id.* at 5.
[544] Ex. 400 at 9 (Gayer Direct).
[545] Ex. 400, Appendix 2 at 15 (Gayer Direct).
[546] Ex. 400 at 9 (Gayer Direct).
[547] Ex. 400, Appendix 2 at 15-16 (Gayer Direct).
[548] Ex. 214 at 3-4 (Mendelsohn Direct).
[549] *Id.*
[550] Ex. 801 at 13 (Hanemann Rebuttal).
[551] *Id.*

cause to all parties.[552] To incorporate only Minnesota damages, asserted the CEOs, would be to ignore the vast majority of external costs.[553] If every political territory only considered external damages within its own boundaries, the CEOs claimed that "there would be virtually no correcting for externalities." While recognizing that some states may fail to take external damages into account in their decision-making, the CEOs stated that those states will be unprepared for future decision-making regarding climate change. By taking into account the full cost of CO_2 externalities, the CEOs said Minnesota will be leading and "preparing for a future where the price of emitting carbon is no longer free."[554]

280. The Agencies stated that the question of whether the geographic scope of CO_2 emissions should be taken into account when determining the FSCC is a policy decision, rather than a matter of economic theory.[555] The Agencies note that the Utilities and MLIG "appeared to agree" that this is a policy decision, although the Utilities and MLIG were critical of the IWG's decision.[556]

281. The Agencies' expert, Dr. Hanemann, believed it was most appropriate to defer to "precedent in Minnesota's previous decisions regarding the environmental cost of electricity that bear on the policy decision involved here."[557] The expert asserted that the Agencies themselves, and the Commission, all state that a global scale of analysis is the proper approach to take to calculating the environmental cost of electricity.[558]

282. Xcel agreed that the geographic scope of damages is a policy decision for the Commission to make. Xcel remarked that, on one hand, the Commission may wish to demonstrate environmental leadership and to provide an example to encourage reciprocity even if implicitly.[559] On the other hand, Xcel maintained, it is important to recognize the small contribution to emissions and climate change that Minnesota makes, even in relation to the United States. Xcel pointed out that, if Minnesota adopts a SCC based on global damages, any resulting resource planning decisions, even if they lead to a complete elimination of CO_2 emissions in Minnesota, would have a small impact on global climate damages or on damages experienced by Minnesotans.[560] Xcel noted that its own proposal could be adjusted if the Commission chooses to base the SCC on United States or Minnesota damages rather than the global damages reflected in the FSCC numbers.[561]

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[552] Ex. 101 at 26 (Polasky Rebuttal).
[553] *Id.*
[554] Ex. 101 at 26 (Polasky Rebuttal).
[555] Ex. 801 at 15 (Hanemann Rebuttal).
[556] *Id.*
[557] *Id.*
[558] *Id.* at 16.
[559] Ex. 601 at 39 (Martin Rebuttal).
[560] *Id.* Xcel linked these concerns to its concerns about leakage, discussed in Section IV.H of this Report. Xcel encouraged the Commission to consider the wider impacts leakage might have on its customers, and in this docket, or a separate docket, to consider ways in which such impacts might be mitigated. *Id.* at 39-40.
[561] Ex. 602 at 6 (Martin Surrebuttal).

283. Specifically responding to MLIG's expert, Dr. Gayer, the CEOs emphasized that Gayer focused on the economic standing of "who is to be counted in the calculation of the external costs of pollution, or, equivalently, the external benefits of reducing pollution."[562] In response to Gayer's query, the CEOs stressed that, because Minn. Stat. § 216B.2422 requires the Commission to "quantify and establish a range of environmental costs associated with each method of electricity generation," economic standing belongs to "all parties damaged by the emission of a unit of CO_2."[563]

284. The CEOs disagreed with Dr. Gayer's economic analysis that standard benefit-cost practice means considering only the benefits for the residents of that political jurisdiction who are bearing the costs of the policy being considered. The CEOs regarded externalities as a market failure, an attempt to reduce damages that Minnesota activity is inflicting on others.[564]

285. The CEOs rejected Dr. Gayer's suggestion that the FSCC's global damages approach would require reconsideration of state poverty policies. The CEOs asserted that Dr. Gayer's comment in this regard conflates two unrelated issues.[565]

286. The CEOs reported that the IWG addressed the issue of global damages in its July 2015 Response to Comments. The CEOs noted that "because GHG emissions are a global problem they set up a classic public goods, or tragedy of the commons, scenario: '[I]f all countries acted independently to set policies based only on the domestic costs and benefits of carbon emissions, it would lead to an economically inefficient level of emissions reductions which could be harmful to all countries, including the United States, because each country would be underestimating the full value of its own reductions.'"[566] The CEOs asserted that the same reasoning applies to Minnesota as a state.[567]

H. Leakage

1. Criticisms

287. The Utilities and MLIG explained that leakage occurs when reduced CO_2 emissions in one jurisdiction are replaced by increased CO2 emissions in another jurisdiction.[568] "Leakage is the extent to which policy-driven decreases in carbon emissions are offset by resulting increases in other jurisdictions."[569]

288. The Utilities and MLIG pointed out that Minnesota's electrical grid is interconnected to electricity systems in other states that may not impose equivalent costs on carbon emissions. As a result, the Utilities and MLIG reasoned, the use of an SCC in

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[562] Ex. 101 at 26 (Polasky Rebuttal).
[563] Ex. 101 at 27 (Polasky Rebuttal).
[564] *Id.* at 27-28.
[565] *Id.* at 28.
[566] *Id.* at 28-29.
[567] Ex. 101 at 29 (Polasky Rebuttal).
[568] Ex. 300 at 27 (Smith Direct).
[569] *Id.* at 27-28.

resource planning in Minnesota will result in fewer CO_2 emissions in Minnesota but additional CO_2 emissions elsewhere to meet electrical demand.

289. According to the Utilities and MLIG, the "net" impact on emissions is the emissions reduction in Minnesota less the amount by which emissions increase elsewhere to supply the demand for electricity in Minnesota.[570]

290. The Utilities and MLIG supported the consideration of leakage when using CO_2 environmental cost values.[571] However, they would not take leakage directly into account in calculating the SCC. Instead, they would apply SCC values to a net total ton of CO_2 emissions, after applying a calculated leakage amount in each particular resource planning situation.[572]

291. The Utilities and MLIG described a method to estimate leakage. Specifically, a detailed generation planning model of the Minnesota electric system and the power pools that connect to Minnesota can be run with and without a specific change in generation resources in Minnesota.[573] "The ratio of the change in emissions outside Minnesota to the change in emissions within Minnesota would yield the amount of estimated leakage."[574] Such a model can be run with and without a specific change in generation resource in Minnesota (and hence a specific direct change in Minnesota's electricity sector CO_2 emissions). The ratio of the change in emissions within Minnesota would yield the amount of estimated leakage."[575]

292. The Utilities and MLIG alleged the rate of leakage can be as high as nearly 100 percent if a state takes an action and the region is not imposing similar policies.[576] The Utilities and MLIG argued that estimated leakage should be accounted for because the SCC should only be applied to the net emissions reduction estimates.[577] Further, the IWG did not account for leakage in its computation of the FSCC values.[578] The Utilities and MLIG asserted that to arrive at a net change in metric tons, the direct CO_2 reduction estimates associated with resource planning should subtract an estimate of potential increases in metric tons occurring outside of the Commission's jurisdiction.[579]

293. The Utilities and MLIG stopped short of making a specific recommendation for a leakage value to consider because it will vary based on the decision under consideration. But, they assert, whatever CO_2 environmental cost values the

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[570] Ex. 300 at 27-28 (Smith Direct).
[571] *Id.* at 28.
[572] *Id.* at 34. In her oral testimony, Dr. Smith noted that the IWG acknowledged in its response to comments that SCC values from the federal government should be applied to the number of tons as adjusted for leakage. Tr. Vol. 2A at 106 (Smith).
[573] Ex. 302, AES-D-2 at 100 (Smith Direct).
[574] *Id.*
[575] *Id.* at 102.
[576] *Id.* at 100; *see also* Tr. Vol. 2A at 102 (Smith).
[577] Ex. 300 at 29 (Smith Direct).
[578] *Id.*
[579] *Id.* at 34.

Commission adopts should be adjusted by the estimated level of leakage.[580] The higher the dollar per ton of CO_2, the greater the likelihood that leakage will be a problem and the benefit of that externality value would be reduced.[581] The Utilities and MLIG noted that it would be easier for manufacturing to decide to move across state boundaries if higher utility prices were triggered in Minnesota.[582]

294. Even if a new generating unit were built in Minnesota, the Utilities and MLIG warned that leakage could still occur if the replacement unit were to have more expensive fuel or be intermittently dispatched, if the new generation is wind or solar. Therefore, they maintained, the potential for leakage is significant and should be closely analyzed. [583]

295. The Utilities and MLIG urged the Administrative Law Judge to recommend that the Commission adopt an estimate of the SCC net of leakage in this proceeding and that the Commission conduct a leakage study "as part of any application of the CO_2 environmental cost values that result from this proceeding."[584]

296. MLIG's witness, Dr. Gayer, supported the Utilities' and MLIG's witness, Dr. Smith, in her suggestion to apply the SCC to the net reduction in emissions.[585] MLIG did not agree with the Agencies' premise that leakage should not be considered because Minnesota only regulates utilities within Minnesota.[586] MLIG maintained that if Minnesota ignores leakage and emissions are increased elsewhere as a result, the regulation would not serve its purpose.[587]

297. MLIG urged the Commission to take leakage seriously and to consider leakage if the SCC is applied inconsistently across states, or Minnesota's regulation would be undermined.[588] Unless the SCC is applied across different countries, MLIG disagreed with the CEOs' view that leakage does not affect the externality value the Commission adopts.[589] At least conceptually, MLIG warned that there could be more harm to the environment through leakage if Minnesota adopts a high SCC.[590] The goal should be to reduce emissions and not simply to price emissions, cautioned MLIG.[591]

298. Peabody emphasized that it is critical that the amount of leakage be calculated and included in the final SCC calculation.[592] Disagreeing with the Agencies, the CEOs, Xcel and the Utilities, Peabody contended that leakage should be considered

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[580] *Id.* at 40.
[581] Tr. Vol. 2A at 103, 105 (Smith)
[582] Ex. 302, AES-D-2 at 101 (Smith Direct).
[583] *Id.* at 102.
[584] *Id.* at 49.
[585] Ex. 401 at 10-11 (Gayer Surrebuttal).
[586] *Id.*
[587] *Id.*
[588] *Id.* at 9-10.
[589] *Id.*
[590] *Id.*
[591] *Id.*
[592] Ex. 220 at 33 (Mendelsohn Surrebuttal).

as part of Minnesota's SCC given that the Commission is trying to determine what value to place on gross, and not net, carbon emissions.[593]

299. Peabody asserted that if Minnesota adopts a high price for CO_2, rates will increase for Minnesota residents who "would be lucky if they get 1% of the benefits of this costly program" at best due to leakage if neighboring states and countries do not adopt similar policies and prices.[594]

300. Peabody argued that the greater the difference in CO_2 cost in Minnesota compared to the rest of the region, the greater the leakage will be.[595] Due to leakage, emissions would be simply reassigned, not reduced.[596] For example, if Minnesota insists that imported power be based on low carbon fuels, neighboring states may assign natural gas generation to the Minnesota market and respond by increasing generation from coal plants for their own markets.[597] Additionally, Peabody speculated that if Minnesota had high prices as a result of a high CO_2 cost, surrounding states could lure businesses from Minnesota to avoid higher prices.[598]

2. Responses

301. The Agencies asserted that leakage should not be considered when applying a SCC value.[599] The Agencies reasoned that, because the Commission regulates utilities that operate in Minnesota and does not have jurisdiction in other states or countries, the Commission has no responsibility for the aggregated level of emissions resulting from other jurisdictions' action or inaction.[600] The Agencies found no reason for the Commission to modify its assessment of an environmental cost based on what may or may not happen in other jurisdictions.[601]

302. The CEOs explained that leakage does not affect the CO_2 values adopted by the Commission and did not support the consideration of leakage when calculating the FSCC values.[602]

303. The CEOs explained that leakage is a policy issue that can be addressed through other Commission actions and agreed with the IWG's response to leakage questions.[603] The IWG is concerned with leakage, but not as leakage affects the calculation of damages.[604] The FSCC is an estimate of the marginal benefit of a net one-

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[593] *Id.*
[594] Ex. 218 at 3 (Mendelsohn Rebuttal Ex. 1).
[595] Ex. 220 at 33 (Mendelsohn Surrebuttal); Tr. Vol. 3B at 42-43 (Mendelsohn).
[596] Ex. 218 at 4 (Mendelsohn Rebuttal Ex. 1).
[597] *Id.* at 3-4.
[598] Ex. 214 at 5 (Mendelsohn Direct).
[599] Ex. 801 at 30 (Hanemann Rebuttal).
[600] *Id.*
[601] *Id.* at 30-31.
[602] Ex. 101 at 29 (Polasky Rebuttal).
[603] *Id.* at 29-30.
[604] Ex. 101 at 30; Schedule 1 at 32-33 (Polasky Rebuttal).

ton reduction in CO_2 emissions.[605] The IWG explained that "[t]he FSCC estimates are multiplied by estimates of net GHG emissions changes to calculate the value of benefits associated with a policy action in a given year."[606] The CEOs concluded that the FSCC assigns a damage cost to emissions.[607] The CEOs reasoned that the FSCC number assigned to the damages from a ton of carbon is not a function of leakage.[608]

304. Xcel also noted that the IWG recommends that any estimate of leakage be applied to emission reductions and not to the SCC itself.[609] Xcel agreed with MLIG and the Utilities that the Commission could consider leakage in another proceeding because leakage is outside the scope of this proceeding, which is intended to determine damage cost values.[610]

305. Xcel disagreed with the Agencies' argument that the Commission should not account for leakage when applying its CO_2 cost range because the Commission lacks jurisdiction over utilities outside of Minnesota.[611] Additionally, Xcel noted, the benefit of avoided climate damages may be overestimated if it ignores the possibility of leakage.[612] In order to derive the value of climate damages avoided by Commission action, Xcel supported the Commission making a case-by-case estimate of leakage in a separate proceeding to derive an adjustment factor that would be multiplied by emission reductions in Minnesota, and then by Xcel's proposed CO_2 environmental cost range.[613]

306. Xcel suggested that an increase to the existing CO_2 externality value would not likely by itself lead to a retirement of a coal-fired generation unit, but would be one of many considerations.[614] In addition, Xcel noted that generation from a coal-fired generation unit could be offset with renewable energy.[615] However, in a regional system such as Midcontinent Independent System Operators (MISO), Xcel maintained that generation from outside Minnesota could result in a net increase in emissions if retired generation in Minnesota is replaced by higher-carbon-emitting generation on a per-MWh basis outside of Minnesota.[616]

307. Xcel agreed with the Utilities and MLIG that it is not appropriate to adjust the SCC itself because leakage affects the total emission reductions.[617] Xcel also agreed with the Utilities and MLIG that the amount of leakage will vary depending on what value

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[605] Ex. 101, Schedule 1 at 33 (Polasky Rebuttal).
[606] *Id.*
[607] Ex. 101 at 30 (Polasky Rebuttal); Tr. Vol. 1 at 126 (Polasky).
[608] Tr. Vol. 1 at 126-127 (Polasky).
[609] Ex. 601 at 52 (Martin Rebuttal).
[610] Ex. 602 at 39-40 (Martin Surrebuttal); Tr. Vol 4 at 14-16 (Martin).
[611] Ex. 602 at 39 (Martin Surrebuttal).
[612] *Id.*
[613] Ex. 601 at 53 (Martin Rebuttal); Tr. Vol. 4 at 43 (Martin). See discussion of Xcel's proposed SCC cost range at section VII below.
[614] Tr. Vol. 4 at 14 (Martin).
[615] Ex. 601 at 53 (Martin Rebuttal); Tr. Vol. 4 at 15 (Martin).
[616] Ex. 601 at 52-53 (Martin Rebuttal).
[617] *Id.* at 53.

the Commission assigns to CO_2.[618] Xcel explained that if leakage led to retirements of generation from fossil fuels, then leakage would be "fairly substantial and immediate" in the near term if that generation is replaced from elsewhere in the MISO system.[619] However, if the CO_2 environmental cost values motivate the addition of new zero-emissions generation, such as wind generation, the wind generation would be dispatched first by MISO, resulting in less leakage.[620] Due to the *de minimis* nature of Minnesota's emissions compared to the rest of the world, Xcel posited that there will likely be little reduction in global CO_2 damages and, therefore, little reduction in CO_2 damages for Minnesotans.[621]

I. Uncertainty

1. Criticisms

308. Peabody noted that, according to the CEOs, estimates of climate change impacts are incomplete and understated. However, Peabody asserted, the IWG models "include all impacts for which a global impact estimate is available."[622] Because the size and sign of uncounted impacts is not known, Peabody argued that the CEOs' claim that missing impacts are significant and negative is speculative.[623]

309. Peabody also argued that the IWG's use of Monte Carlo calculations in running the FSCC does not counter the uncertainty created by the IWG's use of "ill-founded assumptions and arbitrary inputs" when it ran the IAMs. As examples, Peabody reiterated that the IWG's ECS assumptions were likely biased high, and that the IWG failed to incorporate the environmental benefits of carbon dioxide.[624]

310. The nature of IAMs, according to Peabody, is such that they contain uncertainty at each step of the process. Peabody described the IAM process as magnifying uncertainties from step to step, creating a "cascade of uncertainties" that even techniques such as the Monte Carlo analysis and random simulation cannot significantly cure.[625]

311. Peabody criticized the IAMs' use of probability distributions to compensate for the IAMs' questionable damage functions. This use of a range of values around a norm "serves to acknowledge that we have no real scientific evidence to support one value over another – their use introduces another bias into the IAM results. Since the structure of the damage functions are quadratic equations, the results of using probability

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[618] *Id.*
[619] *Id.*
[620] Ex. 601 at 53 (Martin Rebuttal); Tr. Vol. 4 at 15 (Martin).
[621] Ex. 601 at 28 (Martin Rebuttal).
[622] Ex. 238 at 8 (Tol Rebuttal Ex. 2).
[623] *Id.*
[624] Ex. 242 at ¶ 30 (Wecker Rebuttal Ex. 2).
[625] Ex. 230 at 110-111 (Bezdek Direct Ex. 2).

distributions of equation parameters results in so-called 'fat-tail' impacts that are larger for higher increases than for lower increases."[626]

312. Xcel asserted that the IWG had to make inherently uncertain policy judgments and establish uncertain scientific parameters when estimating climate change damages to the year 2300.[627]

313. Xcel acknowledged that the IWG attempted to address the inherent uncertainty regarding climate change in several ways, including using three IAMs, five different socioeconomic and emissions projections, a probability distribution for ECS, and three different discount rates. Despite the FSCC's flaws, Xcel determined that it could be used as the basis for developing CO_2 environmental cost values.[628] However, Xcel found the FSCC's approach of recommending four single point values rather than a range of values to give the impression of false precision. Therefore, based on the numbers calculated by the IWG, Xcel made its own proposal for establishing an SCC in this proceeding, which yielded a range of values.[629] Xcel's proposal is described at section VII, below.

314. Xcel quoted Professor Robert Pindyck on ECS uncertainty:[630]

> We know very little about climate sensitivity, i.e., the temperature increase that would eventually result from a doubling of the atmospheric CO_2 concentration, but this is a key input to any IAM. The problem is that the physical mechanisms that determine climate sensitivity involve crucial feedback loops, and the parameter values that determine the strength (and even the sign) of those feedback loops are largely unknown, and are likely to remain unknown for the foreseeable future. As Freeman, Wagner and Zeckhauser (2015) have shown, over the past decade our uncertainty over climate sensitivity has increased.

315. The Utilities and MLIG observed that there may be more scientific confidence now than in the 1990s that CO_2 emissions will lead to climate change and resultant damages, and some IAMs now try to quantify higher risk outcomes connected with temperature increases that are higher than 2.5 degrees centigrade. Nonetheless, the Utilities and MLIG noted, the damage functions in the IWG's IAMs are still based on limited empirical evidence.[631]

316. The Utilities and MLIG expressed strong concerns about the attempt to calculate damages over a four-degree centigrade increase or "after about 100 years from

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[626] Ex. 234 at 81 (Bezdek Rebuttal Ex. 2).
[627] Ex. 600 at 5 (Martin Direct).
[628] *Id.* at 52.
[629] *Id.*
[630] *Id.* at 39.
[631] Ex. 300, AES-D-2 at 7 (Smith Direct).

the present" as highly speculative.[632] The Utilities and MLIG maintained that the damage functions in the IWG's IAMs create an inaccurate appearance of knowledge and precision about CO_2 emissions reduction benefits. This inaccuracy contributes to the overall uncertainty of the FSCC.[633] The Utilities and MLIG asserted that the IWG failed to analyze the uncertainty in the FSCC resulting from the damage functions in the IAMs.[634] The Utilities and MLIG structured their alternative assumptions for estimating the SCC values to counter the uncertainties resulting from the IWG's IAMs' damage functions.[635]

317. MLIG acknowledged that uncertainty does not justify inaction. However, MLIG cautioned that the uncertainty of a prediction "approaches infinity as time increases indefinitely." Noting that the Congressional Budget Office has recently shifted its focus towards the first 25 years of its 75-year projections, MLIG maintained that "there is a point at which uncertainty gets so large that it makes the forecast useless and not worth basing current policy on."[636]

2. Responses

318. The Agencies explained that the IWG acknowledged the scientific uncertainty that exists regarding climate sensitivity by making the ECS value a random variable in the IAMs with the same probability distribution for each of the models.[637] The CEOs pointed out that ranges of values were selected for global projections of CO_2 emissions and for discount rates and applied to all three IAMs to account for uncertainty concerning those inputs. [638]

319. The Agencies noted that the use of probability distributions for the numerical value of certain parameters in FUND and PAGE is intended to account for the uncertainty regarding the value of those parameters.[639] The Agencies further explained that PAGE contains ten random parameters and FUND contains eleven such parameters.[640]

320. The Agencies acknowledged that the Pindyck quotation cited by Xcel (*see* paragraph 314, above) was accurate in that uncertainty over climate sensitivity has increased.[641] However, the Agencies argued that Dr. Pindyck's concerns are not a persuasive argument against the Commission's adoption of the FSCC.[642] Asserting that Xcel failed to point out the implication that Freeman, Wagner, and Zeckhauser drew from this increase in uncertainty, the Agencies explained that the economic implication of the

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[632] *Id.* at 11.
[633] Ex. 302, AES-D-2, Att. 1 at 5-6 (Smith Direct).
[634] *Id.* at 8-9.
[635] Ex. 300 at 33 (Smith Direct).
[636] Ex. 401 at 12-13 (Gayer Surrebuttal).
[637] Ex. 800 at 46 (Hanemann Direct).
[638] Ex. 100 at 8 (Polasky Direct).
[639] Ex. 800 at 42, fn 32 (Hanemann Direct).
[640] *Id.* at 52.
[641] Ex. 801 at 31-32 (Hanemann Rebuttal).
[642] *Id.*

increase in the uncertainty regarding climate sensitivity is that it raises the SCC in Pindyck's economic model of climate change.[643]

321. The Agencies criticized the Utilities and MLIG for their failure to acknowledge the uncertainties regarding the location in time of climate tipping points and how such tipping points could affect the SCC. The Agencies drew an analogy to a bicyclist racing downhill, with an unknown curve ahead. The Agencies assumed that a good cyclist would brake until he determined how the curve should be handled. Similarly, the Agencies argued: [644]

> The existence of an uncertain threshold for a tipping point lying ahead is shown to raises [sic] the current SCC value. Once the tipping point danger is resolved, the SCC value drops down. This overturns the conventional pattern in which the SCC starts out low and rises over time: with tipping point uncertainty, the SCC would start out high.

322. The Agencies explained that the 2.5 percent discount rate was included in the FSCC to account for the concern that interest rates are quite uncertain over time.[645]

323. The CEOs recognized that uncertainty plays a major role in the process of estimating the SCC, and explained that the IWG dealt with uncertainty by using estimates from multiple IAMs and using a range of parameters in the models as described above.[646] The CEOs emphasized that uncertainty is no excuse for inaction, or for assigning a value of zero for the SCC, but called for moving forward with the best information available in order to insure against the most catastrophic damages. The CEOs recommended adjusting the SCC in the future, as better information becomes available.[647]

J. Adaptation and Mitigation

1. Criticisms

324. Peabody agreed with MLIG that the IWG's assumption of zero abatement in the future is incorrect.[648]

325. Peabody asserted that, because climate change is a very slow process, it is uncertain what it will look like fifty years from now but it is likely that "[i]f climate is not a surprise and it has important impacts, it is very obvious that people will react." Peabody states that human adaptation will "substantially reduce damage."[649]

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[643] *Id.* at 33.
[644] Ex. 801 at 59-60 (Hanemann Rebuttal).
[645] *Id.* at 86.
[646] Ex. 100 at 8, 16 (Polasky Direct).
[647] *Id.* at 16.
[648] Ex. 214 at 15-16 (Mendelsohn Direct).
[649] Ex. 220 at 18-19 (Mendelsohn Surrebuttal).

326. Peabody argued that, even if the IWG's ECS value of 3 is correct, it will take until the year 2100 for the climate to warm three degrees, assuming no attempts are made at abatement or mitigation. That will allow people time to adapt to moderate warming.[650]

327. The Utilities and MLIG pointed out that this proceeding demonstrates that it is not realistic to assume that society will passively allow damaging changes in the climate to occur without taking mitigating action.[651]

328. Xcel, and the Utilities and MLIG maintained that none of the IAMs incorporates, endogenously, any societal response to temperature and climate changes. Therefore, once the emissions trajectory is fixed, the IAMs presume that future societies do nothing beyond what is reflected in the emissions scenarios to mitigate even dramatic projected damages.[652] In relation to this concern, Xcel invoked the Utilities' and MLIG's argument that one difficulty with projecting to the year 2300 is that attempting to model climate damage and society's responses "out to the year 2300 is equivalent to scientists in the early 1700s attempting to model our society today."[653] In addition, the Utilities and MLIG asserted that projections of a society unresponsive to climate change in the future are particularly unrealistic given the likelihood, based on the IWG scenarios, that global society will be three to five times wealthier by 2100, and between seven and 25 times wealthier by 2300.[654]

329. Xcel agreed with Peabody, the Utilities and MLIG that the IWG's "last ton" marginal damages approach unrealistically presumes no further actions will occur in the future to reduce emissions, resulting in an overstatement of the FSCC.[655]

330. Xcel also argued that, while the 95th percentile value captures some of the uncertainty of "tipping point" damages, it fails to account for the counterbalancing adaptation and technological change.[656]

331. The Utilities and MLIG recommended that instead of taking a risk management approach that attempts to value CO_2 damage per ton using IAMs, Minnesota should recognize that a policy that "characterizes the more severe outcomes and experts' best estimates of their probabilities is what is required to motivate action."[657] The Utilities and MLIG recommended balancing decisions on spending resources on incremental emissions reductions now with decisions to fund research and other investments to create future technologies and infrastructure "that will be better able to mitigate the impacts of worst-case outcomes."[658]

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[650] Ex. 206 at 11 (Happer Surrebuttal).
[651] Ex. 300 at 22 (Smith Direct).
[652] Ex. 601 at 24-25 (Martin Rebuttal); *see also* Ex. 302, AES-D-2 at 74 (Smith Direct).
[653] Ex. 601 at 25 (Martin Rebuttal).
[654] Ex. 302, AES-D-2 at 74 (Smith Direct).
[655] Ex. 601 at 46 (Martin Rebuttal).
[656] *Id.* at 22.
[657] Ex. 304 at 13 (Smith Surrebuttal).
[658] *Id.*

2. Responses

332. The Agencies agreed with Xcel that some adaptation and technological change will occur in the future. But, because the degree to which they will occur is not known, the Agencies could not say how such adaptation can be incorporated into the IAMs. In addition, the Agencies presumed that adaptation and technological change will not occur without cost. The Agencies also expressed strong doubts that any adaptation or technological change can counterbalance the uncertainty regarding catastrophic damages due to climate change.[659]

333. The Agencies pointed out that the IWG does account for mitigation, noting that one of its emissions scenarios stabilizes CO_2 at 550 ppm by 2100.[660] The Agencies also noted that mitigation activity is not unique to Minnesota, as demonstrated by the fact that the FSCC was developed to value federal mitigation efforts.[661]

334. The Agencies also questioned the Utilities' and MLIG's predictions about mitigation, given the time lag "before the effects of today's transmissions are translated into future warming" and the concern that global CO_2 reduction is an exercise in global collective action, which can be fraught with difficulties.[662]

335. The CEOs criticized the Utilities and MLIG for altering the models to assume zero emissions of CO_2 after 2020.[663]

K. Use of FSCC Outside of Regulatory Setting

1. Criticisms

336. Several parties criticized the use of the FSCC as a state tool for resource planning, arguing that it was developed by the IWG so that federal agencies could include relevant cost-benefit analyses for proposed GHG emissions regulation in their Regulatory Impact Analyses as required by Executive Order 12866.[664]

337. The Utilities and MLIG asserted that the different purpose for which the FSCC is proposed to be used in Minnesota requires different framing assumptions, which have not been defined by the Agencies.[665] The framing assumptions the Utilities and MLIG found inappropriate for Minnesota's use, as discussed throughout this Report, are the "last ton emitted" approach to calculating damages, the modeling time horizon to 2300, the discount rates of 2.5 percent and nothing above 5 percent, the global scope of

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[659] Ex. 802 at 34 (Hanemann Surrebuttal).
[660] *Id.* at 7.
[661] *Id.*
[662] Ex. 801 at 26 (Hanemann Rebuttal).
[663] Ex. 101 at 14 (Polasky Rebuttal).
[664] Ex. 302, AES-D-2 at 32 (Smith Direct); Ex. 601 at 20 (Martin Rebuttal); Ex. 400, Att. 2 at 6 (Gayer Direct).
[665] Ex. 304 at 4-6 (Smith Surrebuttal). Dr. Smith talks about framing assumptions in the context of the FSCC as "certain key, non-scientific choices made by the modelers in framing their analysis." Ex. 300 at 14 (Smith Direct).

damages, and the failure to account for leakage.[666] In addition, the Utilities and MLIG argued that the Commission "needs a principled way to evaluate the framing assumptions and choose which framing assumptions are appropriate to use in determining Minnesota's" SCC.[667]

338. Xcel argued that the intended regulatory purpose of the FSCC allows for a "greater tolerance for the imprecise nature of the estimates, since a regulation would be warranted" as long as the cost-benefit analysis demonstrated that the benefits significantly outweigh the costs, even if the cost estimates are not precise.[668] In contrast, Xcel claimed, in the resource planning context the FSCC would not be used to determine whether or not to adopt a regulation but "could drive specific, binary decisions that are not easy to reverse and have significant costs."[669]

339. Xcel observed that attempts by the Agencies to conflate externality values with the CO_2 regulatory cost range established pursuant to Minn. Stat. § 216H.06 (2014) are misleading. Xcel asserted that the Department and the CEOs have acknowledged that the regulatory cost range does not include damages, and so cannot serve as the basis for the CO_2 externality value.[670]

340. In addition, Xcel noted that, in response to public comments, the IWG stated "that the SCC was developed for use in 'cost-benefit analysis of regulation actions that have small, or marginal, impacts on cumulative global emissions.' The IWG has not addressed the use of the SCC estimates outside the regulatory context, such as in . . . state-level decision-making, and 'pricing' carbon in the marketplace."[671]

341. Xcel provided an illustrative analogy between the regulatory process with the Environmental Protection Agency's (EPA's) Clean Power Plan (CPP) to regulate CO_2 emissions from existing power plants. Xcel maintained that, in developing the CPP, the EPA did not utilize the FSCC to determine which CO_2 reduction measures "were feasible, cost-effective, or adequately demonstrated, nor was it relied on to determine how stringent the targets should be." It was only after the regulations were developed that the EPA would have used the FSCC to determine whether the benefits of the CPP would likely outweigh its costs.[672]

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[666] Ex. 300 at 15 (Smith Direct).
[667] Ex. 304 at 4 (Smith Surrebuttal).
[668] Ex. 601 at 20 (Martin Rebuttal).
[669] *Id.*
[670] *Id.* at 21.
[671] *Id.*
[672] Ex. 602 at 7 (Martin Surrebuttal). The CPP is a set of EPA regulations authorizing GHG emission performance standards to apply to existing and, to a lesser extent, new power plant emissions sources. Under the CPP, states would be required to make GHG reductions by 2030 using various tools, including increased energy efficiencies, conservation investments, and emissions trading. As of the date of this Report, implementation of the CPP is stayed pursuant to an Order of the United States Supreme Court pending disposition of petitions for review in the Court of Appeals for the District of Columbia Circuit and possible petitions for a writ of certiorari. *Chamber of Commerce et al. v. Environmental Protection Agency et.al*, 136 S. Ct. 999 (Feb. 9, 2016).

342. Xcel maintained that the FSCC in no way would have been involved in determining how states and utilities complied with the CPP and would not have established a carbon price for any state that chose to create a CO_2 trading market. Xcel contrasted the impact of the way in which the FSCC is used at the federal regulatory level with its use as proposed in this proceeding – where using the FSCC for integrated resource planning "could potentially drive how to achieve CO_2 reductions by driving resource choices, such as what to build and what to retire, that have significant customer cost impacts and are not easy to reverse."[673]

343. Xcel concluded that the problem of the false precision associated with a single point value (or even four "single" points that are not a range) could lead to significant decisions being made by the Commission based on values with a false impression of precision.[674]

2. Responses

344. The Agencies reported that the Federal Department of Transportation has used the FSCC in the grant application context for documentation of benefits of proposed economic recovery projects. The Federal Railroad Administration requires use of the FSCC in high-speed rail grant applications to demonstrate reduced CO_2 emissions. In addition, the Agencies asserted that the Federal Aviation Administration has a planning process that is similar to Minnesota's integrated resource planning process in which the FSCC is used to estimate reductions in CO_2 from alternative airport configurations, flight operations and routing and fuel composition. The Agencies also provided information regarding use of the FSCC in other venues, including: Canadian heavy-duty vehicle and engine GHG emissions regulations; a Montgomery County, Maryland county code on environment sustainability; and integrated resource planning processes used by energy providers in Washington, Oregon, Tennessee and Nevada. [675]

345. The CEOs also responded to the criticisms that the FSCC is not meant to be used for the purpose of establishing a CO_2 externality cost to be used in integrated resource planning. The CEOs asserted that, as an estimate of the external damages associated with CO_2 emissions, the FSCC is applicable for a variety of purposes, including establishing a cost value for CO_2 in this proceeding.[676]

346. The CEOs stated they found the "fundamental logic applied in cost-benefit analysis and integrated resource planning to be quite similar. Both . . . are tools that help inform decision-makers about the relative merits of . . . alternative choices." The CEOs insisted that the FSCC is precisely the information the Commission requires to establish the external costs of CO_2 emissions.[677]

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[673] Ex. 602 at 7-8 (Martin Surrebuttal).
[674] *Id.*
[675] Ex. 800 at 61- 62 (Hanemann Direct).
[676] Ex. 101 at 33 (Polasky Rebuttal).
[677] *Id.* at 34.

347. The CEOs refuted the argument that IWG reported only a single value because it reported a value for each of three discount rates, along with the 95th percentile value at the three percent rate. The CEOs acknowledged that the Commission could adopt the full range of FSCC values across all three discount rates as well as the 95th percentile value to avoid the perception of false precision that Xcel raises. However, the CEOs also recommended that the three discount rate values generate a spread of values, with the 95th percentile value to address concerns about missing catastrophic damage costs.[678]

L. Whether the IWG Used a Scientific Process

1. Criticisms

348. Peabody asserted that the IWG process is neither peer-reviewed nor transparent.[679] In addition, Peabody provided examples of non-peer-reviewed sources that witnesses for the CEOs, the Agencies and Xcel cited.[680]

349. Peabody disagreed with the CEO's claim that 97 percent of the world's climate scientists concur that humans are causing climate change.[681] Peabody contended that science is based on evidence, not agreement, and that consensus should not be given any weight. Peabody provided examples of scientists, including Copernicus, Galileo, Einstein, and several contemporary scientists, who made significant breakthroughs in science despite being at odds with a majority consensus.[682]

350. Peabody also disagreed with the CEO's claim that those disputing the premise that humans are causing climate change represent only a small minority of scientists.[683] Peabody provided examples of other scientists who spoke against the understanding that the questions of whether climate change is occurring and is due to human activity are settled.[684]

351. Peabody disagreed with the Agencies' description of the peer review process used by the IPCC and described in Finding 353, below.[685] Peabody also disagreed with the Agencies' assessment of the IPCC's process as "two stringent layers of peer review," but instead characterized the process as relying on a "closed ecosystem

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[678] Ex. 101 at 34-36 (Polasky Rebuttal).
[679] Ex. 235 at 71 (Bezdek Surrebuttal); Ex. 213 at 51-52 (Lindzen Surrebuttal).
[680] Ex. 235 at 71-80 (Bezdek Surrebuttal). Dr. Bezdek's list of sources is lengthy, but only a few of the sources listed are part of the record in this matter. Also, Dr. Bezdek does not state where in the record the other witnesses allegedly rely on the cited sources. Thus it is difficult, if not impossible, to determine the accuracy of Bezdek's allegations regarding whether the cited sources are peer-reviewed, and the context in which the sources were first published or presented.
[681] Ex. 235 at 83 (Bezdek Surrebuttal); Ex. 238 at 9 (Tol Rebuttal Ex. 2); Ex. 213 at 46 (Lindzen Surrebuttal). According to Dr. Tol, the 97 percent figure "refers to the number of papers rather than the number of researchers." Ex. 238 at 9 (Tol Rebuttal Ex. 9).
[682] Ex. 235 at 83, 91-92 (Bezdek Surrebuttal).
[683] Ex, 235 at 96 (Bezdek Surrebuttal); Ex. 213 at 47 (Lindzen Surrebuttal).
[684] Ex. 235 at 96 (Bezdek Surrebuttal).
[685] Ex. 213 at 50 (Lindzen Surrebuttal).

of self-reinforcing voices."[686] Peabody pointed out that the IPPC relied on advocacy groups such as the World Wildlife Fund and Greenpeace for information. Peabody also pointed out that the CEOs, who support the IWG process, have themselves asserted that it is important to avoid relying on non-peer-reviewed material submitted by advocacy groups.[687] Further, Peabody claimed that papers arguing for lower values for the SCC might be selectively omitted from published literature.[688]

352. Peabody alleged the IWG did not rely on the most relevant data and ignored all of the science published after 2007.[689] Peabody argued that the most recent peer-reviewed literature is questioning the level of feedback mechanisms assumed by climate models and that Peabody's expert, Dr. Happer, relied on peer-reviewed literature in his testimony.[690] Peabody disputed the allegations by the Agencies that relying on laboratory studies weakens its argument that increased levels of CO_2 enhance plant growth.[691] According to Peabody, laboratory experiments are crucial for demonstrating biological mechanisms in place.[692]

2. Responses

353. The Agencies challenged Peabody's claims regarding the scientific process as it applies to the IPCC, stating that the IPCC's Assessment Reports are peer-reviewed and synthesize primarily peer-reviewed research, providing much of them with two layers of peer review.[693] The Agencies acknowledged that papers can have conflicting or incomplete results. The IPCC process does not "cherry pick" those results, according to the Agencies, but instead attempts to synthesize all of the research and identify those areas that remain uncertain or for which conflicting results exist in order to arrive at an unbiased assessment of what is known and unknown on climate change.[694]

354. Using metrics, the IPCC AR5 attempted to assign different levels of confidence and likelihood to its key conclusions.[695] Due to the extensive IPCC process, the Agencies stated that, while the process proceeds, new peer-reviewed research becomes available but is unable to be included in the assessment.[696]

355. The Agencies claimed Peabody's witnesses used a pattern of arguments that relied on four patterns of biased or flawed reasoning.[697] The first pattern is the use of selective citation or "cherry-picking" information to support a predisposed

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[686] *Id.* at 61.
[687] *Id.* at 57.
[688] Ex. 213 at 50 (Lindzen Surrebuttal).
[689] Ex. 206 at 6 (Happer Surrebuttal).
[690] *Id.* at 3.
[691] *Id.* at 18.
[692] *Id.*
[693] Ex. 803 at 27 (Gurney Rebuttal).
[694] *Id.* at 26.
[695] *Id.* at 27-28.
[696] *Id.* at 28.
[697] Ex. 804 at 1-2 (Gurney Surrebuttal).

conclusion.[698] The selective citation process has two variations: non-peer-reviewed literature and narrow citation.[699] The Agencies offered numerous examples of non-peer-reviewed papers and other information such as congressional testimony cited by Peabody's witnesses.[700] The Agencies also provided examples of the use of narrow citation, which is the technique of selectively using only a narrow portion of the peer-reviewed literature to support a particular view.[701]

356. The second of four patterns of arguing and reasoning in testimony by Peabody's witnesses, explained the Agencies, was to misunderstand the science or cited literature.[702] The Agencies noted several examples of this misunderstanding of science.[703] For example, the Agencies noted Peabody's witness, Dr. Bezdek, testified that a "recent study finds that less than half (43 percent) of climate scientists who research the topic and for the most part publish in the peer-reviewed literature agree with the IPCC's main conclusion that CO_2 is the dominant driver of climate change."[704] The Agencies could locate no statement or numerical result that was consistent with Dr. Bezdek's testimony. The Agencies suggested that Dr. Bezdek had combined the results of two questions, "multiplying the percentage results of the two separate questions to arrive at the 43 percent value." The Agencies criticized this approach, stating that it "represents flawed reasoning and would violate survey protocol." Finally, the Agencies reported that the peer-reviewed paper which was based on the survey at issue, and which Dr. Bezdek did not mention in his testimony, came to the opposite conclusion, which was "as the level of expertise in climate science grew, so too did the level of agreement on anthropogenic causation. 90% of respondents with more than 10 climate-related peer-reviewed publications . . . agreed with anthropogenic greenhouse gases . . . being the dominant driver of recent global warming."[705]

357. The Agencies provided examples of the third misleading pattern of argument, which they called "straw man argument." A straw man argument gives the impression of successful refutation, but is not refuting an argument offered by an opposing witness.[706] According to the Agencies, Peabody's testimony regarding CO_2 fertilization is the best example of this pattern.[707] Peabody argued that increased CO_2 leads to increased fertilization of plants. The Agencies noted that their testimony all along had been that "the climate science community has not argued that there is no CO_2 fertilization effect or that CO_2 fertilization has a negative impact." Rather, the Agencies asserted, the important question is whether climate change has a net positive or negative effect on food crops and whether this has been included in the scientific assessments and modeling. The Agencies added that the research indicates that the net effect of

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[698] *Id.* at 2.
[699] *Id.* at 2-5.
[700] Ex. 803 at 14 (Gurney Rebuttal); Ex. 804 at 3-4 (Gurney Surrebttal).
[701] Ex. 804 at 5-8 (Gurney Surrebuttal).
[702] *Id.* at 9.
[703] *Id.* at 9-11.
[704] *Id.*
[705] *Id.*
[706] *Id.*
[707] *Id.*

climate change on food crops is negative and the effects have been included in the modeling.[708]

358. The fourth pattern used by Peabody's witnesses is known as "attacking the messenger" whereby Peabody mischaracterized the content of the IPCC reports by using phrases such as "the IPPC claims" or "IPCC models find" when the reports did nothing more than review existing peer-reviewed data.[709] Additionally, the Agencies cited specific concerns regarding the testimony of certain Peabody witnesses, including those witnesses' assertions and criticisms of the other witnesses testifying in this proceeding.[710]

359. The CEOs alleged, and provided examples to establish, that Peabody's witnesses relied on non-peer-reviewed information.[711] The CEOs explained that peer-reviewed literature is the "gold standard" and that relying on non-peer-reviewed information is inappropriate for a scientist or a researcher. [712]

360. The CEOs addressed a number of Peabody's claims in which the CEOs stated Peabody misrepresented or misinterpreted climate science.[713] Specifically, the CEOs claimed Peabody selectively chose evidence that minimizes the threat of climate change, some of which was from advocacy organizations rather than peer-reviewed literature.[714] In other cases, the CEOs stated that Peabody witnesses pointed to their own work to support their own claims.[715] Peabody also neglected to be forthcoming about errors found in work that was later corrected, according to the CEOs.[716] The CEOs claimed Peabody witness Dr. Spencer relied on his own research demonstrating that the Earth's sensitivity to greenhouse gases was far lower than the generally accepted estimate.[717] The CEOs noted that Dr. Spencer's cited research was later discovered to contain errors and a peer-reviewed study addressing corrections to those errors was published by the CEOs' witness, Dr. Abraham.[718]

361. The CEOs discussed the claim that 97 percent of the world's climate scientists agree that humans are causing climate change and many independent studies have provided compelling evidence that there is a "very strong consensus among scientists" on this point.[719] The CEOs maintained that Peabody's views on climate

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[708] *Id.* at 11-12.
[709] Ex. 804 at 12 (Gurney Surrebuttal).
[710] *Id.* at 13-19.
[711] Ex. 102 at 27-28 (Abraham Rebuttal); Ex. 106 at 3 (Dessler Surrebuttal); Tr. Vol. 1 at 92 (Polasky).
[712] Ex. 102 at 27 (Abraham Rebuttal).
[713] Ex. 102 at 5 (Abraham Rebuttal); Ex. 106 at 1-2, 9 (Dessler Surrebuttal); Tr. Vol. 3B at 67, 87 (Abraham).
[714] Ex. 102 at 5 (Abraham Rebuttal); Ex. 105 at 9 (Abraham Surrebuttal); Ex. 106 at 8 (Dessler Surrebuttal).
[715] Ex. 105 at 5-6 (Abraham Surrebuttal).
[716] Ex. 102 at 6 (Abraham Rebuttal); Ex. 105 at 6 (Abraham Surrebuttal).
[717] Dr. Abraham noted that Dr. Spencer claimed the estimate was 3ºC in his rebuttal testimony, but his original claim was that climate sensitivity is as low as 1ºC or less. Ex. 105 at 5 (Abraham Surrebuttal). Further, Dr. Spencer omitted many studies reporting higher than 3ºC climate sensitivity. *Id*.
[718] Ex. 102 at 6 (Abraham Rebuttal).
[719] *Id.* at 20.

change are far outside the mainstream scientific understanding and ignore the bulk of the evidence.[720]

362. DHE criticized Peabody for relying on information almost entirely based on industry-funded reports that are not peer-reviewed by the medical or public health community.[721] DHE specifically criticized a bibliography of articles attached to the testimony of Peabody's witness, Dr. Bezdek, used to support the claim that "humans would flourish in a warmer climate."[722] DHE stated that the sources cited do not lead to this conclusion.[723]

V. Parties' Conclusions and Recommendations

A. Utilities and MLIG

363. The Utilities and MLIG concluded "it is not reasonable to rely upon the IWG's values for the Social Cost of Carbon to determine Minnesota's CO_2 environmental cost values."[724] They contended that the SCC values "vary greatly depending on certain key, non-scientific choices made by the modelers in framing their analysis" and that "several of the IWG's analysis-framing choices are not appropriate for use in determining the range of Minnesota's environmental cost values for CO_2."[725] The Utilities and MLIG argued that the SCC estimates calculated by all of the IAMs "are strongly determined by a relatively small set of judgments about input assumptions that cannot be subjected to empirical validation or other objective evaluation, particularly for projected temperature changes above 3°C and for damages in the far future."[726]

364. The Utilities and MLIG determined that the "sensitivity of the IAMs to unverified and non-scientific assumptions made by the modelers, as well as by model users, throws into question the reasonableness of using any FSCC value that the IAMs may produce."

365. The 2013 estimates of the FSCC incorporate significant changes to several assumptions that the Commission made in 1997 when it established the social cost of carbon for Minnesota, the Utilities and MLIG argued.[727] Choosing to value the last ton emitted instead of the average, adding two hundred years of damages into the estimates, and including values discounted at 2.5 percent are not choices, they argue, that reflect "a higher state of scientific knowledge than was available at the time that the Commission adopted its current SCC values . . . ."[728]

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[720] Ex. 101 at 52-53 (Polasky Rebuttal).
[721] Ex. 500 at 4 (Rom Rebuttal).
[722] Ex. 500 at 6 (Rom Rebuttal).
[723] *Id.*
[724] *Id.* at 14.
[725] *Id.*
[726] Ex. 302, AES-D-2 at 20 (Smith Direct).
[727] Ex. 300 at 17 (Smith Direct).
[728] Ex. 302, AES-D-2 at 9 (Smith Direct); 93-583 PUC ORDER 2 at 8.

366. In the end, the Utilities and MLIG could not endorse the results of the IAMs regardless of the inputs used, even those of their own expert, Dr. Smith. If the Commission nonetheless wishes to use the IAMs, the Utilities and MLIG maintained that the estimates are more reasonable with their changed inputs. Dr. Smith and her colleagues ran the three IAMs with various values for the four of the five framing assumptions she challenged: the marginal ton; model time horizon; discount rate; and geographic scope of damages.[729]

367. The Utilities and MLIG reported that running the IAMs with the "first" ton, a time horizon to 2100, a discount rate of 5 percent, and only United States damages, yields a 2020 SCC range value in 2014 dollars per net tonne of $1.62/net tonne to $5.14/net tonne.[730] While not recommending that the Commission use the IWG's IAMs to estimate the SCC, the Utilities and MLIG provided a table of estimates for 2020 "that includes all the combinations of the analysis framing choices" that they argued are less speculative, more evidentiary-based, and more appropriate than the assumptions made by the IWG:[731]

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[729] Ex. 300 at 33 (Smith Direct). Dr. Smith and her colleagues obtained the models and the instructions for running them in the same fashion as the IWG. While they were able to replicate exactly the results from DICE and FUND, the results they obtained from PAGE were slightly different. The Environmental Protection Agency staff were better able to replicate Dr. Smith's team's results than the IWG's results. Dr. Smith concluded that her team's results with PAGE are more reliable than the results in the IWG report. Ex. 302, AES-D-2 at 38-39 (Smith Direct).

[730] Ex. 300 at 33 (Smith Direct). By "net," Dr. Smith means the reduction in Minnesota emissions net of any "leakage." See section IV.H. for full discussion of leakage. By "tonne," Dr. Smith is indicating a metric ton, the unit of measure used for the IWG's SCC values but not the unit of measure for the current Minnesota cost values, which are in dollars per short ton. Ex. 300 at 34-35 (Smith Direct).

[731] Ex. 300 at 31, 33 (Smith Direct). The table as displayed is taken from Exhibit 307 and includes all of the data with the exception of lines 1-16 displaying the values for first tonne damages. Tr. Vol. 2A at 52-54 (Smith).

	# changes from base inputs	Discount Rate	Time Horizon	Geographic Scope	Which Tonne	2020 SCC Value (2007$/ net tonne)	2020 SCC Value (2014$/ net tonne)
17.	1	3%	2300	Global	First	$27.59	$30.70
18.	2	3%	2140	Global	First	$21.55	$23.98
19.	2	3%	2100	Global	First	$15.55	$17.30
20.	2	5%	2300	Global	First	$8.43	$9.38
21.	3	5%	2140	Global	First	$7.65	$8.51
22.	3	5%	2100	Global	First	$6.70	$7.45
23.	2	7%	2300	Global	First	$3.65	$4.06
24.	3	7%	2100	Global	First	$3.33	$3.70
25.	2	3%	2300	U.S.	First	$4.83	$5.37
26.	3	3%	2140	U.S.	First	$3.88	$4.32
27.	3	3%	2100	U.S.	First	$3.05	$3.40
28.	3	5%	2300	U.S.	First	$1.76	$1.96
29.	4	5%	2140	U.S.	First	$1.59	$1.77
30.	4	5%	2100	U.S.	First	$1.46	$1.62
31.	3	7%	2300	U.S.	First	$0.87	$0.96
32.	4	7%	2100	U.S.	First	$0.81	$0.90
33.	1	3%	2300	Global	Averag	$34.87	$38.79
34.	2	3%	2140	Global	Averag	$27.04	$30.09
35.	2	3%	2100	Global	Averag	$18.85	$20.97
36.	2	5%	2300	Global	Averag	$10.23	$11.39
37.	3	5%	2140	Global	Averag	$9.18	$10.21
38.	3	5%	2100	Global	Averag	$7.87	$8.75
39.	2	7%	2300	Global	Averag	$4.25	$4.72
40.	3	7%	2100	Global	Averag	$3.80	$4.22
41.	2	3%	2300	U.S.	Averag	$5.86	$6.51
42.	3	3%	2140	U.S.	Averag	$4.62	$5.14
43.	3	3%	2100	U.S.	Averag	$3.51	$3.91
44.	3	5%	2300	U.S.	Averag	$2.02	$2.25
45.	4	5%	2140	U.S.	Averag	$1.79	$1.99
46.	4	5%	2100	U.S.	Averag	$1.62	$1.80
47.	3	7%	2300	U.S.	Averag	$0.95	$1.06
48.	4	7%	2100	U.S.	Averag	$0.87	$0.97

B. MLIG

368. Based on its recommendation for a SCC with a more limited geographic scope, MLIG provided two United States-only SCC estimates. The first used the FUND IAM model, which permitted a United States only analysis. MLIG reported that that

analysis suggested "that the national SCC is about 7 to 10 percent of the global benefit. This would imply that using a global SCC measure where a national measure is appropriate results in an over-estimate of benefits of approximately 10- to 14-fold."[732] MLIG calculated that this proportional adjustment of the global FSCC would yield a United States only FSCC of $0.77-$1.10, $2.24-$3.20, $3.57-$5.10, and $6.23-$8.90 (2010 damage values in 2007 dollars)."[733]

369. MLIG's second reported estimate was based on an IWG assumption that the domestic share of the FSCC benefits would be proportional to the United States share of the global GDP, and that the national FSCC "is about 23 percent of the global benefit."[734] Based on the 23 percent estimate, MLIG determined that this would result "in an over-estimate of benefits of approximately 4-fold," yielding FSCC values of $2.53, $7.36, $11.73, and $20.47 (2010 damage values in 2007 dollars).[735]

370. MLIG asserted that applying the IWG's GDP-scaling approach results in extremely small damage estimates, considering that the estimate of the benefit to Minnesota is less than 0.4 percent of the estimated global benefit.[736] Based on this number, and applying the GDP-scaling to the highest FSCC estimate, MLIG estimated a Minnesota-only FSCC value of about $0.37 per metric ton of CO_2 (2010 damage value in 2007 dollars).[737]

C. Peabody

371. Peabody maintained that the IWG's assumptions about GDP, discount rates, and emissions in its implementations of the IAMs are not consistent with each other or with the IAMs.[738] For example, Peabody stated that the IWG's interest rate assumptions were inconsistent with its long-term assumptions about GDP and that the IWG used its own estimate of climate sensitivity instead of the values in the models.[739] Peabody concluded that the IWG's erroneous assumptions resulted in "vastly" overstating the SCC.[740]

372. Peabody expressed concerns that, if the Commission implements the FSCC, it will result in higher energy prices which will unduly burden lower income households.[741] Peabody demonstrated that low-income households spend a much

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[732] Ex. 400, Appendix 2 at 15 (Gayer Direct).
[733] *Id.* (damages calculated at a 5% discount rate, 3% discount rate, 2.5% discount rate, and 3% discount rate, 95th percentile, respectively). Dr. Gayer also testified that another IWG approach, where the national social cost of carbon is about 23 percent of the global benefit, would yield FSCC values of $2.53, $7.36, $11.73, and $20.47 (2010 damage values in 2007 dollars). *Id.*
[734] *Id.* at 16.
[735] Ex. 400, Appendix 2 at 16 (Gayer Direct) (damages calculated at a 5% discount rate, 3% discount rate, 2.5% discount rate, and 3% discount rate, 95th percentile, respectively).
[736] *Id.* at 16-17.
[737] *Id.*
[738] Ex. 214 at 16 (Mendelsohn Direct).
[739] *Id.*
[740] *Id.* at 17.
[741] Ex. 228 at 4-5 (Bezdek Direct).

higher percentage of their incomes on energy than high-income households do.[742] Peabody argued that fixed-income households forced to spend more on energy would suffer from aggravations of asthma and other respiratory disease, as well as poor indoor air quality, all as a result of the policies leading to increased energy prices.[743]

373. Peabody offered differing SCC estimates from different witnesses.

374. Peabody asked its expert, Dr. Tol, to generate estimates with FUND using the same assumptions regarding climate sensitivity as its expert, Professor Mendelsohn, did. Mendelsohn estimated SCC for the year 2015 using the 2013 version of DICE without the IWG's modification to its declining discount rate.[744] Mendelsohn changed the damage function in DICE so that damages did not begin until temperatures warmed more than 1.5° C or more than 2° C.[745] Tol's estimates, using Mendelsohn's assumptions, are shown below:[746]

Climate Sensitivity	1.0	1.5	2.0	2.5	3.0
SCC	-17.97	-12.06	-4.05	7.06	20.05

375. Peabody's witness, Dr. Mendelsohn, defined the "optimal SCC" as the cost of carbon that "minimizes the present value of the sum of the climate damage and the mitigation cost to society. It reduces emissions until the cost of the last reduction is just equal to the marginal damage removed."[747]

376. Peabody used the most recent version of the DICE model (DICE 2013)[748] to develop an estimate of the SCC and obtain results of a cost value between $4 and $6 per ton.[749] In DICE, the discount rate starts at 5% percent and declines to 2.7 percent in 2200. Peabody ran the DICE model using its declining discount rates as well as alternative discount rates of 3, 4, 5, and 7 percent, to determine what effect the alternative discount rates would have.[750]

377. In this instance, Peabody assumed a climate sensitivity of 3, based on the distribution used by the IPCC.[751] Peabody altered DICE damage functions by assuming no net damages from climate change occur until temperatures have increased by 1.5° or 2° above preindustrial levels.[752] The reason for making the damage function modifications, Peabody claimed, is climate damage research demonstrating that it is incorrect to assume that the global temperature in 1900 was "optimal." Peabody's expert

[742] *Id.* at 22-25.
[743] Ex. 206 at 24 (Happer Surrebuttal).
[744] Ex. 216 at 16-17 (Mendelsohn Direct Ex. 2).
[745] Ex. 216 at 14 (Mendelsohn Direct Ex. 2).
[746] Ex. 238 at 8-9 (Tol Rebuttal Ex. 2).
[747] Ex. 214 at 3 (Mendelsohn Direct).
[748] Ex. 216 at 11 (Mendelsohn Direct Ex. 2).
[749] *Id.* at 1.
[750] Ex. 214 at 12 (Mendelsohn Direct); Ex. 216 at 17 (Mendelson Direct Ex. 2).
[751] Ex. 216 at 1 (Mendelsohn Direct Ex. 2).
[752] *Id.*

suggested that a slightly warmer climate is "optimal."[753] One reason for this is the fertilization effect on plants of higher concentrations of atmospheric CO_2.[754] In addition, Peabody performed model runs using climate sensitivity values of 1, 1.5, 2, 2.5, 3, and 4.5.[755]

378. Using an ECS of 3, the DICE model, and modified damage functions, Dr. Mendelsohn derived an estimate of the 2015 SCC of $4 to $6 per ton.[756] He termed this estimate "conservative, in light of the testimony of Professors Lindzen, Happer and Spencer."[757] If the ECS is reduced to 1.5, the SCC is between $0.30 and $0.80 per ton.[758] And if the ECS is 2, the SCC falls between $1.10 and $2.00 per ton.[759]

379. The table below illustrates the SCC recommended by Peabody, based on the DICE model where the ECS is assumed to be 3:[760]

Discount Rate	Damage Relative to +1.5 degrees C	Damage Relative to +2 degrees C
DICE rate	6	4
3%	15	10
4%	7	4
5%	4	2
7%	1	0.5

VI. Xcel Energy Proposal

380. Xcel rejected the FSCC for several reasons, but primarily because Xcel disagreed with the FSCC's quantification of four specific values rather than a range of values.[761] Xcel proposed an alternative approach for calculating a range of CO_2 externality values.[762]

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[753] Ex. 214 at 9 (Mendelsohn Direct).
[754] *Id.* at 10.
[755] *Id.* at 14.
[756] It is not clear what dollar-year is used for the SCC estimates. *See* Ex. 303 at 19-20 (Smith Rebuttal) (stating Mendelsohn "never specifically states the dollar-year for his own estimates.").
[757] Ex. 214 at 15 (Mendelsohn Direct).
[758] *Id.* at 14.
[759] *Id.*
[760] Ex. 216 at 17 (Mendelsohn Direct Ex. 2). Dr. Mendelsohn does not specify a dollar-year for the estimates.
[761] Tr. Vol. 3B at 101 (Martin).
[762] *See* Ex. 600 at 50-69 (Martin Direct).

381. Xcel proposed a range of CO_2 externality values, identified by its low and high ends.[763] The two ends of Xcel's range are intended to be interdependent, and to have equal weight.[764] Xcel contended that each end of the range must be considered for the other end to be rationally included, from a statistical standpoint.[765] Furthermore, Xcel rejected the notion that a midpoint could "be labeled 'central' and used as a base assumption," because to do so would introduce a false precision that Xcel rejected in the FSCC proposal.[766] Xcel proposed that its low and high ends would both be used as sensitivities in the resource planning process.[767]

382. Xcel offered eight criteria to assist the Administrative Law Judge and the Commission in evaluating the various parties' approaches to recommending CO_2 environmental cost values.[768] Xcel used the eight criteria to balance its determination of a recommended range of CO_2 environmental cost values.[769]

383. The eight criteria Xcel recommended are whether the recommended values:

1) use a cost-damage approach;

2) reasonably address the inherent uncertainty in estimating climate change damages over approximately 300 years;

3) reflect the absence of consensus on the choice of discount rate;

4) use statistically sound methods;

5) reflect an appropriate level of risk tolerance;

6) minimize subjective judgments;

7) yield a practicable range; and

8) are transparent, replicable and able to be updated.[770]

384. Given the Commission's requirements in this docket, Xcel concluded that the best approach to calculating CO_2 externality values is a probabilistic problem approach.[771] Xcel utilized statistical methods to identify, from within the universe of FSCC

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[763] Ex. 600 at 54 (Martin Direct).
[764] *Id.*
[765] *Id.*
[766] *Id.*
[767] *Id.*
[768] Tr. Vol. 3B at 102-105 (Martin).
[769] Ex. 600 at 2, 52 (Martin Direct).
[770] *Id.* at 2.
[771] *Id.* at 53.

numbers, Xcel's asserted practicable range of values encompassing "a reasonable probability" of the value of future CO_2-related climate change damages.[772]

385. Xcel retained The Brattle Group (Brattle), an independent consultancy that provides analyses of regulatory economics for energy and environmental matters in utility regulatory proceedings to perform the computations to produce Xcel's CO_2 environmental cost values based on the IWG's FSCC raw data.[773]

386. Brattle requested and received from the IWG the raw FSCC modeling results from the November 2013 FSCC update.[774] There were 2.25 million data points provided, consisting of the three IAMs (DICE, PAGE and FUND), each with five emissions scenarios. Each of those emissions scenarios had 10,000 model runs times three discount years times five emission years (2010, 2020, 2030, 2040, and 2050).[775]

387. For each discount rate/emission year combination, Brattle aggregated the results of the fifteen scenarios (three IAMs times five emissions scenarios).[776] Each of the resulting 15 distributions contained 150,000 data points (10,000 IWG estimates for each scenario times 15 scenarios). For each of the five emissions years, Brattle repeated the process, resulting in 450,000 SCC estimates for each year: three IAMs times five socioeconomic scenarios times 10,000 models runs times three discount rates.[777]

388. Using a statistical technique known as bootstrapping, Brattle calculated summary statistics for each of the IWG's SCC distributions.[778] The bootstrapping analysis used free, open-source statistical software called R.[779] In an exhibit to prefiled testimony, Xcel provided the coding of R as used by Brattle in its analysis of the SCC data.[780]

389. For each SCC distribution (by year and discount rate), Brattle calculated the mean, the median and various other percentiles of the SCC values by arranging the values from smallest to largest and establishing which value matched specific percentiles.[781] Initially, Xcel asked Brattle to establish the full range of percentiles, from 1st to 99th, which resulted in SCC cost values ranging from $-9 per ton (the negative

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[772] *Id.*
[773] Ex. 600 at 54; NFM-1, Schedules 1, 9 (Martin Direct). A Brattle expert who was otherwise not involved in this matter independently audited and replicated the results for each statistical analysis Xcel included. Ex. 600 at 57 (Martin Direct).
[774] Ex. 600 at 54-55 (Martin Direct).
[775] Ex. 600 at 54-55 (Martin Direct). Because of the size of the raw data files, Xcel did not include them as a schedule attached to Mr. Martin's testimony. However, Xcel did offer to provide the raw data to any party upon request. *See* Ex. 600 at 55 (Martin Direct).
[776] Ex. 600 at 55 (Martin Direct).
[777] *Id.*
[778] *Id.* "Bootstrapping" involves repeated sampling of a sample with replacement data from the larger sample population. Ex. 600 at 55, fn 60 (Martin Direct).
[779] Ex, 600 at 55, fn 62 (Martin Direct).
[780] Ex. 600, NFM-1, Schedule 11 (Martin Direct).
[781] Ex, 600 at 56 (Martin Direct).

number signifying a net benefit from a ton of CO_2 emitted) to damages of over $600 per ton.[782]

390. Xcel was concerned that the extremely high and low values included in the percentile distributions Brattle calculated would not yield a practical or meaningful range for the Commission to consider.[783] Xcel understood that the breadth of the range arose from the long tails of damage estimates.[784]

391. Using the statistical percentiles, Xcel excluded the lowest and the highest values. The excluded values were all values that are included in the FSCC modeling results but that, according to Xcel, have a low probability of occurring.[785]

392. Xcel recognized that the decision regarding a selection of percentiles to determine a range involves balancing the public policy considerations of practicability and risk tolerance, with the risk being that the range might not capture the correct damage value of future climate change.[786]

393. Xcel developed its proposed SCC range based on the 25th and 75th percentiles for each of the 15 discount rate/emission year distributions calculated by Brattle.[787]

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[782] *Id.*
[783] *Id.*
[784] *Id.*
[785] *Id.* at 53.
[786] Ex. 600 at 56-57 (Martin Direct).
[787] *Id.*

394. The summary statistics for Xcel's resulting ranges for the years 2010, 2020, 2030, 2040 and 2050, expressed in 2014 dollars per short ton, are illustrated in the following table:[788]

SCC Summary Statistics, by Discount Rate,
for the 25th, 50th, and 75th percentiles in 2014 Dollars per Short Ton

	Emission year			Year	
Summary statistics	**2010**	**2020**	**2030**	**2040**	**2050**
2.5% Discount Rate					
25%	$17.41	$21.13	$24.39	$27.81	$31.24
50% (median)	$32.65	$39.38	$45.56	$52.08	$58.87
75%	$56.04	$67.73	$78.55	$90.03	$102.17
3% Discount Rate					
25%	$9.87	$13.31	$15.76	$18.37	$21.14
50% (median) (median)	$20.23	$25.84	$30.69	$35.89	$41.35
75%	$34.74	$44.40	$52.83	$62.14	$72.06
5% Discount Rate					
25%	$2.07	$2.54	$3.40	$4.46	$5.67
50% (median)	$6.03	$7.58	$9.72	$12.21	$14.93
75%	$10.35	$13.28	$17.10	$21.53	$26.60

395. Xcel approached the discount rate selection by equally weighing the values for each of the three discount rates the IWG used (2.5, 3.0, 5.0) at the low and high ends of Xcel's initial range.[789] For example, for the year 2020 as depicted in the table above, the 25th percentile SCC value at the 2.5 percent discount rate is $21.13, at the 3 percent discount rate it is $13.31 and at the 5 percent discount rate it is $2.54. To equally weight those three numbers, Xcel averaged three SCC cost value amounts, resulting in a 25th percentile low bound of the range of $12.33 per short ton (in 2014 dollars) for emissions in 2020.[790] Xcel performed the same calculations for the 75th percentile upper bound for 2020. For the 75th percentile, Xcel calculated that the amount at the 2.5 percent discount rate is $67.73, the 3 percent discount rate is $44.40 and the 5 percent discount rate is $13.24. The average (equally weighted) amount of these three provided Xcel with a 75th percentile upper bound of the range of $41.80 per short ton (in 2014 dollars) for emissions for 2020.[791]

[788] *Id.* at 59. Xcel provided its cost estimates in 2014 dollars per short ton. The IWG's figures are in 2007 dollars per metric ton. This Report includes a chart from Xcel on page 108 comparing all of the proposed SCC values for 2020 Emissions in nominal dollars per short ton. In addition, the Agencies provided charts listing FSCC values in 2007 and 2015 dollars in both metric and short tons. *See* AGENCIES PROPOSED FINDINGS ATTACHMENT 2 (Dec. 15, 2015) (eDocket No. 201512-116500-03).
[789] Ex. 600 at 7, 59-60 (Martin Direct).
[790] Ex. 600 at 59-60 (Martin Direct).
[791] *Id.*

396. Xcel chose to retain and weigh all three of the IWG's discount rates equally as a way to remain neutral on the question of discount rate choice. In Xcel's estimation, this approach can allow the Commission to avoid the difficult, and what Xcel views as the possibly unresolvable debates, concerning the correct discount rate for the SCC.[792] Xcel pointed out that its approach would also permit an easy substitution of other discount rates, also equally weighted, should the IWG update its discount rates in the future.[793]

397. Xcel acknowledged that its choice to establish the boundaries of its range at the 25th and 75th percentiles of the FSCC cost range based on the IWG raw data contained certain policy judgments involving its balancing of risk tolerance and practicability.[794]

398. In choosing the 25th and 75th percentiles symmetrically around the median value to define the SCC range, Xcel noted that, although including the range of values from the 1st through the 99th percentile would more accurately reflect the full range of risks reflected in the IAM results, the full range would be impracticable because the resulting cost value range would extend from $-9 per ton to $600 per ton. Xcel asserted that such a broad range would not provide meaningful information to the Commission in the resource planning context.[795] Xcel chose its 25th and 75th percentile cutoff points based on the relatively low probability of the lower and higher values occurring, in comparison with the values it targeted in its approach.[796] Because it excluded low and high ends symmetrically, Xcel asserted that there was no bias in the way it limited its proposed SCC range.[797]

399. Xcel requested Brattle to calculate the probability that its initial 25th/75th percentile range (before the averaged discount rate amounts) contains the value of FSCC damages consistent with those predicted by the IWG's IAMs.[798] Given that each year of the FSCC distribution contains 150,000 values for a specific discount rate, when all three discount rates are included there are a total of 450,000 FSCC values per year. Brattle calculated that, for the Xcel distribution for 2020 from the 25th to the 75th percentile, the range included approximately 75 percent of the FSCC's 450,000 data points.[799] Xcel's conclusion, based on Brattle's calculation, is that there is a 75 percent chance that Xcel's underlying statistics "capture the value of future climate change damages as predicted by the IAMs."[800] Xcel further reasoned that the IAMs climate change damages excluded from consideration below the 25th percentile and above the 75th percentile only represent a 25 percent chance of encompassing the cost of future climate change damages predicted by the IAMs.[801]

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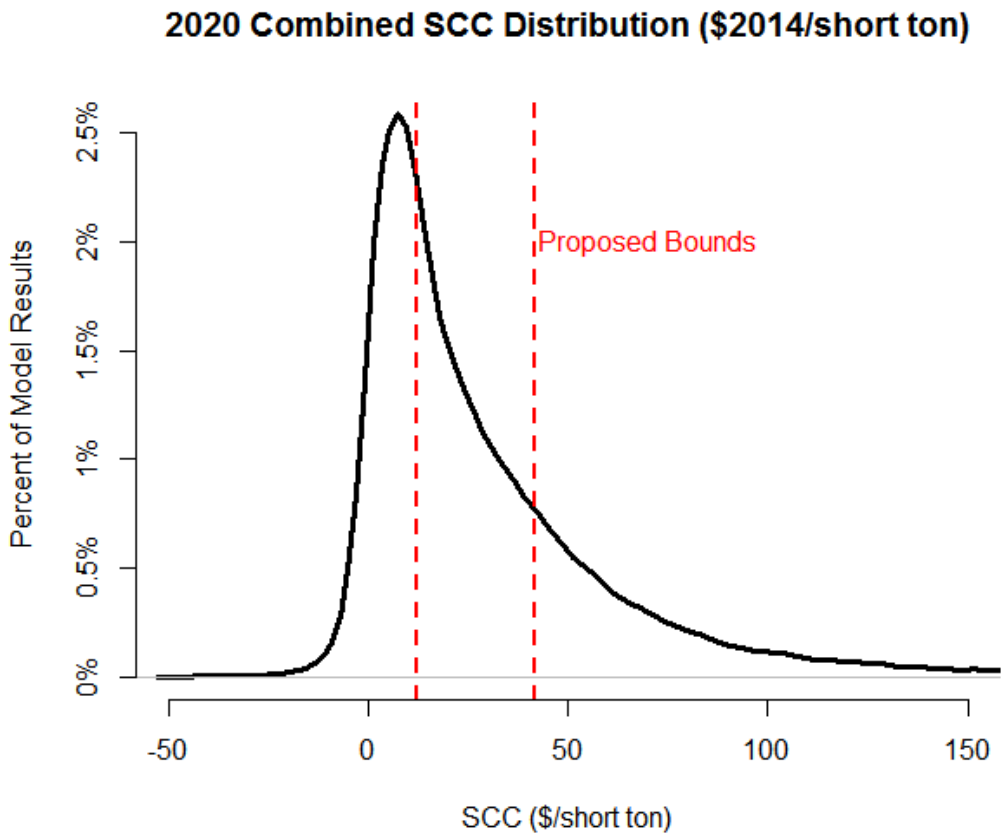
[792] *Id.* at 60.
[793] *Id.*
[794] *Id.* at 60-61.
[795] *Id.*
[796] *Id.* at 61.
[797] *Id.*
[798] *Id.* at 62.
[799] *Id.* at 62-63.
[800] Ex. 600 at 63 (Martin Direct).
[801] *Id.*

400. After averaging the discount rate values at the 25th and 75th percentiles of the 2020 range (in 2014 dollars per short ton), Xcel's proposed FSCC values for that year are $12.33 to $41.80. Brattle calculated that this range would correspond to the 36th and 74th percentiles of future climate change damages predicted by the IAMs for 2020.[802] Thus, after averaging the discount rate values, 35 percent of the IAMs values are below Xcel's range, while 26 percent are above the high end.[803]

401. Xcel maintained that that, when superimposed on the FSCC probability distribution curve, it is apparent that its proposed range excludes more of the higher-probability but lower-cost damages relative to the amount of lower-probability but higher-cost damages it includes.[804] Xcel illustrated this in its Figure 9 of Mr. Martin's testimony:[805]



[802] *Id.*
[803] *Id.* at 64. According to Mr. Martin, the low end of Xcel's range, after averaging the discount values, is the 36th percentile, and 36 percent of the values predicted by the IAMS are below the low end of the proposed range. *Id.* at 63. The Administrative Law Judge assumes this is a misstatement on Mr. Martin's part and he meant 35 percent of the values are below the low end.
[804] *Id.* at 64.
[805] *Id.* at 65.

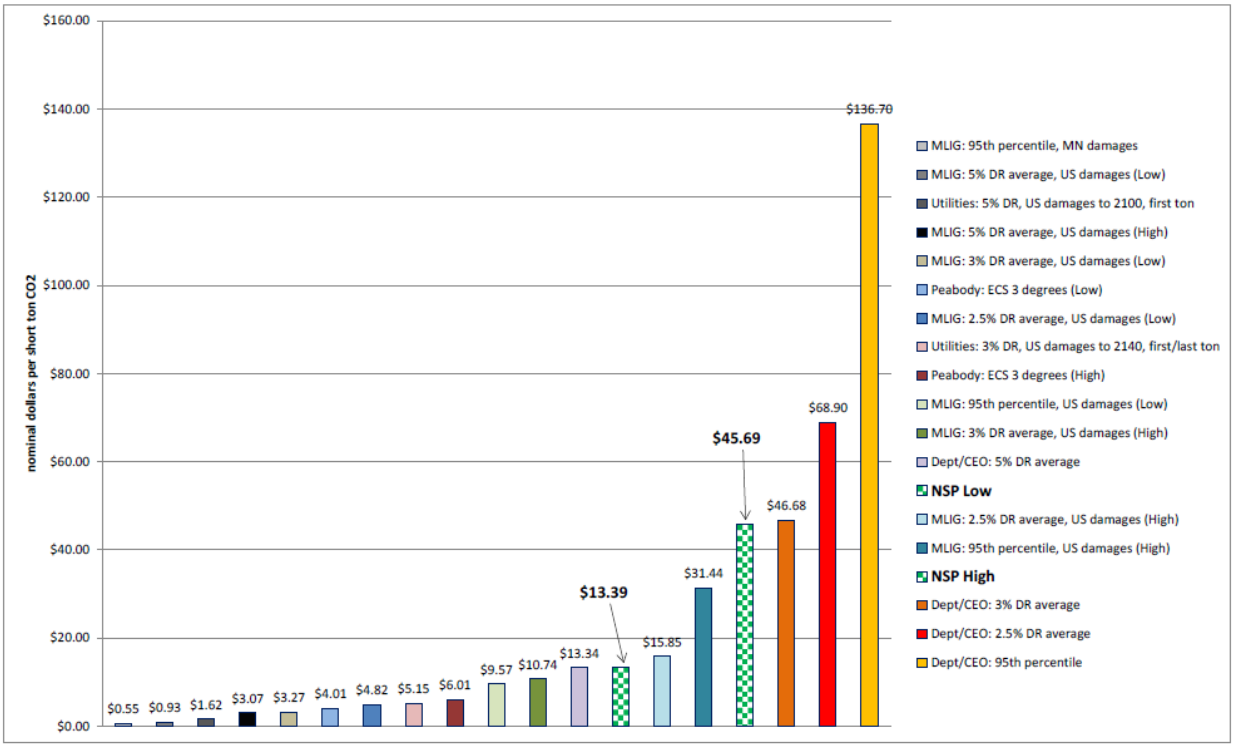
402. Xcel maintained that it made no other subjective judgments in its proposed SCC calculations because its method used results from the IWG IAMs, socioeconomic/emissions futures and discount rates. Xcel stressed that it did not prefer one of the IAMs or emissions models over another; and that it equally weighed the three discount rate values chosen by the IWG.[806]

403. Xcel's final proposed ranges for each of the five years for which the IWG provided FSCC cost values, are as follows:[807]

CO2 Environmental Cost Values Proposed for Commission Adoption in 2014 Dollars per Short Ton

Proposed Range	2010	2020	2030	2040	2050
Low	$9.78	$12.33	$14.52	$16.88	$19.35
High	$33.71	$41.80	$49.49	$57.90	$66.94

404. Xcel provided a comparison of the parties' proposed CO_2 values, for 2020 emissions, in nominal dollars per short ton:[808]



[806] Ex. 600 at 61 (Martin Direct).
[807] *Id.* at 62. Xcel also provided annual low and high values in 2014 dollars per short ton, and in nominal dollars per short ton. Ex. 600, NFM-1, Schedules 3, 4 (Martin Direct).
[808] Ex. 601 at 12 (Martin Rebuttal). The Agencies provided additional comparative charts. *See* AGENCIES PROPOSED FINDINGS ATTACHMENT 2 (Dec. 15, 2015) (eDocket No. 201512-116500-03).

VII. Criticisms of Xcel Proposal

A. The median versus the mean

405. The CEOs criticized Xcel's use of the median rather than the mean to calculate the SCC. The CEOs asserted that the median is more appropriately used in a context where the goal is to understand a typical representation of the subject. In the case of future climate change, there is no typical future climate to consider.[809] Instead, the CEOs argued that the mean incorporates information about the magnitude as well as the likelihood of damages, as reflected in the tails of the distribution. The CEOs asserted that the median only recognizes the magnitude of damages at the middle of the probability distribution and leaves out information about high damage outcomes, which the CEOs contend should be of greatest concern.[810]

406. The Agencies also disagreed with Xcel's use of the median instead of the mean in developing the distribution of its SCC values.[811] Noting that Xcel acknowledged that the FSCC values developed by the IWG are not normally distributed but instead are skewed with a long right tail, the Agencies disagreed with Xcel's statement that the resulting skewed distribution results in a mean that is greatly influenced by "outliers."[812]

407. According to the Agencies, "outlier" is defined in the field of statistics as "an observation that is distant from other observations."[813] The Agencies argued that the long right tail in the IWG distribution is a continuum of observations with increasingly large values, not outlier values disconnected from the rest of the observations on the continuum. The FSCC distribution is simply skewed, with a long right tail which includes some larger data points, said the Agencies.[814]

408. The CEOs provided an analogy between estimated CO_2 damage cost calculations and home insurance pricing, stating that both processes involve uncertainty about what damages might occur in the future. The value of home insurance is above zero because there is some small chance that a damage-causing event, such as a severe storm or fire, will occur to the homeowner's home within the next year. If there is a 5 percent chance such an event will occur, say the CEOs, there is a 95 percent chance that it will not. The CEOs stated that, in this scenario, if one calculates the median of expected damages over the coming year, the number is zero, including in the range from the 25th to the 75th percentile, regardless of how high the damages could be in the 5 percent likelihood that the home will be damaged. If the mean is used to understand the risk to the home, the CEOs argued, it provides a much clearer picture of the actual risk to the home by incorporating information about damages from the 5 percent chance of an event that will cause damage. The mean is the amount that will form the basis for the insurance

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[809] Ex. 101 at 37; Schedule 1 at 26 (Polasky Rebuttal).
[810] Ex. 101 at 37 (Polasky Rebuttal); *see also* Ex. 801 at 68-69 (Hanemann Rebuttal).
[811] Ex. 801 at 66 (Hanemann Rebuttal).
[812] *Id.* at 66-67.
[813] *Id.* at 67, fn 47.
[814] *Id.* at 67.

price. This, contended the CEOs, is the concept to use when calculating SCC damages.[815]

409. The Agencies also viewed the valuation of the social cost of carbon as a risk management process, the goal of which is "to avoid the risk of possibly very harmful climatic outcomes in the right tail of the warming and SCC probability distributions." Because use of the median removes the tails of the distribution from consideration, the Agencies argued that approach is contrary to the goal of a risk management policy.[816]

410. In response to Xcel's criticism that the FSCC was based on a single point rather than a range, the CEOs explained that the IWG took the mean across its 150,000 model runs for each of the three different discount rates it chose to calculate a mean-based value for each discount rate. According to the CEOs, these three rates provide three of the four points in the FSCC's range of values. Thus the FSCC does provide a range and not only a single point.[817]

411. The CEOs pointed out that, although Xcel uses the median in establishing the range of percentiles to define its 25th and 75th percentiles, it uses the mean when it averages the three discount rate amounts.[818]

B. The range of values

412. The CEOs agreed with Xcel that having too much information (or too many points) within a range of values in the probability distribution for the SCC can make the range of values impractical for resource planners.[819] However, the CEOs criticized the method Xcel used to create its range as arbitrary and resulting in a more subjective estimate of the SCC.[820]

413. The CEOs alleged that, because Xcel's range only encompasses the 25th to the 75th percentile of the IWG outcomes, there is a 50 percent probability that the actual CO_2 damages are outside the scope of Xcel's SCC range.[821] The CEOs contended that there is nothing unique about Xcel's chosen endpoints and that a range extending from the 5th to the 95th percentile, for example, would encompass 90 percent of the IWG outcomes.[822] The CEOs argued that Xcel's range is less practical for use in resource planning decisions.[823]

414. The CEOs stated that Xcel's range can lead to misleading representations of the FSCC. Using an example of the IWG process for the 3 percent discount rate (in 2007 dollars for 2020 emissions), the CEOs asserted that the range between the 25th and

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[815] Ex. 101 at 38-39 (Polasky Rebuttal).
[816] Ex. 801 at 70 (Hanemann Rebuttal).
[817] Ex. 101 at 39 (Polasky Rebuttal).
[818] *Id.*
[819] *Id.* at 40.
[820] *Id.*
[821] *Id.* at 41.
[822] *Id.*
[823] *Id.* at 40-41.

75th percentiles is $13 to $44, and that the mean value is $43, just one dollar lower than the 75th percentile value.[824] Because the CO_2 damage distribution is a skewed distribution, the CEOs stated that the mean value of the damages may lie outside the 25th to 75th percentile range.[825] On the other hand, the CEOs argued, using the 5th and 95th percentiles creates a dollar value range from $2 to $128, which is only $11 lower than the low end, but $84 higher than the upper end of Xcel's range. The larger range better captures the uncertainty in the SCC, according to the CEOs.[826]

415. The CEOs supported the IWG's approach, which is to use the mean in the range of values at a given discount rate, because the mean "incorporates all the values of the distribution and is not arbitrarily chosen."[827] The CEOs viewed the IWG's approach as a way to capture the broad distribution of values while still offering the Commission a practical number of values from which to choose.[828]

C. Averaging the discount rates

416. The CEOs also criticized Xcel's decision to average the values of the three discount rates for each end of its distribution range, stating that "[t]here is no reasonable argument that the mean value across the three discount rates is an appropriate measure of the SCC."[829]

417. In addition, the CEOs stated that Xcel's averaging of values of the discount rates is not supported by any theoretical basis because the SCC calculation does not involve considering the entire range of discount rates, or applying a probability distribution to the likelihood of a particular rate being the " 'true' social discount rate."[830]

418. The CEOs stressed that only a moderator or regulator can choose the appropriate discount rate. The CEOs objected to Xcel's approach, which makes it impossible to consider any one of the rates individually. The CEOs supported the IWG's approach, which maintained separate values for each of the three discount rates it considered theoretically appropriate, leaving policy-makers free to apply the most suitable rate in the circumstances.[831]

419. Peabody rejected Xcel's proposal to weight the various discount rates equally as a way to solve the problem of the Commission having to confront the discussion of which discount rate is most appropriate, because "[i]gnoring the problem and using flawed data do not provide an acceptable solution to the problem."[832]

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[824] Ex. 101 at 41 (Polasky Rebuttal).
[825] *Id.*
[826] *Id.*
[827] *Id.*
[828] *Id.* at 41-42.
[829] *Id.* at 42-43.
[830] *Id.* at 43.
[831] *Id.*
[832] Ex. 233 at 50 (Bezdek Rebuttal Ex. 1).

D. Exclusion of 95th Percentile of FSCC Distribution

420. The Agencies also disagreed with Xcel's decision to exclude the IWG's 95th percentile of the FSCC distribution from consideration in Xcel's distribution.[833] The Agencies pointed out that, in other regulatory contexts, a 5 percent risk with potentially catastrophic outcomes is considered. In support of the importance of recognizing the 95th percentile, the Agencies quoted a report on the value at risk from climate change by the Economic Intelligence Unit, pointing out that people "wouldn't get on a plane if there was a 5% chance of the plane crashing, but we're treating the climate with that same level of risk in a very offhand, complacent way."[834]

421. The Agencies asserted that the concern with risks associated with the tails of the distribution range is consistent with, and validates, the decision to report the 95th percentile value of the FSCC distribution.[835]

E. Xcel's Criteria for Reviewing the FSCC

422. The Utilities and MLIG criticized Xcel's eight proposed criteria for reviewing potential environmental cost values. The Utilities and MLIG maintained it is important for the Commission to have specific review criteria. The Utilities and MLIG supported the notion of the Commission adopting the criteria it used in the first Externalities docket,[836] and criticized Xcel because its criteria are "fundamentally different criteria from those previously relied upon by the Commission."[837] Specifically, the Utilities and MLIG rejected Xcel's proposed criterion advising that the SCC "[r]eflect an appropriate level of risk tolerance, i.e. tolerance for risk that the actual value of future climate change damages may lie outside the Commission's adopted range . . . ."[838]

423. The Utilities and MLIG asserted that this criterion calls for "speculative subjectivity," making it inconsistent with another of Xcel's criteria, which calls for minimizing subjective judgments.[839]

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[833] Ex. 801 at 70 (Hanemann Rebuttal).
[834] *Id.*
[835] *Id.* at 71.
[836] The Utilities and MLIG did not specify whether they were referring to the criteria set out in Judge Klein's Recommended Order or to the criteria listed in the Commission's Order. Because the "conservative value" criterion was not explicitly adopted by the Commission, the Administrative Law Judge presumes the Utilities and MLIG were referring to Judge Klein's Recommended Order. *Compare* Ex. 305, *In the Matter of the Quantification of Envtl Costs Pursuant to Laws of Minn. 1993, Chap. 356, Sec. 3,* PUC Docket No. E-999/CI-93-583, FINDINGS OF FACT, CONCLUSIONS, RECOMMENDATION AND MEMORANDUM at 17 (March 22, 1996), *with* 93-583 PUC ORDER 1 at 11-14.
[837] Ex. 304 at 6-7 (Smith Surrebuttal).
[838] *Id.*
[839] *Id.*

F. Use of the Underlying FSCC Data

424. Peabody criticized Xcel generally for accepting the IWG's numbers as a basis for Xcel's SCC proposal. Given all of the perceived flaws in the IWG process and the fundamental disagreement that Peabody had with the IWG's underlying assumptions, Peabody found that Xcel's proposed values were also meaningless.[840] In particular, Peabody asserted that Xcel should have included the 7 percent discount rate in its proposed SCC model.[841]

425. Peabody accused Xcel of misusing statistics and probability theory in its proposal to capture 75 percent of the IAMs' data. Peabody's criticism in this regard focused on its rejection of the underlying IWG data.[842]

426. Peabody also rejected the idea that the FSCC, and therefore Xcel's proposed SCC, minimizes subjective judgments.[843]

G. Xcel's Responses to Criticisms of Its Proposal

427. In response to criticism of the Xcel model's use of the median versus the mean, Xcel claimed it did not propose adopting a median instead of a mean.[844] Xcel argued a median "would be a single point estimate," which it did not recommend.[845] Rather, the Company proposed using "the 25th percentile at 5 percent discount rate and the 75th percentile at 2.5 percent discount rate as the low and high bounds of its initial range, and then equally weighted the values at each discount rate at each end of the range."[846] Xcel believed the proposed percentiles "strike an appropriate balance of accounting for uncertainty, risk tolerance, and practicability."[847]

428. Xcel reiterated its criticisms of the use of the mean because of the "non-normal, right-skewed shape" of the FSCC probability distribution. Xcel argued that the mean in this situation is not trustworthy because IAMs did not completely capture damages at either the high or low end, and it is difficult to know where the errors are greater.[848]

429. Xcel continued to advocate for a range of values, maintaining that a range provides more, rather than less, information for resource planning purposes and will ensure that resource plans will be "robust" under various assumptions.[849]

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[840] Ex. 233 at 44-49 (Bezdek Rebuttal Ex. 1).
[841] *Id.* at 46.
[842] *Id.* at 50-51.
[843] *Id.* at 51-52.
[844] Ex. 602 at 9 (Martin Surrebuttal).
[845] *Id.*
[846] *Id.*
[847] *Id.* at 11.
[848] *Id.*
[849] *Id.* at 38.

430. Xcel responded to the CEOs' criticism that Xcel used the mean when averaging discount rates, but not when choosing values in the FSCC distribution range. Xcel asserted that equally weighting the FSCC values at different discount rates is qualitatively different from finding the mean value for purposes of determining the SCC, and it has a different justification.[850] Xcel explained that it equally weighted the discount rates in an effort to remain neutral regarding an issue where there is no consensus and that "raises highly contested and exceedingly difficult questions of science, economics, philosophy, and law."[851]

431. In response to criticism of the Xcel model's exclusion of the 95th percentile, Xcel argued that "adopting the 95th percentile would have to be accompanied by adopting the 5th percentile," which would not be practical because the two percentiles "point in opposite directions."[852] Xcel believed risk tolerance must "be bounded in good public policymaking," and therefore asserted "it is inappropriate for the Commission to intentionally set the SCC at a level that is by definition 95 percent likely of being too high."[853]

432. In response to criticism that the Xcel model should not accept the IWG's raw numbers as a basis for its model, Xcel argued that deriving new numbers to base the model on "would have required the Company to make myriad scientific and subjective policy judgments."[854] Instead, Xcel used the IWG modeling outputs as a starting point and worked to "find a way to make them more practicable and appropriate for integrated resource planning in Minnesota."[855] According to Xcel, the "IWG's modeling outputs are far from perfect, but no other witnesses have proposed a clearly superior damage cost approach that does not involve subjective judgments of their own and/or require laborious new modeling each time the Commission updated its CO_2 environmental cost range."[856]

433. In response to criticism that the Xcel model accepts the IWG's subjective policy judgments as a basis for the model, Xcel conceded that it "lacks expertise to substitute its judgment for that of the IWG and the climate scientists and economists" in selecting the "analytical framing assumptions" necessary for the model.[857]

CONCLUSIONS

1. The Public Utilities Commission and the Administrative Law Judge have jurisdiction to consider this matter pursuant to Minn. Stat. §§ 14.50, 216B.01-.82 (2014), and Minn. R. 7829.1000 (2015).

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[850] Ex. 602 at 37 (Martin Surrebuttal).
[851] *Id.*
[852] *Id.* at 16.
[853] *Id.* at 17.
[854] *Id.* at 5.
[855] *Id.*
[856] *Id.*
[857] *Id.* at 6.

2. The public and the parties received proper and timely notice of the hearings and the Commission and all parties complied with all procedural requirements of statute and rule.

3. The Administrative Law Judge concludes that the following burdens of proof apply in this proceeding:

a. A party or parties proposing that the Commission adopt a new environmental cost value for CO_2, including the Federal Social Cost of Carbon, bears the burden of showing by a preponderance of the evidence that the value being proposed is reasonable and the best available measure of the environmental cost of CO_2.

b. A party or parties proposing that the Commission retain any environmental cost value as currently assigned by the Commission bears the burden of showing by a preponderance of the evidence that the current value is reasonable and the best available measure to determine the applicable environmental cost.

c. A party or parties opposing a proposed environmental cost value must demonstrate that the evidence offered in support of the proposed values is insufficient to amount to a preponderance of the evidence.

I. Use of IAMS as Damage Cost Models

4. The Administrative Law Judge concludes that the Commission's Notice and Order for Hearing in this docket require the parties to evaluate the environmental cost values using a damage cost, as opposed to market-based or cost-of-control approach. The Commission found the damage-cost approach superior to a market-based or cost-of-control approach "because it appropriately focuses on actual damages from uncontrolled emissions."[858]

5. The Administrative Law Judge concludes that taking the cost of emissions abatement into account when calculating damages is contrary to the Commission's understanding of a damage-cost approach, which focuses "on actual damages from uncontrolled emissions."[859]

6. The Administrative Law Judge concludes that the Agencies and the CEOs demonstrated, by a preponderance of the evidence, that the IWG's use of the DICE, PAGE, and FUND models to calculate the FSCC is a damage-cost approach consistent with the Commission's Notice and Order for Hearing in this docket.[860]

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[858] NOTICE AND ORDER FOR HEARING at 4 (Oct. 15, 2014) (eDocket No. 201410-103872-02).
[859] *Id.*
[860] *Id.*

7. The Administrative Law Judge concludes that the Commission required any consultant retained by the Agencies to use reduced-form modeling to estimate damage costs in this proceeding.[861]

8. The Administrative Law Judge concludes that the Agencies and the CEOs demonstrated, by a preponderance of the evidence, that it was reasonable for them to rely on an environmental cost valuation for CO_2 based on the use of the DICE, PAGE and FUND models, given the combined requirements of a damage-cost approach and reduced-form modeling.

9. The Administrative Law Judge concludes that the Agencies and the CEOs demonstrated, by a preponderance of the evidence, that the IAMs' damage functions were based on empirical studies. However, the Administrative Law Judge further concludes that the empirical evidence on which the IWG relied to calculate damage functions for the FSCC consisted of fewer than fifty empirical studies, which were neither up-to-date nor comprehensive, adding to the uncertainty of the FSCC estimates, particularly in the areas of catastrophic damages and the treatment of the distant future.

10. The Administrative Law Judge concludes that more studies, using new approaches, have been published since the last update of the FSCC and that the IWG has expressed a commitment to continuing to pursue the most current research and to incorporate it as appropriate into future FSCC updates. The Administrative Law Judge concludes that, if the Commission adopted the FSCC, the Commission could update its CO_2 environmental cost values in the future as the IWG revised the FSCC based on more current research.

11. The Administrative Law Judge concludes that a preponderance of the evidence demonstrates that the FSCC underestimates the negative effects that increased warming will have on human health.

12. The Administrative Law Judge concludes that a preponderance of the evidence demonstrates that the IAMs damage functions do not account for a significant number of important environmental impacts which will occur as a result of climate change.

13. The Administrative Law Judge concludes that, based on unreported and underreported health and environmental impacts, along with the IWG's acknowledgement that the FSCC is not based on the most current research, the preponderance of the evidence demonstrates that the FSCC understates the full environmental cost of CO_2.

II. IWG's Choice and Application of Discount Rates

14. The Administrative Law Judge concludes that the preponderance of the evidence demonstrates that both the three percent discount rate and the five percent discount rate are recognized as consumption rates of discount and it is reasonable to apply the three- and five- percent discount rates to the SCC.

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[861] *Id.* at 5.

15. The Administrative Law Judge concludes that Peabody, and the Utilities and MLIG failed to demonstrate by a preponderance of the evidence that a Ramsey rule discount rate that adjusts over time is reasonable to use in calculating the SCC. That approach is not appropriate because it is based on the concept that climate policy can be viewed through the metaphor of a single, infinitely-lived individual rather than the changing views of societies as they evolve over generations. The Administrative Law Judge concludes that the Ramsey rule fails to take into account the idea that priorities and preferences of people and societies will change over an extended period of time and does not address issues of equity between generations. Furthermore, the Administrative Law Judge concludes the Ramsey rule is not appropriate in this proceeding because it begins with a higher discount rate which declines with time. In addition to the intergenerational nature of the FSCC damage calculation, due to the uncertainties associated with the possibility of catastrophic damages from a "tipping point" event which may occur at an unknown time, and the understatement of impacts in the IAMs' damage functions, the Administrative Law Judge concludes that an approach that is designed to begin with a higher discount rate and gradually declines is neither reasonable nor the best approach to for the purpose of calculating an SCC.

16. The Administrative Law Judge concludes that the preponderance of the evidence demonstrated that the OMB Circular A-4 does not require the IWG to use the seven percent discount rate to calculate the FSCC, because the Circular A-4 is advisory and not mandatory in nature. The Administrative Law Judge concludes that the OMB participated in the IWG's development of the FSCC and there was no evidence that the OMB objected to the IWG's choice not to use a seven percent discount rate in calculating the FSCC.

17. The Administrative Law Judge concludes that the proposal advanced by the Utilities and MLIG to increase the upper end of the discount rate range to incorporate the opportunity cost of emissions reductions in the IWG's IAMs would be a "cost-of-control" approach, contrary to the Commission's required damage-cost approach.

18. The Administrative Law Judge concludes that the Agencies and the CEOs demonstrated, by a preponderance of the evidence, that the IWG's choice of a 2.5 percent rate of discount is within the existing bounds of rates used in other climate change models. The 2.5 percent rate of discount is a reasonable approach to account for the multi-generational scope of the FSCC and to address the concern that interest rates are uncertain over time.

19. The Administrative Law Judge concludes that Peabody failed to demonstrate, by a preponderance of the evidence, that the IWG's discount rates are arbitrary.

III. 95th Percentile Value at 3 Percent Discount Rate

20. The Administrative Law Judge concludes that the CEOs and the Agencies demonstrated by a preponderance of the evidence that the FSCC likely understates

damages and that the risk of a "tipping point" is not well-represented within the scope of the 2.5, 3.0 and 5.0 percent rate of discount.

21. Nonetheless, the Administrative Law Judge concludes that the CEOs and the Agencies failed to demonstrate, by a preponderance of the evidence, that the 95th percentile value at a three percent discount is a reasonable means of representing the high side of the FSCC distribution. The Agencies and the CEOs failed to demonstrate a reasonable basis for choosing the 95th percentile at three percent to represent the uncertainties regarding understated damages and a potential "tipping point." The 95th percentile value provided a larger damages number but was not supported by specific evidence or reasoning to demonstrate that the number is a meaningful estimate of the uncertainties it represents.

IV. Equilibrium Climate Sensitivity

22. The Administrative Law Judge concludes that Peabody failed to demonstrate, by a preponderance of the evidence, that an ECS value of 1 or 1.5 degrees centigrade is correct and that an ECS of more than 2 degrees centigrade is "extremely unlikely."

23. The Administrative Law Judge concludes that the preponderance of the evidence demonstrates that the ECS doubling ranges as reported by the IPCC in the IPCC AR4 (2.0-4.5 °C) and the IPCC AR5 (1.5-4.5 °C) are more accurate ECS ranges than the range advanced by Peabody because the IPCC ranges are representative of a comprehensive, peer-reviewed body of scientific study based on multiple lines of evidence.

24. The Administrative Law Judge concludes that the preponderance of the evidence demonstrates the IWG had a reasoned basis to refrain from adopting the IPCC AR5 ECS values in the IWG's 2013 FSCC update. While the IWG could have chosen to adopt the updated values at that time, it stated that it viewed that IPCC AR4 ECS values as the most authoritative at the time of the 2013 update and affirmed its intention to update the ECS values as appropriate in the future, based on the latest science and external expert advice.

25. The Administrative Law Judge concludes that the preponderance of the evidence demonstrates that it was reasonable for the IWG to adopt the ECS range of 2.0-4.5 °C as stated in the IPCC AR4.

V. Marginal Ton

26. The Administrative Law Judge concludes that the Utilities and MLIG failed to demonstrate, by a preponderance of the evidence, that the proposal to value CO_2 emissions by using baselines in which there are no additional emissions of CO_2 after the incremental emission is a reasonable approach to measuring damages in this proceeding. The Utilities and MLIG based this approach on the idea that incremental emissions reduction costs should be balanced with societal damage costs in calculating the SCC. This approach is contrary to the Commission's understanding of a damage-cost approach

because, by incorporating the cost of emissions reductions, the Utilities' and MLIG's proposal incorporates a "cost-of-control" approach.

27. The Administrative Law Judge concludes that the Utilities and MLIG failed to demonstrate, by a preponderance of the evidence, that the proposal to value CO_2 emissions by using baselines in which there are no additional emissions of CO_2 after the incremental emission is a reasonable approach because this approach presumes an effective global emissions reduction program will be in effect. The Utilities and MLIG failed to present any evidence of such a program.

28. The Administrative Law Judge concludes that the Utilities and MLIG failed to demonstrate by a preponderance of the evidence that the proposal to value CO_2 emissions by using an average ton approach is a reasonable approach in this proceeding. The Administrative Law Judge concludes that by averaging the first and last tons to calculate the average ton, the Utilities' and MLIG's average ton incorporates the cost of emissions reductions. Therefore, the Utilities' and MLIG's proposal incorporates a "cost-of-control" approach. In addition, the Administrative Law Judge concludes that the Utilities and MLIG failed to demonstrate that the Commission used an average ton approach in the first Externalities case.

29. The Administrative Law Judge concludes that the Agencies and the CEOs demonstrated, by a preponderance of the evidence that the FSCC's approach to counting the last ton of CO_2 emitted as the marginal ton is reasonable and the best approach to calculate damages. This is the best and most reasonable approach because it most closely matches the scientific understanding of what is known about the nature of CO_2, which is that each ton of CO_2 emitted has a cumulative impact, both with respect to the CO_2 emitted in the past and the CO_2 emitted in the future, as long as that ton of CO_2 remains in the atmosphere.

VI. Modeling Time Horizon

30. The Administrative Law Judge concludes that a preponderance of the evidence demonstrates that a ton of CO_2 released into the atmosphere will not be fully absorbed into the land or the oceans for a minimum of two hundred years. The Administrative Law Judge finds that it will be hundreds of years before that ton will be fully absorbed.

31. The Administrative Law Judge concludes that a preponderance of the evidence demonstrates that CO_2 will continue to have a cumulative impact on the climate for as long as it remains in the atmosphere.

32. The Administrative Law Judge concludes that the CEOs and Agencies failed to demonstrate that the IWG's prediction of damages from the year 2100 to the year 2300 meet the same standards of reliability as the IWG's predictions of damages from the present to the year 2100. The IWG used the peer-reviewed EMF-22 emissions scenarios, which were constructed through the year 2100. The IWG extrapolated the EMF inputs to the year 2300 based on limited data, without the benefit of peer review.

33. The Administrative Law Judge concludes the Utilities and MLIG demonstrated by a preponderance of the evidence that approximately 50 percent of the FSCC estimates at a three percent rate are in the post-2100 era.

34. The Administrative Law Judge concludes that the Agencies and the CEOs failed to demonstrate by a preponderance of the evidence that a modeling time horizon extending to the year 2300 is reasonable. An additional two-hundred years will add increased numbers of cost values at lower interest rates and accelerating rates of damages with the passage of time and increased temperature. Therefore, the Administrative Law Judge finds that an extrapolation extending two-hundred years beyond the year that the EMF-22 scenarios were constructed to end is a degree of uncertainty that is not reasonably supported by adequate evidence.

35. However, weighing the importance of accounting for the CO_2 that will remain in the atmosphere beyond the year 2100, and the understated nature of the FSCC, the Administrative Law Judge concludes that it is reasonable to implement the IWG's extrapolation for 100 years, to the year 2200. While the evidentiary underpinning is no greater for this extrapolation than it would be to extend the model to the year 2300, this approach lessens the danger of multiplication of errors within the extrapolation while providing a response to the strong evidence of damage from CO_2.

VII. Geographic Scope

36. The Administrative Law Judge concludes that the preponderance of the evidence in this docket demonstrates that CO_2 emissions emitted in one location on the Earth mix with GHGs emitted from all other locations on the planet, with each GHG molecule contributing to climate change experienced everywhere. In addition, in the first Externalities proceeding the Minnesota Court of Appeals held that, "[r]egardless of its emission point, CO_2 is believed to contribute to global warming, which in turn adversely impacts the global environment."[862]

37. The Administrative Law Judge concludes that the Utilities and MLIG failed to demonstrate, by a preponderance of the evidence, that limiting damages to the United States or Minnesota will capture all of the damage caused by CO_2 emissions released from electric power generating facilities within Minnesota.

38. The Administrative Law Judge concludes that MLIG improperly framed the calculation of the environmental cost value of CO_2 as a question of economic standing by stating the question in terms of who pays the costs of the policy and who receives the benefits.

39. The Administrative Law Judge concludes that Minn. Stat. § 216B.2442, subd. 3, and the Commission's requirement that the parties use a damage-cost analysis compel that the question of the geographic scope of damages be viewed in terms of the source of the CO_2 emissions and all their damaging impacts, wherever they are

[862] *In re Quantification of Envtl Costs*, 578 N.W.2d 794, 796 (Minn. Ct. App. 1998), *review denied* (Minn. Aug. 18, 1998).

experienced. Therefore, the Administrative Law Judge concludes that this proceeding requires a global scope for damages.

VIII. Leakage

40. The Administrative Law Judge concludes that the preponderance of the evidence demonstrates that calculating leakage of increased CO_2 emissions is not properly a part of this proceeding.

IX. Uncertainty

41. The Administrative Law Judge concludes that the preponderance of the evidence shows that the task of predicting the SCC is highly uncertain, because it is an exercise in predicting impacts of CO_2 emissions many years into the future. The process involves forecasting such uncertainties as changing temperatures, global GDP far into the future, and the possible occurrence of a "tipping point" event leading to irreversible, catastrophic damages.

42. The Administrative Law Judge concludes that the preponderance of the evidence demonstrates the IWG partially accounts for uncertainty in the FSCC by using three IAMs, five different socioeconomic emissions projections and probability distributions for the ECS values, as well as a number of parameters in the FUND and PAGE IAMs.

43. The Administrative Law Judge concludes that the Agencies and CEOs demonstrated by a preponderance of the evidence that, given the increased scientific certainty of the link between CO_2 emissions and climate change, uncertainties such as the potential danger of a "tipping point" catastrophe reasonably require an initially high SCC until more is known about such uncertainties.

X. Adaptation and Mitigation

44. The Administrative Law Judge concludes that the Agencies and CEOs demonstrated by a preponderance of the evidence that the IWG adequately accounted for adaptation and mitigation in the FSCC. No other party demonstrated by a preponderance of the evidence that it is reasonable to account for adaptation or mitigation to any extent beyond that included in the FSCC. There was no specific evidence presented regarding the efficacy of any specific mode of adaptation or mitigation.

45. The Administrative Law Judge concludes that approaching the damage calculation to achieve an "optimal mitigation level" such as Peabody recommended is not consistent with the cost-damage approach required by the Commission.

XI. Use of FSCC Outside of Federal Regulatory Setting

46. The Administrative Law Judge concludes that the preponderance of the evidence demonstrates that the IWG has not taken a position regarding whether it is appropriate for a state to adopt the FSCC for purposes such as those outlined in Minn.

Stat. § 216B.2422, subd. 3. The Administrative Law Judge concludes that the FSCC could provide the Commission with the information it requires to implement Minn. Stat. § 216B.2422, subd.3. There was no evidence offered in this proceeding to demonstrate that the IWG's FSCC values are different than they would have been had the IWG developed an SCC specifically for the purpose of complying with Minn. Stat. § 216B.2422, subd.3.

XII. Scientific Process

47. The Administrative Law Judge concludes that Peabody failed to demonstrate by a preponderance of the evidence that the IWG is neither peer-reviewed nor transparent. While the FSCC itself is not peer-reviewed, a preponderance of the evidence demonstrated that the IWG relied primarily on peer-reviewed literature, particularly the work of the IPCC, which is recognized by the Commission, the Minnesota Court of Appeals and the United States Supreme Court as a credible source of expertise in the area of climate change. The experts in this proceeding reviewed the FSCC process exhaustively, providing extensive analysis and critique. While technically not a peer review, this contested case process has provided a thorough level of scrutiny of the FSCC and the IWG's process in developing the FSCC. The IWG's Technical Support Documents are all part of the record in this proceeding, along with numerous commentaries regarding the IWG's process and the FSCC.

48. The Administrative Law Judge concludes that Peabody failed to demonstrate by a preponderance of the evidence that the Agencies and the CEOs relied primarily on non-peer-reviewed literature. The Administrative Law Judge was unable to verify Peabody's non-specific assertions that the Agencies and CEOs relied on such literature.

XIII. Xcel Proposal

49. The Administrative Law Judge concludes that Xcel failed to demonstrate by a preponderance of the evidence that its proposal to calculate the upper and lower SCC values at the 25th and 75th percentiles of the IWG data distribution was reasonable. The Administrative Law Judge concludes that, by choosing the 25th and 75th percentiles, Xcel centered its SCC range around the 50th percentile, which is the median of the distribution. By choosing to center its range around the median value, Xcel unreasonably excluded information about the magnitude, as well as the likelihood of significant damages, as reflected in the higher end tails of the distribution. These high damage outcomes are of great concern and it would be unreasonable to ignore them.

50. The Administrative Law Judge concludes that Xcel failed to demonstrate by a preponderance of the evidence that it had a reasonable basis on which to average the three FSCC discount rate values at the upper and lower ends of its range of values to establish its final SCC range of cost values. Xcel presented no evidence of theoretical, practical or scholarly support for its idea that averaging the values of the three discount rates for each end of its distribution range is an appropriate way in which to account for the controversy among the parties regarding a proper discount rate in this proceeding.

51. The Administrative Law Judge concludes that Xcel failed to demonstrate by a preponderance of the evidence that the FSCC does not offer a range of values. The FSCC chooses one cost based on an average of the values on the distribution scale, then creates a range of values from the single cost by offering that value at three different discount rates, and adding the 95th percentile as a fourth high-end value.

XIV. Reasonable and the Best Available Measure of CO_2

52. The Administrative Law Judge concludes that Peabody failed to demonstrate by a preponderance of the evidence that any of the CO_2 environmental cost values it proposed are reasonable and the best available measure of CO_2 cost values.

53. The Administrative Law Judge concludes that MLIG failed to demonstrate, by a preponderance of the evidence, that any of the CO_2 environmental cost values it proposed are reasonable and the best available measure of CO_2 cost values.

54. The Administrative Law Judge concludes that the Utilities and MLIG failed to demonstrate, by a preponderance of the evidence, that any of the CO_2 environmental cost values they proposed are reasonable and the best available measure of CO_2 cost values.

55. The Administrative Law Judge concludes that Xcel failed to demonstrate by a preponderance of the evidence that its proposal for measuring CO_2 cost values is reasonable and the best available measure of CO_2 cost values.

56. The Administrative Law Judge concludes that the Agencies and the CEOs demonstrated by a preponderance of the evidence that the Federal Social Cost of Carbon is reasonable and the best available measure to determine the environmental cost of CO_2, with the exceptions described in these findings regarding the 95th percentile and the time modeling horizon.

57. Any Findings of Fact more properly designated as Conclusions of Law are hereby adopted as such.

Based upon these Conclusions of Law, the Administrative Law Judge makes the following:

RECOMMENDATIONS

1. The Administrative Law Judge respectfully recommends that the Commission adopt the Federal Social Cost of Carbon as reasonable and the best available measure to determine the environmental cost of CO_2, establishing a range of values including the 2.5 percent, 3.0 percent, and 5 percent discount rates, with the following amendments:

a. The FSCC values will be re-calculated to reflect a shortened time horizon extending to the year 2200.

b. The Commission will exclude the value derived from the 95th percentile at a 3 percent discount rate value from the range of values.

2. The Administrative Law Judge respectfully recommends that the Commission open an investigation into the questions of how to best measure leakage, and whether and how to take leakage into account in other proceedings, as suggested by Xcel in this proceeding.

Dated: April 15, 2016

LAURASUE SCHLATTER
Administrative Law Judge

Recorded: Digitally Recorded

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.2700, .3100 (2015), unless otherwise directed by the Commission. Exceptions should be specific and stated and numbered separately. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations. The recommendations of the Administrative Law Judge have no legal effect unless expressly adopted by the Commission as its final order.

MEMORANDUM

The parties in this proceeding were very well-represented, offering their arguments thoroughly and vigorously. The record is large, in part because the parties raised so many issues in the discussion of how best to measure the social cost of carbon. The discussion was informative and wide-ranging. The Administrative Law Judge appreciates the parties' significant efforts at insuring that the record in this proceeding is comprehensive.

I. Guiding Criteria

In reviewing the issues raised by the parties, the Administrative Law Judge has been guided by several criteria. The Commission established certain of these criteria in the first Externalities case.

In the first Externalities case, the Commission considered the statutory requirement that its task under Minn. Stat. § 216B.2422, subd. 3, is "to the extent practicable, [to] quantify and establish a range of environmental costs associated with each method of electricity generation."[863] In its January 1997 Order, the Commission adopted the Administrative Law Judge's definition of the term "practicable" for purposes of the statute, finding that "practicable" means "feasible" or "capable of being accomplished."[864] Practicability must be demonstrated by a preponderance of the evidence, as discussed earlier in this report.[865]

The Commission established several additional criteria in 1997, several of which are relevant to this portion of the present docket.[866] Those criteria are that: 1) the damage-cost approach is preferred; 2) using a range of environmental cost values appropriately takes into consideration a certain level of unavoidable scientific uncertainty; and 3) while it is generally appropriate to focus on damages occurring in Minnesota, that approach does not apply to values adopted for CO_2, for which damages should be assessed globally.[867] In addition, the Commission's Notice and Order for Hearing in this docket required any consultant retained by the Agencies to use reduced-form modeling to estimate damage costs.[868]

II. Adopting Conservative Values

Several of the guiding criteria the Commission established in 1997 were first recommended by the Administrative Law Judge Allan Klein in his report as criteria "appropriate for use in determining which environmental impacts to value and whether

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[863] Minn. Stat. § 216B.2422, subd.3.
[864] 93-583 PUC ORDER 1 at 11.
[865] 93-583 PUC ORDER 1 at 13-14; ORDER REGARDING BURDENS OF PROOF at 2-3 (Mar. 27, 2015) (eDocket 20153-108636-01).
[866] Certain principles in 93-583 PUC ORDER 1 are relevant to the Criteria Pollutants portion of the docket, but not to the CO_2 portion. They are not discussed here.
[867] 93-583 PUC ORDER 1 at 13-16.
[868] NOTICE AND ORDER FOR HEARING at 5 (Oct. 15, 2014) (eDocket No. 201410-103872-02).

and how to value these impacts . . . ."[869] However, the Commission did not adopt all of those principles in its 1997 Orders.

One of the criteria recommended by the Judge Klein but not mentioned in the Commission's 1997 Orders was "[t]he adopted values should be conservative."[870] Judge Klein urged the Commission to adopt lower values,[871]

> because . . . the quantification of environmental costs is still in its infancy. [Internal citation omitted.] While using reasonably accurate estimates is better than imputing no values, not all estimates are better than zero. For instance, valuing an impact at more than twice its "true" residual damage may lead to a worse allocation of resources than imputing no value. In other words, the possibility of utilities paying more for resources than their environmental benefits justify is just as bad as paying less than their benefits justify. Given the current uncertainty regarding the estimation process, overestimating the damages is a distinct possibility.

In this docket, the Utilities, MLIG and Peabody each cited Judge Klein's language regarding conservative values, along with the cost values the Commission adopted in that docket, to support their arguments that the Commission should adopt conservative cost values in this proceeding.[872] Contrary to the arguments made by Peabody, MLIG and the Utilities, there is no explicit language in the Commission's 1997 Order approving Judge Klein's reasoning regarding adopting conservative cost values. The values chosen by the Commission in 1997 were based on the lower of two ranges recommended by the Minnesota Pollution Control Agency (MPCA). The Commission's reasoning for choosing the lower range was based on its determination that the lower range was better supported by the evidence in the record. The Commission made no mention of Judge Klein's "conservative cost value" approach.[873]

Even if the Commission understands the 1997 Order to be based on an implicit adoption of Judge Klein's "conservative cost value" approach, this Administrative Law Judge respectfully recommends that the Commission not follow that approach in this proceeding. Judge Klein did not explain the reasoning underlying his statement that "the possibility of utilities paying more for resources than their environmental benefits justify is just as bad as paying less than their benefits justify."[874] Judge Klein did not say why the Commission should have been more concerned about risking an error that would cost more money than absolutely necessary to avoid environmental damage than an error that would cost more damage because too little money was spent. Perhaps, in 1997, the

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[869] Ex. 305 at 12 (1996 Report).
[870] *Id.*
[871] *Id.* at 17.
[872] *See, e.g.,* MLIG's Initial Br. at 11, 22 (November 24 2015); Peabody's Initial Br. at 1, 11, 15, 17, 31 (November 24 2015); Utilities' Initial Br. at 7 (November 24 2015).
[873] 93-583 PUC ORDER 1 at 25-26.
[874] Ex. 305 at 17 (1996 Report).

science was less clear than it was by 2015 about the consequences of allowing climate change to continue.

While estimating damages, particularly far into the future, remains a difficult problem full of uncertainty, there is now undeniable evidence that CO_2 emissions are already having a dramatic impact on the Earth and its climate. A modern proverb graphically illustrates the dichotomy of conservatism in the face of climate change: "When the last tree is cut down, the last fish eaten, and the last stream poisoned, you will realize that you cannot eat money."[875] In establishing cost values in this proceeding, the Administrative Law Judge respectfully recommends that the Commission consider applying conservative values to the well-being of future generations and the planet needed to sustain them, rather than primarily to the financial cost of providing that well-being.[876]

III. DHE and CEBC Testimony

As noted in footnote 162, *supra*, MLIG argued in its post-hearing brief in this proceeding that neither DHE nor CEBC introduced "admissible foundational evidence to support adoption of the FSCC."[877]

IV. DHE Testimony

As to DHE, MLIG argues that DHE's witness, Dr. Rom, while well-qualified as a physician, is not qualified to provide an opinion as to "the reliability, practicability, or appropriateness of the FSCC for application in the Minnesota regulatory context, such that [DHE] has failed to introduce admissible foundational evidence to support adoption of the FSCC as developed by the IWG."[878] Because DHE failed to "propose any specific value" in the proceeding and "has not assigned any values to damages that [DHE] claims may not be included in the IAMS," MLIG asserted that DHE has failed to meet its burden of proof.

MLIG raised no timely objections, foundational or otherwise, to Dr. Rom as an expert witness in the area of environmental health. Dr. Rom is a Professor of

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[875] OXFORD DICTIONARY OF PROVERBS at 177 (5th ed. 2009).

[876] Peabody and MLIG both argued that the Administrative Law Judge and the Commission should consider the dangers of rate increases if the Commission adopts the FSCC in this proceeding. In particular, both parties expressed concerns about low-income ratepayers being unable to afford increases in their utility bills caused by a possible significant rise in environmental cost values under Minn. Stat. § 216B.2422. The scope of this proceeding does not include an inquiry into the possibility and extent of potential rate increases as a result of the Commission's decisions in this docket. Furthermore, Peabody and MLIG did not demonstrate that such increases would occur. Moreover, as Xcel's witness noted during the hearing, Minnesota has programs in place to help low-income ratepayers with utility bills. Finally, it is noteworthy that those people at the public hearing who stated that they live in low-income neighborhoods, although not without concern about rate increases, were generally more concerned about the health effects of increased CO_2 and other pollutants.

[877] MLIG Initial Br. at 11-17 (November 24, 2015). The Administrative Law Judge notes that neither MLIG nor any of the other parties made a formal motion in this regard. DHE and CEBC responded to MLIG's arguments in their Post-Hearing Reply Briefs.

[878] MLIG Initial Br. at 14.

Environmental Medicine at New York University School of Medicine. His research includes the health effects of air pollution.[879] The health impacts of climate change were the focus of Dr. Rom's testimony and it is admissible for the purpose of demonstrating that, contrary to Peabody's testimony, the medical community does not project that climate change, and in particular, climate warming, will benefit human health.

In addition to countering Peabody's witnesses about the health impacts of climate warming, Dr. Rom testified about certain health impacts that are not included in the FSCC. He also testified about a federal report that estimated the potential for reducing premature deaths in 2050 and 2100 by reducing GHG emissions, along with economic benefits of the reductions in death.[880] Based on this testimony, Dr. Rom stated his opinion that the FSCC likely underestimates the health impacts of climate change by at least $930 billion in 2100. Dr. Rom's opinion was well-supported by his training and credentials and by the documents on which he relied, according to his testimony. Dr. Rom's testimony did not actually speak to the "reliability [or] practicability" of the FSCC. He spoke about the appropriateness of the FSCC only to say that it "should be used. But used as an extremely optimistic estimate."[881]

In its post-hearing brief, DHE stated that its position is that the IAMs' damage functions "contain rudimentary approximations of economic damages attributable to global climate change, and are therefore likely underestimates;" and that the FSCC is nevertheless "reasonable and the best available measure of the environmental cost of CO_2."[882]

The Administrative Law Judge understands DHE's participation in this proceeding as limited to providing expert opinion testimony about the health impacts of climate change and the extent to which those impacts are accounted for in the FSCC. The conclusion the Administrative Law Judge draws from DHE's testimony is that the FSCC fails to account for the health impacts of climate change, to a significant extent. For that reason, according to DHE, the FSCC damage functions are likely underestimates.

The Agencies and the CEOs have provided witnesses qualified to testify regarding the details of the FSCC. Other parties are free to join in support of the Agencies and CEOs, and to rise or fall with their success or failure in this proceeding. DHE's testimony in this matter supports the Agencies and the CEOs given that no other party has proposed a SCC that better takes into account the costs to which DHE testified. DHE alone would not be qualified to carry the burden of proposing the FSCC as reasonable and the best available environmental cost value for CO_2. But that does not prohibit DHE from speaking in support of that option. DHE's testimony is fully admissible.

The Administrative Law Judge acknowledges that this is a question of the weight of the evidence rather than its admissibility. As a physician testifying in his specialized area of expertise, Dr. Rom's testimony carries considerable weight. Other than crediting

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[879] Ex. 500 at 2 (Rom Rebuttal).
[880] *Id.* at 18-19.
[881] *Id.* at 9.
[882] DHE POST HEARING BRIEF at 2 (November 24, 2015).

Dr. Rom's testimony and weighing it in favor of adoption of the FSCC, the Administrative Law Judge does not rely on DHE's support of the Agencies and CEOs for her conclusions regarding whether the Agencies and CEOs have shown, by a preponderance of the evidence, that the FSCC is the reasonable and the best range of values to adopt.

V. CEBC Testimony

Essentially the same analysis applies to CEBC and its witnesses, Mr. Rumery and Mr. Kunkle. Their testimony was admitted for the limited purpose of responding to Peabody's assertions that the global economy of the future requires fossil fuels in part because renewable energy is too expensive and unreliable. Their testimony was consistent with the Administrative Law Judge's earlier Orders permitting CEBC's testimony for a limited purpose, and is admissible as such.

CEBC and MLIG stipulated regarding the testimony of both witnesses, agreeing that neither was expressing an opinion "about the best money amount to account for the costs or benefits of carbon emissions."[883] The stipulations also stated that nothing in them "limits or precludes [CEBC] from taking a position on any of these issues, based on testimony of other witnesses or record evidence."[884]

For its initial post-hearing submission, CEBC filed a single-page document stating that it joined in support of the CEOs' post-hearing brief. The analysis here is identical to the discussion above regarding DHE. CEBC, as a party, is free to join with any party it wishes to support. It need not independently prove its case, and the case will rise or fall independent of CEBC. But nothing in the rules of evidence requires a party wishing to support another party to shoulder the burden of proof independently. The Administrative Law Judge recognizes and accepts the statement of support from CEBC for the CEOs for what it is, and separate from the value CEBC's witnesses provided in this proceeding.

VI. Modeling Time Horizon

The Commission is faced with a decision regarding the time horizon which requires a balancing of evidentiary and policy considerations. The evidence is clear that carbon remains in the atmosphere, cumulates, and will continue to affect the climate for hundreds of years to come. The dilemma facing the Administrative Law Judge, and the Commission, is a certainty that damages will continue to occur after 2100, coupled with a significant drop-off in the reliability of how to predict those damages after 2100. Predicting future damages is not at all certain, even based on the peer-reviewed EMF-22 scenarios designed to project to the year 2100. The IWG's extrapolation beyond that time frame with the scenarios is more tenuous. Yet, the certainty that damages are there remains.

The best evidence supports recalculating the damages to the year 2100. On the other hand, there is a strong argument that, knowing the damages continue, it is

[883] Ex. 437 (Kunkle Stipulation); Ex. 438 (Rumery Stipulation).
[884] Ex. 437 (Kunkle Stipulation); Ex. 438 (Rumery Stipulation).

reasonable to include damages until the year 2200. This compromise position would account for the ongoing damages yet limit, to some extent, the compounding effect of continuing the calculation for another 100 years. The Agencies' and the CEOs' experts did not perceive the level of speculation between the EMF-22 projections from the present until 2100 and from 2100 until 2300 to be significantly different in terms of reliability. While the Administrative Law Judge cannot credit the projections for the two periods equally in an evidentiary sense, neither can she completely discount the latter. Therefore, the Administrative Law Judge recommends recalculating the FSCC based on IAMs with inputs through the year 2200.

VII. Xcel's Proposal

The Administrative Law Judge recognizes that Xcel proposed a comprehensive and practicable alternative approach to calculating the SCC in this proceeding. While finding two key flaws in Xcel's proposal, the Administrative Law Judge appreciates it is a noteworthy attempt to reconcile Xcel's concerns with the FSCC and arrive at a compromise to resolve this complex problem. The Administrative Law Judge cannot recommend Xcel's solution to the Commission because of the flaws in central elements of its proposal, but commends Xcel on its attempt to find a solution based on reason and compromise. While not recommending adoption of Xcel's proposed criteria, the Administrative Law Judge notes that the criteria provide a useful set of guideposts for considering the CO_2 cost values.

VIII. Use of the FSCC to Fulfill the Requirements of Minn. Stat. § 216B.2422

The dispute over whether the FSCC is properly used for resource planning and certificate of need proceedings when it was designed to be used for cost-benefit analyses in federal rulemaking proceedings is, at its heart, a question about process. The real difference between how the FSCC is used as originally intended and how it would be used if adopted by the Commission in this proceeding is essentially the difference between internal agency policy and a requirement that functions like an agency rule. The FSCC was designed for agencies to internally to evaluate their own rules, not to apply to outside parties. Environmental cost values, pursuant to Minn. Stat. § 216B.2422, subd. 3, are numbers which regulated parties are required to use as part of proceedings in which they are required to participate. Those numbers will affect how the parties are treated in resource planning and certificate of need proceedings. In that sense, the Commission's choice of numbers as a result of this proceeding resembles rulemaking.

The legislature could have required the Commission to establish the environmental cost values through formal rulemaking proceedings, but it did not. However, the Commission found that a contested case proceeding was necessary to fully develop the record, to provide interested parties with differing points of view the opportunity to present evidence and argument, to allow for public input and to allow an Administrative Law Judge to synthesize the evidence, arguments and input in the form of this Report. The Commission did not rubber stamp the FSCC. The comprehensive and vigorous nature of these proceedings provided for a thorough review of the FSCC. Therefore, while the FSCC was originally developed for a different purpose through a process with

less input from the public and regulated parties than is usual in Minnesota, those criticisms have been cured through this proceeding.

L. S.

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Further Investigation in to Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3	**ATTACHMENT A: LIST OF PARTIES AND THEIR EXPERT WITNESSES**

The parties in this proceeding sponsored the witnesses listed below. All of the witnesses' testimony was received, with very limited exceptions as described at paragraph 19 of this Report. Witnesses whose hearing presence was waived by agreement of the parties are noted as such.

1. The Clean Energy Organizations (CEOs), sponsored the following witnesses:

- Dr. Stephen Polasky: Dr. Polasky is a Regents Professor and the Fesler-Lampert Professor of Ecological/Environmental Economics at the University of Minnesota, Department of Applied Economics. His research and publications focus on issues at the intersection of ecology and economics, including the impacts of land use and land management on the provision and values of ecosystem services and natural capital, biodiversity conservation, sustainability, environmental regulation, renewable energy, and common property resources.[885]

- Dr. John Abraham: Dr. Abraham is a Professor of Thermal Sciences at the University of St. Thomas in Saint Paul, Minnesota. He specializes in the topics of heat transfer, fluid mechanics, climate change, and numerical modeling. Dr. Abraham teaches and carries out both basic and applied research in those areas, including research in climate change, ocean warming, climate sensitivity, numerical modeling, paleoclimate research, and renewable energy.[886]

- Dr. Andrew Dessler: Dr. Dessler is a Professor in the Department of Atmospheric Sciences at Texas A&M University. His research focuses on water vapor and clouds, and the role they play in regulating the

[885] Ex. 100 at 1 (Polasky Direct).
[886] Ex. 103 at 1 (Abraham Rebuttal).

Earth's climate. Dr. Dessler has co-authored two books on climate change.[887]

- Dr. Peter Reich: Dr. Reich is a Regents Professor at the University of Minnesota, where he is also the F.B. Hubachek Sr. Endowed Chair in Forest Resources. His expertise is in the physiology and productivity of forests and grasslands. His research addresses the impacts of climate change on a variety of aspects of plant physiology and ecosystem ecology.[888]

2. Peabody Energy Corporation (Peabody) sponsored the following witnesses:

- Dr. William Happer: Dr. Happer is a Professor, Emeritus at Princeton University. From 2003 until his retirement in 2014, he held the Cyrus Fogg Brackett Chair of Physics at Princeton. From 1987 to 1990, Dr. Happer served as Chairman of the Steering Committee of JASON, a group of scientists and engineers who advise federal agencies on matters of defense, intelligence, energy policy, and other technical issues. From August 1991 through May 1993, Dr. Happer was Director of Energy Research in the Department of Energy under Secretary James Watkins. Dr. Happer invented the sodium guidestar used in atronomical adaptive optics to correct for the degrading effects of atmospheric turbulence.[889]

- Dr. Richard Lindzen: Dr. Lindzen is a meteorologist and the Alfred P. Sloan Professor of Meteorology in the Department of Earth, Atmospheric and Planetary Sciences at the Massachusetts Institute of Technology.[890] Dr. Lindzen's current research interests include the general circulation of the earth's atmosphere, climate dynamics, hydrodynamic shear instability, dynamics of the middle atmosphere, dynamics of the planetary atmosphere, parameterization of cumulus convection and tropical meteorology.[891]

- Dr. Robert Mendelsohn: Dr. Mendelsohn is the Edwin Weyerhaeuser Davis Professor at the School of Forestry and Environmental Studies at Yale University, with appointments in the Department of Economics and the School of Management. For the last 22 years, Dr. Mendelsohn has been working on measuring the benefits of mitigating greenhouse gas emissions.[892]

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[887] Ex. 103 at 1 (Dessler Rebuttal).
[888] Ex. 107 at 1 (Reich Surrebuttal).
[889] Ex. 200 at 1 (Happer Direct).
[890] Ex. 207 at 1 (Lindzen Direct).
[891] Ex. 208 at 3 (Lindzen Direct Ex. 1).
[892] Ex. 214 at 1 (Mendelsohn Direct).

- Dr. Roy Spencer: Dr. Spencer has been a Principal Research Scientist at the University of Alabama in Huntsville since 2001. Prior to that, he was a Senior Scientist for Climate Studies at NASA's Marshall Space Flight Center from 1997-2001. Dr. Spencer has twenty-five years of experience monitoring global temperatures with Earth orbiting satellites, and seven years researching climate sensitivity with satellite measures of the radiative budget of the Earth and deep ocean temperatures using a 1D climate model.[893]

- Dr. Roger H. Bezdek: Dr. Bezdek is an economist, and president of Management Information Services, Inc., an economic research firm specializing in energy, environmental and regulatory issues. Dr. Bezdek has 40 years' experience in research, management, and consulting in the energy, utility, environmental, and regulatory areas and has served in private industry, academia and the federal government.[894] Dr. Bezdek's hearing presence was waived by agreement of the parties.

- Dr. Richard S.J. Tol: Dr. Tol is a Professor of the Economics of Climate Change at Vrije Universiteit, Amsterdam, and a Professor of Economics at the University of Sussex. Dr. Tol has served on the IPCC since 1994, and also participated in the Stanford Energy Modeling Forums He is the principal author of FUND, which he began work on in 1993. Until joined by Dr. David Anthoff in 2004, Dr. Tol was the sole developer of FUND.[895] Dr. Tol's hearing presence was waived by agreement of the parties.

- Dr. William Wecker: Dr. Wecker is president of William E. Wecker Associates, Inc., which is an applied mathematics consulting firm. Since 1972, Dr. Wecker has engaged in research in statistical theory, statistical methods, and applied mathematics.[896] Dr. Wecker's hearing presence was waived by agreement of the parties.

3. Great River Energy, Minnesota Power, Otter Tail Power (the Utilities) and the Minnesota Large Industrial Group (MLIG) jointly sponsored:

- Dr. Anne E. Smith: Dr. Smith is an economist and Senior Vice President at NERA Economic Consulting, a firm of consulting economists. Dr. Smith is one of the co-chairs of the firm's Global Environment Practice. As an economist, modeler, and decision analyst, Dr. Smith's professional focus is on environmental policy matters, including climate change, air pollution, and environmental risk management, as well as the costs and benefits of environmental policies.[897]

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[893] Ex. 221 at 1 (Spencer Direct).
[894] Ex. 228 at 1 (Bezdek Direct).
[895] Ex. 237 at 2 (Tol Rebuttal Ex.1).
[896] Ex. 240 at 1 (Wecker Rebuttal).
[897] Ex. 300 at 3-4 (Smith Direct).

4. MLIG sponsored:

- Dr. Ted Gayer: Dr. Gayer is the Vice President and Director of the Economic Studies Program and the Joseph A. Pechman Senior Fellow at the Brookings Institution in Washington, D.C. Dr. Gayer conducts research on a variety of economic issues, with an emphasis on public finance, environmental and energy economics, housing, and regulatory policy.[898] Dr. Gayer's hearing presence was waived by agreement of the parties.

5. Doctors for a Healthy Environment (DHE) sponsored:

- Dr. William N. Rom: Dr. Rom is physician with a Master's in Public Health. He is a Professor of Medicine and Environmental Medicine at the New York University School of Medicine. Dr. Rom's research centers on environmental lung disease, lung cancer, tuberculosis, and the health effects of air pollution.[899]

6. Northern States Power Company, d/b/a Xcel Energy (Xcel), sponsored:

- Mr. Nicholas Martin: Mr. Martin is Environmental Policy Manager for Xcel Energy Services, Inc. Mr. Martin has a Master's degree in Energy & Resources from the University of California at Berkeley and 15 years of experience in environmental policy, economics, and science, including climate change and carbon reduction policy, protocols and projects. In his current position, Mr. Martin is the lead carbon policy expert for Xcel.[900]

7. The Clean Energy Business Coalition (CEBC) sponsored:

- Mr. Shawn Rumery: Mr. Rumery is Director of Research at the Solar Energy Industries Association in Washington, D.C. Mr. Rumery has a Master's degree in Public Administration from the George Washington University and four years of experience as a researcher in the solar industry, including extensive work on solar deployment tracking and analysis, policy analysis, and economic development.[901] Mr. Rumery's hearing presence was waived pursuant to a Stipulation with MLIG and by agreement of the parties.

- Mr. Christopher Kunkle: Mr. Kunkle is a Regional Policy Manager for Wind on the Wires in St. Paul, Minnesota. Mr. Kunkle has covered energy policy in five states, including Minnesota, for Wind on the Wires, since January 2015. Before joining Wind on the Wires, Mr. Kunkle was

[898] Ex. 400 at 1-2 (Gayer Direct).
[899] Ex. 500 at 2 (Rom Rebuttal).
[900] Ex. 600 at 1; NFM-1, Schedule 1 at 1 (Martin Direct).
[901] Ex. 700 at 1 (Rumery Rebuttal).

an Energy and Telecommunications Paralegal and Government Affairs Specialist at Cullen Weston Pines & Bach LLP in Madison, Wisconsin. Mr. Kunkle received his undergraduate degree from the University of Wisconsin-Madison.[902]

8. The Department of Commerce and Minnesota Pollution Control Agency (Agencies) sponsored:

- Dr. Michael Hanemann: Dr. Hanemann is a Professor of Economics and the Julie A. Wrigley Professor of Sustainability in the Department of Economics and the School of Sustainability at Arizona State University. Dr. Hanemann's research has been in the field known as environmental and resource economics. His Ph.D dissertation was on what is known as non-market valuation – the monetary valuation of the natural environment. Dr. Hanemann has continued to conduct research on that topic throughout his career, including contributing to the development of the two main empirical methods of measurement used in that field.[903]

- Dr. Kevin Gurney: Dr. Gurney is an Associate Professor at Arizona State University. Dr. Gurney's research in the past 15 years has focused on the global carbon cycle. Dr, Gurney has performed this research through the use of observations and modeling to better understand how carbon flows through the Earth systems and ultimately impacts the Earth's climate.[904]

[902] Ex. 701 at 1 (Kunkle Rebuttal).
[903] Ex. 800 at 1-2 (Hanemann Direct).
[904] Ex. 803 at 1; KG-R-1 at 1 (Gurney Rebuttal)

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Further Investigation in to Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3

ATTACHMENT B:
SUMMARY OF PUBLIC COMMENT

1. On August 26, 2015, a public hearing was held in the large hearing room at the Commission's office in Saint Paul.

2. Kevin Lee appeared on behalf of DHE and made a statement on the record regarding DHE's involvement in the proceedings.[905]

3. Bruce Gerhardson appeared on behalf of the Utilities and made a statement on the record regarding the Utilities' involvement in the proceedings.[906]

4. Andrew Moratzka appeared on behalf of MLIG and made a statement on the record regarding MLIG's involvement in the proceedings.[907]

5. Ben Gerber appeared on behalf of MCC and made a statement on the record regarding MCC's involvement in the proceedings.[908]

6. Hudson Kingston appeared on behalf of the CEOs and made a statement on the record regarding the CEOs' involvement in the proceedings.[909] Mr. Kingston also posted a chart showing the CEOs' proposed externality values.[910]

7. Sean Stalpes, a Commission staff member, attended the public hearing and explained the Commission's role in the proceedings on the record.[911]

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[905] Public Hearing Tr. at 14-16 (Aug. 26, 2015) (eDocket No. 20159-113775-01).
[906] *Id.* at 16-19.
[907] *Id.* at 19-22.
[908] *Id.* at 23-26.
[909] *Id.* at 26-29.
[910] Public Hearing Ex. 1 (Aug. 26, 2015) (eDocket No. 20159-113729-02).
[911] Public Hearing Tr. at 30-31 (Aug. 26, 2015) (eDocket No. 20159-113775-01).

I. Public Hearing Comments

8. Approximately 100 members of the public attended the hearing and 34 individuals spoke on the record.[912] All speakers were afforded a full opportunity to make a statement on the record and to ask questions. In addition to the oral comments, 14 exhibits were received as part of the public hearing record.[913]

9. Eight individuals spoke on the record in support of the position being taken by the CEOs in this matter.[914]

10. Fourteen members of the public specifically urged the Administrative Law Judge and the Commission to adopt the federal social cost of carbon.[915] However, Jim Horan, counsel for the Minnesota Rural Electric Association, specifically disagreed with the federal social cost of carbon and voiced his concern that energy prices will increase without any benefit to the State.[916]

11. Four individuals raised concerns about health problems caused by air pollution, especially asthma and pulmonary diseases.[917] A letter addressing the issue

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[912] Public Hearing Sign-In Sheet (Aug. 26, 2015) (eDocket No. 20159-113729-01).

[913] Public Hearing Tr. at 3 (Aug. 26, 2015) (eDocket No. 20159-113775-01).

[914] Comment by Amy Blumenshine (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Benjamin Bourgoin (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Alexis Boxer (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Rebecca Corruccini (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Carrie Johnson (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Beth Mercer-Taylor (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Grant Ruckhein (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Preeti Yonjon (Aug. 26, 2015) (eDocket No. 20159-113729-01).

[915] Comment by Amy Blumenshine (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Alexis Boxer (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Sally Downing (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Julie Drennen (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by James Hietala (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Faith Holschbach (Aug. 26, 2015) (eDocket No. 20159-113729-01); Public Hearing Ex. 14 (Aug. 26, 2015) (eDocket No. 20159-113759-01); Comment by Boise Jones (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Rachel Kerr (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Linda Kriel (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Beth Mercer-Taylor (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Jean Ross (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Grant Ruckhein (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Tammy Walhof (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Preeti Yonjon (Aug. 26, 2015) (eDocket No. 20159-113729-01); Public Hearing Ex. 6 (Aug. 26, 2015) (eDocket No. 20159-113729-07).

[916] Jim Horan, Minnesota Rural Electric Association (Aug. 26, 2015) (eDocket No. 20159-113729-01).

[917] Comment by Tess Ergen (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Kerry Felder (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Iresha Herath (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Carrie Johnson (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Boise Jones (Aug. 26, 2015) (eDocket No. 20159-113729-01); Public Hearing Ex. 5 (Aug. 26, 2015) (eDocket No. 20159-113729-06); Comment by Linda Kriel (Aug. 26, 2015) (eDocket No. 20159-113729-01); Public Hearing Ex. 3 (Aug. 26, 2015) (20159-113729-04); Comment by Beth Mercer-Taylor (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Katie Mercer-Taylor (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Karen Monahan (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Stephanie Spitzer (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Brady Steigauf (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Rose Thelen (Aug. 26,

and signed by 29 doctors and public health professionals from across Minnesota was put into the record.[918] Some of the concerned individuals believe the profits of utilities are being put ahead of the protection of human health.[919]

12. Three individuals spoke specifically about the affects air pollution has on low income neighborhoods and people.[920] Kerry Felder, a resident of North Minneapolis and secretary for the Minneapolis NAACP, talked about low income people who struggle to pay utility bills and watch their children suffer from asthma, and asked for a progressive solution addressing both issues.[921]

13. Michael Troutman, a member of the nonprofit Bread for the World, a national organization fighting hunger and poverty globally, asked the Administrative Law Judge and the Commission to consider the moral cost of air pollution and climate change.[922]

14. Louis Asher and Dale Lutz highlighted a program used by 3M called Pollution Prevention Pays, and recommended consideration of the program as a model.[923]

15. Two members of the public voiced their belief that adoption of higher cost values will drive greater growth and use of sustainable energy sources.[924] Lea Foushee, the Environmental Justice Director for the North American Water Office, stressed that electric utility industry profits must be tied to the efficient use of their product.[925]

16. Julie Drennen, a member of the Sierra Club, submitted video statements from 25 individuals living in Minnesota describing their feelings about the true cost of

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2015) (eDocket No. 20159-113729-01); Public Hearing Ex. 13 (Aug. 26, 2015) (eDocket No. 20159-113730-04); Comment by William Waisbren (Aug. 26, 2015) (eDocket No. 20159-113729-01).

[918] Public Hearing Ex. 2 (Aug. 26, 2015) (eDocket No. 20159-113729-03).

[919] Comment by Brady Steigauf (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by William Waisbren (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Michael Troutman (Aug. 26, 2015) (eDocket No. 20159-113729-01); Public Hearing Ex. 12 (Aug. 26, 2015) (eDocket 20159-113730-02); Comment by John Landgraf (Aug. 26, 2015) (eDocket No. 20159-113729-01).

[920] Comment by Kerry Felder (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Boise Jones (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Carrie Johnson (Aug. 26, 2015) (eDocket No. 20159-113729-01).

[921] Comment by Kerry Felder (Aug. 26, 2015) (eDocket No. 20159-113729-01).

[922] Comment by Michael Troutman (Aug. 26, 2015) (eDocket No. 20159-113729-01); Public Hearing Ex. 12 (Aug. 26, 2015) (eDocket 20159-113730-02).

[923] Comment by Louis Asher (Aug. 26, 2015) (eDocket No. 20159-113729-01); Comment by Dale Lutz (Aug. 26, 2015) (eDocket No. 20159-113729-01).

[924] Comment by Tim Chapp (Aug. 26, 2015) (eDocket No. 20159-113729-01); Public Hearing Ex. 7 (Aug. 26, 2015) (eDocket No. 20159-113729-08); Comment by Diwin Daley (Aug. 26, 2015) (eDocket No. 20159-113729-01); Public Hearing Ex. 11 (Aug. 26, 2015) (eDocket No. 20159-113730-02).

[925] Comment by Lea Foushee, North American Water Office (Aug. 26, 2015) (eDocket No. 20159-113729-01); Public Hearing Ex. 4 (Aug. 26, 2015) (eDocket No. 20159-113729-05).

pollution.[926] All of the individuals urged the Commission to recognize the negative impacts of pollution and increase the cost values accordingly.[927]

17. The Sierra Club also submitted more than two thousand petitions signed by individuals living in Minnesota who believe public officials should implement policies to support clean energy. The petitions, addressed "Dear Commissioner:" read as follows: [928]

> I urge you to recognize the true costs of pollution by updating pollution cost estimates for utility energy planning based on current, credible science. Pollution from fossil fuels costs Minnesotans $2.1 billion annually in health and environmental costs – 94 percent of this impact is from coal. Burning coal at Xcel Energy's Sherco plant in Becker contributes to an estimated 1600 asthma attacks, 150 heart attacks and 92 deaths each year.
>
> Scientists and health experts have made significant progress in the past 20 years in understanding just how damaging pollution is to our health and environment; yet, Minnesota hasn't update its pollution cost estimates, except for inflation. In addition to our monthly electricity bill, when a utility chooses to continue to burn coal and other dirty fuel sources it is sticking us with the bill for increased health care expenses, missed work and school, and environmental damages. Please include the EPA's social cost of carbon and most up-to-date scientific costs for other pollutants in Minnesota's energy decision-making.
>
> It's time to count the true costs of pollution when making decisions about our energy future!

II. Written Public Comments

18. Three individuals submitted written comments via the Commission's SpeakUp website.[929] Two of the commenters voiced their support for adoption of the federal social cost of carbon, although both agreed the standard is a minimum starting point.[930]

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[926] Public Hearing Ex. 8 (Aug. 26, 2015) (eDocket No. 20159-113729-09); Public Hearing Ex. 9 (Aug. 26, 2015) (eDocket No. 20159-113729-10).
[927] Public Hearing Ex. 8 (Aug. 26, 2015) (eDocket No. 20159-113729-09); Public Hearing Ex. 9 (Aug. 26, 2015) (eDocket No. 20159-113729-10).
[928] Public Hearing Ex. 10 (Aug. 26, 2015) (eDocket Nos. 20159-114142-01, 20159-114143-01, 20159-114145-01, 20159-114148-01, 20159-114155-01, 20159-114156-01, 20159-114158-01, 20159-114159-01, 20159-114160-01, 20159-114161-01, 20159-114-162-01, 20159-114163-01, 20159-114164-01).
[929] Comment by Allan Campbell (Sept. 1, 2015) (SpeakUp) (eDocket No. 20159-114130-01); Comment by Barbara Draper (Sept. 15, 2015) (SpeakUp) (eDocket No. 20159-114130-01); Comment by Terrence Nayes (June 5, 2015) (SpeakUp) (eDocket No. 20159-114130-01).
[930] Comment by Allan Campbell (Sept. 1, 2015) (SpeakUp) (eDocket No. 20159-114130-01); Comment by Barbara Draper (Sept. 15, 2015) (SpeakUp) (eDocket No. 20159-114130-01).

19. On September 15, 2015, the Metropolitan Council submitted a written comment.[931] The Metropolitan Council "is responsible for coordinating regional transportation planning efforts" and has "adopted transportation plans [that] emphasize strategies and investments to reduce transportation-related greenhouse gas and criteria pollutant emissions."[932] The Metropolitan Council supports adoption of updated cost values and believes the updated values will help achieve "regional sustainability outcomes."[933]

20. On September 17, 2015, the Minnesota Rural Electric Association (MREA) submitted a written comment.[934] The MREA represents the interests of the State's 44 electric distribution cooperatives as well as the six generation and transmission cooperatives that supply them with power.[935] The MREA opposes an increase in externality cost values, "especially the use of an unrealistically high value of the federal Social Cost of Carbon for carbon dioxide emissions," based on its concern that higher externality costs will result in increased costs to its members.[936] Instead, the MREA urges the Administrative Law Judge and the Commission to consider the federal Environmental Protection Agency's Clean Power Plan to avoid burdening consumers with duplicative and potentially conflicting requirements.[937]

21. On September 17, 2015, the Minneapolis Health Department (MHD) submitted a written comment.[938] As the largest city in Minnesota, MHD believes Minneapolis "bear[s] a larger brunt of the burden of air pollution in [the] State."[939] MHD supports updating the cost values to reflect current scientific evidence on environmental externalities.[940]

22. On September 18, 2015, the Minnesota Division of the Isaak Walton League of America (MN-IWLA) submitted a written comment.[941] The MN-IWLA voiced its support for the position taken by the CEOs in the externality proceedings.[942] The MN-IWLA encouraged adoption of the federal social cost of carbon "as a transparent, well-vetted value for carbon dioxide."[943]

23. On September 18, 2015, Missouri River Energy Services (Missouri River) submitted a written comment.[944] Missouri River opposes adoption of the federal social

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[931] Comment by Metropolitan Council (Sept. 15, 2015) (eDocket No. 20159-114130-01).
[932] *Id.*
[933] *Id.*
[934] Comment by Minnesota Rural Electric Association (Sept. 17, 2015) (eDocket No. 20159-114087-01).
[935] *Id.*
[936] *Id.*
[937] *Id.*
[938] Comment by Minneapolis Health Department (Sept. 17, 2015) (eDocket No. 20159-114130-01).
[939] *Id.*
[940] *Id.*
[941] Comment by Minnesota Division of the Izaak Walton League of America (Sept. 18, 2015) (eDocket No. 20159-114120-01).
[942] *Id.*
[943] *Id.*
[944] Comment by Missouri River Energy Services (Sept. 18, 2015) (eDocket No. 20159-114102-01).

cost of carbon, and instead encourages the State "to create a single, centralized and consolidated state cost value for carbon dioxide rather than clinging to both regulatory and externality values applicable for matters governed by [the Commission] which results in multiple cost points."[945] Missouri River believes "it is premature for the Commission to adopt or modify a carbon dioxide value for externalities."[946]

[945] *Id.*
[946] *Id.*

Utility DIVE

FEATURE

Ohio's REV: PUCO to explore grid modernization, utility reform in PowerForward initiative

Unlike other initiatives, which began with an end goal in mind, PUCO Chair Asim Haque says his proceeding will be more 'exploratory' at the outset

By **Gavin Bade** • March 8, 2017

The Public Utilities Commission of Ohio (PUCO) is launching a regulatory proceeding to review technological and regulatory innovations related to utility grid modernization.

Dubbed “PowerForward,” the initiative aims "to chart a path forward for future grid modernization projects, innovative regulations and forward-thinking policies" that could later be integrated into utility business practices, according to a PUCO release.

In particular, the initiative seeks to understand how changes to utility regulation and revenue models could enhance the customer experience, such as through the deployment of distributed resources and efficiency programs.

The initiative will be split into three parts, beginning with three days of technical conferences in April. In that phase, the proceeding will focus on “creating a venue for a comprehensive review of all things innovation — technological and regulatory,” PUCO Chairman Asim Haque told Utility Dive.

But, he stressed, PowerForward is more than a fact-finding mission. As the proceeding progresses, Haque expects PUCO regulators will apply its findings to individual utility proposals such as grid planning and rate cases.

“A technology review just for the sake of a technology review, that won’t get us to where we need to be,” Haque told Utility Dive. “We need to find a way to incent this technology to be deployed, so how we go about that and how we go about the ratemaking is something that needs to be explored.”

Haque said PowerForward will address many of the issues discussed in utility reform dockets elsewhere in the United States, such as New York’s Reforming the Energy Vision, which seeks to remove utility disincentives toward the deployment of distributed resources.

“The goose is not cooked here...we have not said we are pushing the docket for DERs or efficiency or anything. We want to see what’s out there.”

Asim Haque
Chairman of the Public Utilities Commission of Ohio

But, he added, PUCO going into the process with “eyes wide open,” and has no preconceived notions of what grid modernization will mean for utility and regulatory models.

“The goose is not cooked here,” Haque said. “We have not said we are pushing the docket for DERs or efficiency or anything. We want to see what’s out there.”

States look to utility reform

Haque’s Ohio is far from alone in investigating new business models for utilities.

Regulatory proceedings to reform the traditional utility model are taking hold in a number of states as regulators look to remove disincentives to the deployment of distributed resources and demand management programs.

Under traditional cost-of-service regulation, utilities meet power system needs by deploying infrastructure like substations and wires, earning a rate of return from regulators for their investments.

That model, however, does not provide an incentive for utilities to deploy distributed resources or efficiency programs to meet the same grid needs, which can often be more cost-effective and environmentally sustainable.

In response, a number of states are reviewing how they regulate utility revenue models, testing new ways to incentivize non-wire alternatives for grid modernization.

Last year, New York instituted new revenue models for utilities in its Reforming the Energy Vision docket, allowing companies to earn a rate of return not just on traditional investments, but DER deployment as well. California, which opened its first regulatory docket on DERs in 1997, is currently considering a similar proposal as a part of a "DER mega-proceeding."

While those states have captured the most headlines, the push for business model reform has spread elsewhere, to states like Hawaii, Minnesota, Rhode Island, Massachusetts and the District of Columbia.

Now Chairman Haque wants to add Ohio to that list, but he said his effort will be more “exploratory” than reforms in other states, particularly New York.

“REV is a trailblazing proceeding,” Haque said, but it was envisioned with an end goal in mind. In 2014, New York regulators launched the proceeding with the explicit goal to turn utilities into distribution platform providers — impartial operators of the grid that facilitate DER interconnection and the development of distributed energy markets.

“In my mind, this is our REV, but it’s far different than what the New York Commission proposed ... we’re going to look at the end game first.”

Asim Haque
Chaiman of the Public Utilities Commission of Ohio

By contrast, Haque said the PowerForward technical conferences will allow stakeholders to influence what that end goal of the proceeding will be, after which the initiative will shift to understanding how to achieve it through technological adoption and regulatory reforms.

“In my mind, this is our REV,” Haque said, “but it’s far different than what the New York Commission proposed ... we’re going to look at the end game first.”

Three stages of grid mod

The PowerForward initiative is scheduled to span three key phases, reaching into 2018.

The first phase — “a glimpse into the future” — involves the conferences on April 18, 19 and 20. The gatherings will involve presentations from national utility experts to “give Ohioans a glimpse of what the energy future could be,” Haque said.

Those conferences will help regulators determine the vision for the PowerForward docket ahead of the second phase of the proceeding, scheduled for July. At that point, regulators will address which technologies will be necessary to make the vision a reality.

Finally, in a third phase of the proceeding, regulators will address how reforms to utility rate designs, revenue models and other business practices could deliver on the goals of the docket. That stage of the proceeding is scheduled for “late fall,” according to Haque, and will likely reach into 2018.

At the end of the proceeding, Haque plans to have PUCO release a document outlining how regulators envision the future of the state's power grid, potentially including recommendations for utility reforms and changes to state law.

"Our plan is to actually provide our view as a commission on what will work as a state of Ohio," Haque said.

Proceeding a longstanding goal for Haque

Launching a grid modernization proceeding has been one of Haque's central goals since he took leadership of the regulatory body in 2016.

In June of last year, the newly-minted PUCO chair told Utility Dive he intended to launch a utility reform docket after the commission worked through contentious proposals for subsidies to aging coal and nuclear plants owned by FirstEnergy and AEP.

Those issues are not completely resolved, but FERC's rejection of the generation subsidies last year led the utilities to scale back their proposals and sell some of the plants, allowing regulators some breathing room.

"I think we have largely taken care of some of our major cases," Haque said. "We have some rehearings and further comments to review ... but the general utility populace understands where those cases are headed based on initial orders."

Going forward, Haque said he intends to focus PUCO's efforts on the distribution system and consumers, while leaving contentious issues of generation subsidies, renewable energy supports and the potential re-regulation of Ohio power markets to the legislature.

"Largely speaking, the PUCO is going to focus on the wires — the distribution system — and consumers and that will be our drive going forward," he said.

The PUCO chair said he has received positive feedback from sector stakeholders at the prospect of a grid modernization docket, including the state's regulated utilities.

“They understand that this is where the industry is heading,” Haque said.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 15-E-0302 - Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard.

CASE 16-E-0270 - Petition of Constellation Energy Nuclear Group LLC; R.E. Ginna Nuclear Power Plant, LLC; and Nine Mile Point Nuclear Station, LLC to Initiate a Proceeding to Establish the Facility Costs for the R.E. Ginna and Nine Mile Point Nuclear Power Plants.

ORDER ADOPTING A CLEAN ENERGY STANDARD

Issued and Effective: August 1, 2016

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on August 1, 2016

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Gregg C. Sayre
Diane X. Burman, concurring

CASE 15-E-0302 - Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard.

CASE 16-E-0270 - Petition of Constellation Energy Nuclear Group LLC; R.E. Ginna Nuclear Power Plant, LLC; and Nine Mile Point Nuclear Station, LLC to Initiate a Proceeding to Establish the Facility Costs for the R.E. Ginna and Nine Mile Point Nuclear Power Plants.

ORDER ADOPTING A CLEAN ENERGY STANDARD

(Issued and Effective August 1, 2016)

BY THE COMMISSION:

I. INTRODUCTION AND SUMMARY

By this Order, the Commission determines that a series of deliberate and mandatory actions to build upon and enhance opportunities for consumer choice are necessary to achieve State environmental, public health, climate policy and economic goals; to enhance and animate voluntary retail markets for energy efficiency, clean energy and renewable resources; to preserve existing zero-emissions nuclear generation resources as a bridge to the clean energy future; to ensure a modern and resilient

energy system; and to accomplish its objectives in a fair and cost-effective manner. In accordance with the statutory obligation that agency actions must be reasonably consistent with the most recent State Energy Plan (SEP), the Commission adopts the SEP goal that 50% of New York's electricity is to be generated by renewable sources by 2030 as part of a strategy to reduce statewide greenhouse gas emissions by 40% by 2030.[1]

In furtherance of that goal, and mindful of the Commission's role as a State regulator sharing jurisdiction with the federal government, in this Order the Commission also adopts a Clean Energy Standard (CES) consistent with the SEP goal, including: (a) program and market structures to encourage consumer-initiated clean energy purchases or investments; (b) obligations on load serving entities to financially support new renewable generation resources to serve their retail customers; (c) a requirement for regular renewable energy credit (REC) procurement solicitations; (d) obligations on distribution utilities on behalf of all retail customers to continue to financially support the maintenance of certain existing at-risk small hydro, wind and biomass generation attributes; (e) a program to maximize the value potential of new offshore wind resources; and (f) obligations on load serving entities to financially support the preservation of existing at-risk nuclear zero-emissions attributes to serve their retail customers.

[1] By Executive Order, it is also a goal of the State of New York to reduce current greenhouse gas emissions from all sources within the State 80% below levels emitted in the year 1990 by the year 2050. Executive Order No. 24 (2009) [9 N.Y.C.R.R. 7.24; continued, Executive Order No. 2 (2011) 9 N.Y.C.R.R. 8.2].

State Policy Goals

New York has adopted strongly proactive policies to combat climate change and modernize the electric system to improve the efficiency, affordability, resiliency, and sustainability of the system. One of the primary benefits of the CES will be a reduction in total emissions of air pollutants resulting from fossil fuel combustion. Increasing the contribution of renewable generation to meet the 50 by 30 mandate will not only reduce carbon emissions, but will reduce nitrogen oxides, sulfur dioxide, and particulate matter emissions as well by thousands of tons per year. Increased use of renewable energy sources leads to improved air quality and societal benefits from reduced health impacts and increased employee productivity. For example, as air quality improves, state health care expenditures for treatment of asthma, acute bronchitis, and respiratory conditions may be reduced. Reduced exposure to fine particulates may avoid other health problems such as increased morbidity and exacerbation of respiratory and cardiovascular ailments.

The CES adds to the regulatory and retail market changes that New York is already pursuing under its Reforming the Energy Vision (REV) program. Through existing initiatives, clean energy resources including energy efficiency, distributed energy, advanced storage and load control technologies are being integrated into the system to promote a modern, resilient and cost-effective network. As the Commission's stated in its 2013 initiating Order, the time has come to integrate clean energy as core, as opposed to ancillary, to our energy systems. Unlike in even the recent past, advancements in the capabilities of resources such as wind, solar and storage to work in combination, both on the bulk power system and behind the meter, results in the ability to develop and operate the grid to be

more responsive, efficient, secure and clean. Through better pricing and retail market design, New York is positioning itself to create a two-way fully transactive electric system that uses demand and clean energy as solutions that drive consumer value and choice. As noted in the order approving the Clean Energy Fund, a significant aspect of gaining this value is ensuring that markets are created that have the scale and scope to attract investment and reduce costs. The CES provides both.

For New York, the need and ability to take steps to combat climate change is immediate. New York's vulnerability to extreme weather events was vividly illustrated in 2011 and 2012 by the storms Sandy, Irene, and Lee. These storms, however, were only the most visible warning signs. Climate change will cause not only sea level rise, heat waves, and extreme weather events, but also threatens massive economic and lifestyle disruption from damage to agriculture, water resources, public health, energy and communication systems, and the natural ecosystems that define and support communities.[2]

Nationally, the U.S. Environmental Protection Agency estimates that in the absence of emission reductions and adaptation measures, damage to U.S. coastal property by 2100 will exceed $5 trillion.[3] Power outages caused by severe weather

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[2] See Intergovernmental Panel on Climate Change, IPCC, 2014: Climate Change 2014: Synthesis Report, Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change; Case 14-M-0101, Reforming the Energy Vision, Final Generic Environmental Impact Statement, Chapter Three (February 6, 2015); and New York State Climate Action Plan Interim Report, Chapter Two (November 9, 2010).

[3] EPA 2015. Climate Change in the United States: Benefits of Global Action. United States Environmental Protection Agency, Office of Atmospheric Programs, EPA 430-R-15-001.

between 2003 and 2012 are estimated to have already cost the U.S. economy an annual average of $18 billion to $33 billion.[4]

Another weather event that revealed the vulnerability of New York's energy system was the polar vortex of January, 2014, which resulted in severe price spikes for gas and electric customers. In that event, the vulnerability was due to a prolonged and extremely cold weather system coupled with over-reliance on natural gas for both heating fuel and electric production. Electric customers suffered terribly from a streak of cold weather that increased prices by more than $2 billion over a three-month period.[5] The price increases were especially challenging to businesses and low-income and fixed-income customers.[6]

The 2015 SEP recognizes the importance of ensuring that New York's power system is modern, clean, and diverse. It concludes that to achieve these objectives, 50% of all electricity used in New York by 2030 should be generated from renewable sources.[7] The SEP goal for renewable electricity is in the context of broader clean energy and economic development goals: 40% reduction in greenhouse gas emissions, 50% renewable electricity, and 600 trillion Btu in energy efficiency gains. An overwhelming majority of parties to the CES proceeding, as well as thousands of public comments, support the renewable

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[4] Economic Benefits of Increasing Electric Grid Resilience to Weather Outages, President's Council of Economic Advisers and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology, August 2013.

[5] This figure is mitigated for some customers by hedged contracts although the extent of hedging value during that period is not known.

[6] Northeastern Winter Natural Gas and Electricity Issues," U.S. EIA, January 7, 2014.

[7] The Energy to Lead, 2015 New York State Energy Plan, p.112.

resource objectives of the SEP. The goals directed in the SEP are aggressive. Ambitious goals are needed, however, to provide scale to the industry and impetus to markets. Moreover, given the urgent challenge of climate change, the SEP goals should be considered the minimum to be achieved, not the maximum. Consistent with these realities and with the State's policy objectives, including the actions the Commission has already taken under the REV program, the Commission finds in this Order that achieving a fifty percent renewable goal by 2030 is not only achievable but is an imperative of the Commission meeting its statutory responsibilities.

By letter of December 2, 2015, Governor Andrew Cuomo directed the Department of Public Service Staff (Staff) to develop and propose a CES that if adopted would convert the SEP goals into enforceable requirements. Staff filed its White Paper on Clean Energy Standard (White Paper or Staff Proposal) on January 25, 2016. This Order addresses the Staff proposal, the parties' written filings, and the outpouring of public comments that have followed the Staff proposal. In this Order, the Commission adopts a CES consistent with the SEP goal.

The 50 by 30 goal is not only part of a larger greenhouse gas goal, it is part of the State's sweeping initiative to transform the way energy is produced, delivered, and consumed. REV encompasses many interrelated initiatives, through which energy efficiency and clean energy development achieve not only carbon reduction but also market animation and grid modernization. There are many participants in REV beyond the Commission. The New York Power Authority (NYPA) and the Long Island Power Authority (LIPA), for example, will participate in the CES not only to conform to a carbon requirement but to engage in an integrated statewide policy.

The programs and retail market design elements approved to implement the CES conform to the Commission's objectives of using free consumer choice as the first mechanism to achieve this goal, but balanced by regulatory action and government activities that will ensure such market animation by establishing firm and clear targets, reducing barriers to entry, supporting economies of scale, and establishing a mechanism to ensure that regardless of the pace of self-initiating consumer actions, New York consumers will be well positioned to meet the State's necessary climate goals in a fair and cost effective manner. The CES is an ambitious but necessary response to the challenges of climate change and modernizing the electric system. By this Order, the Commission further advances the achievement of the broad set of industry reforms under REV and adopts significant carbon reducing measures.

The CES, along with REV, will benefit New York energy consumers and the overall economy by encouraging new investments in the State, maintaining existing jobs, and attracting capital from outside the State. It reflects a comprehensive and balanced approach to the challenges of climate change and the opportunities presented by a transforming electric industry.

Customer Choice

Under REV, the Commission initiated regulatory and retail market reforms to ensure the regulated distribution utility companies, the competitive energy and distributed energy providers, and the complementary actions of the State energy entities, including the New York State Energy Research and Development Authority (NYSERDA), NYPA and LIPA, are linked through the uniform goal of promoting consumer choice through competition and innovation as the chief vehicles of integrating clean energy into the fabric of a two-way integrated, efficient,

reliable and resilient modern New York electric power industry.[8] The reforms being implemented in REV are designed to ensure that over time, all New York electric customers will have unfettered access to clean, efficient, reliable and resilient power. The REV policies are also looking to advance energy democracy by facilitating meaningful consumer choice so that regardless of income, location, or living structure, all consumers have the ability to choose the type of supply they want and how much they want to consume. Similarly, the SEP goals address concerns that affect all New Yorkers. The CES obligations to conform to a resource mix and the benefits they will bring should be shared by all energy consumers regardless of their energy supplier. While all suppliers are not subject to the Commission's jurisdiction, the Commission is looking to all suppliers, including NYPA, LIPA and all others, to participate by satisfying their requisite share of responsibility.

These energy policies are also reflecting the fact that New Yorkers are concerned about the natural environment and when they have the choice and financial opportunity, many New Yorkers will gladly choose the more environmentally benign resource.[9] Energy efficiency, voluntary green energy purchases, and other market responses to REV will contribute towards the SEP goals. The public in New York is increasingly asserting its desire and preference for clean energy solutions. The Commission is compelled to ensure that New Yorkers are able to reveal their preference for clean energy by first giving them full opportunity to choose solutions that meet their individual

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[8] Case 14-M-0101, Reforming the Energy Vision.

[9] For example, an April 2016 survey conducted by The Nature Conservancy indicated that a majority of New Yorkers in the survey were willing to pay higher costs for renewable electricity.

needs and advance the greater public interest. The CES must encourage individual customer choice that exceeds the State's objectives. Business and individual customers voluntarily choosing to become more energy efficient, and to deploy or buy economic clean energy resources are New York's most valuable asset towards achieving the SEP goals. Under well-designed products and regulatory structures, the value of those choices will only grow.

Jurisdiction and Markets

Under the system of federalism, governmental power is divided between the national or federal government and the governments of the states. The federally-designed wholesale markets operated by the New York Independent System Operator (NYISO) pursuant to tariffs approved by the Federal Energy Regulatory Commission (FERC) are by law fuel-neutral and do not value resources based upon their environmental attributes or their ability to offer a fuel diversity hedge. Public interest determinations of fuel type and resource adequacy are specifically reserved to the states. As the "laboratories of democracy,"[10] it is welcomed that many states are advancing the achievement of our Nation's clean energy objectives by demonstrating through retail electric power market innovation various mechanisms available to encourage clean energy. Today at least twenty-nine states, including New York, serve this public interest through resource portfolio standards. In recent years, many jurisdictions including California, Oregon, Hawaii, District of Columbia, Vermont, and Maine have adopted renewable goals consistent with New York's adoption of the CES.

[10] A concept described by U.S. Supreme Court Justice Louis Brandeis in New State Ice Co. v. Liebmann, 285 U.S. 262 (1932).

Therefore, while the CES places New York in a leadership position among states, it is not a fully unilateral action.

The mechanisms any state applies to best meet its clean energy goals are inextricably tied to the design of power markets in that state and their participation in federally regulated wholesale markets. In states with traditional fully-integrated utilities that are simultaneously responsible for the generation, distribution and retail sales functions, utilities bear the obligation directly to meet clean energy goals and fulfill them consistent with their obligation to serve. In California where the wholesale generation sector is competitive and supervised by the California ISO, but distribution and retail sales remain a utility function, clean energy obligations are met by the utilities by purchasing clean energy from independent generators for distribution and retail sale by the utility. Finally, in states which fully restructured and permit both wholesale and retail competition, clean energy standards have primarily been met through the development of REC markets that are reflective of the presence of competition and associated reluctance by retail suppliers to enter into supply purchase obligations that are incongruous with their short-term retail contracts. The obligation to meet clean energy goals falls on the individual retail commodity supplier that must either purchase sufficient RECs to cover its obligations or make a generally higher-priced Alternative Compliance Payment (ACP) to a central authority.

New York, a state that is fully restructured, has historically met its clean energy goals through a unique system that treated the compliance obligation as a delivery function of the distribution utility with RECs centrally-procured for the utilities by NYSERDA in long-term contracts intended to provide greater certainty to generators and corresponding lower REC

costs for consumers. Renewable resource generation facilities are long-lived capital assets that will only be financed and constructed if the investor building them can be assured of a reasonable opportunity to recover its costs. Generally, long-term contracts or other durable mechanisms are necessary to provide sufficient certainty for prospective investors to induce them to make the investment. By this Order, the Commission retains the benefit of New York's unique central procurement system while shifting the obligation for compliance from the distribution utility to the retail commodity supplier load serving entity (LSE), where it naturally belongs.

Cost Containment

The Commission must ensure that the actions it takes in pursuing the State's energy policy objectives rest soundly within its jurisdictional responsibilities. The existing electric system was designed at a time where the monopolistic regulatory structure reflected the domination of capital intensive long-lived assets, central station supply and the reality of inelastic demand. And while the structure of the industry including the asset base is changing, the Commission anticipates that the transformed modern electric system will continue to be capital intensive and long-lived. For that reason, markets and regulatory actions to promote markets must always be mindful of the need to retain and build investor confidence. The design of the CES is intended to retain and create investor confidence in this sector both for existing and new investors through the avoidance of actions that are abrupt, unfair and otherwise fail to provide sufficient clarity and certainty to offer investors sufficient confidence. As the economic regulator, the Commission deeply understands that investor confidence yields consumer benefits through encouraging

capital deployment, competition and lower overall financing expense.

Further, as the chief State agency with the experience and obligation of protecting consumer interests in an industry so affected with the broad public interest, the Commission is statutorily compelled to act in a manner that ensures that it is effective in ensuring that both during the transformation of the industry and in achieving the transformed industry that the energy sector in New York remains safe, cost-effective, reliable, resilient and protective of the natural environment. Cost containment and investor confidence will be achieved through a range of measures, including direct program elements (e.g., an alternative compliance mechanism), closely-related cost reduction programs such as aggressive pursuit of energy efficiency, and a deep transformation of the electric industry, which is needed to move beyond the inefficiencies of the traditional electric system and regulatory structure, as described in previous REV orders.

Program Elements

In this Order the Commission adopts a goal that 50% of electricity consumed in New York by 2030 will be generated from renewable sources. The Commission identifies numerous avenues for achieving the goal, including:

- Existing State-owned renewable attributes including NYPA hydropower as well as projects funded through the Renewable Portfolio Standard and NY-Sun;

- Aggressive pursuit of cost-effective energy efficiency, established through market initiatives and the Clean Energy Fund, with guidance from the Clean Energy Advisory Council;

- Consumer-initiated green energy purchases or investments, which will be encouraged through market-based incentives and a transparent certification program;

- A continued obligation and opportunity for utilities to ensure that low-income consumers have access to clean energy alternatives that help them reduce their energy burden and improve the environment;

- A program to maximize the value potential of offshore wind, designed and sponsored by NYSERDA in cooperation with the federal government, industry, and an inter-agency task force;

- Actions to reduce soft costs of development, including measures to reduce the cost and enhance the speed and predictability of interconnection and siting;

- Jurisdictional obligations on load serving entities to ensure the procurement of renewable credits generated in New York or delivered into New York;

- Jurisdictional maintenance obligations on distribution utilities to maintain the contributions of older, small, renewable facilities;

- Long Island Power Authority actions for its retail customers in concert with a broader range of REV initiatives;

- New York Power Authority actions for its retail customers in concert with a broader range of REV initiatives;

- Continued actions by the State and State entities as energy users to individually exceed the standard through their energy development and purchasing activities; and

- Continued participation and leadership in the Regional Green House Gas Initiative (RGGI) and support of universal complementary federal action under the Clean Power Plan.

Commission action on the CES will be comprised of this Order and subsequent implementation orders. This Order also enumerates implementation details to be proposed by Staff, subject to public comment, and to be considered and resolved by the Commission in the implementation phase. The CES is divided

into a Renewable Energy Standard (RES) and a Zero-Emissions Credit (ZEC) requirement.

Renewable Energy Standard

Tier 1 - New Renewable Resources

Tier 1 consists of an obligation imposed upon every LSE. LSEs comprise all entities serving retail load within a regulated utility territory. This includes investor-owned distribution utilities, energy service companies (ESCOs), Community Choice Aggregation programs (CCAs) not served by ESCOs, and jurisdictional municipal utilities. Retail customers self-supplying through the New York Independent System Operator will also be considered LSEs for this purpose.

In this Order, the Commission requires each New York LSE[11] to serve their retail customers by procuring new renewable resources, evidenced by the procurement of qualifying RECs, acquired in the following proportions of the total load served by the LSE for the years 2017 through 2021:

Year	Percentage of LSE Total Load
2017	0.6%
2018	1.1%
2019	2.0%
2020	3.4%
2021	4.8%

Over time through a triennial review process, the Commission will adopt incrementally larger percentages for the years 2022 through 2030, with sufficient lead time for the LSEs

[11] This discussion assumes participation by LIPA and NYPA customers. As described more fully below, the load forecasts used to set targets account for historic behind-the-meter generation and incremental annual energy efficiency achievements.

to incorporate the changes into their planning processes. As part of the implementation phase the Commission directs staff to develop a possible scenario for acquisitions up to 2030. The Commission recognizes that the actual procurement requirements will depend upon a number of exogenous market factors, and thus should only be taken as a potential guide, not a schedule. The periodic review and target setting will also take into account the balance of likely incremental supply with demand. Based on current forecasts of future loads, the above percentages will yield the following MWhs of output from new renewable resources:

Statewide Yield (MWhs)

Year	Distribution Utilities & ESCOs	LIPA	NYPA	Direct Customers	Statewide Total
2017	705,595	120,244	139,225	8,936	974,000
2018	1,261,429	214,967	248,900	15,975	1,741,270
2019	2,263,192	385,682	446,563	28,662	3,124,100
2020	3,841,197	654,599	757,928	48,647	5,302,371
2021	5,455,424	929,688	1,076,440	69,090	7,530,642

	Renewable Resource MWhs	Percentage Renewable Resources
Baseline	41,296,000	25.71%
2017	42,270,000	26.32%
2018	43,037,270	26.81%
2019	44,420,100	27.69%
2020	46,598,371	29.08%
2021	48,826,642	30.54%

The LSEs will be able to meet their obligations by purchasing RECs from NYSERDA, by purchasing qualified RECs from other sources, or by making Alternative Compliance Payments to NYSERDA. Resources eligible to produce RECs will be resources that came into operation after January 1, 2015, and that meet the eligibility criteria set forth in Appendix A.

This Order also provides for NYSERDA to conduct regularly scheduled solicitations for the long-term procurement of RECs to achieve the following anticipated and minimum results for the years 2017 through 2021:[12]

Year	Anticipated Procurement Target (MWh)	Minimum Procurement Target (MWh)*
2017	1,966,449	1,769,804
2018	2,022,004	1,819,804
2019	2,077,560	1,869,804
2020	2,133,116	1,919,804
2021	2,188,671	1,969,804

* Assumes a 10% attrition rate from the Anticipated Procurement Target

As noted above, the statewide procurement of new large-scale renewable generation expected to result from Tier 1 during the period 2017 to 2021 is 9,347,020 MWh, or approximately 1,869,400 MWh per year. This is over two times the level of large-scale renewable generation that was procured through Renewable Portfolio Standard (RPS) solicitations during the period 2011 to 2015, which averaged 788,600 MWh per year.

[12] This discussion also assumes participation by LIPA and NYPA customers.

NYSERDA will thus acquire, annually, sufficient RECs to meet the entire electric demand of approximately 240,859 homes.

Consistent with the policy established in the Clean Energy Fund, the cost of Tier 1 REC procurement will not result in new charges to delivery customers; all charges will be to commodity customers. If periodic review of REC procurement reveals that REC demand is not being supplied at reasonable prices, procurement methods and this objective will be reconsidered.

The Commission's further objective is to ensure that in its totality the CES achieves the goals of a reliable clean energy industry in a cost-effective manner. Measures to achieve this will include:

- The continued use of long tenure REC procurement;
- An Alternative Compliance Mechanism which will cap the potential cost of RECs on an annual basis;
- Banking of excess RECs for use in future years;
- Establishing markets for voluntary green products;[13] and
- Periodic review of the program to ensure best practices are followed, that balance is maintained between supply and demand, and to establish firm minimum targets.

Tier 2 - Maintenance Tier

At this time, there is no necessity for Tiers 2a and 2b as proposed in the Staff White Paper. The categories for REC support payments in Staff's proposal are either premature, unnecessary, or already provided for under the current maintenance program. For those resources such as small hydro that may retire without additional support for their

[13] LIPA and NYPA are also anticipated to develop such market opportunities.

environmental benefits, Tier 2 as adopted in this Order will consist of a maintenance program as existed under the RPS. Staff is directed to develop and recommend for Commission consideration as part of an implementation plan whether there should be changes to the maintenance program to align support with zero-emissions facilities. For resources that are currently under NYSERDA contracts but might export their power to another state at the end of the contract period and jeopardize achievement of the 2030 target, the Commission will monitor their activities and consider action at a later time if necessary.

Offshore Wind

Achieving a de-carbonized electric system for the long-term, with reliable generation and an economically sustainable capacity factor, will inevitably depend on a mixture of technologies and combinations that are not fully developed at this time. New York is fortunate to have substantial potential for offshore wind production and with appropriate time, careful planning and deliberate action, the State has the opportunity to exploit its geographic advantage to develop offshore wind and promote the beneficial attendant economic activity associated with this burgeoning industry. In order to maximize the potential for offshore wind, in addition to the actions taken in this Order, the Commission is requesting NYSERDA to identify the appropriate mechanisms the Commission and the State may wish to consider to achieve this objective. Through this additional work and the actions the Commission is promoting in this Order, a future is being enabled where older, less efficient plants in New York are replaced exclusively with clean energy resources, including higher capacity factor offshore wind and renewable/storage combinations.

Zero-Emissions Credit Requirement

Tier 3, the independent but related component of the CES concerns the State's nuclear facilities. New York's total electric generation mix in 2014 was 37% gas, 31% nuclear, 23.5% hydro, 4.5% coal, 3.5% wind, solar, biomass and biogas, 1.3% solid waste, and 0.4% oil. New York's upstate nuclear plants avoid the emission of over 15 million tons of carbon dioxide per year. Based on current market conditions, losing the carbon-free attributes of this generation before the development of new renewable resources between now and 2030, would undoubtedly result in significantly increased air emissions due to heavier reliance on existing fossil-fueled plants or the construction of new gas plants to replace the supplanted energy. The added emissions would complicate the State's compliance with likely federal carbon standards and would result in dangerously higher reliance on natural gas, radically reducing the State's fuel diversity. Such reduced fuel diversity could affect system reliability and price stability, making consumers more vulnerable to natural gas and concomitant electric price spikes. The loss would also have other significant adverse economic impacts on State energy consumers and the State as a whole. New York can look to another leader in renewable power – Germany – for a lesson in the unintended consequences of losing zero-emissions attributes from all its nuclear plants. Germany's abrupt closure of all its nuclear plants resulted in a large increase in the use of coal, causing total carbon emissions to rise despite an aggressive increase in solar generation.

The Order establishes a mechanism and a price for zero-emissions attributes of nuclear zero-carbon electric generating facilities where public necessity to encourage the continued creation of the attributes is demonstrated. NYSERDA will offer qualifying nuclear facilities a multi-year contract

for the purchase of ZECs. For facilities that demonstrate public necessity and are awarded contracts prior to April 1, 2017, the contract period will run from April 1, 2017 through March 31, 2029. The ZEC price for these contracts will be $17.48 per MWh for the first two-year tranche designated Tranche 1. The ZEC price would be adjusted every two years for Tranches 2 through 6 in accordance with the formula articulated in this Order, which is based on the social cost of carbon. Facilities subsequently demonstrating public necessity will be offered contracts at a ZEC price calculated by the formula established by this Order.

Each LSE that serves end-use customers in New York will be required, beginning April 1, 2017, for the benefit of the electric system, its customers and the environment, to purchase the percentage of ZECs purchased by NYSERDA in a year that represents the portion of the electric energy load served by the LSE in relation to the total electric energy load served by all such LSEs. LSEs will make ZEC purchases by contract with NYSERDA and will recover costs from ratepayers through commodity charges on customer bills.

The ZEC mechanism adopted in this Order is the best way for the State to preserve the nuclear units' environmental attributes while staying within the State's jurisdictional boundaries. ZECs provide a vehicle for monetizing the State's environmental preferences and the program will allow time for new clean energy technologies to mature and take their place in the ultimate generation mix. The independent renewable resource and ZEC obligations that together make up the CES each contribute uniquely to serving the long-term goal of achieving a largely de-carbonized energy system by the middle of the century.

II. PROCEDURAL BACKGROUND

This Order is a continuation of a series of Commission and State actions to increase the use of renewable electric generation and reduce the production of greenhouse gasses. In 2004, the Commission adopted a Renewable Portfolio Standard designed to achieve total renewable generation of 25% by 2013.[14] In 2008, the Commission adopted an Energy Efficiency Portfolio Standard (EEPS) designed to reduce total electricity consumption in the state 15% by 2015. Reduction of greenhouse gasses was one of the principal goals of the EEPS initiative.[15] Also in 2008, New York's Department of Environmental Conservation adopted a rule to establish the Regional Greenhouse Gas Initiative (RGGI). Through RGGI, New York, along with eight other Northeastern and Mid-Atlantic states, set a cap on total carbon dioxide emissions from electric generating facilities within the region.[16] In December 2009, the Commission expanded the RPS goal to 30% by 2015.[17]

On February 26, 2015, in its REV proceeding, the Commission directed a reassessment of New York's approach for encouraging the expansion of large scale renewable energy

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[14] Case 03-E-0188, Retail Renewable Portfolio Standard, Order Regarding Retail Renewable Portfolio Standard (issued September 24, 2004).

[15] Case 07-M-0548, Energy Efficiency Portfolio Standard, Order Establishing Energy Efficiency Portfolio Standard and Approving Programs (issued June 23, 2008), p. 2.

[16] 6 NYCRR Part 242, CO_2 Budget Trading Program; 21 NYCRR Part 507, CO_2 Allowance Auction Program.

[17] Case 03-E-0188, Retail Renewable Portfolio Standard, Order Establishing New RPS Goal and Resolving Main Tier Issues (issued January 8, 2010).

generation.[18] On June 1, 2015, the Secretary issued a notice instituting this proceeding, and Staff filed a Large Scale Renewable Energy Development in New York Options and Assessment (Options Paper) prepared by NYSERDA. Forty-eight comments were filed on the Options Paper and 14 replies.

As noted, on June 25, 2015, the State Energy Planning Board adopted the SEP. The SEP calls for 50% of New York's electricity to be generated by renewable sources by 2030, as part of a strategy to reduce statewide greenhouse gas emissions by 40% by 2030.[19] This goal exceeds the targets and caps established in the RPS and RGGI.[20]

The State Energy Law requires that agency actions must be reasonably consistent with the most recent State Energy Plan.[21] Further, on December 2, 2015, Governor Cuomo instructed the Department of Public Service (DPS) to begin implementing the State's goal of 50% renewable electricity by 2030.[22] On January 21, 2016, the Commission expanded the scope of this proceeding to implement the 50% renewables by 2030 goal, and maintenance of

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[18] Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015), p. 83.

[19] 2015 Energy Plan, Vol. I, p. 112.

[20] The State's climate change initiatives are paralleled by federal and international developments. On December 22, 2015, the U.S. Environmental Protection Agency adopted the Clean Power Plan which requires states to implement carbon emission reduction plans. On December 12, 2015, an international climate change accord was approved, including commitments from the United States.

[21] New York Energy Law §6-104(5)(b).

[22] Letter from Governor Andrew M. Cuomo to Audrey Zibelman, CEO, New York State Department of Public Service, December 2, 2105 (Cuomo Letter) available at https://www.governor.ny.gov/sites/governor.ny.gov/files/atoms/files/Renewable_Energy_Letter.pdf.

certain nuclear plants.[23] On the same date, the Commission adopted the social cost of carbon, less the RGGI value already internalized, as a component of externality values that could not otherwise be calculated.[24] The Commission further expanded the instant proceeding on February 24, 2016 to consider an expedited program to maintain the viability of certain nuclear power plants in order to maintain their zero-emissions characteristics.[25]

Staff filed its White Paper on January 25, 2016. One hundred and five comments were filed on the White Paper and 34 replies. On April 8, 2016, Staff filed a Cost Study regarding the White Paper (Cost Study or Study), and on April 12th a Supplement to the Cost Study. Twenty-six comments were filed on the Cost Study. On July 8, 2016, Staff's Responsive Proposal for Preserving Zero-Emissions Attributes (Staff's Responsive Proposal) was filed. Thirty-two comments were filed in response to that filing. A summary of comments on the White Paper, Cost Study, and Staff's Responsive Proposal is attached as Appendix B.

The written comment process has been supplemented by an extensive series of public hearings and technical conferences. Staff convened five on-the-record technical conferences with active participation from a range of diverse stakeholder perspectives. The technical conferences focused on various topics included in the White Paper and Cost Study in

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[23] Case 15-E-0302, Clean Energy Standard, Order Expanding Scope of Proceeding and Seeking Comments (issued January 21, 2016).

[24] Case 14-M-0101, Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016), p. 18.

[25] Case 15-E-0302, supra, Order Further Expanding Scope of Proceeding and Seeking Comments (issued February 24, 2016).

order to further discuss and investigate issues pertinent to development of the Clean Energy Standard.

Twenty-four public statement hearings where conducted across the state during the months of May and June to provide interested individuals and stakeholders the opportunity to comment on the Clean Energy Standard proposal. Over 3,500 comments have been submitted to the Commission's public comment website since the proceeding was expanded to consider the Clean Energy Standard proposal. In addition, at one of the public statement hearings, the Sierra Club presented 11,000 written public comments for inclusion into the record. Public comments have been overwhelmingly supportive of the CES initiative in general,[26] with commenters mixed on the inclusion of nuclear facilities, as described below.

A parallel process that will be affected by the implementation of the CES is the development of the State Resource Plan (SRP).[27] The Department of Public Service initiated the SRP in 2014 to determine bulk power system actions (e.g., procurement of additional regulation service, transmission) that will need to be taken to accommodate increased penetration of weather-variable resources in the supply mix. A base case will be evaluated to determine the potential electric resource needs for 2024 and 2030 under business-as-usual conditions. Then a policy scenario will be evaluated to determine the potential electric resource needs to

[26] The Nature Conservancy also conducted a survey of New Yorkers, as described in party comments, which indicated broad support for increased investment in renewable energy sources.

[27] The SRP working group consists of Staff, NYSERDA, the Department of Environmental Conservation, and the Utility Intervention Unit of the Department of State, the NYISO, and the major New York transmission owners.

meet the CES goal and federal requirements. SRP results will be taken into account in the ongoing review of the CES.

These proceedings have occurred against the backdrop of the overall REV initiative, which is the State's sweeping reform of the manner in which electricity will be generated, distributed, and consumed. REV intends to transform the century-old paradigm of a centralized, unidirectional utility system that is built to serve inelastic demand and be compensated through cost-of-service ratemaking. Under REV, system efficiency and customer value will be driven by markets and by new business and regulatory models that encourage the integration of distributed resources including generation, demand response, and energy efficiency.

III. NOTICE OF PROPOSED RULEMAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), Notices of Proposed Rulemaking regarding various aspects of the Commission's consideration of the CES were published on January 27, 2016 [SAPA No. 15-E-0302SP1]; March 16, 2016 [SAPA No. 15-E-0302SP2]; April 20, 2016 [SAPA Nos. 15-E-0302SP3 and 15-E-0302SP4] and May 25, 2016 [SAPA No. 16-E-0270SP1]). In addition, a Notice Soliciting Comments and Providing for a Technical Conference and Public Statement Hearings was issued January 26, 2016, establishing initial and reply comment periods, which were later extended.[28] A Notice of Comment Period for the Staff White Paper and Cost Study was issued April 8, 2016. On July 8, 2016, a Notice Soliciting Additional Comments was issued regarding Staff's Responsive

[28] See Case 15-E-0302, et al., supra, Notice Extending Comment Period (issued March 8, 2016); Notice Extending Reply Comment Period (issued April 29, 2016); Notice Extending Deadline for Comments (issued July 15, 20).

Proposal for Preserving Zero-Emissions Attributes. Final comments in these proceedings were due July 22, 2016.[29] As noted above and discussed below, numerous comments were received from parties and the general public and have been relied upon to inform this decision.

IV. STAFF PROPOSALS, COST STUDY, AND PARTY COMMENTS

A. Renewable Standard: Obligation of Participating Entities

1. Staff Proposal

a. Jurisdictional Entities.

Staff proposes specific goals for MWh of renewable energy for 2017-2020, with subsequent goals to be established in triennial reviews. Achievement of the goals would be the responsibility of all LSEs serving retail load in the territory of electric distribution companies (EDCs). LSEs are defined as investor-owned utilities (in their capacity as commodity suppliers), jurisdictional municipal utilities, and all competitive ESCOs. Each LSE would be responsible for supplying a defined percentage of retail load with supply derived from eligible resources during each calendar year (Compliance Year).

Staff explains that this approach is already used by other Northeastern states with restructured retail markets. It has the advantage of placing compliance costs primarily in the generation supply charges, which sends the most direct price signal and reduces the need for charges on the delivery bill. The LSE obligation would also promote REV objectives by encouraging ESCOs to develop innovative products to increase customer options and reduce customer costs.

The CES obligation for each LSE would be determined by multiplying its MWh load obligation by the renewable percentage

[29] Case 15-E-0302, et al., supra, Notice Extending Comment Deadline (issued July 15, 2016).

CES target for that year. Each LSE would be required to meet its obligation for each tier within each Compliance Year.[30]

A number of large institutions and customers take power directly from the NYISO. These end-use, direct NYISO customers are LSEs in their own right and are subject to the CES obligation.

b. Non-Jurisdictional Entities.

Staff states that NYPA and LIPA are expected to adopt renewable and non-emitting energy targets that are proportional to their load. This includes municipal utilities and rural cooperatives that obtain their full requirements from NYPA. The CES obligation of jurisdictional entities would be calculated under the assumption that NYPA and LIPA are adopting their proportional shares of the statewide goals.

2. Party Comments

Parties overwhelmingly support the basic goals of the CES initiative. Along with environmental advocates and clean energy industries, utilities and most consumer and citizen groups recognize the need for the CES. With few exceptions, party comments relate to how, not whether, to implement the 50 by 30 goal.[31] The LSE mandate as a foundational approach to CES implementation is generally supported, although most of the discussion is framed in terms of the need for and approach to long-term contracts, described below. The Clean Energy Organization Collaborative (CEOC) and Environmental Defense Fund (EDF) support the LSE mandate in particular, because it would

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[30] Staff's proposal regarding tiers is discussed below.

[31] The Business Council questions whether the CES goal can be achieved without damaging the state's economy. The Green Education and Legal Fund argue that the 50 by 30 goal is inadequate to address the urgency of climate change and a 100% goal should be adopted.

hold market participants directly accountable, and it would reflect compliance costs in energy commodity charges.

Three EDCs filing jointly as "the Companies"[32] describe the potential for CES to overlap with other forms of payments for renewables including non-wires-alternative projects, net metering, and voluntary green products. The Companies emphasize the importance of coordinating so that customers do not pay more than once for the same benefit. The Companies also urge that the CES obligation apply to self-generating microgrids. EDF notes that self-generating fossil units not connected to the grid would not be encompassed within the CES mandate, and that distributed generation must be measured with precision in order not to encourage either polluting generation that escapes the mandate or clean generation that is not properly credited. Three utility EDCs filing as the Indicated Joint Utilities (IJU)[33] argue that projects receiving net metering should transfer any REC value they receive to the host utility in order to avoid an excess payment.

The Natural Gas Supply Association (NGSA) proposes a fundamentally different approach to carbon reduction that recognizes environmental advantages of gas. The General Electric Company (GE) also argues that carbon benefits of natural gas should be accounted for. The Entergy entities (Entergy) also oppose the renewables approach to the CES and argue that a source-neutral carbon-intensity standard is the most effective was to reduce carbon emissions.

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[32] The Companies are New York State Electric & Gas Corporation (NYSEG), Rochester Gas and Electric Corporation (RG&E) and Central Hudson Gas & Electric Corporation (Central Hudson).

[33] The Indicated Joint Utilities are Consolidated Edison, Orange and Rockland, and Niagara Mohawk d/b/a National Grid.

The Business Council does not oppose the CES but the Business Council as well as the Manufacturing Association of Central New York (MACNY) oppose applying the REC obligation to sales to business customers. Multiple Intervenors (MI) and the New York Farm Bureau also express concern about impacts on energy costs. MI questions whether the 50 by 30 goal should be assumed to be a reasonable starting point.

The Retail Energy Supply Association (RESA) has strong concerns over the LSE mandate, citing fixed price contracts with customers and long-term supply contracts that have been entered into without anticipating the additional costs of the LSE mandate. NYPA and the New York State Economic Development Council (NYSEDC) express concern over the potential impact on NYPA's economic development customers. MI and Nucor Steel Auburn, Inc. (Nucor) also argue that application of the LSE mandate to energy intensive large customers would be counter-productive. NYPA states that it will work aggressively to implement its share of the 50 by 30 goal, but that its contracts do not provide it with flexibility to pass through costs. NYPA also states that sales to storage facilities should not be considered retail sales for purposes of triggering an LSE obligation to purchase RECs.

The New York Association of Public Power (NYAPP) and the New York Municipal Power Agency (NYMPA) argue that the CES mandate should not apply to municipal and cooperative utilities. The New York Battery Storage Technology Consortium (NYBEST) supported the CES but proposes that RECs should be supplemented by Flexible Energy Credits (FLECs) with a separate mandate for LSEs to acquire FLECs in addition to RECs; Alliance for a Green Economy (AGREE) supports this proposal.

In response to Staff's request for comments on how to avoid unintended consequences for beneficial electric end-use

technologies (BETs) such as geothermal heat pumps and electric vehicles, the NY Geothermal Energy Organization (NY GEO) proposes two options: the first option is to not count increased load from BETs against the LSE requirement; the second option is to establish Thermal Renewable Energy Certificates (TRECs). A TREC would be generated for every three units of geothermal heat paired with one unit of electricity. TRECs are under consideration in several states.

B. Eligible Resources

1. Staff Proposal

Staff proposes a list of eligible renewable resources that tracks the list under the current RPS, with an exception that would eliminate the 30 MW limit on low-impact run-of-river facilities and allow for larger run-of-river facilities. The requirement of no new storage impoundments will remain both for upgrades and, by definition, for run-of-river facilities.

Out-of-state generation would be eligible if it is located in a control area adjacent to the NYISO control area, and if the generation is accompanied by documentation of a contract path between the generator and the in-state purchaser that includes transmission rights. Staff notes that inclusion of these resources will help to reduce overall costs, and will also avoid any legal concerns related to interstate commerce.

Staff recognizes that some market activities can have the effect of reducing carbon while increasing electric demand (e.g., electric vehicles and geothermal heat pumps). This creates a concern that the CES obligation, based on total demand for electricity, could create a disincentive to the development of these beneficial uses.

2. Party Comments

Parties offer a wide range of comments on eligibility. Many comments submitted by representatives of industries argue

for the eligibility of their particular products, including waste-to-energy, biomass, biogas, and hydroelectricity. The Department of Environmental Conservation (DEC) observes that there are significant differences among various types of biomass and biogas generation. AGREE and the Citizens Environmental Coalition (CEC) are opposed to many forms of biomass and biogas eligibility. Vanguard Renewables seeks to clarify that the principle difference is between biomass and biogas. The Cow Power Coalition and Cornell University agree that biogas generation from anaerobic digestion should be considered renewable. The Energy Recovery Council (ERC) argues that waste-to-energy should be considered an eligible resource.

Hydro Quebec Energy Services U.S. (HQ) argues that there should be no limits on large scale hydropower, while a coalition of Renewable Energy Industries (REI)[34] along with the Sierra Club opposed any inclusion of large scale hydropower. The Low Impact Hydropower Institute (LIHI) suggests that its criteria for low-impact hydropower should be used to determine eligibility. The NYISO and RESA agree that out-of-state generation should be eligible. The Canadian Wind Energy Association (CanWEA) propose that hydropower eligibility should be broadened and that transmission projects to deliver wind and hydro should be solicited as part of the CES. The Independent Power Producers of New York (IPPNY) oppose any out-of-state generation owned by a government entity. HQ states that it is government-owned but that it receives no subsidies.

[34] REI is a coalition of renewable industry representatives. The members of REI do not encompass the entire renewable industry. Further references to REI in this Order are made in recognition that REI is a functional coalition of industries with common interests but does not represent all renewable interests.

GE supports the inclusion of combined heat and power (CHP) as well as supply efficiencies that reduce the amount of fuel needed for fossil generation. NY BEST argues that storage should be an eligible technology; AGREE and CEC support this. AGREE and Otego Microgrid Ratepayers agree with NY GEO that beneficial electric end uses should be eligible for some form of benefit to at least ensure that no disincentives for these technologies are created by the REC requirement.

C. Tiers

1. Staff Proposal

Staff describes that many states with RPS and CES programs utilize tiers that distinguish among eligible resources based on factors including vintage and technology, to promote both growth of new resources and maintenance of existing ones. For purposes of administrative simplicity, a small number of broad tiers is preferable; this also encourages competition among technologies within a tier. For purposes of minimizing compliance costs, tiers may need to distinguish among resources due to differing degrees of needed support. Co-incentives may also be used to target specific technologies within a tier, either because they have a specific public policy value or to improve the competitive balance within the tier.

Staff's proposal includes a single tier for new renewable resources, and a second tier for existing generation that is subdivided in sub-tiers to minimize compliance costs. A third tier is proposed to maintain existing eligible nuclear facilities.

Tier 1 would include all new resources with an in-service date on or after January 1, 2015. The categories of eligible generation sources generally mirror the current Main Tier of the RPS program. Co-incentives such as NY Sun would balance the competitive opportunities within the tier.

Tier 2 would include existing resources to support their continued contribution to meeting New York goals. Because the cost structures and alternative revenue opportunities of these resources vary significantly, Staff recommends further differentiation.

Tier 2a would be the competitive sub-tier intended to provide sufficient revenue to attract renewable attribute supply for which New York must compete with other states. Tier 2a would include merchant projects not currently receiving state support, expired RPS Main Tier contracts, and outputs from current RPS projects that exceed the contracted amounts.

Tier 2b would be the non-competitive sub-tier intended to provide sufficient revenue to maintain existing renewables that are not eligible to participate in growth tiers of other states. All existing resources that are not eligible under Tier 2a would automatically be included in Tier 2b.

Tier 3 is proposed for nuclear facilities, as discussed below. Tier 3 resources do not produce RECs for purposes of the LSE REC obligation.

2. Party Comments

Many parties including Town of Brookhaven, CEOC, Citizens for Local Power (CLP), Green Education and Legal Fund, REI, Otsego 2000 and Pepacton Institute (Pepacton), Deepwater Wind, and Dong Energy, urge a separate tier for offshore wind. These parties argue that offshore wind will be essential in meeting renewable goals and a separate tier would enable financing and accelerated development.

The City of New York (NYC or the City) strongly supports the CES initiative but expresses concern over geographic equity stemming from the fact that downstate consumers would have to pay for renewable generation that would have upstate economic benefits. According to the City, one

option to address this would be a downstate sub-tier of Tier 1, with costs socialized across the state in the same manner as the White Paper describes. The NYC notes that carbon emissions are often associated with other more local emissions, and the CES should provide an opportunity to reduce local emissions in the concentrated downstate area.

NYC also observes that the multi-tier purchase requirement could discourage customers who choose to voluntarily purchase 100% of their supply from new renewables, if those customers must also purchase a share of RECs and ZECs from Tiers 2 and 3. IJU also emphasizes that voluntary renewable purchases in excess of the LSE requirement must be encouraged, not discouraged, by the CES structure.

The IJU proposes that a separate Tier 4 should be established for large hydropower supply, so that environmental attributes can be considered along with the cost structure of large hydropower. GE proposes a separate tier for new emerging technologies, to encourage development of innovative technology solutions.

Numerous parties representing specific industries comment on the manner in which the tier structure would affect their product offerings. Brookfield Renewables (Brookfield) argues that existing hydropower should be eligible under Tier 1 as it is in some other states, and that Tier 2 will require midpoint reviews. Brookfield also argues that Tiers 2a and 2b should be merged into a single tier that provides appropriate compensation to retain all existing renewable resources.

Ampersand Hydro states that most small hydropower facilities would fall into Tier 2b and suggested a Social Benefits Adder of four cents per kWh for these facilities. HQ proposes that hydropower delivered over existing transmission lines should be included in Tier 2, with hydro delivered over

new transmission lines treated as incremental under Tier 1. The National Fuel Cell Research Center (NFCRC) describes the benefits of distributed power for meeting CES and REV objectives and proposes that 35% of the CES obligation should be set aside for distributed generation. The NY Cow Power Coalition advocates a separate tier for anaerobic digester generation, which would enable the aggregation of dairy-farm generated power within a utility service territory. The New York Solar Energy Industries Association (NYSEIA) supports the proposed tiered structure, but urges that a sub-tier for solar be established within Tier 1 for the growth of utility-scale solar.

D. Annual Targets

1. Defining the Baseline

a. Staff Proposal

Staff describes its method of calculating the CES baseline in Appendix B of the White Paper. The NYISO load forecast for 2025 was extrapolated to 2030 assuming linear continuation from 2024-2025 through 2030.[35] This forecast was supplemented with an assumption of 8,615,000 MWh of additional load by 2030 from electric vehicles and geothermal heat pumps, and 410,000 MWh of behind-the-meter generation. From this subtotal, incremental annual energy efficiency achievements of 2,227,000 Mwh were subtracted.[36] The resulting total of statewide need for 2030 is 150,017,000 MWh.

The 50% renewable goal, expressed in MWh, for the CES was obtained by dividing the total anticipated load by two, resulting in approximately 75,000,000 MWh in 2030. In 2014,

[35] The White Paper mistakenly describes the period 2023-2025 as the basis for extrapolation.

[36] The energy efficiency estimates are based on recently approved targets, increased pro rata to include NYPA, LIPA, and direct NYISO customers.

41,296,000 MWh, or approximately 26% of the fuel mix, was supplied from renewable sources. Subtracting this from the 50% goal resulted in a need for 33,700,000 MWh of additional renewable generation in 2030.

b. Party Comments

MI notes that the baseline calculation contains several assumptions that will need to be revisited periodically, including the load forecast, energy efficiency savings, and electric vehicle load. The Companies state that resources to be counted toward the baseline should be registered through the New York Generation Attribute Tracking System (NYGATS) (see below).

EDF, MI and IPPNY note that if CES targets are not coordinated with corresponding reductions in RGGI allowance caps, then reductions in New York will simply free up allowances for use elsewhere in the RGGI market, resulting in no actual reductions in greenhouse gas emissions on a regional level. Otsego 2000 argues that the RGGI caps and 25 MW threshold must be reduced.

NYSEIA argues that the baseline resources are such an important part of the overall goal that they should be tracked through a separate Tier 0, with no corresponding LSE obligation. CEOC argues that the amount of energy efficiency assumed in the baseline is far lower than is practically achievable, and submitted a study which claims that more than twice as much efficiency could be economically achieved, with corresponding reduction in the cost to achieve the CES. Energy Efficiency for All argues that the energy efficiency estimate in the baseline should be established through a clear mandate.

2. Establishing Tier Targets

a. Staff Proposal

Recognizing the many variables and forecasting difficulties beyond 2020, Staff proposes that fixed annual

targets be set for each tier through 2020, with targets for the next three years established well in advance of the end of 2020, and subsequent targets established through similar triennial reviews. Staff notes that this approach allows the achievement trajectory to be responsive to market developments, with specific targets established in time to avoid uncertainty.

Staff proposes targets for specific tiers, with the existing resources in Tier 2 remaining relatively stable while the annual percentage of new renewables increases each year. Progressive targets for the initial years of Tier 1 reflect estimates of projects being developed under the RPS and NY Sun programs.

b. Party Comments

The Companies and MI support the establishment of fixed targets through 2020 with a triennial review to fix targets beyond that date. The Department of State Utility Intervention Unit (UIU) supports the use of triennial reviews to establish targets.

Numerous parties including REI, EDF, GE, Green Education and Legal Fund, NFCRC, NYC, and NYSEIA argue that firm targets should be set for each year through 2030 in order to provide a predictable signal to the market. The Green Education and Legal Fund argues that a 100% renewables portfolio by 2030 should be the target. REI states that triennial reviews could be used to adjust targets if necessary. REI and EDP Renewables argue that the targets should be front-loaded in order to take advantage of federal tax credits before they expire. CEC and CEOC agree that targets should not be backloaded.

3. Start Date for Targets

a. Staff Proposal

Staff proposes that the first Compliance Year be 2017, for all tiers.

b. Party Comments

MI argues that the initial target should be set for 2018 rather than 2017, which would provide time for the necessary markets and associated infrastructure to be developed. REI opposes this suggestion, arguing that an additional year would create a gap in large-scale renewables procurements.

E. Compliance Mechanism

1. Renewable Energy Credits

a. Staff Proposal

Staff proposes that the principal medium of compliance would be the REC. One REC would be created for each renewable MWh generated. This is the universal unit of measure that allows RECs to be marketed within and among states. The REC method would make New York's CES system compatible across multiple systems, policies, and markets. Each LSE can self-supply, trade, and purchase RECs through short-term or long-term instruments. LSEs would demonstrate through annual compliance filings that they possess sufficient RECs to meet their obligations.

b. Party Comments

Most parties support the use of RECs as the medium of compliance, although support for RECs is qualified by a wide variety of positions as to the details of implementation. As noted above, several parties oppose the approach to renewables and supported a source-neutral carbon intensity standard. The National Energy Marketers Association (NEMA) stresses that the compliance system adopted for the CES should be clear and consistent. NEMA recommends that the Massachusetts model be followed.

MI voices the strongest concerns over the use of RECs. MI cites Staff's acknowledgement that interstate REC markets could result in generation owners pursuing the highest revenues

across state lines. MI argues that New York has been developing renewables under its RPS without having to resort to marketable RECs, and that this may be the mechanism that results in the lowest costs to ratepayers.

2. Alternative Compliance Payments

a. Staff Proposal

Staff proposes that LSEs have the option of complying with their REC obligation by making Alternative Compliance Payments. ACPs are widely used in other competitive market states. They provide flexibility and an effective cost cap. An ACP is not a penalty for non-compliance; it is a discretionary alternative mode of compliance. ACP levels would be established by the Commission based on forecasted REC prices, system needs, and other relevant factors.

Because ACPs do not represent actual renewable MWh, Staff proposes that the proceeds of ACPs be directed to reducing the costs of in-state renewable development toward meeting the 50 by 30 goal.

b. Party Comments

Most parties agree that some form of ACP is needed both to provide a price cap on RECs and to provide an alternative procurement method for smaller LSEs. Parties disagree over the method for setting ACP levels and over the disposition of ACP proceeds.

CEOC states that ACPs should only be used during scarcity conditions to guard against price spikes. Direct Energy Services suggests that ACPs start at a low level and gradually increase; this would allow time to adjust for LSEs with fixed price commodity contracts. REI and NYSEIA propose that ACPs should be set substantially higher than the estimated REC price in order to stimulate development. NRG, Energy, Inc. (NRG) states that ACPs must be set as high as other states to

avoid export. SEIA (Solar Energy Industries Association), Vote Solar, CEOC and EDF suggest that best practices identified from other states with REC markets should be used. Nucor and MI express the concern that ACPs can tend to establish a floor as well as a ceiling on REC prices. Nucor argues that ACP pricing should be tied to the value of the externality benefit.

The Companies and IJU agree with Nucor and MI that the ACP will have the effect of a price floor, to the point where the administratively determined ACP will act as a substitute for market forces. The Companies argue that central procurement through a competitive process would eliminate the need for an ACP and avoid this problem.

Parties broadly agree that ACP proceeds should not be used to support government functions but should instead be used to promote achievement of the CES. Parties have varying approaches to this goal. Several parties favor a broader approach that would use the funds to promote renewables development, comparable to the use of RGGI proceeds. Others including NYC, MI and UIU argue that proceeds should be refunded directly to customers. NYC argue that if ACP proceeds are refunded, while still holding LSEs as a whole to meeting the CES targets, then cost-effective compliance will be promoted. UIU, AGREE, and PosiGen Solar Solutions propose that ACP proceeds be targeted to low-income customer energy efficiency or CES compliance.

3. Banking and Borrowing

a. Staff Proposal

Additional flexibility and cost control can be achieved through banking of excess RECs and borrowing against shortfalls. These devices can help to smooth fluctuations in REC supply, and allow hedging against future price increases. Staff does not recommend any specific time limits on banking and

borrowing but notes that banking is typically subject to a time limit of two to three years and the amount bankable is limited to a percentage of individual LSE obligation such as 30%. The typical period for borrowing is much shorter, for example one or two calendar quarters, to ensure that compliance obligations are not inappropriately avoided.

b. Party Comments

Parties generally support banking and borrowing in the context of the LSE REC obligation. GE proposes that a force majeure provision be added to provide additional flexibility in the event of natural disasters.

F. Long-Term Contracting for RES Resources

1. Staff Proposal

Staff explains that one challenge of the LSE obligation approach is that financing of renewable facilities will often require long-term contracts, and LSEs in competitive markets do not have the certainty of long-term load commitments that would support their entering long-term purchase contracts for renewables.

Staff describes the risks faced by renewable project developers in a competitive market. Demand risk – i.e., the risk that there will be a market for the product – is addressed by the establishment of the CES mandate. Significant risks remain, however. As technology prices fall, project owners will need to compete against new entrants with lower costs. Also, if energy prices fall below forecasted levels, anticipated project revenues will not materialize. In a REC-only market, these risks will likely be passed along to consumers in increased REC costs. The Cost Study also indicates that a REC-only approach to long-term procurement is likely to result in higher REC costs by 2023 than an approach based on bundled PPAs.

In response to this challenge, Staff discusses a number of options related to long-term contracting. Staff draws heavily on the June 2015 Options Report and party comments that followed it.

Long-term contracts backed by EDCs provide near-term benefits for CES compliance, but they carry risks for utility ratepayers if energy costs or technology costs decline below forecasted levels. Also, the near-term benefits of utility-backed contracts must be balanced with the long-term benefits of self-initiated markets. Staff also considers the potential for utility-owned generation and recommends that there was no basis to deviate from the policy direction adopted in the REV Framework Order that generally prohibits utility ownership of generation resources, in order to promote entry by market participants.

Staff proposes that EDCs be required to purchase some portion of the REC target through long-term PPAs that provide for RECs, energy and/or capacity. EDCs should further be allowed to resell to third parties for shorter terms, and to keep an appropriate portion of the profits from those transactions as an incentive.

Staff also proposes that NYSERDA should serve as a central procurement entity for RECs. NYSERDA has long experience in this role, and the cost advantages of central procurement are described in the Options Report. Although NYSERDA's role will be intermediary, some assurance against financial risk will be needed; Staff proposes that EDCs serve as financial guarantors of NYSERDA's procurements.

2. Party Comments

Parties are split over the use of PPAs and over the potential for utility-owned generation facilities (UOGs) in the context of the CES. The Indicated Joint Utilities and the

Companies oppose PPAs backed by EDCs, arguing that this places risk onto utility customers in the event that energy prices or technology prices decline. Consumer Power Advocates (CPA)and Nucor agree with the utilities that PPAs would represent an inappropriate imposition of risk onto customers, citing past experience with PURPA[37] contracts and contracts pursuant to PSL Section 66-c.

As an alternative, the IJU proposes a portfolio approach comprised of continued NYSERDA procurement of REC-only contracts, self-initiated market activity, and a "universal renewables" model in which EDCs would take ownership of projects built by independent developers. IJU argues that where there is uncertainty as to the best approach, a portfolio of approaches is prudent.

IJU submitted studies indicating that UOGs would be substantially less costly than PPAs, mainly because of lower utility finance costs and because UOGs would retain the residual value of facilities beyond the limited term of PPAs.

IPPNY opposes PPAs on the grounds that the contracts would insulate projects from competitive market pressures. The NYISO states that PPAs could endanger the efficient operation of markets.

Most clean energy developers and advocates are strongly in favor of the PPA approach. REI advocates that at least 85% of new renewables be procured through PPAs. REI and CEOC argues that any risk posed by PPAs is offset by hedging value in the event that prices rise above forecasted levels. REI further argues that the current proposal differs greatly from the older PURPA and 66-c situation because PPAs would be subject to competitive processes under the CES. REI also argues

[37] Public Utility Regulatory Policy Act of 1978, 16 U.S.C. §§ 2601, et seq.

that it was inconsistent for the IJU to advocate a portfolio approach while excluding PPAs from the portfolio.[38]

NFCRC and Bloom Energy are not opposed to PPAs but caution that they should not crowd out the potential for distributed generation to meet CSE obligations. EDF also urges the Commission to consider the objective of a highly distributed system when deciding on procurement options.

IPPNY opposes allowing utility-owned generation, arguing that UOGs would overturn decades of policy that favors competitive markets in which risk is undertaken by market participants and not by ratepayers. IPPNY argues that EDCs' ability to recover all costs in rates would provide an incentive to bid low and then pass cost overruns through to ratepayers.[39]

CPA supports the IJU proposal, arguing that EDCs could be held accountable for pursuing the least-cost options, and that they could only exert market power by withholding production which would be very difficult to do. EDF argues that more analysis is needed of the procurement options before the Commission commits to any one course of action. CEOC states that it would support further process to consider UOGs but only as a complement to a primary reliance on PPAs.

The Companies state that if the Commission decides to adopt a PPA approach, then NYPA should be the financial backer of the PPAs, instead of EDCs. CEOC also supports an approach where NYPA provides financial support for PPAs.

Central procurement through NYSERDA is supported from parties on both sides of the PPA/UOG division. The Companies argue that central procurement through NYSERDA should be the

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[38] Other parties supporting the use of PPAs included AGREE, Brookfield, NYSEIA, NRG, SEIA/VoteSolar, and MI.

[39] Other parties opposed to UOGs included REI, Deepwater Wind, Citizens for Local Power, EDP Renewables, NYSEIA, and NRD.

only source for RECs, and that LSEs should not be allowed to bypass the NYSERDA process by self-supplying or procuring from other sources.

Energy Infrastructure Advocates (EIA) propose a process in which a central procurement entity (e.g., NYSERDA) obtains contracts through competitive bidding and PPAs are undertaken by a central supply aggregator (e.g., NYPA). EIA states that multiple pathways should be pursued for procurement.

G. Nuclear Facilities

1. Staff Proposal

In its initial proposal, Staff described how conditions in wholesale power markets, particularly low natural gas prices, have benefited consumers but have impaired the financial viability of upstate nuclear plants, to the point where plant owners have announced the intention to close plants that are otherwise fully licensed and operational. The closure of upstate nuclear plants would have a tremendous negative impact on the State's ability to meet the greenhouse gas reduction goal in the State Energy Plan. It would result in an increase of CO_2 emissions of more than 15.5 million tons per year.

Accordingly, in the White Paper, Staff proposed a Nuclear Tier (Tier 3) to ensure the proper valuation of carbon-free power from nuclear plants. Tier 3 would entail a separate obligation for LSEs to purchase ZECs. ZECs would not be eligible to demonstrate compliance with the REC obligation. In other words, the carbon-free generation represented by ZECs is in addition to the 50% renewable generation that will be represented by RECs. Staff described Tier 3 as a bridge to a renewable future, to avoid backsliding in the State's efforts to reduce carbon emissions, and to assist the transition from nuclear to non-nuclear resources if wholesale prices remain too

low to support the existing nuclear plants during their license lives.

As there are too few owners of the affected nuclear generation facilities to create sufficient competition to determine an accurate price to be paid for ZECs, the price of ZECs would be administratively determined by the Commission. Staff originally proposed that the price be based on a review of the anticipated operating costs of the plants and anticipated wholesale prices of energy. This would result in a fair price for the environmental attribute of each facility. However, upon further consideration and in response to party comments, Staff modified its proposal, filing Staff's Responsive Proposal, described below.

2. Party Comments

A wide spectrum of comments were submitted on Staff's initial proposal, ranging from strongly held views for and against nuclear power in general, to technical points regarding the ways that a ZEC program would operate in the context of the CES mandate.

A number of parties were opposed to any support for nuclear facilities, arguing that nuclear power is not safe, clean, or carbon-free.[40] Another group of parties were strongly supportive of ZECs, for the reasons expressed by Staff but also

[40] These parties include AGREE, Council on Intelligent Energy & Conservation Policy, Promoting Health and Sustainable Energy, Indian Point Safe Energy Coalition (IPSEC), Susan Shapiro, Green Education and Legal Fund, NY Climate Action Group, and CEC. Public comments supporting this position were also filed by Assemblywoman Barbara Lifton, Assemblywoman Ellen Jaffee, the Dutchess County Legislature, the Rockland County Legislature, the Suffolk County Legislature, and the Ulster County Legislature.

because of the economic impacts of the upstate nuclear plants.[41] The strongly opposed and strongly supportive views were each represented by large numbers of participants in public statement hearings and contributors to the Commission's public comment page.

Most of the party comments on Staff's initial nuclear proposal did not fall simply into a "Yes" or "No" formula. A majority of the active parties either supported the proposal with conditions, or were neutral with concerns.

Both of the nuclear plant owners, Entergy and Constellation Energy Nuclear Group (CENG) argued that a fuel-neutral carbon standard would be a preferable approach rather than Staff's initial proposal which took financial need into account. CENG did not oppose the mechanism proposed by Staff, however, and emphasized the urgent need for action based on the refueling cycles of individual plants and the imminence of closure decisions. CENG also urged that 12-year contracts would be needed in order to provide assurance and suggested that a backstop pricing mechanism tied to the social cost of carbon be adopted to be available in the event that Staff's original proposal was found preempted under federal law.

Entergy opposed Staff's initial proposal because it was restricted to plants that are fully licensed and would thereby exclude the Indian Point facilities. Entergy argued

[41] Comments supporting this view were filed by Assemblyman William Barclay, Assemblyman Robert Oakes, Senator Rich Funke, Senator Joseph Robach, Senator Pattie Ritchie, Boilermakers Local Lodge No. 5, Business Council, City of Oswego, Greater Oswego-Fulton Chamber of Commerce, IBEW Local 43, IBEW Local 1-2, Utility Workers Union of America Local 1-2, Laborers' International Union of North America Local 633, Onondaga County Legislature, Oswego County Legislature, Operation Oswego County, Plumbers and Pipefitters Local 112, Plumbers and Steamfitters Local 73, Town of Scriba, Upstate Energy Jobs, MACNY, and New York State Utility Labor Council.

that this distinction was arbitrary, discriminatory, not rationally based, and preempted by federal law. NYC argued that the Indian Point facilities reduce total carbon, are important to reliability, and provide economic support to the community. IPPNY and the New York Affordable Reliable Electricity Alliance also argued that the Indian Point plants should be included in the ZEC mandate.

IJU supported Staff's proposal but stated that the future of nuclear plants and their treatment in wholesale markets is a national issue that will eventually need to be addressed at the national level. The Companies supported the proposal, stating that procurement of ZECs should be centralized and allocated to all LSEs.

AGREE and GELF argued that Staff did not support its assumption that maintaining nuclear facilities was a necessary component of an overall strategy to reduce greenhouse gasses. In opposition to that view, the Nuclear Energy Institute observed that the closure of only the Ginna plant (R.E. Ginna Nuclear Power Plant) would undo all of the carbon reductions obtained through the RPS program to date.

Many parties representing environmental and clean energy interests argued that any support for nuclear power must be completely separate from a Clean Energy Standard. REI, CLP, CEOC, and EDF argued that nuclear subsidies should in no event divert support for renewable generation, and ideally should be established (if at all) in an entirely separate program.

Several parties expressed concern over the way that financial need would be determined. MI stated that Staff had not supported its assumptions of financial need. Both MI and Nucor argued that any proceeding to determine a level of support should be open, as it would be comparable to a utility rate proceeding to determine the cost of service to be supported by

ratepayers. MI also argued that, because nuclear facilities are allowed to earn unregulated levels of profits while energy prices are high, any support provided to nuclear facilities to maintain them in the short-term should be subject to a clawback – i.e., return to ratepayers – when the plants return to profitability.

Otsego 2000 supported Staff's proposal but only if it is found to be the most cost-effective way to reduce greenhouse gasses. Otego Microgrid Ratepayers support the Staff approach but only if it is not open-ended and if there is a clear plan to work toward eventual closure of nuclear plants.

AGREE, in the context of strong opposition to the proposal, argued that it is not clear what value the ZEC payments would be capturing – carbon, reliability, or economic. AGREE and other parties stated that the plants have been determined not to be necessary for reliability.

NYC, CLP, and AGREE stated that a ZEC mandate should not be imposed on LSEs that offer 100% renewable energy. They argued that customers should have the option of voluntarily buying 100% green power that does not include nuclear.

3. Staff's Responsive Proposal

After considering the comments submitted in response to the White Paper and Cost Study, Staff refined its recommendations pertaining to the proposed methodology for encouraging the preservation of the environmental attributes of zero-emissions nuclear power electric generating facilities. Staff's Responsive Proposal recommends valuing and paying for the zero-emissions attributes based on a formula that begins with published estimates of the social cost of carbon.

Specifically, Staff proposes that payments for zero-emissions attributes would be based upon the U.S. Interagency Working Group's (USIWG) projected social cost of carbon (SCC).

Such payments would be provided where there is a public necessity to encourage the preservation of a facility's zero-emissions environmental values or attributes for the benefit of the electric system, its customers and the environment. Staff proposes that public necessity be determined on a plant-specific basis at the discretion of the Commission, upon considerations of the following factors: (a) the verifiable historic contribution the facility has made to the clean energy resource mix consumed by retail consumers in New York State regardless of the location of the facility; (b) the degree to which energy, capacity and ancillary services revenues projected to be received by the facility are at a level that is insufficient to provide adequate compensation to preserve the zero-emissions environmental values or attributes historically provided by the facility; (c) the costs and benefits of such a payment for zero-emissions attributes for the facility in relation to other clean energy alternatives for the benefit of the electric system, its customers and the environment; (d) the impacts of such costs on ratepayers; and (e) the public interest.

Upon a determination of facility-specific public necessity, the owner of the zero-emissions generating facility would be offered a multi-year contract administered by NYSERDA to purchase ZECs from the period beginning on the first day of the two-year tranche for which that facility was found eligible, through March 31, 2029. The facility will have an obligation to produce the ZECs and to sell them to NYSERDA for the duration of the contract, except during periods when the calculated ZEC price pursuant to the contract is $0. This contractual obligation would be enforced by appropriate financial consequences for failure to produce.

For the contract period of Tranche 1, Staff proposes that the price of the ZEC would be based upon the average April

2017 through March 2019 projected SCC as published by the USIWG in July 2015 (nominal $42.87/short ton), less a fixed baseline portion of that cost already captured in the market revenues received by the eligible facilities due to the RGGI program based upon the average of the April 2017 through March 2019 forecast RGGI prices embedded in the Congestion Assessment and Resource Integration Study (CARIS) Phase 1 report (nominal $10.41/short ton). Staff's formula yields a net cost of carbon of $32.47 (nominal $/short ton), and a ZEC price of $17.48 per MWh for the contract period of Tranche 1. For the contract periods of Tranche 2 through Tranche 6, the ZEC prices would be calculated pursuant to a formula, as follows: upstate ZEC Price = Social Cost of Carbon (average for each Tranche) - Baseline RGGI Effect (fixed at $10.41/short ton) – Amount by which sum of Zone A Forecast Energy Price and ROS Forecast Capacity Price exceeds $39/MWh. The 39/MWh reference price is used to measure the change in independent forecasts over time, it is not used to establish a quantity of energy or capacity revenues.

The amount of ZECs to be purchased annually would be based on actual output but will be capped at a MWh amount that represents the verifiable historic contribution the facility has made to the clean energy resource mix consumed by retail consumers in New York State, as specified in the NYSERDA contract.

Through contracts with NYSERDA, each LSE (including NYPA and LIPA) would be required to purchase an amount of ZECs per year of the total amount of ZECs purchased by NYSERDA in proportion to the electric energy load served by the LSE in relation to the total electric energy load served by all load serving entities in the New York Control Area. The price charged by NYSERDA per ZEC would be the price established administratively by the Commission for the purchase of zero-

emissions attributes, plus NYSERDA's incremental administrative costs and fees associated with the ZEC program and ZEC revenues.

The contracts between NYSERDA and the LSEs would be based on initial forecasts of load and utilize a balancing reconciliation at the end of each program year such that each LSE would have purchased the correct proportion of ZECs on an annual basis. Staff proposes that ZECs not be tradable except between NYSERDA and the LSEs in this balancing process. Finally, Staff suggests that the Commission entertain proposals by LSEs and perhaps self-supply customers to alternatively meet their ZECs obligations by entering into combined energy and/or capacity and ZEC contracts with the nuclear facilities if such contracts are structured in a way as to not unfairly shift ZECs costs onto other ratepayers.

4. Party Comments to Responsive Proposal

Comments related to Staff's Responsive Proposal represent a broad range of topics and viewpoints. Both comments supporting and those opposing the proposal cite environmental and economic reasons to support or oppose the proposal. Many comments opposing the proposal claim the review process was too truncated for such a long-lived program.

A vast number of comments from individuals members of the public were submitted either opposing or supporting Staff's Responsive Proposal. A large number of State and local officials submitted comments. Support for the proposal among public officials is strong but not universal. Those opposing the proposal state that nuclear power is not renewable and is detrimental to the environment. They argue that the State would be better off investing in renewable energy.

State and local officials expressing support for Staff's proposal state that Staff's Responsive Proposal is a reasonable approach to maintaining emission levels and an

overall benefit for the environment. They also note the positives related to the local and regional economy.

Similarly, comments among environmental groups are divided. A number of environmental advocates oppose supporting nuclear, particularly for the 12 years Staff proposes. Citizens' Environmental Coalition (the Coalition) opposes the Responsive Proposal claiming that no environmental impact analysis or alternative analysis was performed. The Coalition, as well as other parties, also suggests that investing in renewable energy solutions would be more cost-effective. AGREE also argues that nuclear generation is dirty and dangerous and laments that the proceeding is no longer singularly focused on supporting large-scale renewable energy.

Many parties generally support the program as a means of limiting greenhouse gas emission until higher penetration of renewable generation is achieved including Pace Energy and Climate Center (Pace) and Californians for Green Nuclear Power. Environmental Progress supports the program arguing that nuclear power must play a central role in the effort to combat climate change and that closure of the upstate plants will result in increased emissions. It claims that New York's power sector emissions, per-capita, are 25% of the national average in part, because nuclear power generated 57% of the State's zero-emissions power last year.

Supporting comments also point toward the benefits of fuel diversity and protection against price volatility. The Indicated Joint Utilities expressed support for Staff's Responsive Proposal because the proposed program will ensure the continuance of the environmental benefits of the plants' emission attributes that is not being captured by existing markets.

Many commenters including Pace and the Indicated Joint Utilities support Staff's incorporation of the SCC into the ZEC price calculation as a step toward properly internalizing the true cost of carbon emissions including Pace and the Institute of Policy Integrity at New York University School of Law.

The American Petroleum Institute (API) and MI both question the use of the SCC because they argue, it has not been properly vetted or demonstrated to accurately reflect cost savings related to avoiding carbon emissions. MI further questions adjusting the SCC for inflation when future estimates of the SCC increase over time.

Public Utility Law Project (PULP) believes that the proposal does not properly consider the social costs of nuclear storage, radiation leaks, decommissioning and other attendant costs.

CENG supports basing the ZEC on SCC but notes that it likely undervalues the nuclear facilities environmental attributes because it does not account for other air pollutants avoided. CENG also notes that tying the ZEC price to the cost of carbon leaves the nuclear generators exposed to operating and market risks.

Many comments raised issues or concerns related to the cost of the ZEC program. However, many comments also indicate that the costs seemed reasonable.

Upstate Energy Jobs supports the program, and along with others, believes that the costs associated with the program are outweighed by the benefits including avoiding energy and economic costs related to the facilities shutting down. Similarly, many public officials and community leaders support Staff's proposal as a cost effective means of limiting emissions and transitioning to the 50% by 2030 goal.

AGREE claims that Staff's Responsive Proposal amounts to the largest gift of public funds to a single corporation in the State's history. Nucor also expresses concern regarding subsidizing the sale of FitzPatrick (James A. FitzPatrick Nuclear Generating Facility) arguing that New York rate payers should not need to provide financial support for transactions between private parties.

Many commenters argued that any program designed to value emission attributes would be more cost efficient and fair if it was technology neutral including Potomac Economics and API. Similarly, AGREE objects to the fact that even lower cost resources would be prevented from competing with nuclear facilities. The Institute of Policy Integrity argues that inconsistent valuation methods for emission attributes (market versus administratively set) across generation types could lead to a situation where consumers are paying more for ZECs than RECs resulting in an unfair advantage for nuclear generation. Ampersand Hydro, LLC and others argue that the program contradicts the rest of the CES proposal as well as the REV framework. CENG notes that the proposed ZEC price is well below subsidies for renewable energy including the average subsidy paid by NYSERDA and the federal production tax credit.

The NGSA opposes Staff's proposal, stating that the Commission should allow market forces to establish a path for carbon reduction. NGSA argues for preserving competitive market signals through: implementation flexibility; fuel and technology neutral incentives; and fostering the regional market.

MI raised cost concerns specific to high-load-factor customers which it states are disproportionately impacted by the CES costs. MI states that any economic benefits relied on to support the program must be weighed against the negative

economic impacts of higher-cost electricity – particularly the economic impacts on high-load customers.

New York City opposes the program because it feels that it will impose costs on downstate consumers who are unable to receive its direct benefits. The City argues that due to geography and system constraints that it is unlikely that the electricity or the economic benefits expected from the program will be enjoyed downstate. The City argues that costs associated with the program should be allocated to follow the benefits.

Individuals and groups located downstate submitted comments supporting the program including ArtsWestchester and New York City Hispanic Chamber of Commerce. National Grid argues that the beneficiaries are statewide and encourages inclusion of NYPA and LIPA in the ZEC program.

PULP challenges the Responsive Proposal over concerns that it will have a disproportionate impact on low-income and fixed-income customers. PULP argues that further analysis must be done to measure the impact of the program on the State's goal of a 6% energy burden for low-income customers.

NEMA argues that the support for emission free generation outside of the wholesale market is likely to disrupt markets and result in high cost to consumers because it would be outside the NYISO's least cost dispatch model.

The NYISO evaluated Staff's proposal pursuant to its market monitoring and mitigation obligations and concludes that Staff's proposal does not raise wholesale market power concerns. The Indicated Joint Utilities agree that the ZEC price must be administratively set because of the limited number of suppliers and the potential for market power issues to arise.

Some commenters challenge specifics contained in Staff's proposed formula for setting the ZEC price. MI

challenges the use of a 3% discount rate, suggesting a 5% rate would be more appropriate and less expensive. MI, the Indicated Joint Utilities and others argue that RGGI values should not be held constant. MI argues that RGGI could have a much higher impact if RGGI total allowances are reduced, as is being contemplated. The Indicated Joint Utilities argue that RGGI prices should follow the CARIS model to increase over time.

The Indicated Joint Utilities further argue that the emission factor should be updated in future tranches (to calculate how much carbon is avoided per MWh), to reflect changes in the resource mix. Some commenters suggested that the contract between NYSERDA and the nuclear generators should include performance factors to hold the generators accountable for performance.

NEMA raised concerns about the impact of the ZEC mandate on ESCOs expressing concern that ESCOs may not recover the cost of compliance. Specifically, NEMA requests that the Commission clarify that ESCOs can recover ZEC compliance costs from customers under "regulatory change," "change in law" or similar contract provisions without violating any disclosure requirements.

Nucor states that it supports continued operation of the upstate nuclear facilities but only at a reasonable cost, which it claims cannot be assured through Staff's Responsive Proposal. Nucor claims that its own analysis indicates that the proposal would overpay Constellation by overstating costs and unnecessarily including all upstate nuclear facilities.

Nucor and MI both believe that before any nuclear plant be eligible for subsidies they must demonstrate that they would otherwise deactivate the facility. Other parties, including New York City question whether and to what extent nuclear plants have demonstrated a need for any subsidy.

Nucor also suggests limiting ZEC contracts to three-years (with reapplication allowed) as another means of limiting program costs. National Grid believes that 12 years is too long because of the need to transition away from nuclear and into renewables. National Grid also argues that the best long-term solution is reforming the markets in order to properly internalize the cost of carbon.

Nucor points out that Exelon has disclosed to the investment community that through forward power sales from its existing New York units, it has largely hedged the prices that Constellation expects to realize at levels that are considerably higher that the near-term forward price indices. According to Nucor, Exelon has stated that it expects these forward sales to produce $105 million in additional gross margin which NUCOR points out is not captured in Staff's Responsive Proposal.

New York City raises concerns regarding customers choosing to purchase renewable power over and above any mandate arguing that cost imposed related to ZECs will limit the monies available to support renewables. Many commenters echoed the comments from the City of Kingston which points out that because the mandate will be allocated across all retail customers, it becomes impossible for customers to pay only for renewable energy and be 100% renewable.

A number of commenters are dissatisfied with the time frame in which the Commission is acting on the ZEC program generally and Staff's Responsive Proposal. The New York Public Interest Research Group, Reinvent Albany and Common Cause New York as well as others submitted comments requesting more time to review the proposal. AGREE filed comments expressing concern that Staff's Responsive Proposal introduces new concepts, new obligations for utilities and new costs and that it reaches conclusions related to eligibility for specific units without

the required analysis. MI also raises concerns that Staff's Responsive Proposal has not been fully evaluated.

Other comments urged the Commission to act swiftly to ensure the economic and environmental benefits associated with keeping the plants operational.

Many commenters raised concerns relating to timing and the interactions between Case 16-E-0270 related to specific generation facilities and 15-E-0320 addressing support for environmental attributes of nuclear energy more broadly. Nucor and MI both argued that the Commission should refrain from responding to the petition until it has responded to Staff's Responsive Proposal.

Some parties claim that Staff's Responsive Proposal lacks the necessary detail or analysis to be fully evaluated. AGREE and MI raise a concern regarding the apparent lack of analysis regarding the cost and benefits of nuclear generation in comparison to other emission free resources. MI points to additional concerns including details regarding what would constitute an appropriate financial consequence for a nuclear facility's failure to produce ZECs. AGREE further points out that one factor for considering a public necessity determination is the cost and benefits of such a subsidy in relation to other clean energy alternatives but claims that no such analysis is available to support Staff's recommendation.

NEMA claims that the process violates the State Administrative Procedures Act because it failed to provide adequate notice or a meaningful opportunity to comment on the Responsive Proposal. NEMA further claims that Staff's Responsive Proposal is the same type of regulatory action invalidated by the Court in Hughes v Talen Energy Marketing,

LLC.[42] Similarly, NSGA cautions that the ZEC proposal intrudes on FERC jurisdiction.

New York City states that the proposal lacks a discussion of the Commission's statutory authority to mandate that load serving entities enter into contracts with NYSERDA to purchase ZEC's and that the City is unaware of any such authority. PULP similarly states that the legal underpinnings are not sufficiently developed.

Ampersand Hydro raises the concern that if other non-emitting resources do not receive similar or greater value for their attributes, it would amount to an unconstitutional taking of the property of those facilities.

NYAPP argues that the Commission should exempt municipal and cooperative utilities from the ZEC requirement. NYAPP points out that as a group, 86% of NYAPP power comes from NYPA's Niagara Project, and through utilization of this low-cost renewable source, the group demonstrates a meaningful contribution to the State's renewable goals even absent mandatory requirements.

LIPA Staff submitted comments stating that it intends to seek the approval of its Board of Trustees to enter into the necessary agreements to procure its appropriate share of zero-emissions credits and to receive its appropriate share of such revenues as co-owner of the Nine Mile Point 2 Nuclear Station. Similarly, NYPA states that it fully intends to comply with the Staff Proposal, subject to any directive from its Board of Trustees following finalization of the initiative. MI and others state that NYPA customers should not pay any ZEC cost, as they have the ability to leave the State and go where there is no subsidy for the nuclear plants. They state that NYPA rates

[42] Hughes v Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1292 (2016).

are for economic development, and such rates have not traditionally been charged for similar subsidies

H. Cost Study and Cost Management

1. Summary of the Cost Study

The Cost Study makes detailed projections to 2023. Beyond 2023, the combination of variables makes detailed projections less reliable.

Critical findings of the Cost Study are total bill impacts to customers of less than 1% under the base case scenario, with net benefits of $1.8 billion taking into account $3.1 billion in carbon savings.

Assumptions in the base case scenario through 2023 include:

- a 50/50 split between long-term PPAs and annual REC procurements;
- carbon values established by the Environmental Protection Agency and adopted in the Commission's Benefit Cost Analysis framework;
- a calculation that netted the gross program costs – i.e., the additional payments above energy and capacity that will be required to make projects viable – against the societal value of avoided carbon dioxide emissions;
- inclusion of Tier 3 nuclear costs and benefits;[43]
- no costs or benefits of grid integration beyond costs borne by project developers;
- no offshore wind by 2023; and

[43] The study noted several indirect benefits of maintaining nuclear plants that were not included in the calculations. These are 28,800 jobs, $3.16 billion in direct or secondary GDP, and $144 million in State tax revenues.

- no distributed resources beyond the existing NY Sun goals.

The Study includes sensitivity analyses across major variables including procurement method, total power usage, and energy prices. The difference between 100% long-term procurement through PPAs and 100% reliance on RECs is estimated to be over $1.4 billion by 2023. The Study does not include a utility-owned generation option, but it notes that UOG has the potential to reduce costs below those of PPAs.

The Study considers a high energy usage scenario of 22,000 additional GWh (which could be caused by numerous factors). The gross cost of compliance doubles under the high usage scenario.

High and low energy price scenarios, applied to the base case, result in a difference of 0.65% in bill impacts directly tied to the CES. The context of this sensitivity is very important. Lower energy prices increase the relative cost of CES compliance, but those higher CES premiums are paid in a context of lower overall energy bills. Conversely, higher energy prices reduce the relative cost of CES premiums but in the context of higher overall bills. The conclusion of the Study is that, while fluctuations in energy prices will have a strong effect on the gross cost of CES compliance, they will have a moderating effect on relative bill impacts of the CES.

The Study also notes that the value of PPAs is likely to increase in the years following 2023, as energy prices rise and the size of the required CES premium is reduced relative to new procurements.

Federal tax credits have a substantial impact on program costs. The base case assumes the currently scheduled phase out of credits. The Study also considers potential

changes in interest rates and technology costs and found that they have a relatively minor impact on costs.

Although the Study does not incorporate any estimated benefits from REV, it notes that an increase in economically responsive demand measures could have a substantial beneficial effect on total CES compliance costs, and will establish conditions to increase renewable procurement on an economic basis.

2. Party Comments

Comments on the Cost Study vary widely, with some parties arguing that important benefits have not been considered, while others argue that important costs have been omitted. CEOC and REI comment that the Study demonstrates overall net benefits and minimal bill impacts, and REI notes that the bill impacts were consistent with a comprehensive study of other states' renewable programs conducted in 2014 by the National Renewable Energy Laboratory (NREL).

Numerous parties comment that the Study was lacking in detail and transparency, to the point that it was not adequate to support a full decision on the issues.[44] A subset of these parties (Business Council, MI, and IPPNY) argue that due to uncertainty in the Cost Study the Commission should refrain from imposing any mandate at this time. NYC argues that the Commission should refrain from committing to a single procurement strategy. Other parties argue that uncertainty is best addressed through mandates, for example, that due to the sensitivity of overall costs to various load growth scenarios, the Commission should mandate energy efficiency targets. The Labor Coalition argues that the uncertainty of Tier 1 estimates reinforces the need to rely on nuclear facilities to achieve

[44] These parties include AGREE, Brookfield, Business Council, NYC, IPPNY, IJU, MI, and Nucor.

carbon goals. IJU agrees with limiting the mandate and schedule to 2023 due to the difficulty of estimating beyond that point.

The cost assumptions in the Study produce a wide range of comments. Many parties emphasize that there is little treatment of the potential costs of transmission upgrades.[45] MI and the Business Council argue that impacts on Installed Reserve Margins are also ignored; the API argues that the need for backup gas-fired capacity is not analyzed. IPPNY, IJU, and MI state that the energy price forecasts used in the Study may be too high, which has the result of lowering forecasts of net costs from the CES. MI notes that the subsidies provided to renewables coming on line in the 2017-2019 period are not factored into the analysis although the carbon benefits of those projects are included. NYC argues that the bill impact estimate covers the CES but not the nuclear mandate. AGREE argues that the estimated costs of nuclear support are understated. Nucor and Pepacton note that administrative costs of procurement are not identified.

Parties also note potential benefits, and cost-mitigating factors, that are not included in the Study. NYC, IJU, CEOC, and REI argue that other environmental benefits such as reductions in criteria pollutants should be counted. IJU objects to the absence of an analysis of utility-owned generation, and submitted a study concluding that a utility-owned generation option could reduce costs by 21% compared with PPAs. By contrast, several parties argue that PPAs are the most cost-effective procurement approach. REI argues that the potential for technology cost reductions is understated. Brookfield and LIHI argue that carbon benefits of Tier 2b procurements should have been counted, and that low-impact hydro

[45] These parties included IPPNY, NYC, the Business Council, Entergy, IJU, MI, and Nucor.

benefits are understated. Several parties argue that biogas can have a much more cost-beneficial role than is estimated in the Study. AGREE argues that the costs of replacing nuclear facilities with additional renewables has not been analyzed but that this could reduce the overall cost of the program. Pepacton notes that the benefits of distributed resources are not fully incorporated into the Study.

Several parties identify comparisons that are not made in the Study. NYC and Nucor argue that the cost of more energy efficiency should have been compared with the cost of renewables to achieve the State's goals. API states that the macroeconomic effects of CES should have been compared with alternative ways of achieving the goals. IPPNY states that the macroeconomic effect of plant retirements should have been accounted for. MI questions the basic premise of the netting of monetary costs against carbon benefits, noting that the monetary costs will be carried by New Yorkers while the benefits are global.

V. ESTABLISHING THE CLEAN ENERGY STANDARD

A. General Description

The Clean Energy Standard adopted here begins with adoption of the State Energy Plan goal that 50% of New York's electricity is to be generated by renewable sources by 2030, as part of a strategy to reduce statewide greenhouse gas emissions by 40% by 2030. To implement that goal, the CES is further comprised of a series of deliberate and mandatory actions to enhance opportunities for customer choice necessary to achieve the SEP goal. The mandated actions are divided into two categories, a Renewable Energy Standard and a Zero-Emissions Credit requirement. The RES consists of a Tier 1 obligation on LSEs to invest in new renewable generation resources to serve their retail customers; a Tier 2 obligation on distribution

utilities on behalf of all retail customers to continue to invest in the maintenance of existing at-risk generation attributes; and a program to maximize the value potential of new offshore wind resources. The ZEC requirement consists of a Tier 3 obligation on LSEs to invest in the preservation of existing at-risk nuclear zero-emissions attributes to serve their retail customers. The RES component and the ZEC component are interrelated but the goals are additive; that is, the carbon benefits of preserving the nuclear zero-emissions attributes will not count toward achieving the required number of renewable resources to satisfy the 50% by 2030 goal. The RES and ZEC components will however, in combination, contribute toward the State's comprehensive greenhouse gas reduction goals.

B. Legal Authority

The Commission's authority derives primarily from the New York Public Service Law (PSL), through which numerous legislative powers are delegated to the Commission. Pursuant to PSL §5(1), the jurisdiction, supervision, powers and duties of the Commission extends to the manufacture, conveying, transportation, sale or distribution of electricity. PSL §5(2) requires the Commission to encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources. PSL §66(2) provides that the Commission shall examine or investigate the methods employed by persons, corporations and municipalities in manufacturing, distributing and supplying electricity and have power to order such reasonable improvements as will best promote the public interest, preserve the public health and protect those using

such gas or electricity. PSL §4(1) also expressly provides the Commission with all powers necessary or proper to enable [the Commission] to carry out the purposes of the PSL including, without limitation, a guarantee to the public of safe and adequate service at just and reasonable rates,[46] environmental stewardship, and the conservation of resources.[47]

In addition to the PSL, the New York Energy Law §6-104(5)(b) requires that "[a]ny energy-related action or decision of a state agency, board, commission or authority shall be reasonably consistent with the forecasts and the policies and long-range energy planning objectives and strategies contained in the plan, including its most recent update." The program established here is consistent with the renewable and clean energy targets established in the 2015 New York State Energy Plan, as well as the underlying principles elucidated in the Plan.[48] Therefore under State law, the Commission's authority to direct a comprehensive CES program is quite clear.

Federal law preempts contrary state law pursuant to the Supremacy Clause of the U.S. Constitution. Under the Federal Power Act, the FERC has exclusive authority to regulate the sale of electric energy at wholesale in interstate commerce.

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[46] See International R. Co. v Public Service Com., 264 AD 506, 510 (1942).

[47] PSL §5(2); see also, Consolidated Edison Co. v Public Service Commission, 47 NY2d 94 (1979)(overturned on other grounds) (describing the broad delegation of authority to the Commission and the Legislature's unqualified recognition of the importance of environmental stewardship and resource conservation in amending the PSL to include §5).

[48] See 2015 New York State Energy Plan available at http://energyplan.ny.gov/Plans/2015.aspx (setting a target of 50% renewable consumption by 2030 and describing "guiding principles" including "Market Transformation"; "Community Engagement"; "Private Sector Investment"; "Innovation and Technology;" and "Customer Value and Choice."

States retain the power to regulate the retail sale of electricity to end-use consumers. All Commission actions must take place within the "cooperative federalism"[49] structure of energy regulation and the myriad state and federal court cases each shedding its own light on the jurisdictional boundaries. FERC has previously said that REC programs, purchasing "attributes," are for a commodity created by states that is not within the wholesale sale of electricity jurisdiction of FERC. Recent U.S. Supreme Court cases also make it clear that all retail sales of electricity, as well as "any other sale" not considered a wholesale transaction, are under State Commission authority.[50] The directives to LSEs and distribution utilities under consideration in these proceedings are only related to retail sales of electricity and carbon-free energy generation attributes (RECs and ZECs), Commission jurisdiction over which is well established and settled.[51]

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[49] See FERC v Elec. Power Supply Assn, 136 S. Ct. 760 (2016); The Federal Power Act (June 10, 1920, ch. 285, pt. III, § 321, formerly § 320, as added Aug. 26, 1935, ch. 687, title II, § 213, 49 Stat. 863; renumbered Pub. L. 95-617, title II, § 212, Nov. 9, 1978, 92 Stat. 3148).

[50] Hughes v Talen Energy Mktg., LLC., 136 S. Ct. 1288, 1292 (2016) and FERC v Elec. Power Supply Assn, 136 S. Ct. 760, 766 (2016)(explaining that the Federal Power Act places any sale of electricity other than those at wholesale beyond the jurisdiction of the Federal Energy Regulatory Commission).

[51] Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1291 [2016]; see also WSPP, Inc., 139 F.E.R.C. 61,061 (2012)(explaining the REC transactions unbundled with wholesale energy and capacity are beyond FERC's jurisdiction); and Morgantown Energy Associates, 139 F.E.R.C. 61,066 (2012) (recognizing that RECs are state-created and are a separate product from energy and capacity); American Ref-Fuel Company, 105 F.E.R.C. 61,004 (2003)(explaining that RECs are a state law creation and not within FERC's jurisdiction).

"Wholesale" sales include "energy" and "capacity" sales among other types of wholesale sales. Federal Law gives FERC the responsibility to ensure that prices charged in wholesale sales are just and reasonable. In deregulated markets like New York, wholesale transactions typically occur through two mechanisms: bilateral contracts and auctions. For bilateral contracts between generators and LSEs, FERC may review the rate in the contract for reasonableness, although FERC generally presumes that rates established by good-faith arm's-length negotiation are reasonable. FERC may abrogate an otherwise valid bilateral contract if it harms the public interest, or it may apply buyer-side mitigation in the marketplace to counteract what it perceives to be the negative effects of the contract. Auctions in New York are conducted by the NYISO pursuant to a FERC-approved tariff. The clearing price if based on a reasonably competitive auction is generally accepted by FERC as being the basis for a just and reasonable rate. Once FERC sets wholesale rates, a state may not conclude in setting retail rates that FERC-approved wholesale rates are unreasonable. A state must give effect to Congress' desire to give FERC plenary authority over interstate wholesale rates, and FERC and the courts will ensure that the states do not interfere with this authority. States may not seek to achieve ends, however legitimate, through regulatory means that intrude on FERC's authority over interstate wholesale rates. States may encourage production of new or clean generation through measures "untethered" to a generator's wholesale market participation.[52]

C. Cost Study and Cost Mitigation

The Cost Study demonstrates that CES targets through 2023 can be achieved with net societal benefits and modest bill

[52] See Hughes, supra 136 S. Ct. 1288, 1299 (2016).

impacts, taking into account critical known facts, projected trends, and sensitivities around major variables. The comments of parties, both supportive and challenging of the Cost Study conclusions, illustrate that there are numerous detailed factors that will unfold during the implementation of the CES.[53] Parties who argue that the Cost Study is incomplete unless it has integrated all of the factors they enumerate miss the basic function of the Study in the context of the CES. The purpose of the Clean Energy Standard is to transform the electric system. It is not an isolated, discretionary spending program. The CES implements State policy decisions that are made necessary in part, and urgent, by a global problem that challenges traditional administrative and jurisdictional approaches.

Consideration of the Cost Study is driven by the dual statutory charges of providing for just and reasonable rates and achieving reasonable consistency with the State Energy Plan. In this context, the chief purpose of the Cost Study is to estimate a range of cost and bill impacts, to inform the determination whether the CES is likely to achieve its goals within a reasonable range of estimated bill impacts.

To accomplish this purpose, the Study used best estimates of critical cost and benefits elements and applied sensitivity analyses across several important variables. To avoid overreaching beyond what can be foreseen with a reasonable degree of confidence, the Study limited its scope to the period concluding at the end of 2023. The findings of the Study demonstrate both a reasonable range of bill impacts and a net

[53] Some of the parties' objections are factually incorrect. For example, an estimate for the cost of transmission upgrades is reflected in the Study at page 256. Also, the Study counts neither the costs nor the benefits of Tier 1 2017-2019 installations (pg. 284), as support for those projects is already approved.

societal benefit. By its nature, transformative change cannot rest on precise long-range forecasts of the very matters that are undergoing transformation. Several parties argued that the consequence of uncertainty should be inaction. It is certain, though, that the consequences of inaction on air pollution and climate change are not acceptable.

MI observed that the costs of renewable purchases will be borne locally, while the benefits of carbon reduction will be dispersed globally. Conversely, CEOC and others argued that other environmental benefits should have been counted. The treatment of externalities was subject to comment and was determined in the adoption of the Benefit Cost Analysis framework.[54] A narrow view of costs and benefits might limit environmental benefits to those experienced solely within New York. In the case of climate change, such an approach could lead to inaction not only in New York but in all other jurisdictions.

MI's point is important, however, in illustrating both the value for combined action and the need for leadership. The State Energy Plan determined that New York take its place among the leaders in this effort. Under the CES, New York's goals are comparable to those of California and Oregon. Of the 29 states that have adopted renewable portfolio standards, several more either have adopted or are considering increased goals.[55] The CES strikes a reasonable balance between the lowest common denominator of inaction, which is unacceptable, and aggressive unilateral action with its attendant economic risks.

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[54] Case 14-M-0101, supra, Order Establishing the Benefit Cost Analysis Framework, January 21, 2016, pg. 17.

[55] See, e.g., Cal S.B. 350 (adopted February 14, 2015); Oregon S.B. 1547 (2016); Hawaii H.B. 623 (2015); Vermont H.B. 40 (2015).

On a similar note, several parties argued that the efficacy of New York's CES will be limited unless RGGI caps are also reduced. The setting of RGGI caps is a multi-state endeavor that also must be coordinated with plans to comply with the federal Clean Power Plan. Monitoring of this effort and its impact on RES targets, will be a subject for periodic review. Uncertainty around the future direction of RGGI further illustrates the importance of leadership shown by New York.

In adopting the CES, the Commission is implementing policy as developed by the statutory State Energy Plan process and in furtherance of the Commission's responsibilities pursuant to the PSL. The Cost Study is an essential way to inform the Commission's decision, and it demonstrates that the balanced approach of the CES as adopted is within a reasonable range of potential impacts.

A second important purpose of the Cost Study is to inform the development of the CES by identifying controllable variables that can be used to mitigate potential costs. The CES framework adopted here contains several mitigation measures, including continued aggressive pursuit of energy efficiency through various proceedings; the Alternative Compliance Payment option; adjustment of targets via triennial review to optimize targets in response to market developments; interim review as a safeguard against divergences; the banking of RECs; the consideration of the contributions of voluntary market activity; and Distributed Energy Resource integration via the REV initiative, so that load management and system balancing can improve the economic value of weather-variable generation. A related purpose is the identification of factors which, although not controllable, influence cost and should be considered. Examples include federal tax credits, interest rates, etc.

In a late filing, the NYISO stated that substantial transmission upgrades may be needed to move power from traditional generation centers to load centers. The NYISO also stated that a large increase in reserve margins will be needed to account for weather-variable generation. The NYISO further stated that it intends to develop long-term market mechanisms to retain nuclear generation.

The Commission agrees with the NYISO to the extent its comments are suggesting that the Commission must consider the reliability impacts of a change in the resource mix. Ensuring both the reliability and efficiency of the power system is one of the Commission's chief responsibilities. Under REV, the design and operations of the distribution grid will be modernized to take advantage of information and technology innovations that enhance value to consumers. The positive effects of these changes are already materializing. While the NYISO is a public entity regulated by FERC, as a significant participant in the State's power system, New York consumers need a NYISO that possesses the knowledge and skill sets to match the sophistication and transformation being made in the power system to ensure that consumer needs for a reliable power system are met in as an efficient way as possible. The Commission is confident that the NYISO is up for these challenges and will look forward to its continued cooperation.

The Public Service Law requires the Commission to ensure that utilities provide safe and adequate service. In carrying out its responsibilities, the Commission cannot and will not compromise the safety and reliability of New York State's electric system, both at the bulk system and distribution levels. For this reason, two years ago, DPS initiated the SRP working group primarily to study the potential

effects on reliability and to determine the tools needed to address any concerns identified.

The NYISO's filing describes outcomes that could potentially occur if the Commission were not proactive in considering the issues of grid reliability and system efficiency. The NYISO's filing represents a status quo outlook that fails to take into account a likely shift in system characteristics and generation location, the ongoing SRP process, the opportunities to deploy new fast-acting resources like storage and the overall system and operations of modernization that will address many of the expressed concerns.

The NYISO's declaration of transmission needs of over 1,000 miles of incremental bulk power transmission lines, above and beyond those in the AC Transmission and Western New York public policy initiatives now underway, assumes no actions beyond the current status quo. Notably, its position appears to ignore the consequential retirements of upstate fossil-fueled generating plants, the diversity of renewable resource output, and the probability of offshore wind, as well as other resources and technologies that are developed closer to load being a substantial component of the 2030 generation mix.

Similarly, the NYISO's simple declaration that reserve margins may need to increase overlooks the operational characteristics and benefits of a modernizing grid. New York and other states are experiencing a tremendous growth in entrepreneurial innovation and customer participation toward a grid that both incorporates storage technologies and is characterized by increasing levels of dynamic load management, both of which will complement the variable nature of some renewable generation.

Even under a status quo approach, the NYISO's concern about the reserve margin seems misplaced. As the NYISO itself

has stated, the increased capacity requirement will be largely met by the additional capacity contribution of the proposed renewable resources.[56] Importantly, the capacity market is valued in "unforced capacity" (UCAP) MWs and prices, and therefore, intermittent resources receive capacity payments that reflect their relative contribution to serving peak loads. The dynamic load management made possible by modernizing the grid, including new storage, will have a leveling effect on the difference between fossil-fueled and renewable generation that exists under the status quo.

This Order has been painstakingly designed to produce needed reforms and carbon reductions while protecting utility customers and maintaining an effective wholesale market and ensuring the continued bulk electric system reliability that New Yorkers expect and require. The SRP working group was created largely in response to a DPS request that the NYISO and transmission owners identify any potential reliability concerns and address how to deal with these concerns going forward. Nonetheless, if the SRP process itself does not sufficiently deal with potential bottlenecks or the need for new transmission lines, it is important for all stakeholders to continue to work towards the necessary solutions. Further, it is important that the design and operation of the bulk electric system and wholesale markets be modernized, much like is being done at the distribution level. Therefore, Staff is directed to engage stakeholders, including the NYISO, after the initial SRP working group completes its work, to ensure that the bulk transmission system is sufficiently modernized such that it can fully support the State's renewable goals. Further, the Commission through its triennial review process will have ample opportunity to

[56] NYISO July 8, 2016, Supplemental Comments on the Clean Energy Standard, p. 10.

review the bill and system impacts of the ever changing system topology and ensure that appropriate actions are taken to protect the public interest in secure and cost effective electric service.

D. Adoption of the 50% by 2030 Goal

The statewide goal of 50% renewable resources by 2030 encompasses a wide range of initiatives, of which a requirement on load serving entities is only one. The 50 by 30 goal is itself a component of a larger statewide greenhouse gas goal, and is the product of a lengthy State Energy Planning process. The 50 by 30 goal is also consistent with goals adopted by other leading states.

MI questions why the 50 by 30 goal is assumed to be a reasonable starting point. From the standpoint of fuel diversity, a goal of at least 50% renewable resources by 2030 is imperative. The 2014 generation mix for New York included 37% natural gas, 31% nuclear, and 27% renewable resources as well as small amounts of coal, oil, and solid waste. As the licenses of half of the upstate nuclear generation units expire by 2030, a renewable resource goal of at least 50% will be needed to avoid an over-reliance on a single fuel.

The Cost Study indicates that 50 by 30 is reasonably achievable. The Commission has even greater concern over the potential cost of a less ambitious standard that would leave consumers vulnerable to an over-dependency on natural gas and uneconomic bypass by many consumers if the economic and performance advances in renewable and distributed energy resource and load management technologies are not accommodated. The resiliency advantages of clean power choices, and the economies of scale and scope that can be achieved through ambitious standards and well-designed retail markets that

support consumer-motivated transactions, are the best path to a better energy future.

Concerns on whether the 50 by 30 goal may impose too high a regulatory burden conflate the State's overall clean energy goal of 50 by 30 with the more discrete effort to establish mandatory resource obligations on LSEs. The 50 by 30 goal is a cumulative outcome that will be achieved through a number of activities in addition to the LSE mandatory obligation.

Understandably, given the task of developing a mechanism to achieve the CES, the bulk of the record concerns itself with the mandatory aspect of the RES. However, in establishing a mandatory RES obligation on jurisdictional LSEs, the Commission first considered the activities that occur outside of this process that will necessarily impact the scope of compulsory elements of the plan. Those activities include the existing inventory of baseline renewable resources including the sizable state-owned renewable resources; aggressive pursuit of cost effective energy efficiency; a continued obligation and opportunity for utilities to ensure that low-income consumers have access to clean energy alternatives that help them reduce their energy burden and improve the environment; consumer initiated green energy purchases or investments; State initiated green energy purchases or investments for energy consumption by State entities; and continued participation and leadership in RGGI and support of universal complementary federal action.

Gas and nuclear industry representatives argued that rather than a renewable resources goal, the Commission should adopt a source-neutral carbon intensity goal. The carbon reductions associated with the 50 by 30 goal, however, are not the only objective of the CES. Increasing fuel diversity is another goal, and even more importantly, the CES is one

component of a long-term strategy that aims to transform and de-carbonize the way in which electricity is generated.[57] For those reasons the chief focus of the CES initiative is on building new renewable resource power generation facilities.

In consideration of the discussion above, the Commission finds and determines that the goal of the SEP that 50% of New York's electricity is to be generated by renewable sources by 2030, as part of a strategy to reduce statewide greenhouse gas emissions 40% by 2030, is reasonable and necessary to provide for the safe and adequate service of retail electric consumers in New York State and in a manner that promotes economy, efficiency, and care for the public safety, the preservation of environmental values and he conservation of natural resources. Therefore, the 50% by 2030 goal is hereby adopted by the Commission as a foundational basis and essential component of the Clean Energy Standard.

VI. THE RENEWABLE ENERGY STANDARD

A. Tier 1 - New Renewable Resources

1. Overall Incremental 2030 Statewide Target

Tier 1 of the RES consists of obligations on LSEs to invest in new renewable generation resources to serve their retail customers. The obligation is to be in the form of the procurement of new renewable resources, evidenced by the procurement of qualifying RECs, acquired in quantities that satisfy mandatory minimum percentage proportions of the total load served by the LSE for the applicable calendar year. In order to establish annual incremental targets, it is necessary to first establish a calculation methodology to translate the

[57] The relative carbon intensity of gas-fired generation is already taken into account in the RGGI market.

SEP goal of 50% renewable resources by 2030 into an incremental 2030 target for achieving the goal.

a. Calculating Statewide Load

The first step in the calculation methodology is to determine forecasted statewide load for 2030. Staff relies on the NYISO Gold Book forecast to estimate the total load expected in 2030. Since the Gold Book forecast only extends ten years, Staff extrapolates the forecast values to 2030 using a linear extension of the rate in the most recent Gold Book forecast. The Commission agrees that this is a reasonable starting point and will adopt this approach as the initial basis for the determination. Under this approach the unadjusted forecast statewide load for 2030 is 176,619,000 MWhs.

b. No Behind-the-Meter Generation Adjustment

Staff proposes to modify the base forecast by the addition of customer usage that is currently offset by behind-the-meter renewable generation. Staff proposes, for the purpose of calculating the 2014 base line, an addition of 410,000 MWhs based on NYSERDA estimates.

As a general principle, the Commission's concern in the RES is to calculate the level of load that all individual customers are placing on the electric system as the basis for establishing the level of load to be served by renewable resources. Where customers' consumption is offset by generation behind the meter, with the net result that no load is measured at the meter, whether the customers' consumption counts toward the base forecast depends on whether the generation results in RECs that are counted toward an LSE's RES compliance obligation. However, this criterion creates a version of double counting if the load is being served by renewable resources and the owner of the renewable attribute wishes to receive RECs for the MWh production. In this circumstance failing to include the load

associated with the REC would result in an underestimate of the amount of total demand that should be counted towards the 2030 goal. Ignoring such load is appropriate if the behind-the-meter generation is either not being registered in NYGATS or if such RECs are not counted towards the RES goal. In effect, as discussed below concerning voluntary consumer actions, the REC is retired. In this circumstance, neither the load associated with the renewable generation nor the generation itself is part of the program and the load will not count towards the RES goal.[58]

The Indicated Joint Utilities commented that when BTM generation is receiving net energy metering (NEM) compensation, the associated REC should be provided to the benefit of ratepayers who have contributed to the payments received through NEM. The Commission does not agree with this approach. The RECs have been contractually allocated within each transaction and, therefore, RECs should not now be reallocated to ratepayers. However, while RECs will not be reallocated, a proceeding is underway to move from NEM to a more granular and hence accurate methodology for pricing the value of distributed energy resources.[59] Until that time and because of the value that NEM provides to solar development, it is fair to say that ratepayers are as a whole supporting the development of the industry and in recognition of this contribution, the BTM load

[58] This issue will be revisited if at some later date the Commission decides that while voluntary market actions with additionality will not offset LSE compliance obligation but may be counted toward achievement of the overall program goal.

[59] Case 15-E-0751, Value of Distributed Energy Resources.

will not be included as part of the base forecast or as future load growth.[60]

At the time the current net energy metering (NEM) compensation mechanism moves to a LMP+D approach based on a more precise determination of the value of distributed energy resources, it will be appropriate to revisit the question of under what circumstances BTM load should be considered as part of the base forecast.

c. Energy Efficiency Adjustment

Staff proposes to modify the base forecast by the subtraction of customer usage that is expected to be supplanted by energy efficiency measures. Staff proposes the subtraction of 35,627,000 MWhs (2,227,000 MWhs annually) based on its analysis the State would achieve that level of statewide incremental energy efficiency gains, and believes that growth level is consistent with current NYSERDA and utility targets.[61]

Energy efficiency is a crucial and cost effective means to achieve clean energy objectives. Study after study has shown that when deployed well, energy efficiency is the cheapest

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[60] This outcome is also consistent with the way BTM generation is treated by other states in the region. In states with similar LSE obligations, certificates associated with each MWh of behind the meter generation are treated on the same basis as other generation delivering directly to the grid, without adjustments to individual or aggregate obligations. See http://www.mass.gov/eea/docs/doer/rps-aps/225-cmr-14-00-draft-srec-ii-reg-020414-tracked-changes.pdf; 225 CMR 14.00 RENEWABLE ENERGY PORTFOLIO STANDARD – CLASS I.

[61] This figure includes an assumed contribution from NYPA and LIPA based on their proportional share of load, in addition to targets established for utilities and NYSERDA. Case 15-M-0252, Utility Energy Efficiency Programs, Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2016 – 2018 (Issued and Effective January 22, 2016), Case 14-M-0094, Clean Energy Fund, Order Authorizing the Clean Energy Fund Framework (Issued and Effective January 21, 2016).

and most effective manner to reduce carbon emissions in the energy sector. In the CEF Order, the Commission requested that the stakeholders work with Staff and NYSERDA to determine whether the State should adopt a MWh and MW target for energy efficiency and, if so, to identify the appropriate level to be achieved and over what time period. In the REV Ratemaking Order, the Commission added to this opportunity by allowing utilities to achieve specific incentives to achieve added levels of energy efficiency.

The achievement of higher levels than the current energy efficiency targets can clearly benefit individual consumers and create system-wide value through the cost effective achievement of the RES and carbon reduction goals.[62] Higher levels of energy efficiency and its timing will positively impact both the total target and the trajectory proposed to achieve it. However, for the purpose of the initial calculation of the 2030 target, it is premature for the Commission to presume any level more than the current objectives. Rather, this determination will be revisited after the work of the Clean Energy Advisory Council is concluded. In addition, the Commission agrees with parties that the demand forecast should not remain static. During the triennial reviews the Commission will update the forecast to taken into account actions or events that are having a measurable impact on demand forecasts.

d. No Adjustment for Carbon Reducing Technologies

Staff proposes to modify the base forecast by the addition of customer usage that is expected to be created by the deployment of electric vehicles (EVs) and thermal heat pumps. Staff proposes the addition of 8,615,000 MWhs based on its

[62] Case 14-M-0101, supra, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, issued May 19, 2016.

projections. As a general principle, load growth associated with de-carbonizing actions in the transportation and building sectors requires encouragement in the State's regulatory and market approaches to encourage clean energy activity of all types. In this vein, in the DSIP Order and CEF Order the Commission asked parties to pay particular attention to actions and incentives that would encourage these efforts.

With regard to EV penetration, it is appropriate for utilities to have specific incentives and offer services to build out this critical industry. Increased levels of EV can have several beneficial aspects for the electric system, including increasing load factor efficiency through the addition of night time load and increasing the levels of fast acting local regulation and other ancillary services that support integration of higher levels of renewable resources. Similarly, the use of geothermal heat pumps can also support reduction of carbon in the heating sector and again improve electric load efficiency.

The Commission does not agree, therefore, that the load estimates should be increased to account for these activities. In both instances, rather than affecting the calculation of the RES, improved pricing will be developed through the Value of DER proceeding,[63] where adoption of an LMP+D methodology is being considered, the actions of FERC in the wholesale market, and the activities of the Clean Energy Advisory Council to ensure that the total net impact of these efforts are carbon neutral or positive. In addition, as discussed further herein, the Commission will consider whether a TREC program should be added. Individual actors who engage in

[63] Case 15-E-0751, supra.

these carbon saving activities also should be attracted to participate in other carbon reducing activities like energy efficiency programs that in combination allow them to achieve either low or net zero carbon impact.

Moreover, given the limited current market share it is not necessary at this time to calculate their impact on load growth. Over time, if these efforts do have a significant impact on electric demand to the point where they would represent a substantial increase in the RES requirement, the Commission will reconsider how best to treat these particular forms of load growth. However, for the purposes of setting the initial base line target, the Commission rejects this element of the Staff's recommendation.

e. Net Total Load

The net result of the two approved adjustments to the original base load is as follows:

	2030 MWhs
NYISO Load Extrapolated to 2030	176,619,000
Energy Efficiency Subtractions	(35,627,000)
Resultant 2030 Load	140,992,000
50% of 2030 Load	70,496,000

f. Baseline Renewable Resource Adjustment

The next step in the calculation methodology is to subtract the existing baseline of renewable resources from the 50% of load figure to determine the incremental level of new renewable resources needed to satisfy the goal. The Commission believes that because these resources are already included in the base of resources used to meet State load, it is appropriate to subtract out the existing quantity. The Commission will accept Staff's estimate of 41,296,000 MWh and assumes that all

of these resources will remain operational.[64] The net result of the adjustment is as follows:

50% of 2030 Load	70,496,000
Baseline Renewable Resources 2014	(41,296,000)
2030 Incremental Statewide Target	29,200,000

2. Annual Targets

Although the 2030 target of 50% renewable resources is clear as a percentage goal, the targeted number of MWh that must be procured by LSE's in any time period is dependent on a number of factors that will necessarily alter the level of annual requirements. In the previous Renewable Portfolio Standard and Energy Efficiency Portfolio Standard programs the Commission derived final targets from forecasts at the outset and did not subsequently revise them.[65] The approach taken here reflects the longer term, market driven and more comprehensive nature of REV and the RES as a component of this reform. In particular, the Commission anticipates that the trajectory for renewable development will be impacted by all forms of voluntary market activity. In other words, retail market participation, including customer behavior in terms of energy efficiency, behind the meter supply investments, supply mix, and hedging strategies, can and will impact the requisite level of mandated procurement in any given time period. As already discussed, the Commission expects that utilities and NYSERDA will both pursue

[64] If any of the renewable resources currently counted in the baseline sell RECs into other markets at some point in the future, the Commission may adjust the baseline in the future accordingly.

[65] Case 07-M-0548, Energy Efficiency Portfolio Standard, Order Establishing Energy Efficiency Portfolio Standard and Approving Programs, issued June 23, 2008. Case 03-E-0188, Retail Renewable Portfolio Standard, Order Regarding Retail Renewable Portfolio Standard, issued September 24, 2004.

and achieve higher levels of energy efficiency savings than currently forecasted. This outcome will positively affect consumers both in terms of overall bill impacts and achievement of environmental objectives. It will also necessarily require an adjustment of both the ultimate 2030 target and the trajectory to achieve it.

Establishing annual targets also must be done in the framework of other REV enabled system changes and associated market developments. There are considerable efforts underway to support the wide deployment of distributed energy resources throughout New York as a means to increase system reliability and resiliency as well as promote a more efficient, cost effective and cleaner grid. Starting with existing efforts related to NY-Sun, community solar, community aggregation, demonstration projects and demand response activities, this market momentum is already taking root. In the last three years related to solar alone there has been a 500% increase in growth. With the efforts being made in the CEF fund, the growth of the Green Bank, the recent filing of the DSIPs and the Commission's Order on Regulatory and Rate Design changes, it is anticipated these markets will develop even more rapidly and consequently have a dynamic and positive effect on the supply available to meet the demand for renewable energy. Based upon the speed of this activity and the choices of individual customers, the State may find itself in an enviable position of accelerated achievement of the 2030 target.

Related to these market developments are the effect that improved information, pricing, and product definition will have on customer grid-based supply choices. One of the great advantages that the Commission has in the development of the RES targets is the increased public awareness and interest in taking personal action to combat climate change, whether in the

interest of protecting against environmental damage or to ensure resiliency and to achieve positive economic as well as environmental outcomes. Businesses and institutions as diverse as Walmart, Google, the State University of New York and the U.S. Military have adopted programs that increasingly rely on renewable resources due to their economic and environmental benefits. From 2012 to 2015, the capacity of publicly announced corporate renewable power purchases increased from 0.05 GW in 2012 to 3.23 GW in 2015.[66]

The State also has the opportunity to stimulate mass market consumer interest in grid based renewable purchases through the actions taken in the development of the retail market, including product requirement and product definition. Increasingly, utilities and retail market providers are recognizing that the mass market that purchases their services is far from monolithic. Many ESCOS are finding that product differentiation beyond price and target marketing as part of customer attraction and retention is of significant value. As part of the ESCO reset process, the Commission is considering how to best define value added products offered by ESCOS to the mass market. Many ESCOs today offer green energy products that may or may not conform to the forthcoming RES requirements. There is considerable value in the development of defined green products that consumers who have an interest in protecting the

[66] Corporate Renewable Deals 2012 to 2016, Business Renewables Center. In 2015, USEPA's Green Power Partnership program had over 1300 partners collectively using 30 GWh of green power annually. https://www.epa.gov/greenpower/green-power-partnership-program-success-metrics. From 2012 to 2016 there was a 40% increase in companies adopting sustainable business principles, and the amount of assets subject to fossil divestment rose from $50 billion in 2014 to $2.6 trillion in 2015. State of Green Business 2016, GreenBiz Group Inc., pp. 34, 54. See also, Creating Renewable Energy Opportunities, Utility-Corporate Buyer Collaborative Forum, June 2016.

environment will naturally gravitate to if they have confidence in the veracity of the offering.

Defining these products is the appropriate subject of the ESCO reset docket where these issues are currently pending. However, in the interest of supplying additional guidance, the Commission notes that for these products to be real and avoid market place confusion, they must offer environmental value that is greater than the level of renewable resources that can be acquired as part of normal default load. Thus, in defining a green product, the minimum content should be in excess of annual mandatory targets.

Based upon experience in the development of shared renewable resources, the value of these products to customers will also be enhanced if customers are confident that some if not all of the renewable energy they are purchasing is produced in New York. Again, the determination of this content issue is beyond the scope of this proceeding, but Staff is directed to work with NYSERDA and other interested stakeholders within the pending reset process to develop content and definition standards that can be used to market a New York certified green electric product, i.e., a product that customers know has a defined content of NY-based green power.[67]

The successful stimulation of these customer-initiated choices will have a necessary impact on the trajectory of the required acquisitions to achieve the 50% target for 2030. It is anticipated this demand will have separate effects based upon the consumers' individual choices. Many consumers will want to

[67] To avoid any suggestion of a commerce clause violation, the Commission is not suggesting that the LSE must use NY produced power to meet its compliance obligations. Rather, the focus here is on directing efforts to meet consumer demand for accurate information and full choice on the content of the supply they purchase and the location of the source.

claim that their participation is voluntary or additional to the State's program. When a purchase of renewable resources is made in the absence of a government mandate, or if it is not counted toward compliance with a government mandate, it is typically described as "voluntary" or "additional" to any compliance obligation. Over the years, well-established national and international protocols have been developed to ensure that any commercial claims of voluntary or additional activity conform to guidelines and are not misleading to the public.[68]

In the context of the RES, for example, if a customer served by an LSE chooses 100% renewable energy, the customer may want to claim "additionality" and require the LSE to retire RECs associated with more than 50% of the served load. This action prevents the LSE from reducing the amount of RECs it would otherwise require to meet its minimal compliance obligation. In this way, the customer is increasing the amount of incremental renewable resources.

Other customers choosing to go higher than 50% may instead want or be indifferent to the LSE applying the excess to other customers less willing or able to make those choices. The net effect of this action is that, by revealing their preferences, customers may be able to accelerate the State's achievement of the 50% target, or, that the target becomes the minimum and that the revealed preference of New Yorkers as a whole is to have a greater than 50% resource mix of renewable resources. In all cases, the development of a vibrant market for consumer choice for clean resources and the development of standard products that create confidence, will impact the timing

[68] See, e.g., Guides for the Use of Environmental Marketing Claims (Federal Trade Commission Green Guide), 16 CFR Part 260; also see Environmental Marketing Guidelines for Electricity, National Association of Attorneys General.

of the mandated requirements and their associated costs. As discussed below, banking of RECs will be available for LSEs if demand for green products, as expected, proves to be substantial. A high demand for green products may also warrant an adjustment to the mandated target that better reflects positive market interest for renewable development and attendant lower risks and costs to those New York consumers who do not share that interest.[69]

The Commission also is sympathetic to the interests of some consumers who would prefer to have a 100% renewable energy mix and make no contribution to the ZEC program. This type of reallocation of individual consumer obligations may prove to be in the broader public interest if it results in new renewable development in New York that counts towards the 50 by 30 standard and is subject to contractual obligations for at least as long as the NYSERDA contract with the nuclear units as described infra. Staff shall review the development of this opportunity and provide recommendations to be considered as part of the ESCO reset Order and implementation phase

The Commission also recognizes that even while it is optimistic for success, the development of new renewable resources or any new resource can take more time than anticipated. The concern here is that if supply is not able to meet the jurisdictional level of demand, the prices may increase higher than is reasonable for consumers. In this circumstance, the Commission may decide to adjust near-term targets downward, increase obligations in later years, or focus on actions that

[69] The Commission also notes that in addition to the consumer based actions, changes in RGGI pricing, wholesale market rules and federal clean energy requirements can all impact the pace of State action. Rather than detract, these phenomena add to the need for the State to remain flexible in its approach to annual targets.

can facilitate development. Before taking such a step, all reasonable measures to reduce project costs, including soft costs such as siting and interconnection, should be pursued.

Along with the ability to accommodate market dynamics, the trajectory for acquiring renewable resources under the RES must be informed by improvements in the cost structure for renewable resources, both in front of and behind the meter. Over the last three years the reported installed cost of solar has declined by about 26%. The cost of wind has seen a similar improvement and technology changes associated with offshore wind development and economies of scale will also improve these cost dynamics. Additionally, as noted in the cost study, supply prices for natural gas may also increase electric prices. The cost study also noted other factors such as the availability of federal tax credits, interest rates and other market factors which can affect the economics of acquiring new renewable resources. All of these fundamentals have the effect of potentially improving the competitiveness of renewable resources and reduce the attributed payment they seek in the REC auctions, all which benefit consumers.

All of these factors suggest a pragmatic approach to establishing the yearly targets for LSE compliance under the RES. Staff has recommended that the Commission establish firm targets in the initial years and then provide a triennial review. While firm targets for planning purposes are necessary for the near-term, there is value to the market in seeing a potential trajectory that is non-linear and that looks to take advantage of voluntary consumer activities and reduced renewable supply costs. The Commission directs Staff, as part of the implementation plan to i) review and either confirm or propose modifications to the targets adopted here for 2018-2021 after taking into consideration current market conditions including

the result of the 2016 NYSERDA LSR solicitation[70] and ii) develop a potential acquisition curve for the years 2022-2030. The curve will serve simply as a base case calculation that will be adjusted as necessary based upon actual market dynamics.

In summary, the Commission establishes, subject to the review directed above, the following fixed targets and requires each New York LSE to serve their retail customers by procuring new renewable resources, evidenced by the procurement of qualifying RECs, acquired in the following proportions of the total load served by the LSE for the years 2017 through 2021:

Year	Percentage of LSE Total Load
2017	0.6%
2018	1.1%
2019	2.0%
2020	3.4%
2021	4.8%

[70] NYSERDA is currently evaluating responses to the 2016 RPS solicitation. RECs procured through that solicitation will be treated as Tier 1 resources that will provides RECs in or after 2018. The Commission recognizes that current market conditions, including the limited continuation of applicable federal tax credits, may be favorable, resulting in attractive pricing in this current solicitation. In that case, there is no reason to delay additional procurement or supply. Any such additional procurement can be funded through an acceleration of the consumption targets for the years 2018 - 2030. Accordingly, if NYSERDA determines that acceleration is warranted because the additional financial commitment would result in an overall weighted average award price of 2016 Main Tier projects equal to or less than the 2015 Main Tier weighted average price of $24.57 per REC, it is authorized to implement additional procurement levels in the 2016 procurement and file a report with the Commission documenting its determination and the results.

Over time through the triennial review process, the Commission will adopt incrementally larger percentages for the year 2022 through 2030, with sufficient lead time for the LSEs to incorporate the changes into their planning processes. The periodic review and target setting will also take into account the balance of likely incremental supply with demand. Based on current forecasts of future loads, the above percentages will yield the following MWhs of output from new renewable resources:

Statewide Yield (MWhs)

Year	Distribution Utilities & ESCOs	LIPA	NYPA	Direct Customers	Statewide Total
2017	705,595	120,244	139,225	8,936	974,000
2018	1,261,429	214,967	248,900	15,975	1,741,270
2019	2,263,192	385,682	446,563	28,662	3,124,100
2020	3,841,197	654,599	757,928	48,647	5,302,371
2021	5,455,424	929,688	1,076,440	69,090	7,530,642

3. LSE Obligation

Achieving the statewide 50 by 30 goal will involve a variety of elements and resources, including market-based, regulatory, and non-jurisdictional factors. The basic regulatory component of the RES will be an obligation on LSEs, consistent with the approach used in neighboring states. This will place compliance costs primarily on generation supply charges, where they are most appropriately applied. Placing compliance costs on supply will encourage efficiency, support voluntary hedging and power purchase agreements, and help to develop markets at the retail level, by encouraging competitive LSEs to develop innovative products. Consistency with other states will allow developers to participate in markets in

multiple jurisdictions and may enable trading to reduce overall costs.

The obligation will apply to every LSE serving retail load within a regulated distribution utility territory. This will include investor-owned utilities serving in their role as electric commodity supplier of last resort, jurisdictional municipal utilities, competitive ESCOs serving electric commodity to retail customers, and community choice aggregators not otherwise served by an ESCO.[71] Customers purchasing power directly from the NYISO will be considered LSEs for this purpose, so that their consumption levels are accounted for without other customers bearing the burden.[72] This adoption of the Renewable Energy Standard is a changed regulatory requirement for the purposes of the Uniform Business Practices (UBP).

Each LSE will be responsible for supplying a defined percentage of retail load with supply derived from eligible resources, as defined by the compliance methods discussed below. The obligation will be annual, determined by multiplying the LSE's actual load for that year by the percentage RES target for that year.[73]

Representatives of ESCOs argued that some ESCOs have fixed price contracts with customers, and that these ESCOs could

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[71] See, Case 14-M-0224, Community Choice Aggregation Programs, Order Authorizing Framework for Community Choice Aggregation Opt-Out Program, issued April 21, 2016.

[72] Under the Federal Power Act, any sale of electricity that is not a sale for resale s subject to Commission's jurisdiction instead of FERC's. A sale by the NYISO to a direct customer consumer is not a sale for resale, it is a retail sale subject to Commission jurisdiction.

[73] The LSE's obligation will be measured at the wholesale level, i.e., grossed up to reflect the generation needed to serve customers prior to line losses.

not pass through the additional costs created by the LSE obligation. As an equitable matter, all customers and market participants must share in the RES effort. In the early years of the RES, the incremental obligation will be small, so this will not fall outside the range of normal business risks. As the LSE obligation grows, ESCOs will have timed out of their fixed price obligations, and the RES obligation will provide both incentives for ESCOs to develop new products, and opportunities to appeal to voluntary 100% green markets.

Municipal utilities have argued that they should be exempt from the LSE obligation because they already are supplied with large amounts of hydropower. NYPA hydropower that is sold to municipal utilities on a wholesale basis, however, is part of the baseline. The jurisdictional increment of the RES is in addition to the baseline and is the responsibility of every load serving entity. If municipal utilities were exempt from the LSE obligation, other LSEs would have to carry their portion of the statewide goal. The fact that municipal utilities currently obtain very low-cost power is not a persuasive argument for exempting them from sharing in a statewide obligation.

Several parties commented that microgrids and combined heat and power generators should be subject to the LSE obligation. At this time, the amount of load represented by these categories is relatively small, and the CES should not become an obstacle to their further development. Potential application of the LSE obligation to new microgrids and CHP generators should be considered as part of the triennial review process.

4. Long-Term Procurement Issues

a. Need for Long-term Procurement

The entire RES goal could theoretically be satisfied by a spot market for RECs. In practice, however, given the

conditions of markets at this time, a sole reliance on a spot market – i.e., a completely self-initiated market without a long-term coordinated procurement strategy - would result in high compliance costs. A long-term procurement process is needed to achieve the 50 by 30 goal.

Staff described the risks faced by renewable project developers in competitive markets. These risks would lead to high compliance costs that would be passed on to customers. The most obvious concern is that financing for renewable projects will be more expensive without a long-term assurance of a revenue stream. Under an approach that relied on a spot market for RECs, developers would assume the risk of technology costs declining, with established projects having to compete against lower-cost entrants. A long-term contract for RECs can address this problem, although there will be a remaining risk of change in energy prices.

This concern is enhanced where there is a competitive retail market structure. Each LSE will have a compliance obligation based on its annual retail load. Customers are free to switch suppliers, however, and no LSE is guaranteed constant or predictable retail sales volume for commodity sales. There will be risk attached to long-term procurement obligations undertaken by any LSE, because the LSE has no assurance that it will retain customers to support the long-term obligation.

In short, developers argue that they will face risk in the absence of long-term bundled contracts, while LSEs argue that they will face risk in entering long-term contracts. Because demand for RECs will be mandated and thus relatively inelastic, REC supply shortages caused by these risks would result either in high prices or in non-compliance.

Establishing a long-term procurement process is intended to complement a spot market for RECs, not to eliminate

it. Depending on how procurement targets are set and how the market responds to solicitations, there are likely to be times when long-term procurement does not satisfy the entire LSE obligation. There will also be LSEs that choose not to participate in the long-term procurement process.

b. Types of Long-term Procurement

Much of the comments about long-term contracts have centered on a choice between bundled power-purchase agreements and utility-owned generation. REI argued that PPAs will be the most cost-effective means of bringing renewable developers into New York on the scale needed to meet the targets. They cited the Cost Study as confirming the value of PPAs. Utilities argued that PPAs would present risks to ratepayers, but that UOGs can substantially reduce costs due to lower financing costs and continued ownership of the residual value of plants. Renewable developers who oppose utility ownership argued that the residual value is reflected in their bid prices. IPPNY argued that allowing utility ownership would reverse a long-standing Commission policy. Opponents of utility ownership claimed that utilities would have an advantage in competitive processes because they could understate initial costs and then recover cost overruns from ratepayers. Utilities proposed that their ownership could be limited to a financial basis, with independent companies developing, building, and potentially operating the renewable facilities. IJU proposed a portfolio approach, combining a utility finance-only ownership model with a REC-only market and a voluntary market.

Under the current RPS program, long-term procurement is achieved through REC-only contracts executed by NYSERDA following competitive solicitations. In this model, developers sell the power commodity in capacity and energy markets and only the REC is subject to a long-term contract. Proponents of PPAs

and UOGs argued that the energy price risk involved in a REC-only contract will result in higher bids for the REC attribute. Those parties suggest that REC contracts should be used only for the residual LSE obligation that is not procured through a bundled contract.

c. Power Markets in New York

The manner in which to best achieve the Commission's goals, at reasonable cost, is directly tied to the design of power markets in New York. In New York's restructured markets, distribution utilities do not own generation facilities. Generation plants are owned by independent producers, who sell wholesale power primarily through markets operated by the New York Independent System Operator. Power is sold at retail to customers by competitive ESCOs as well as distribution utilities as default service suppliers for those customers who do not choose a competitive supplier. The power sold at retail by ESCOs and utilities is primarily purchased from the independent generators through the wholesale market, and is delivered physically by distribution utilities.[74]

Under this structure, competitive markets set the power price, and most of the Commission's rate regulation activities are limited to the costs of physically delivering the power and maintaining a reliable delivery system. The previously established clean energy programs such as the RPS and EEPS have been funded through surcharges on delivery bills. Costs related to energy usage, however, should be reflected in the energy component of the bill for the reasons previously discussed.

[74] The wholesale markets are complemented by bilateral markets. This description of New York's market structure is intended to be a general overview and does not reflect numerous exceptions and detailed qualifications.

d. Determination

The volume of new development that will be needed to achieve 50 by 30 is much greater than the annual pace the RPS program has achieved to date. Analysis of this issue is driven by the Commission's fundamental responsibility to consumers to achieve the SEP goal at a reasonable cost. For this it is apparent that some form of long-term procurement will be needed.

Investors simply will not look to build renewable generation facilities without sufficient certainty that they will successfully earn a return on their investment. In the case of the type of long-lived capital investment necessary to construct and operate a generation facility, a long-term contract or other durable mechanism providing reasonably certain terms will be necessary to induce such investment. Without the assurances that a long-term contract provides, the renewable generation projects that the State requires will not come to fruition.

The principal question is whether that procurement should involve only RECs or whether it should also involve bundled power contracts and/or direct utility investment. A subsidiary question would be whether a bundled procurement approach, if taken, should be achieved through PPAs, UOGs, or some combination. Reasonable arguments were made on various sides of this issue. In addressing this question, the Commission has broad authority under the Public Service Law. The determination will be governed by policy concerns as to the most reasonable and effective way to achieve the renewable goal.

Mandating utilities to enter long-term PPAs would present a significant financial risk to ratepayers and to utilities. Because customers in New York can choose their power suppliers, no supplier is assured of the size of its customer base, for purposes of energy sales, over the long-term. This is

true of distribution utilities as well as ESCOs. Because there is no assurance of a long-term customer base from which to recover the cost of power contracts, mandated PPAs would create the risk of utilities recovering costs from a dwindling group of default energy customers, or to resort to a non-bypassable surcharge that applies to all delivery customers. Because a delivery surcharge limits competitive choice, it is not the preferred alternative. Advocates of PPAs argued that there are hedge benefits as well; but hedging in power markets tends to occur over three- to five-year periods, not 20-year periods.

Utility-owned generation can cost less than the alternatives, in the near-term, largely because utilities have lower finance costs. But utility owned generation also has the potential to inhibit entry by other market participants, which can result in less competition and higher costs in the long-run.

Procurement that is limited to the REC, and does not include the power supply itself, avoids the pitfalls of PPAs and UOGs, but may result in higher costs for the renewable attribute, as developers build the increased risk of power cost fluctuation into their bids to sell the renewable attribute.

The potential for federal preemption creates a risk that could slow the implementation of the RES. The U.S. Supreme Court decision in Hughes v. Talen Energy Marketing, LLC, 136 S. Ct. 1288 (2016) does not directly bar power purchase agreements. It does, however, cast uncertainty over state-mandated contracts that parties may argue interfere with federally supervised wholesale markets.

An additional concern is a practice of FERC which places constraints on the Commission's ability to mandate PPAs in a cost-effective manner. FERC's current policy of imposing "buyer-side mitigation measures" upon various resources participating in the downstate installed capacity markets

creates significant risk that a PPA backed by a public resource (including utility ratepayers) could fail to clear the capacity market thereby forcing ratepayers to purchase capacity from other resources that would not otherwise be needed.[75] Although exemptions for certain renewable resources or other policy-driven procurements have been discussed in various orders, no clear policy delineations exist at this time. For instance, a proposal currently pending before FERC would allow limited exemptions from buyer-side mitigation for certain intermittent renewable resources below a 1,000 MW annual cap.[76] Whether this policy is ultimately adopted or not, FERC's current approach to capacity markets, and presumptions against bilateral contracts of major retail suppliers, cast a shadow over a reliance on mandated PPAs to achieve RES targets. The risk of federal preemption could disrupt and delay the entire RES initiative.

The arguments in favor of PPAs and UOGs are substantial. Consistent with the Commission's long-standing policies, however, as a matter of first preference long-term PPAs will not be mandated, nor will the Commission revert to a blanket authorization of traditional UOGs. Long-term procurement will begin by employing the current method of fixed-price REC contracts. This approach will provide a simple transition from the RPS program into the RES. Because of the much larger procurement levels under the RES, and because the

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[75] There is also considerable risk that the buyer-side mitigation measures may be extended to the rest-of-state capacity markets, which is pending before FERC. Docket No. EL13-62, Independent Power Producers of New York, Inc. v. New York Independent System Operator, Inc., Order Denying Complaint (issued March 19, 2015).

[76] See Docket No. ER16-1404, New York Independent System Operator, Inc., NYISO Compliance Filing (filed April 13, 2016).

procurements will not be budget-bounded as RPS procurements are, a wider range of developers is expected to participate.

e. Review of Procurement Practices

The determination here is a continuation of the Commission's policy of relying on markets where feasible, as the best long-run approach to reducing costs and promoting innovation.[77] In the context of the RES, a balance is needed between long-run reliance on markets and the need to achieve consistent and measured progress toward the 2030 goal. For that reason, REC markets will be closely monitored and if projects are not being developed in New York at a satisfactory pace, the Commission will consider alternative procurement approaches.

The effectiveness of REC-only procurement will be evaluated in the triennial review process. Criteria to be considered in this review include:

- whether supply is available to meet LSE obligations;
- cost of RECs compared with neighboring states and other markets;
- extent of reliance on Alternative Compliance Payments;
- effects on ratepayer cost and risk and overall bill impacts;
- rate of entry by competitive developers;
- extent to which projects are developed in-state; and
- extent of in-state projects selling RECs into neighboring markets.

[77] The Commission's decision to limit mandated procurements to REC-only should not inhibit market participants in developing innovative approaches for the procurement of new Tier 1 resources.

5. Design Parameters

a. No Separate New Resource Tiers

Tier 1 is for the procurement of new renewable resources of all types beginning commercial operation on or after January 1, 2015. The use of multiple tiers would reduce the competition within tiers that is necessary to achieve lower long-term costs. Although numerous parties propose separate tiers for preferred types of new resources, it is more effective to allow all new resources to compete directly with each other. In its White Paper, Staff correctly points out that co-incentives can serve as an effective means to provide financial support that is determined to be appropriate to advance state policy.

Some parties argue for a separate obligation for offshore wind. Offshore wind is an evolving technology. The Bureau of Ocean Energy Management identified the coastal region of New York as an ideal location for offshore wind development. The Commission agrees that offshore wind will be a vital component in achieving the State's renewable goals. There is no need, however, to immediately establish a specific near-term target because NYSERDA is already tasked with developing a blue print for offshore wind development for the State. The appropriate next step, therefore, is to await NYSERDA's study and request that NYSERDA include in its analysis recommendations on the best solutions for maximizing the potential for offshore wind in New York.

Some parties also argue for a separate obligation related to energy storage. Storage is a critically important component of the energy system that is both distributed and increasingly reliant on intermittent resources. Unlike other resources, the load shifting and fast response capabilities of various forms of storage resources allow them to provide

simultaneous value as an energy and reliability resource. Storage can also provide value to the distribution based retail and bulk power markets. The Commission agrees with the view expressed by NYBEST that it is important for utilities to gain understanding of the capabilities of storage through direct hands on experience. For those reasons and in order for storage to gain its appropriate place as a resource that provides network value to the distribution system provider, the Commission has allowed utilities to invest in storage to support integration of renewables and is looking for the best mechanisms to value fast acting firming resources on the distribution grid in the development of pricing for DER. The Commission has specifically directed the utilities to consider the impact of storage as part of their DSIPs. It is expected that the value of storage to be accurately monetized in the development of the retail markets for energy efficiency and the utility EAMs for system efficiency. In this Order the Commission is also directing Staff to work with the ISO to make sure as part of the development of the CES, the ISO is improving the bulk power market to better signal and value the ability of storage to firm resources and improve the reliability of the bulk power system in a manner that is more efficient and secure than transmission alone. FERC has already commenced working on this specific issue.[78] In short, it is without question that modern markets must sufficiently and accurately value storage as a vehicle to design and optimize network planning and operations. However, as a reliability support and system optimizing resource, storage is not properly characterized as a standalone renewable energy

[78] FERC Docket No. AD16-20-000, Electric Storage Participation in Regions with Organized Wholesale Electric Markets, Letter Requesting New York Independent System Operator, Inc. Response (issued April 11, 2016).

resource under the CES. That being said, if the various mechanisms that the Commission is pursuing to ensure storage takes it rightful place as a critical resource for the modern grid prove insufficient, this topic will be revisited.

NY GEO proposes a separate thermal renewable energy credit or "TREC" requirement applicable to geothermal heat pumps, to recognize the manner in which they utilize renewable geothermal energy and reduce system wide carbon emissions. Including geothermal heat pumps as an eligible technology could add an additional source of competitive RECs to the overall compliance pool, which could reduce costs for all participants. NY GEO's proposal acknowledges, however, that there are administrative complexities involved in determining the mechanism by which geothermal exploitation can be converted into TRECs. During the Implementation Phase Staff will propose a process for parties to consider such complexities and to explore practical administrative mechanisms that might be employed to accommodate geothermal heat pumps as an eligible technology.

b. Eligibility

Staff’s proposed eligibility framework is reasonable. Resources eligible to provide Tier 1 compliance will mirror the eligibility rules currently used for the Main Tier of the RPS, with the exception that the former 30 MW limit on low-impact run-of-river hydroelectric facilities is eliminated. The eligible resource categories will include Biogas, Biomass, Liquid Biofuels, Fuel Cells, Hydroelectric, Solar, Tidal/Ocean, and Wind. More detailed requirements as to eligibility of these resources are contained in Appendix A entitled Eligibility of Resources. Several parties argued that there should be no restrictions at all on the eligibility of large scale hydro facilities. This issue was extensively debated in the creation of the RPS, with many parties opposing the environmental impacts

of large impoundments, including methane emissions. The resolution in that proceeding, that no new storage impoundment will be permitted for any eligible hydroelectric facility, remains reasonable and is not changed. To the extent any factor has changed since the RPS Order, it is an increasing awareness of the climate change impacts of methane and concern over methane releases from large hydro impoundments, particularly new ones in which flooded vegetation would be decomposing and releasing methane.

Staff's proposed delivery criteria for geographic eligibility is also adopted. Eligible facilities must either be located in New York or in a control area adjacent to the New York Control Area, with documentation of a contract path and delivery of the underlying energy for consumption in New York between the generator and either the New York Spot Market administered by the NYISO or an LSE in New York, including transmission or transmission rights. More detailed requirements as to geographic eligibility are contained in Appendix A entitled Eligibility of Resources.

c. Compliance.

The medium of compliance will be the REC, with one REC created for each one MWh generated by an eligible facility. As mentioned, this is the universal unit of measure used in multiple jurisdictions, which allows efficient trading with liquidity, transparency, and verification. RECs will be tracked and verified through NYGATS. Ideally, NYGATS will be able to verify eligibility including the delivery requirement described above for some or all of the resources such that the delivery requirement documentation can be mostly met through NYGATS. A description of NYGATS is included in Appendix C.

Each LSE will demonstrate compliance through an annual compliance filing. LSEs may purchase RECs from NYSERDA for

retirement by the purchaser, or may self-supply by direct purchase and/or sale of tradable RECs,[79] but a REC can only be used once for compliance and after a REC is used to demonstrate compliance it is permanently retired. ESCO's may also develop and own renewable resources for sale to their retail customers. RECs purchased from NYSERDA in 2017 may not be traded, but may be sold back to NYSERDA at cost if not needed to demonstrate compliance. Any excess RECs held by NYSERDA at the end of a compliance period will be eligible and offered for sale by NYSERDA in subsequent compliance periods. NYSERDA's role as the central procurer of RECs is intended to contribute to reducing the cost of compliance. However, the tradability of NYSERDA procured RECs could result in increased cost. Accordingly, for Compliance Year 2018 and following, Staff will include a recommendation regarding whether NYSERDA procured RECs should be tradable as part of its implementation proposal and parties should be prepared to comment on the concern that trading of NYSERDA procured RECs may result in increased cost through the arbitrage.

MI questions the need for a REC obligation, arguing that the current method of RPS procurement may result in lower costs by preventing developers from selling RECs into other states. In a similar vein, some utilities argued that fully centralized procurement would obviate the need for a REC market.

Notwithstanding those comments, the parties demonstrated strong support for NYSERDA's continuing role as a central procurement agent. Some utilities argue that NYSERDA procurement should be exclusive. Their proposal that LSEs

[79] For example, if an entity enters into a combined power purchase agreement with RECs obtained outside of the NYSERDA central procurement process, the RECs obtained in that contact would be fully tradable.

should not be able to self-supply outside of the NYSERDA process is rejected. Self-supply and third-party procurement by LSEs will provide competition and a benchmark for measuring the effectiveness of central procurement.[80]

The compliance period shall be January 1 to December 31 of each year, beginning in 2017. The settlement date for demonstrating compliance will not occur until a reasonable time after the NYISO settlement process for the compliance period ends to allow LSEs a settlement period opportunity to re-calibrate their REC supply for the compliance period to match their actual obligation quantity. The details of the settlement process will be included in an implementation proposal by staff for inclusion in an implementation order.

For the Year 2017 compliance period, by December 1, 2016, NYSERDA shall publish on its website a REC price and the estimated quantity of the RECs NYSERDA will offer for sale in the 2017 compliance period. The REC price offered will equal the weighted average cost per MWh NYSERDA paid to acquire the RECs to be offered, plus a reasonable Commission-approved adder to cover the administrative costs and fees incurred by NYSERDA to administer Tier 1. NYSERDA will file a petition with the Commission proposing the amount of the adder by August 25, 2016, in order to allow the Commission an opportunity to consider the adder at its November 2016 Session. For subsequent years, Staff will propose a methodology for pricing and offering RECs as part of the implementation phase of this proceeding.

By December 1, 2016 for the Year 2017 compliance period, each LSE will inform NYSERDA whether it intends to

[80] Although the precise terms of independent procurement may not be known due to proprietary reasons, the competitiveness of independent procurement may be inferred from the resulting market offerings.

purchase RECs from NYSERDA during the compliance period. During the 2017 compliance period, NYSERDA will offer the RECs for sale in the compliance period to each participating LSE with a right of first refusal to each participating LSE to purchase their proportional share of the available RECs based on historical share of load. As part of the aforementioned petition, NYSERDA will establish a sales and payment schedule during the compliance period intended to generally match on a periodic basis (monthly or quarterly) the sales quantity to the expected actual load quantity so as to minimize the time that NYSERDA is holding RECs in its own account. Any unsold RECs at the end of the compliance period will then be offered by NYSERDA for sale generally to the participating LSEs that wish to purchase them in a non-discriminatory manner during the settlement period to satisfy their then-current obligation. For years following 2017, Staff will propose a methodology for consideration by the Commission for determining the terms for the purchase of RECs.

d. Alternative Compliance Payment

The development of voluntary market activity, as described above, can potentially have a large effect on the overall bill impacts of the CES, as voluntary and market-driven actions increase the amount of renewable generation, reduce the total amount of jurisdictional load, and shift usage.

With respect to the LSE obligation itself, one vehicle by which costs will be mitigated through a principal compliance flexibility measure is the Alternative Compliance Payment (ACP), which is a payment made as an alternative to demonstrating compliance with RECs. The ACP is not a penalty for non-compliance; rather, it is an alternative avenue to compliance. In effect, it caps the total cost of the RES because LSEs will have no need to incur costs higher than the ACP. ACP payments

will be made to NYSERDA during the settlement period for the Compliance Year.

Disposition of ACP payments must always be applied to the benefit of consumers by reducing the cost of the RES program. As part of an implementation proposal, Staff will consider the ways this policy can be achieved and will make recommendations for consideration by the Commission as part of an implementation order.

By December 1, 2016 for the Year 2017 compliance period, NYSERDA shall publish on its website a per MWh ACP price for the 2017 compliance period. The ACP price will equal an amount calculated as the published REC price plus 10%. Staff will propose a methodology for establishing the ACP for the Commission's consideration for subsequent years as part of the implementation phase. Many states within our region have adopted ACP as part of their RPS programs. The alignment or divergence of ACP requirements can materially affect the cost of compliance. Moreover, regional markets enabled through consistency of state requirements can contribute to reducing the cost of achieving the RES goal. Accordingly, as part of implementation, the Commission will work with the State's RGGI counterparts to find ways of supporting stronger regional consistency that can benefit all consumers.

e. Banking and Borrowing

A second vehicle by which costs will be mitigated through a principal compliance flexibility measure is the banking of RECs. Staff proposes that banking of RECs should be permitted and left open the issue of borrowing. The Commission agrees that short-term banking of RECs is an effective tool to allow flexibility and manage compliance efficiently. Banking will also apply to NYSERDA procurements, which may exceed LSE Obligation targets by large amounts if market conditions are

favorable. Terms for banking will be adopted in an implementation order. As discussed previously, the cost of complying with the RES program can be reduced through consistency with other States and the development of regional markets. Accordingly, Staff should consider how other state programs in the region have addressed this issue and the applicability of those approaches to the NY RES.

The Commission will not allow borrowing of RECs at this time. It is not necessary because of ACP and produces a risk of non-compliance. An LSE facing a shortfall can either purchase tradable RECs on the market from eligible in-state or out-of-state sources, or make an ACP payment. If borrowing is not an option, LSEs will have a greater incentive to procure sufficient RECs during the compliance period.

GE proposed that a force majeure provision should be added to increase flexibility in the event of disasters. Rather than establishing a general provision in advance that could give rise to uncertainty and argumentation, the Commission will leave open the possibility of making adjustments as needed if exigent circumstances arise.

f. Role of NYSERDA

Although NYSERDA's role will be intermediary, NYSERDA will take title to RECs (including as a result of the 2016 solicitation and all other solicitations going forward) and will need initial capitalization as well as assurance against financial risk. Unlike the RPS, which operates on a pre-established budget, RES procurement will be driven by supply and demand and the total procurement expenditures in any given cycle will not be known beforehand. Although the financial risk to NYSERDA will be relatively small, it may nevertheless require a guarantor. The distribution utilities may be best situated to provide this service, subject to cost recovery from ratepayers

and accordingly are required to do so.[81] Staff will consult with NYSERDA and develop for Commission consideration as part of an implementation proposal a plan for providing appropriate capitalization and cash flow for NYSERDA's role and to establish an equitable mechanism for distribution utilities to provide the necessary financing and guarantees, as necessary.

6. Solicitation/Procurement Cycle

There is considerable discussion in the record on the importance of establishing annual targets for REC contract solicitations. Renewable energy developers were uniform and clear that knowing the specifics of the State's procurement plan well in advance allows them to engage in the pre-development activities that yield the advantages of competition. Developers and others also pointed to the fact that historically the uncertainty around the timing and level of NYSERDA renewable solicitations reduced their interest and ability to compete and provide value to consumers. Developer and investor confidence will be critical to success moving forward. The Commission will require scheduled annual solicitations so that developers can prepare their participation.

Annual procurement targets must be established on a forward-looking basis that accounts for the typical lead time needed to develop projects and bring them into operation. Factors to be considered include:

- The amount of investment that can be driven by spot REC markets, and voluntary market activity whether based on REV market activity or customer initiatives intended to be additional to an LSE's compliance requirements;

[81] In furtherance of the ongoing effort to reduce the cost of compliance, NYSERDA should consider and present any options by which the costs associated with the development of a Tier 1 resource and therefore the cost of RECs can be reduced through securitization.

- Expected attrition, i.e., the rate at which executed contracts may fail to result in constructed projects;
- Time-lag and uncertainty in bringing projects into operation; and
- Likely development rates of policy-driven projects; and
- Whether NYPA and/or LIPA will be participating in NYSERDA's procurement process.

In contrast to RPS procurement, NYSERDA's procurement under the RES will be more predictable and reliable from the developers' standpoint thereby enabling the commitment of resources to actively participate in the New York market. Instead of being budget-bounded, RES procurements will be driven by a process that is predictable with established dates for solicitations, fixed targets and clear procurement goals set forth in both the compliance and procurement schedules. To that end, the Commission requires that no less than one solicitation will be conducted during the first half of each calendar year. If the solicitation acquires less than the minimum procurement target for that year, it will be followed by a second solicitation within the same calendar year. For the 2017 procurement period NYSERDA shall establish and publish on its website no later than December 1, 2016, a firm schedule of fixed dates for the annual and potential supplemental solicitations. Details regarding the procurement process from 2018 and following will be addressed in an implementation proposal and order.

The initial Anticipated and mandated Minimum procurement targets for years 2017-2021 will be as follows:

Year	Distribution Utilities & ESCOs	LIPA	NYPA	Direct Customers	Anticipated Procurement Target (MWh)*
2017	1,424,555	242,766	281,087	18,041	1,966,449
2018	1,464,801	249,624	289,028	18,551	2,022,004
2019	1,505,047	256,483	296,969	19,061	2,077,560
2020	1,545,293	263,342	304,911	19,570	2,133,116
2021	1,585,539	270,200	312,852	20,080	2,188,671

* Assumes that NYSERDA will be procuring RECs for NYPA and LIPA customer loads. In the event that NYPA and LIPA do not participate in NYSERDA's procurements, the procurement targets will be adjusted accordingly by reviewing the NYPA or LIPA portions shown in this table.

Year	Distribution Utilities & ESCOs	LIPA	NYPA	Direct Customers	Minimum Procurement Target (MWh)*
2017	1,282,099	218,489	252,978	16,237	1,769,804
2018	1,318,321	224,662	260,125	16,696	1,819,804
2019	1,354,542	230,835	267,272	17,155	1,869,804
2020	1,390,764	237,007	274,419	17,613	1,919,804
2021	1,426,985	243,180	281,567	18,072	1,969,804

* Assumes a 10% attrition rate from the Anticipated Procurement Target

7. Procurement Guidelines

Staff, in consultation with NYSERDA, will propose procurement guidelines for consideration by the Commission as part of the implementation plan. As a default, the part price, part economic development scoring that was previously used in RPS REC contract solicitations for comparing bids shall be

incorporated into the proposed guidelines unless it can be demonstrated to be ineffective. In addition to cost and deliverability, the following additional factors at a minimum should be considered for inclusion in the guidelines and evaluative criteria that will guide selection of projects:

- Viability of the project;
- Time frame for bid acceptance to operation;
- Diversity of resources of the overall portfolio;
- Diversity of owners;
- Alignment with REV goals specified in procurement solicitations;
- Project developer experience; and
- Non-cost economic benefits.

B. Tier 2

Staff proposes that Tier 2 be subdivided between Tier 2a representing renewable resources that are eligible to compete in other states' procurements, and Tier 2b representing renewable resources with no opportunities, likely due to vintage, to sell their resources outside of New York. The distinction is primarily based on concerns that without New York support, facilities with the option to do so will sell their resources into other states' REC programs thereby limiting New York's ability to benefit from them. Concern was also expressed that even with the low level of New York payments proposed by Staff under Tier 2b, the clean energy attributes of certain small hydroelectric facilities in the Tier 2b category would be at risk because the facilities might fail financially and retire for the lack of sufficient overall revenues. Under the RPS program, such small hydroelectric facilities were eligible for

maintenance contracts to ensure preservation of their clean energy attributes.

The facilities that Staff proposes to classify under Tier 2a have all likely already recovered all or most of their initial capital costs and only need to obtain market revenues sufficient to fund their comparatively low, going-forward operation and maintenance costs. These are primarily wind generation facilities that have no fuel costs unlike other large scale electric generation facilities and should be profitable even under today's lower market prices for energy and capacity. While it may be possible that some of these facilities will sell their clean energy attributes into other states, given vintage and delivery requirements in other states it remains merely hypothetical that there will be a mass flight of these resources. Therefore, at this time, there is no imminent risk of losing the emission attributes associated with these facilities permanently and no concomitant need to provide them with additional New York consumer support for those emission attributes. In the event that significant out-of-state sales occur to the detriment of the RES program, the Commission will reconsider the need to compete for these resources in one of the triennial reviews prior to 2030. The Tier 2a concept is not adopted.

Staff’s proposal for Tier 2b includes facilities that by definition do not have competitive opportunities outside of New York because of their size and location. There is no need for a Tier 2b except for the concern that the clean energy attributes of these facilities may be at risk because they may fail financially and retire for the lack of sufficient overall revenues due to the failure of markets to fully internalize the value of their clean energy and fuel diversity benefits. Rather than adopting Staff’s Tier 2a and 2b proposal, the Commission

will instead generally renew the RPS maintenance program in a new Tier 2 of the RES.

Eligibility for the new Tier 2 is limited to run-of-river hydroelectric facilities of 5 MW or less; wind facilities; and biomass direct combustion facilities that were in commercial operation any time prior to January 1, 2003, and were originally included in New York's baseline of renewable resources calculated when the RPS program was first adopted. Each facility seeking funds under this Tier 2 will be required to demonstrate that but for the maintenance contracts, the facility will cease operations and no longer produce positive emission attributes. Maintenance Contracts will be provided on a case-by-case basis and relief will be tailored to the situation presented. The criteria and process for determining eligibility of the facilities is set forth in Appendix D. Eligible costs, which are expected to be limited in relation to the other Tier costs, would be recovered from delivery customers in the same manner as in the RPS Program Maintenance Tier, or from such other sources as the Commission shall determine. Staff will review the current maintenance program, including the eligibility criteria, and propose any changes for consideration as part of the implementation phase.

C. Periodic Review

1. Triennial review process

Beginning in 2020 and each third year thereafter, the Commission will conduct a review of the CES initiative. The triennial review is an integral part of the program, establishing fixed targets on a going-forward basis to provide certainty to market participants. Triennial review will include a divergence test, i.e., an examination of the balance between mandated demand and anticipated supply. Criteria for the divergence test will be developed in the implementation phase.

The divergence test will affect the setting of the targets and will also be used to evaluate the effectiveness of centralized REC-only procurement as described above. The targets established in triennial reviews will also reflect the development of voluntary activity and the portion of the RES attainment wedge to be represented by voluntary activity in the subsequent procurement period. Other issues to be examined in the triennial review include:

- the effectiveness of compliance mechanisms including ACPs;
- changes to eligibility rules;
- application to microgrids and CHP;
- fuel diversity; and
- interactions with RGGI and the federal Clean Power Plan.

2. Interim review

Based on targets established in triennial review, markets bounded by ACPs will supply RECs within a reasonable cost range. As a safeguard against undersupply or oversupply imbalances, Staff will perform at least annually the divergence test which, if the test results fall outside of prescribed ranges, may trigger an interim review by the Commission. Interim review serves primarily as a safety valve against undersupply, but it should also consider potential oversupply situations. If serious imbalances develop, the Commission will consider taking corrective actions to maintain a reasonable level of price stability. Although interim review is an important safeguard, the triennial targets will be presumed reasonable and interim revisions will be undertaken only in unusual circumstances. Compliance flexibility measures

including the ACP should serve to mitigate most short-term divergences.

VII. ZERO-EMISSIONS CREDIT REQUIREMENT

A. Procedural Matters

Staff's White Paper filed on January 25, 2016, proposed that a Nuclear Tier be created to ensure that, to prevent backsliding from the State's efforts to limit greenhouse gas emissions, emission-free attributes from eligible operating nuclear generating plants are properly valued. Under Staff's White Paper proposal, each LSE would be obligated to purchase ZECs from nuclear facilities facing financial difficulty as determined by a Staff examination of the books and records of the facility at a price administratively set by the Commission and updated every year based upon the difference between the anticipated operating costs of the units and forecasted wholesale prices. Importantly, Staff characterized the proposed payments as only setting an appropriate and fair value of the environmental attribute independent of the actual wholesale prices for energy and capacity in the NYISO administered markets. Staff noted that plant owners had already announced the planned closure of the Ginna and FitzPatrick plants, that the Vermont Yankee nuclear plant was closed in December 2014 due to identical concerns, that it was announced that the Pilgrim nuclear power plant in Massachusetts would be closed for similar reasons, and that the economic pressures facing Ginna and FitzPatrick also apply to the Nine Mile Point 1 and 2 plants.

Additional reductions in the price of natural gas occurred during the time between when Staff prepared its analysis and then filed its White Paper. On February 24, 2016, the Commission issued an order further expanding the scope of the CES proceeding and seeking additional comments expressing

its concern that the need for support to maintain the zero-emissions attributes of the nuclear plants is reaching a critical turning point such that expedited action is necessary.[82] The Commission noted that nuclear power plant operation is highly dependent on pre-scheduled fuel cycles, therefore certainty as to the availability and level of maintenance support may be critical to the decision of plant operators to order fuel and commence future cycles, and that these practical operational considerations create urgency that it is likely desirable to put an expedited maintenance support system in place. Attached to the February 24, 2016 order was a secondary proposal for expedited maintenance contracts that was intended to be simpler to implement pending the resolution of the proposed broader program.

In response to the expedited maintenance contract proposal, Entergy remained steadfast in its position that no ZEC program, expedited or not, would cause it as the owner of the FitzPatrick nuclear plant to keep that facility open.

In anticipation that the Commission might approve the expedited maintenance contract proposal, Constellation filed a petition to initiate a proceeding to establish the facility costs for the Ginna and Nine Mile Point nuclear power plants. Case 16-E-0270 (the Constellation Case) was established to consider the petition. That case is being heard here on a common record with Case 15-E-0302, the CES case. The parties in the Constellation Case had an opportunity, pursuant to a protective order to preserve the confidentiality of the commercially sensitive financial details, to participate in

[82] Case 15-E-0302, Clean Energy Standard, Order Further Expanding Scope of Proceeding and Seeking Comments (issued February 24, 2016).

technical conferences examining the confidential financial data of the Ginna and Nine Mile Point nuclear power plants.[83]

Among the many comments received on Staff's White Paper and the expedited maintenance contract proposals, Entergy, the owner of the FitzPatrick and Indian Point nuclear plants, proposed an option of using the social cost of carbon to set the fair value of the environmental attribute as a method to better keep the ZEC price independent of the actual wholesale prices for energy and capacity in the NYISO administered markets than Staff's originally proposed differential between the anticipated operating costs of the units and forecasted wholesale prices. Entergy proposed that its methodology be applied to all nuclear plants. Despite its proposal, Entergy reiterated that no program would cause it as the owner of the FitzPatrick nuclear plant to keep that facility open. Constellation proposed a similar methodology as a back-stop in the event the original methodology failed for any reason. Many of the comments expressed concern that any encouragement by the State of the production of clean generation must be by a methodology that is "untethered" to a generator’s wholesale market participation, but that federal law on what measures are or are not untethered is currently unclear, creating an element of risk for any kind of program.

After consideration of the many comments that were received, Staff prepared and filed on July 8, 2016, Staff's Responsive Proposal. A notice and additional ten-day comment period was provided for parties to comment on Staff's Responsive

[83] Public Citizen Inc. requests that the owners of the nuclear power plants make available full unredacted balance sheet data so that the public can have a better understanding of their profit and so that ZECs can be properly formulated. Pursuant to the protective order, it could have had access to that data if it had participated in the Constellation Case.

Proposal, which was extended to become a full two-week additional comment period. A number of individuals and entities have asked for even more time to comment for the sake of broader participation.

In correspondence with the Secretary about the need to act expeditiously, Constellation, as the owner of R.E. Ginna and Nine Mile Station nuclear electric generating facilities, asserts that it must make critical, multi-million dollar business investment decisions by September 2016 regarding the future of its nuclear facilities that have been losing money, and that those decisions cannot be made in reliance on a mere proposal. According to Constellation, its decision regarding the investment of approximately $55 million to refuel Nine Mile Unit 1 is already overdue if the facility is to be kept in service at the end of the current fuel cycle, and it must make a final decision whether to order fuel no later than the end of September 2016. Additionally, Constellation must file a notice of its intent to continue commercial operations with the Commission by September 30, 2016, and will incur substantial capital recovery balance costs if it does not intend to retire the Ginna facility at the expiration of the current Reliability Support Services Agreement supporting the facility. Constellation states that it will need a contract in hand by September 2016; therefore an order is needed from the Commission by August 1, 2016, to allow sufficient time to finalize a contract for the zero-emission attributes. Constellation also suggests that if there is any hope of saving the James A. FitzPatrick Nuclear Power Plant, the owner must also soon make near-term investment decisions, including a refueling determination. Constellation's subsidiary Exelon Corporation is in discussions with Entergy Corporation to purchase the FitzPatrick facility.

The Notice Extending Comment Period[84] to a full two-week period explained, among other things, the difficult balance between the desire for parties to have sufficient time to prepare their comments and the need to avoid implementing procedures that would defeat potential important Commission objectives or options in addressing the significant policy questions that must be decided. The extensive reasoning on all matters as set forth in the Notice is reaffirmed here and supports the need for the Commission to proceed with deliberate speed and without further extensions of the comment periods.

Regarding the facility cost matters in the Constellation Case, AGREE asserts that the petition is premature given the absence of a policy to subsidize nuclear power plants or a process established by the Commission for determining the cost of ZECs. AGREE believes Staff's Responsive Proposal proves their concerns correct in that Staff proposes a price-setting mechanism irrespective of plant operating costs. MI similarly asserts that the parties should not be expected to address Constellation's projected operating costs in detail given the fact that Staff's Responsive Proposal, if adopted, would render such costs meaningless, but that the Commission should allow for the submission of supplemental comments herein if, following the resolution of CES-related issues, Constellation's projected operating costs are determined to have relevance to potential customer-funded payments that may be awarded.

The parties are correct that the methodology in Staff's Responsive Proposal (later adopted herein with some modifications) does not rely on a detailed finding of the exact costs to operate the affected nuclear plants as might have been

[84] Case 15-E-0302, Clean Energy Standard, & Case 16-E-0270, Constellation Energy Nuclear Group LLC - Facility Costs, Notice Extending Comment Deadline (issued July 15, 2016).

done in a cost-of-service approach, therefore there is no need for further investigation or comments on the detailed costs. But the Commission notes that the in-depth examination of costs did reveal significant information confirming the Commission's concerns that the zero-emissions attributes of the upstate nuclear plants, are at serious risk absent a program to value and pay for the attributes. The Commission is aware that Staff in particular is extremely grateful to the parties that participated in the Constellation Case for the insight they brought to assist Staff in its examination.

B. Public Necessity

Staff proposes that the ZEC program provide a ZEC payment where there exists a public necessity to preserve the zero-emissions environmental attributes of a nuclear generating facility. Staff further proposes that public necessity be determined on a plant-specific basis at the discretion of the Commission, using criteria the Commission finds to be reasonable, on the basis of (a) the verifiable historic contribution the facility has made to the clean energy resource mix consumed by retail consumers in New York State regardless of the location of the facility; (b) the degree to which energy, capacity and ancillary services revenues projected to be received by the facility are at a level that is insufficient to provide adequate compensation to preserve the zero-emission environmental values or attributes historically provided by the facility; (c) the costs and benefits of such a payment for zero-emissions attributes for the facility in relation to other clean energy alternatives for the benefit of the electric system, its customers and the environment; (d) the impacts of such costs on ratepayers; and (e) the public interest.

1. Verifiable Historic Contribution

There does not appear to be any dispute that the FitzPatrick, Ginna, and Nine Mile Point nuclear generation facilities have all made verifiable historic contributions to the clean energy resource mix consumed by retail consumers in New York State regardless of the location of the facility.[85] Their unit-specific contributions are well documented in numerous NYISO reports as well as in the DPS-administered Environmental Disclosure database. The Commission finds that these facilities have provided a significant verifiable contribution to New York State's clean energy resource mix as consumed by New Yorkers.

2. Inadequate Compensation to Preserve Attributes[86]

The Commission accepts Entergy's commercial decision to close the FitzPatrick nuclear generating facility, evidenced by the filing of a Notice of Intent to Retire with the Secretary on November 2, 2015, as proof that the owner was receiving inadequate compensation to ensure that the zero-emissions attributes of the facility will be preserved and that the risk of losing those attributes is a certainty without action by the Commission. In the Constellation Case that makes up a part of the record in these proceedings, the Commission, Staff, as well as other interested parties, have reviewed financial data from the Ginna and Nine Mile facilities. The Commission has already authorized the Ginna facility to retire without further action

[85] The Indian Point nuclear generation facility has also made verifiable historic contributions, but is not included further in this discussion because its zero-emissions attributes are not currently at risk. The owner of Indian Point has not claimed that the zero-emissions attributes of the Indian Point facility are currently at risk.

[86] Units in single ownership located in the same NYISO Zone and that share costs at the same site are treated as a single facility for the determination.

from the Commission in 2017.[87] The information demonstrates that the projected revenues fall well short of anticipated costs, which seriously jeopardizes the preservation of the zero-emissions attributes of these facilities.

3. BCA in Relation to Alternatives

Considering the anticipated costs of the ZEC program against the benefits related to the large amount of zero-emission power the facilities will produce,[88] the benefits clearly outweigh the costs. Indeed, during the first two years of the program, the total attribute payments are calculated to be up to $965 million, achieving a carbon-alone benefit of $1.4 billion. If more of the value of the carbon-free attributes becomes internalized into the forecasts of energy and capacity prices in New York, as expected, it will result in reductions of the ZEC attribute payments adopted here. Further, given that the model adopted here locks in 12 years of significant carbon emission reductions at a fraction of the benefit to be achieved, New York customers will continue to benefit for years to come.

AGREE and NIRS suggest that because the marginal cost of additional increments of energy efficiency compares on a cost basis favorably with ZEC unit costs, it provides an alternative to nuclear plant retention. As noted elsewhere in this Order, the Commission is working to ensure that the potential of energy efficiency is maximized in New York. However, it is simply unrealistic to assume that sufficient additional energy efficiency measures could be identified and implemented in time to offset the 27.6 million MWh of zero-emissions nuclear power

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[87] Case 14-E-0270, Proposal for Continued Operation of the R.E. Ginna Nuclear Power Plant, LLC., Order Adopting the Terms of a Joint Proposal (issued February 24, 2016), pp. 29-30.

[88] Upstate New York nuclear-power generating facilities are expected to produce approximately 27.6 million MWh of zero-emissions power per year.

that would need to be replaced per year. For example, even if the incremental energy efficiency rate could be increased by 25% per year above the projected rate, only 13% of the cumulative zero-emissions MWh produced by the nuclear plants would be offset during the 12-year duration of the program. To offset all of the cumulative zero-emissions MWh the annual incremental rate of energy efficiency would have to be tripled to 6.6 million MWh per year.

The marginal cost of additional increments of renewable resources is expected to always be significantly higher than ZEC prices. In periods where market revenues are expected to be low, both ZEC and REC prices will tend to be high, with REC prices projected to be higher than ZEC prices. In periods where market revenues are expected to be high, ZEC prices will fall, perhaps all the way to zero, but REC prices, while lower too, may not. In any event, under the RES the Commission is pursuing new renewable resources at an ambitious pace. As in the case of energy efficiency, it is not realistic to assume that sufficient additional renewable resources at a reasonable price or perhaps any price could be identified and implemented in sufficient time to offset the 27.6 million MWh of zero-emissions nuclear power per year. For example, replacing all the 27.6 Million MWh of zero-emission energy with renewable resources would require 9,000 MW of onshore wind or 22,000 MW of solar deployment. It is virtually impossible to deploy this magnitude of resources in the short-term.

4. Cost Impacts on Ratepayers

The Commission has reviewed the potential customer bill impacts of these investments and finds them to be reasonable, particularly in the context of today's historically low commodity costs. The expected bill impact for a residential customer using the statewide average monthly usage of about 600

kWh is less than $2 per month in the first tranche. Since the cost of maintaining the zero-emissions attributes of the nuclear plants will be recovered on a volumetric energy consumption basis from all the LSEs, the expected impact on the State's higher load factor commercial and industrial customers will be higher and vary depending on their level of energy intensity. Such customers frequently benefit from low-cost power and/or reduced delivery charges resulting from their participation in various economic development programs offered by the utilities or NYPA. Additionally, the future ZEC prices can decline if market energy and capacity price forecasts go up; perhaps all the way to zero.

5. Overall Public Interest

Retention of the zero-emissions attributes of New York's upstate nuclear plants would avoid the emission of approximately 15 million tons of carbon per year. Losing the carbon-free attributes of nuclear generation, before the development of new renewable resources between now and 2030, would undoubtedly result, based on current market conditions, in significantly increased air emissions due to heavier utilization of existing fossil-fueled plants or the construction of new gas plants. The added emissions would complicate the State's compliance with likely federal carbon standards and would result in dangerously higher reliance on natural gas, radically reducing the State's fuel diversity and making consumers more vulnerable to natural gas and concomitant electric price spikes.

Applying the public necessity criteria described above, the Commission determines that there is a public necessity to provide ZEC payments to the FitzPatrick, Ginna and the Nine Mile Point facilities. The Commission finds that it is in the public interest to provide these ZEC payments for the purpose of maintaining the emission-free attributes because

there are insufficient zero-emission alternatives available to replace them any time soon. Retention of the upstate nuclear facilities would also help maintain fuel diversity and fuel security. The facilities in question represent significant investment in infrastructure, are operational, and have excellent safety records.

This determination of necessity in no way undermines the Commission's commitment to meeting the SEP's goal of having 50% of the State's electricity be generated by renewable resources by 2030. As Staff's proposal makes clear, the obligation of LSEs to purchase ZECs will be independent of the obligations imposed herein to encourage generation utilizing renewable resources. Ideally, as markets and technologies develop and more renewable generation becomes available, nuclear power could be replaced by those alternatives. In the near-term, however, the Commission is convinced that it is essential to keep these zero-emissions attributes available for New York consumers.

AGREE characterizes the ZEC proposal as contrary to the Commission's action in 1996 of divesting generation from utilities, where the Commission acted to shield ratepayers from the economic risks of failing power plants. This is an entirely different situation. The ZEC proposal does not leave the stranded costs of a closed facility on the shoulders of ratepayers. Quite to the contrary, it provides a mechanism to preserve the zero-emissions attributes these facilities are providing. Qualifying facilities will be paid for the value of the ZEC attributes, not reimbursed for costs stranded by their market position.

C. ZEC Price Formula Mechanics

Staff proposes that the ZEC contracts be administered in six two-year tranches with the price paid for the ZECs being

updated for each tranche pursuant to a set formula that provides certainty as to how the prices will be set. Staff proposes that the Tranche 1 ZEC price be based upon the average April 2017 through March 2019 projected SCC as published by the USIWG in July 2015 (nominal $42.87/short ton). The proposal then subtracts a fixed baseline portion of that cost that is already captured in the market revenues received by the eligible facilities due to the Regional Greenhouse Gas Initiative (RGGI) program based upon the average of the April 2017 through March 2019 forecast RGGI prices embedded in the CARIS Phase 1 report (nominal $10.41/short ton).[89] This yields a Tranche 1 net cost of carbon of $32.47 (nominal $/short ton), and a ZEC price of $17.48 per MWh.[90]

The Commission notes Staff's caveat that this approach may not make sense for establishing a ZEC price for the downstate Indian Point facility because of its location. Indian Point is located in an area of higher electric system constraints and has a much higher level of market revenues. At this time, the Indian Point zero-emissions attributes are not at risk. However, the Commission reserves the right should the Indian Point attributes become at risk, to possibly calculate the ZEC price to reflect the difference between upstate and downstate market revenues in order to put downstate facilities on an equal footing with upstate facilities. A methodology to calculate the upstate/downstate price differential may be developed if its use becomes necessary.

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[89] The need for an administratively determined price results from too few owners of the affected facilities for there to be a valid competitive process.

[90] Staff's Responsive Proposal provided detailed calculations behind this price. They are also provided in Appendix E.

Staff proposes that for the contract periods of Tranche 2 through Tranche 6, the ZEC prices would be calculated pursuant to a formula by tranche. In general concept, the formula is as follows:

Social Cost of Carbon - **Baseline RGGI Effect** - **Amount Zone A Forecast Energy Price and ROS Forecast Capacity Price combined exceeds $39/MWh** = **ZEC Price ($/MWh)**

1. Social Cost of Carbon

Staff proposes that the Social Cost of Carbon component (nominal $$ per short ton of CO_2) would be fixed by tranche based on SCC estimates published in July 2015 by the USIWG, as follows:

Period	SCC
Tranche 2	$46.79
Tranche 3	$50.11
Tranche 4	$54.66
Tranche 5	$59.54
Tranche 6	$64.54

API expresses concerns about the certainty of the USIWG estimates because it believes they were not subject to a rigorous federal notice, review and comment process. MI characterizes the estimates as highly controversial and having not been subject to independent analysis or shown to be an accurate measure of savings if emissions are avoided. MI also notes that internalizing the SCC benefits society at large, not New York. NYC expresses concern that there is no link between the value of carbon and the ZEC payment needed to maintain the operation of the nuclear plants.

NYU Institute for Policy Integrity supports use of the SCC as the best available estimate of the marginal external damage caused by carbon dioxide emissions. Pace applauds the

proposal as an important first step in pricing the cost of carbon into energy consumption more broadly. Environmental Progress states that putting a monetary value on the benefits provided by zero emissions nuclear power derived from the federal government's estimate of SCC is a common-sense principle. The Indicated Joint Utilities state that basing the price of ZECs on the SCC, adjusted by removing the RGGI value embedded in rates, is a reasonable method to establish the emissions credit value that is not reflected in electric prices. CENG stated that compensating nuclear facilities based on the SCC is consistent with the programs' original environmental purpose and appropriately values the environmental attribute that nuclear facilities provide.

Indicated Suppliers (IS) argue that Staff's Responsive Proposal will significantly harm the NYISO wholesale competitive electricity market by artificially suppressing installed capacity (ICAP) prices thereby dis-incenting development of new capacity. Further, it claims that the proposal is a discriminatory and inefficient tool to meet the State's clean energy goals. As previously noted, FERC has determined that attributes credit payments do not interfere with wholesale competition. Instead, it argues that unless the RGGI emissions allowance cap is substantially reduced to increase RGGI auction prices to the level of the social cost of carbon, which is not anticipated in Staff's Responsive Proposal, all other resources in New York that provide carbon emissions reductions benefits will receive less than one fourth of the price that the uneconomic nuclear facilities receive for providing the same benefits.

IS is incorrect. The proposal is neither inefficient nor an attempt to artificially suppress wholesale prices. It does not establish wholesale energy or capacity prices, it only

establishes pricing for attributes completely outside of the wholesale commodity markets administered by NYISO. To the contrary, it addresses a well-recognized externality that otherwise would lead to economic inefficiencies with respect to the costs incurred due to environmental damage, in particular, climate change. Failing to adequately account for these costs has led the world's best scientists and economists to warn that inefficiencies caused by this externality will be significant unless action is taken immediately.[91] In this case, failing to recognize this externality will lead to the uneconomic loss of significant zero-emissions attributes. But such losses and the related permanent environmental damage, is unnecessary if the value of zero-emissions attributes is better recognized.

Further, IS's suggestion that the only solution is to reduce RGGI caps and raise RGGI prices to the federal SCC is flawed. It fails to recognize the alternative ways the State can improve on the status quo. Raising the RGGI price is not within the State's unilateral control and is clearly not the only way to incent clean generation and conservation in an efficient manner. Indeed, each of the RGGI States have renewable portfolio standards that they apply to supplement and help implement RGGI's overall objective of reducing carbon in electric supply.

The cost to consumers of reducing the RGGI caps until wholesale energy market prices increase by $17.48/MWh would be about $2.8 billion dollars in the first year alone, or almost

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[91] See, e.g., IPCC, 2014: R.K. Pachauri and L.A. Meyer, "Climate Change 2014: Synthesis Report, Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change"; IPCC, Geneva, Switzerland, p. 151; William Nordhaus, The Climate Casino: Risk, Uncertainty, and Economics for a Warming World (New Haven: Yale University Press, 2013).

six times higher than the costs of Staff's Responsive Proposal (this could be partially offset by additional RGGI revenues). A residential customer using the statewide average monthly usage of about 600 kWh per month would see a bill increase of over $11 per month under this alternative. Meanwhile, the only incremental emissions reductions of this approach identified by the Independent Market Monitor would be the potential construction of a 300 MW gas-fired combined cycle plant on Long Island, which could provide lower emissions relative to existing, less efficient gas-fired units.[92]

Based on the comments received, the USIWG value of the SCC is the best available estimate and will be adopted. Notably, the USIWG value was developed by the Environmental Protection Agency in extensive coordination with other federal agencies. As noted earlier, the Commission has previously directed that avoided CO_2 emissions be valued at the SCC, less the RGGI value already internalized" in the bulk power market.[93] Those opposed to its use do not offer a method of setting ZEC prices by alternatively valuing the damage caused by carbon emissions. Instead, NYC and others propose different methodologies that fail to recognize the need to keep the ZEC pricing methodology untethered to a generator's wholesale market participation.

MI questions why future estimates of the SCC, which increase from year to year, then should be adjusted by inflation. The USIWG's SCC central values are expressed in constant 2007 dollars per metric ton, and reflects the federal group's estimation that the climate change damage caused by carbon emissions will increase over time. Staff correctly

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[92] See 2015 State of the Market Report, pp. 17 and A-24.

[93] Case 14-M-0101, supra, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016), p. 13.

inflated the 2007 values to nominal year values by using the gross domestic product implicit price deflator, since the purchasing power of the dollar is forecast to decrease over time.

MI also questions why the SCC values are based on a 3% discount rate when using a larger discount rate, such as 5%, would be more appropriate and less expensive. This issue has been previously settled in the BCA Order wherein the Commission adopted the central SCC values after consideration of party comments. Use of SCC values in the ZEC formula based on the central value 3% discount rate is approved consistent with the Commission's prior determination.

2. Baseline RGGI Effect

Staff proposes that the fixed baseline portion of the SCC already captured in the market revenues received by the eligible facilities due to the RGGI program be subtracted from the SCC at the same fixed amount for all tranches at a nominal $10.41/short ton. Staff notes that the energy price forecast part of the adjustment in the methodology would capture forward-going changes due to RGGI.

Some parties (e.g. MI, the Indicated Joint Utilities) urge that RGGI values not be held constant in future tranches. MI states that if RGGI allowances are reduced, the impact of RGGI on wholesale energy prices might be much higher in the future. The Indicated Joint Utilities agree with the approach of estimating RGGI values using the CARIS forecasts of RGGI prices, but offer that RGGI prices should follow the CARIS model to increase over time, either at the SCC escalation rate or the rate of inflation.

Staff's Responsive Proposal held RGGI prices constant in the ZEC price formula since increases in RGGI prices are expected to be reflected in the Forecast Energy & Capacity Price

Change Adjustment. The Commission agrees with Staff that inflating the RGGI offset in future tranches would constitute a double count when combined with the Adjustment. If for some reason increased RGGI prices failed to be reflected in Zone A energy price forecasts due to transmission constraints between upstate and downstate, the upstate nuclear units would receive reduced market revenues and therefore no additional offset to the SCC would be warranted.

3. Conversion Factor $$/Ton to $$/MWh

Staff proposes the use of a fixed 0.53846 conversion factor for all tranches to convert the SCC figures from $$/short ton to $$/MWh.[94] The conversion factor is based on the emissions rates of the mix of resources that would be avoided by the preservation of zero-emissions attributes. Indicated Joint Utilities believe the conversion factor used to reflect the quantity of carbon emissions avoided per MWh should be updated in future tranches to reflect changes that will occur in the resource mix.

While the Commission does not expect there to be radical swings in the resource mix over short time periods, the duration of the program is such that as cleaner resources enter the mix, continuing to use the current factor may overstate carbon value. The Staff Responsive Proposal utilized a marginal carbon emissions rate of 0.53846 short tons per MWh. This rate

[94] The 0.538456 is made up of contributions from natural gas, coal and oil on the margin. "The Benefits and Costs of Net Energy Metering in New York," Energy and Environmental Economics, Inc., December 11, 2015, p. 57, submitted December 17, 2015 in Case 15-E-0703 – In the Matter of Performing a Study on the Economic and Environmental Benefits and Costs of Net Metering Pursuant to Public Service Law §66-n.

was developed in the 2015 Net Metering Study[95] and measures the change in system emissions due to an incremental change in resources. The use of this rate is conservative, as the elimination of up to 27,618,000 MWh of nuclear zero-emissions attributes would likely lead to an increased reliance, at least in the near-term, on higher-emitting resources such as coal, oil, less efficient gas, and imports. Parties have pointed out that as the system mix changes, it may be appropriate to reduce the marginal emissions rate in the event that a significant amount of incremental renewable resources are built. The Commission agrees with this assessment, and believes that when setting the marginal emissions rate the formula must be forward-looking regarding the possible change in the rate that increasing amounts of renewable energy might bring about.

Given the forecasts under the RES, a material change is not expected to the marginal emissions rate due to additional renewable energy penetration in the near-term. However, beginning with Tranche 4, the total amount of renewable energy consumed in the State will be used to determine if a reduction in the marginal emissions rate is warranted. Tranche 4, which will cover the April 2023 through March 2025 time period, will use a marginal emissions rate based on the renewable energy consumed in the State during calendar year 2022. If this level is over 50,000,000 MWh, the marginal emissions rate will be adjusted downward. The amount of the adjustment will be 0.00491 tons per MWh for each 1,000,000 MWh of renewable energy consumed above 50,000,000 MWh.[96] Under this methodology, should the State

[95] See id.

[96] This adjustment factor is designed so that the marginal emissions rate begins to fall once 50,000,000 MWh of renewable energy is achieved, and a rate of 0.45 tons per MWh is reached when 68,000,000 MWh of renewable energy is achieved.

achieve a level of renewable energy consumed of 68,000,000 MWh (a level approximately 27,000,000 MWh above the 2014 baseline amount), the marginal rate will be 0.45 per MWh. This is a reasonable result, as an incremental 27,000,000 MWh of renewable energy would be approximately enough to replace all of the upstate nuclear plants' zero-emissions attributes. It is anticipated that this level of renewable energy usage would allow the marginal emission rate to reach a level consistent with natural gas units being on the margin.

For Tranche 5, the 2024 calendar year renewable energy level will be used (again, with a marginal emissions rate of 0.00491 per 1,000,000 MWh of renewable energy consumed above 50,000,000 GWh). For Tranche 6, the calendar year 2026 renewable energy level will be used. This approach will recognize the emissions impact of significant additional renewable energy, while providing a further incentive to ramp up renewable energy penetration New York.

4. Forecast Energy & Capacity Price Change Adjustment

For Tranches 2 through 6, Staff proposes to use changes in independently published forecasts of going-forward energy and capacity prices to adjust the ZEC price (downward only so as not to exceed the SCC) by the amount that future forecasts predict that NYISO Zone A energy prices combined with the Rest of State (ROS) capacity prices will exceed $39/MWh. NYISO Zone A and ROS were chosen as relevant proxies that have liquidity and available data. These components measure only the change in forecasts over time; they do not establish energy or capacity prices. The $39/MWh baseline figure approximates a recent period average of the forecasts of Intercontinental Exchange (ICE) of the NYISO Zone A energy prices projected by ICE for the period April 2017 through March 2019 combined with the per MWh equivalent of a recent period average of the

forecasts of New York Mercantile Exchange (NYMEX) NYISO Rest of State Capacity Calendar Month Futures projected by NYMEX for the period April 2017 through March 2018.[97]

Various parties (e.g. Nucor, AGREE) incorrectly interpret the $39/MWh baseline figure in the adjustment mechanism to be either an estimate of the market revenues that the upstate nuclear plants are currently receiving, or a floor price that they would be paid in the future for energy and capacity. Both of those interpretations are incorrect. Based on that misinterpretation, Nucor mistakenly concludes that the formula would result in combined market and ZEC payments to the upstate nuclear plants of $56.48/MWh (the sum of the $39/MWH Zone A market price forecasts and the $17.48/MWh ZEC price), or more forecasted revenue than Constellation requested in the Constellation Case for its Ginna and Nine Mile Point facilities.

The upstate nuclear units, which are located in NYISO Zones B and C, do not receive market energy revenues at the Zone A LMP price. Zone A was chosen as a reference price solely for the mechanics of the adjustment mechanism because of the availability of regular ICE and NYMEX forecasts based on sufficiently liquid transactions. That same quality of independent forecasts is not available for Zones B and C. It must be understood that the reference price forecast does not act within the formula to establish a quantity of energy and capacity revenues. As a deliberate intention, no part of the formula establishes energy or capacity prices or revenues. Rather, the Zone A forecasts are used in the Adjustment to measure only the change in independent forecasts over time.

A significant basis differential exists between the Zone A prices and the prices within Zones B and C at the

[97] See Appendix E.

connection points called "busses" where the revenues paid to the nuclear facilities are determined. A forecast of approximately $39/MWh at Zone A is inclusive of about $6/MWh equivalent for the capacity forecast for "Rest of State" based on recent 12-month forecast prices and about $33/MWh for energy. When the $33/MWh LMP forecast is adjusted for the recent 12-month basis differential between Zone A and the nuclear unit busses of about $6/MWh, the generator energy revenues forecast becomes only about $27/MWh. Notwithstanding the capacity price forecast of $6/MWh, if the most recent 12-month period actual capacity revenues of $3/MWh equivalent is utilized as potential revenue to the generator, then the total revenue the generator is expected to receive would be only $30/MWh at the relevant busses for energy and capacity.[98] The $56.48/MWh computed by Nucor should be $47.48/MWh (the sum of the $30/MWh at-the-busses market price forecast and the $17.48/MWh ZEC price). That forecasted level would be less than the level of revenue that Constellation requested in the Constellation Case for its Ginna and Nine Mile Point facilities.[99]

The Indicated Joint Utilities believe that it would be reasonable to include a basis differential update in the mechanism. It is true that the current level of basis could be

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[98] Using a $3/MWh capacity price expectation is reasonable, rather than the $6/MWh capacity price referenced in the Staff Responsive Proposal, because at the time of the $6/MWh forecast, the market would have been factoring in the closure of both the Ginna and FitzPatrick plants. If these plants continue to operate, the capacity revenues will presumably be lower.

[99] In the Constellation case, the cost study presented was for Nine Mile and Ginna plants for a weighted average cost of $49.60/MWh. FitzPatrick cost data is not included and as it is a single unit facility, its costs would be higher than the blended average of the Nine Mile and Ginna plant costs, driving the total weighted average cost above $49.60/MWh.

an anomaly compared to historic lower levels. If the basis differential goes down, the revenue the generator would receive increases, all else equal. The formula could be adjusted to subtract the change in the basis differential from the $39/MWh reference price. While again, the Commission does not expect there to be radical swings in the differential basis over short time periods, the duration of the program is such that the formula should be updated in Tranche 4, half way through the contract period.

The basis differential is dependent on the electric system configuration and especially the congestion patterns in the region. There are efforts to address Western New York congestion and it is likely the basis differential will change in the future. However, these changes will not happen overnight and will take some time. In order to capture the effects that changed congestion patterns will have on the basis differential, the $39/MWh reference price used in ZEC price formula will be updated one time, at the time of the Tranche 4 ZEC price is determined.

The one-time update will be calculated by determining the historic basis over the 2017-2022 time period and adjusting the $39/MWh reference price used in the ZEC price formula if the historic basis is outside of a range of $5-$7/MWh. The exact methodology is described in Appendix E.

5. Contract Duration

Comments were received from several parties regarding the duration of the ZEC requirement. The major theme of these comments was that if the Commission should approve a ZEC mechanism, the design and duration of the mechanism should be such that it can be modified or eliminated if market-based solutions develop or if the energy resources in New York are such that supporting the nuclear facilities is no longer

necessary. MI and some others suggest that in future tranches, the Commission should review whether the public interest criteria would still be satisfied.

Of those that indicate a preferred duration of the ZEC requirement, MI advocates for the shortest time period. It states that a time period of two years, or ideally no longer than the refueling cycles of the plants (e.g. 18-to-24 months), would be best. MI points out that the energy markets are continually evolving, so customers should not be locked into binding agreements through March 2029. MI also states that energy and capacity prices may not act in a manner which would lead to Staff's Responsive Proposal making sense over the full 12 years.

Like MI, Nucor is concerned with the proposed 12-year duration of the ZEC mechanism and states that the term of the program should not extend beyond 2020. Nucor urges that the proposal only lead to a bridge to a market-compatible approach. Nucor states that by 2020, it would be possible to revise NYISO's market-based tariff products and implement a new ZEC requirement that would be consistent with the revised market-based tariffs.

National Grid proposes a period of six years for the ZEC mechanism. It counsels that this time period is long enough to provide the nuclear plant owners with a reasonable level of financial certainty, while giving the Commission time to reassess if the nuclear plants are even still needed. National Grid expresses concern that a 12-year contract could delay the transition to a post-nuclear future which will be based on renewable energy. Further, National Grid says that market-based solutions to keeping the nuclear plants open could be developed, negating the need for the ZEC requirement.

The Indicated Joint Utilities do not propose any specific duration for the ZEC requirement, but agree that it was important to build in the flexibility to respond to future wholesale market and CO_2 allowance market development. Similarly, Pace states that the mechanism should be flexible so that given the State's evolving energy resource mix, it does not continue past the point where it is needed.

The Commission approves the 12-year duration for the program in six two-year tranches. As in the case with the RES, durability is important to the program's success. Under the RES program developers of new renewable facilities are to be offered 20-year REC contracts to provide sufficient certainty to induce them build new generation facilities. Just as it is unreasonable to expect an investor to make a long-lived capital investment without a revenue stream that is durable and certain, a purchaser will not invest in FitzPatrick without similar assurances. In the case of FitzPatrick, the magnitude of the risk taken on in the investment far exceeds refueling costs and capital improvements because a new owner must assume the risks of the ownership as part of the transaction. Given the continuing significant long-lived investments required for all of the units, a long-term contract providing certain terms is warranted. The long duration also has the considerable benefit of ensuring that the zero-emissions attributes will be preserved for a considerable period of time to give the RES program an opportunity to provide new renewable resources on a scale necessary to prevent backsliding on carbon emissions. The 12-year duration however will be conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018, the date six months before the commencement of the period of Tranche 2. If the sale and closing does not occur, there will be no commitment for the program to continue

beyond Tranche 1 and the Commission will have six months before the otherwise-planned commencement of Tranche 2 to determine a future course of action, if any. Similarly, the program and especially the caps on eligible production of ZECs is designed to preserve the zero-emissions attributes of all of the qualifying facilities and NYSERDA as the contract administrator shall ensure that contracts for all of the facilities are in place before any of the contracts are allowed to become effective.

The Commission also agrees and determines that the design and duration of the mechanism shall be such that it can be modified or eliminated by the Commission if there is a national, NYISO, or other program instituted that pays for or internalizes the value of the zero-emissions attributes in a manner that adequately replicates the economics of the program such that the Commission in its sole discretion is satisfied that the zero-emissions attributes are no longer at risk and that discontinuing the mechanism can be done in a manner that is fair to both the facility owners and the ratepayers.

6. Contract Performance

Staff proposes that the amount of ZECs to be purchased on an annual basis will be capped at a MWh amount that represents the verifiable historic contribution the facility has made to the clean energy resource mix consumed by retail consumers in New York State. Staff further proposes that each facility have an obligation to produce the ZECs and to sell them to NYSERDA through March 31, 2029, except during periods when the calculated ZEC price pursuant to the contract is $0. Finally, Staff proposes that the obligation to produce be enforced by appropriate financial consequences for failure to produce. Some parties have also advocated that the contract

between NYSERDA and the generators should include performance factors to hold the generators accountable for performance.

While the verifiable historic output of zero-emissions MWhs of the FitzPatrick, Ginna, and Nine Mile Point facilities has varied from year to year, the sum of the most recent four quarters of production, July 2015 through June 2016, is the most recent and is a reasonable measure of their output and will be applied as the MWh cap on an annual basis requested by Staff. Therefore, the amount of ZECs to be purchased on an annual basis will be capped at that amount, which sums to 27,618,000 MWh. The FitzPatrick plant, so long as it remains in ownership separate from the other facilities, shall have an individual cap and obligation of 25.4% of the total or 7,014,972 MWhs (based on a multi-year historic average). The Ginna and Nine Mile Point facilities under common ownership shall have a group cap and obligation of the remaining 74.6% of the total or 20,603,028 MWhs. If the FitzPatrick facility is acquired by the owner of the Ginna and Nine Mile Point facilities, the caps will all be combined and treated as a single group.

Clearly the mechanism that pays for ZECs on a per unit output basis provides incentives for the generators to maximize output. These plants have been performing at a very high level of performance. The intent of the ZEC program is to preserve the zero-emissions attribute benefits of the facilities to prevent backsliding in the State's carbon reduction performance that likely could not be avoided in any other way. However, the scale of the investment being made warrants further protections against poor short-term performance. A performance mechanism will be included in the contract between NYSERDA and the plant owners. The Ginna and Nine Mile Point facilities under common ownership will be treated as a group for these purposes. The FitzPatrick facility when in separate ownership from the other

facilities shall be considered a group of one for these purposes. If the FitzPatrick facility is acquired by the owner of the Ginna and Nine Mile Point facilities all three facilities will be considered together as a group for these purposes. If the facilities in a group perform in any tranche period at less than 85% of their group MWh cap and obligation for the tranche period, then the cap and obligation for the next tranche period for the group will be reduced by 1,000,000 MWh if all three facilities are in the group; 666,666 MWh if two facilities are in the group, and 333,333 MWh if only one facility is in the group. After the next tranche in which the facilities in a group perform at or above the new lower cap and obligation, the original cap and obligation will be restored for the subsequent tranche.

7. Facility Closure Contingency

Should any of the three facilities (FitzPatrick, Ginna and Nine Mile Point[100]) permanently cease producing zero-emissions attributes for any reason whatsoever the overall cap of 27,618,000 MWh will be reduced by one-third for each facility that permanently ceases producing zero-emissions attributes. Therefore, if one of the facilities ceases producing zero-emissions attributes, the overall cap will be reduced to 18,412,000 MWh; if two of the facilities cease producing zero-emissions attributes, the overall cap will be reduced to 9,206,000 MWh. These requirements will act both as an incentive to the facility owners to keep all of the plants operating, and to ensure that the continuing program keeps the original balance between ratepayer and generator interests. The reductions will

[100] Nine Mile Point Units 1 & 2 qualified jointly as a single facility. If either unit permanently ceases producing zero-emissions credits, it will be treated as if the entire qualified Nine Mile Point facility has permanently ceased producing zero-emissions credits.

be pro-rated within a tranche period to the date upon which the facility permanently ceased producing zero-emissions.

8. LSE Obligations and Allocations

Staff proposes that each LSE, including NYPA and LIPA, be required to encourage the preservation of the environmental values or attributes of qualified zero-emissions nuclear-powered electric generating facilities for the benefit of the electric system, its customers and the environment by purchasing an amount of ZECs per year of the total amount of ZECs purchased by NYSERDA in proportion to the electric energy load served by the LSE in relation to the total electric energy load served by all LSEs in the New York Control Area. The ZECs obligation is separate from any obligation on LSEs to encourage generation utilizing renewable resources.

MI and Nucor raise concerns regarding the volumetric cost allocation, pointing out that nuclear costs have traditionally been recovered through delivery rates (physical plant) and energy prices. MI and others urge that NYPA customers should not pay any ZEC cost, as they have the ability to leave the State and go where there is no subsidy for the nuclear plants. They state that NYPA rates are for economic development, and such rates have not traditionally been charged for similar subsidies (e.g. SBC, RPS). Similarly, NYAPP urges that municipal and cooperative utilities should be exempted from the obligation to purchase ZEC’s from NYSERDA based on the Commission's long-standing recognition of the unique nature of municipal utilities and co-op’s which in the past has resulted in exemption from similar policies. For instance, in 2003, they were exempted from the Renewable Portfolio Standard because NYAPP members had already exceeded the proposed target, so additional requirements were not appropriate. NYAPP urges that the same rational applies to the Clean Energy Standard in

general and ZEC's in particular because as a group, 86% of NYAPP energy comes from renewable resources, namely NYPA's Niagara Project. NYAPP says that it has demonstrated that it can meaningfully contribute to the State's clean energy goals even in the absence of mandatory requirements. Further, a mandate to purchase ZEC's may be counterproductive, inhibiting NYAPP's or NYPA's ability to develop innovative proposals to advance the State's clean energy goals.

NYPA commented that given the importance of retaining nuclear resources for New York's clean energy and emissions reduction goals, and subject to any directive from its Board of Trustees following finalization of the initiative, NYPA fully intends to comply with the Staff Responsive Proposal. LIPA also supports Staff's Responsive Proposal stating that LIPA staff intends to seek the approval of its Board of Trustees and applicable regulatory authorities to enter into the necessary agreements to procure its appropriate share of zero-emissions credits and to receive its appropriate share of such revenues as a co-owner of the Nine Mile Point 2 Nuclear Station, in accordance with the requirements to be adopted by the Commission.

AGREE urges exemption of customers who have voluntarily purchased extra renewable resources above and beyond that prescribed by the Clean Energy Standard as forcing these customers to pay for ZEC's on top of the premium for renewable resources will reduce the amount of funds they would have otherwise spent on renewable power and be a disincentive to voluntarily purchase additional renewable resources that would run counter to the State's clean energy goals. Similarly, ClearChoice Energy, an ESCO, argues that ESCOs that provide 100% renewable energy to their customers should not be required to purchase ZECs that subsidize nuclear facilities. ClearChoice

Energy notes that while nuclear power is zero-emission, it is not a renewable resource, and therefore, to the extent that LSEs that provide renewable energy to customers are forced to subsidize nuclear resources, there will be a double payment. ClearChoice Energy proposes a narrow exception that would exempt ESCOs that provide 100% renewable energy to their customers. AGREE also opposes allocating ZEC purchases based on electric usage that will impose costs on downstate consumers who will receive few direct benefits due to transmission constraints.

PULP asserts that the program places disproportionate costs on low-income and fixed-income customers and that more weight should be given to avoiding bill impacts and to avoid undermining the newly created statewide low-income/fixed-income rate reduction program.

The Commission has considered the requests for exemptions and is of the opinion that the threat to the preservation of the zero-emissions attributes of nuclear facilities is a general threat that affects all ratepayers and is of such a scope that the costs of protection should be spread as broadly as possible. The ZECs program obligation on LSEs is a separate obligation from the RES and is not satisfied by supporting renewable resources of whatever quantity. Applying the obligation on a volumetric basis is a rational and the most appropriate basis to broadly allocate the costs given the nature of carbon emissions that are a creature of the volume of electric generation and consumption. The Commission is instituting this program to prevent widespread damage from carbon emissions that affect everyone. It is fair and appropriate for all consumers to participate. Accordingly, the Commission directs each LSE that serves end-use customers in New York, beginning April 1, 2017, for the benefit of the electric system, its customers and the environment, to purchase the

percentage of ZECs purchased by NYSERDA in a year that represents the portion of the electric energy load served by the LSE in relation to the total electric energy load served by all such LSEs. LSEs will make ZEC purchases by contract with NYSERDA and will recover costs from ratepayers through commodity charges on customer bills.

9. Conclusion

Staff's research, the comments received in this proceeding and the Commission's review of the arguments made all point the Commission toward an undeniable conclusion that preservation of the zero-emissions attributes of New York State's existing upstate nuclear facilities in the near future is crucial in the strategy to fight climate change and to achieve New York State's commitment to reduce carbon emissions. Further, as Staff points out, the benefits of maintaining these attributes far outweighs the costs.

The Commission finds Staff's Responsive Proposal, in which it recommends paying ZEC payments to zero-emissions attributes based upon the social cost of carbon to be fully consistent with the Commission's approach in setting guidelines for Benefit-Cost Analysis.[101] As emphasized by the Institute for Policy Integrity, the value of avoided carbon emissions is most accurate if tied to the value of the avoided external damage, or the value of avoiding the carbon emissions that would be emitted

[101] Case 14-M-0101, Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016), pp. 17-19.

if zero-carbon generators are replaced by other generators.[102] Further, this model more closely ties the pricing mechanism for ZECs to the environmental attribute, leaving no doubt that it falls squarely within the State's exclusive jurisdiction. Therefore, the Commission adopts Staff's Responsive Proposal, as modified and set forth in Appendix E, for a mechanism and a price for zero-emissions attributes of nuclear zero-carbon electric generating facilities where public necessity to encourage the continued creation of the attributes is demonstrated. This adoption of the Zero-Emissions Credit Requirement is a changed regulatory requirement for the purposes of the UBP.

Each Load Serving Entity is directed to enter into a contractual relationship with NYSERDA to periodically purchase ZECs during a program year based on initial forecasts of load and a balancing reconciliation at the end of each program year. In this manner, after the reconciliation process, each Load Serving Entity will have purchased the correct proportion of ZECs on an annual basis. In accordance with Staff's proposal, that ZECs will not be tradable except between NYSERDA and the Load Serving Entities during this balancing process.

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[102] Comments of the Institute for Policy Integrity, New York University School of Law (filed April 22, 2016), p. 16; see also, Reply Comments of Constellation Energy Nuclear Group, LLC Concerning Staff White Paper on Clean Energy Standard (filed May 13, 2016), p. 13. It is significant to point out that the cost of carbon-based approach for pricing RECs that appears in Staff's Responsive Proposal was proposed by these other parties in their comments to the White Paper. As more fully discussed with the July 15, 2016 Notice Extending Comment Deadline, supra, Staff's Responsive Proposal falls squarely within the issues that have been contemplated since the inception of this proceeding and within the scope of original Notice of Proposed Rulemaking issued in contemplation of the determinations made today.

As an alternative to contracting for ZECs with NYSERDA, LSEs and self-supply customers may seek permission from the Commission to meet their ZECs obligations by entering into combined ZEC plus energy and/or capacity contracts directly with the nuclear facilities. However, such proposals will be carefully scrutinized by the Commission to ensure that these alternate contracts will not unfairly shift ZECs costs onto other ratepayers.

The ZEC mechanism adopted in this Order is the best way for the State to preserve the nuclear units' environmental attributes while staying within the State's jurisdictional boundaries. ZECs provide a vehicle for monetizing the State's environmental preferences and the program will allow time for new clean energy technologies to mature and take their place in the ultimate generation mix. The independent renewable resource and ZEC obligations that together make up the CES each contribute uniquely to serving the long-term goal of achieving a largely de-carbonized energy system by the middle of the century.

VIII. IMPLEMENTATION

This Order adopts the Clean Energy Standard (CES) and establishes the policies that will govern the Renewable Energy Standard and the Zero-Emissions Credits Requirement. Given the need for momentum to implement the important initiatives adopted here, in many cases this Order establishes specific requirements to provide for swift implementation where necessary. But there are also a number of additional implementation measures that will be necessary to fully administer the CES. Those additional measures will be determined in an implementation phase that will address a number of issues identified in Appendix F, along with other implementation issues that may arise. Full implementation

will require various phases going forward and typically will involve a Staff or NYSERDA proposal, adequate notice, and the opportunity for comment before Commission action. The Commission intends that implementation matters will be addressed in a planned and deliberate manner to ensure that market participants receive timely guidance on matters that affect them.

IX. SEQRA FINDINGS

In February 2015, in accordance with the State Environmental Quality Review Act (SEQRA), the Commission finalized and published a Generic Environmental Impact Statement that explored the potential environmental impacts associated with two major Commission policy initiatives: REV and the Clean Energy Fund. On February 23, 2016, the Commission issued a Draft Supplemental Generic Environmental Impact Statement specifically relating to the CES and the establishment of a support mechanism to sustain the operations of eligible nuclear facilities. Seven entities submitted comments, and on May 19, 2016, the Commission adopted the Final Supplemental Generic Environmental Impact Statement (FSGEIS). In conjunction with the decisions made in this Order, the Commission has considered the information in the FSGEIS and FGEIS and hereby adopts the SEQRA Findings Statement prepared in accordance with Article 8 of the Environmental Conservation Law (SEQRA) and 6 NYCRR Part 617, by the Commission as lead agency for these actions. The SEQRA Findings Statement is attached to this Order as Appendix G. The SEQRA Findings Statement is based on the facts and conclusions set forth in the FSGEIS and the FGEIS. The CES program is expected to yield overall positive environmental impacts, primarily by reducing the State's use of, and dependence on, fossil fuels, among other benefits. In

conjunction with other State and Federal policies and initiatives, CES is designed to reduce the adverse environmental, social and economic impacts of fossil fuel energy resources by increasing the use of clean energy resources and technologies.

X. CONCLUSION

For the reasons stated above, and in accord with the discussion in the body of this Order, the Commission adopts a Clean Energy Standard consisting of a Renewable Energy Standard and a Zero-Emissions Credit Requirement program.

The Commission orders:

1. The goal of the State Energy Plan that 50% of New York's electricity is to be generated by renewable sources by 2030, as part of a strategy to reduce statewide greenhouse gas emissions 40% by 2030, is adopted as a foundational basis and essential component of the Clean Energy Standard.

2. The Clean Energy Standard consisting of the Renewable Energy Standard (RES) and the Zero-Emissions Credit Requirement, as described in the body of this order and in the appendices, is adopted.

3. Every Load Serving Entity (LSE) in New York State shall pursuant to Tier 1 of the RES invest in new renewable generation resources to serve their retail customers evidenced by the procurement of qualifying Renewable Energy Credits (RECs), acquired in quantities that satisfy mandatory minimum percentage proportions of the total load served by the LSE for the applicable calendar year as set forth herein. The compliance period shall be January 1 to December 31 of each year, beginning in 2017, and will continue annually, determined by multiplying the LSE's actual load for the year by the

percentage RES requirement for that year. LSEs may satisfy their obligation by either purchasing RECs acquired through central procurement by the New York State Energy Research and development Authority (NYSERDA); by self-supply by direct purchase of tradable RECs; or by making Alternative Compliance Payments to NYSERDA. Each LSE will demonstrate compliance through an annual compliance filing.

4. NYSERDA may offer RECs acquired in the 2016 Procurement for RES Tier 1 compliance and if NYSERDA determines that acceleration is warranted because the additional financial commitment would result in an overall weighted average award price of 2016 Main Tier projects equal to or less than the 2015 Main Tier weighted average award price of $24.57 per REC, it is authorized to implement additional procurement levels in the 2016 procurement and file a report with the Commission documenting its determination and the results.

5. For the Year 2017 compliance period, by December 1, 2016, NYSERDA shall publish on its website a REC price and the estimated quantity of the RECs NYSERDA will offer for sale in the 2017 compliance period. The REC price offered will equal the weighted average cost per MWh NYSERDA paid to acquire the RECs to be offered, plus a reasonable Commission-approved adder to cover the administrative costs and fees incurred by NYSERDA to administer Tier 1. NYSERDA will file a petition with the Commission proposing the amount of the adder by August 25, 2016.

6. By December 1, 2016 for the Year 2017 compliance period, NYSERDA shall publish on its website a per MWh ACP price for the 2017 compliance period. The ACP price will equal an amount calculated as the published REC price plus 10%.

7. By December 1, 2016 for the Year 2017 compliance period, each LSE will inform NYSERDA whether it intends to purchase RECs from NYSERDA during the compliance period.

8. For the 2017 procurement period NYSERDA shall establish and publish on its website no later than December 1, 2016, a firm schedule of fixed dates for the annual and potential supplemental solicitations.

9. Pursuant to Tier 2 of the RES, if the Commission awards Maintenance Contracts, eligible costs will be recovered from delivery customers in the same manner as in the Renewable Portfolio Standard program Maintenance Tier, or from such other sources as the Commission shall determine.

10. Every LSE in New York State shall purchase through contract with NYSERDA, at a price and by the terms described in this Order, an amount of zero-emission credits (ZECs) representing that LSEs proportional share of ZECs purchased annually by NYSERDA pursuant to the Zero-Emissions Credit Requirement. The LSE's proportional share is determined based on the proportion of electric energy load served by the LSE in relation to the total electric energy load served by all LSEs in the New York Control Area. The LSE/NYSERDA contractual relationship will require LSEs to periodically purchase ZECs during a program year based on initial forecasts of load and a balancing reconciliation at the end of each program year.

11. The compliance period shall be for two-year tranches commencing April 1, 2017 and will continue until March 31, 2029. Each LSE will demonstrate compliance through an annual compliance filing.

12. There being a public necessity to preserve the zero-emissions environmental attributes of certain Zero Carbon Electric Generating Facilities, NYSERDA shall offer long-term contracts for the purchase of ZECs from the FitzPatrick, Ginna

and Nine Mile Point generating facilities in accordance with the price, contract period and other terms specified in this Order. The contract terms shall conform to all of the requirements specified in this Order.

13. In the Secretary's sole discretion, the deadlines set forth in this Order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least one day prior to the affected deadline.

14. Case 15-E-0302 is continued; Case 16-E-0270 is closed.

By the Commission,

(SIGNED) KATHLEEN H. BURGESS
Secretary

APPENDICES

Appendix A – Eligibility of Resources
Appendix B – Comment Summaries
Appendix C – New York Generation Attribute Tracking System
Appendix D – Renewable Energy Standard - Tier 2
Appendix E – Zero-Emissions Credits Requirement
Appendix F – Implementation Phase
Appendix G – SEQRA Findings Statement

Commissioner Diane X. Burman, concurring:

As reflected in my comments made at the August 1, 2016 session, I concur on this item.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 15-E-0751 - In the Matter of the Value of Distributed Energy Resources.

CASE 15-E-0082 – Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program.

ORDER ON NET ENERGY METERING TRANSITION, PHASE ONE OF VALUE OF DISTRIBUTED ENERGY RESOURCES, AND RELATED MATTERS

Issued and Effective: March 9, 2017

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on March 9, 2017

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Gregg C. Sayre
Diane X. Burman, concurring

CASE 15-E-0751 - In the Matter of the Value of Distributed Energy Resources.

CASE 15-E-0082 - Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program.

ORDER ON NET ENERGY METERING TRANSITION, PHASE ONE OF VALUE OF DISTRIBUTED ENERGY RESOURCES, AND RELATED MATTERS

(Issued and Effective March 9, 2017)

BY THE COMMISSION:

INTRODUCTION

This order achieves a major milestone in the Reforming the Energy Vision (REV) initiative by beginning the actual transition to a distributed, transactive, and integrated electric system. Our decisions here represent the first steps in the necessary evolution of compensation for Distributed Energy Resources (DER) from the mechanisms of the past to the accurate models needed to develop the modern electric system envisioned by REV through the development of Value of Distributed Energy Resources (VDER) tariffs. The impacts of the electric system on the lives and interests of New York residents are both significant and wide-ranging, from the health, safety, and business needs for secure and reliable energy to the

financial impacts of utility bills to the environmental impacts of the generation of electricity. However, as the Commission has recognized through the REV initiative, many aspects of the electric system reflect legacy policies, technologies, and interests and have not been sufficiently reformed to reflect developments over the past decades, including technological developments, evolving consumer and market interests, and full recognition of environmental externalities. A failure to bring the electric system and industry fully into the modern world and to keep it apace with continuing developments could have disastrous consequences, including a failure to meet modern reliability needs and expectations, enormous and avoidable costs associated with the inefficient replacement of aging components, and unchecked emissions of greenhouse gasses and other pollutants. In addition, DER participation should be open to all customers, including low-income customers, and should be coupled with strong consumer protection measures.

The transition described herein is guided by core principles in the REV Framework Order.[1] First, the unidirectional grid must evolve into a more diversified and resilient distributed model engaging customers and third parties. Second, ensuring universal, reliable, resilient, and secure delivery service at just and reasonable prices remains a function of regulated utilities. Third, the overall efficiency of the system and consumer value and choice must be improved by achieving a more productive mix of utility and third-party investment.

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[1] Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2016) (REV Framework Order or Track One Order); Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (Track Two Order).

The Commission also recognizes that existing DER business models are well-established and based largely on net energy metering (NEM). These business models reflect the capabilities and needs of the electric system at the time they were designed and they appropriately served to open up markets and drive initial development. But such business models and NEM in particular are inaccurate mechanisms of the past that operate as blunt instruments to obscure value and are incapable of taking into account locational, environmental, and temporal values of projects. By failing to accurately reflect the values provided by and to the DER they compensate, these mechanisms will neither encourage the high level of DER development necessary for developing a clean, distributed grid nor incentivize the location, design, and operation of DER in a way that maximizes overall value to all utility customers. As such, they are unsustainable. To the degree that they over-compensate DER providers by transferring their fair share of fixed costs onto other customers, they operate now in a manner that will not sustain wide-scale deployment as the inherent subsidies reach a level that is oppressive to non-participants. While it is natural for the existing DER businesses to want to maintain the business models and financial support that they have enjoyed, the public interest requires the development of and prompt transition to more accurate valuation and compensation mechanisms for DER, particularly for project types currently compensated through NEM, that accurately reflect and properly reward DER's actual value to the electric system and that ensure all customers pay their fair share for the costs of grid operation and benefit from the value they provide.

The VDER Phase One tariffs will provide immediate improvements in granularity in understanding and compensating for the value of DER to the electric system while setting the

foundation for continual improvement. This transition will encourage the location, design, and operation of DER in a manner that maximizes benefits to the customer, the electric system, and society while also ensuring the development of clean generation needed to meet the necessary and aggressive goals embodied in the Clean Energy Standard (CES) and in this order. This transition will also ensure that the values and costs created by DER will be identified, monitored, and managed to ensure that all customers continue to receive safe and adequate service at just and reasonable rates, and that participation in DER markets is open to all customers, including low-income customers.

To ensure that development and interconnection of distributed generation (DG) projects can continue unabated, a transitional period is necessary so that the market and customers can fully understand the mechanisms of and incentives provided by the methodology adopted in this order. During an initial period, commencing with the date of this order, new projects will continue to receive compensation based on NEM methodologies, except that those projects will be limited to receiving such compensation to 20 years before transitioning to new compensation mechanisms; this initial compensation mechanism is described as Phase One NEM in this order. While Phase One NEM contains inefficiencies similar to NEM as a compensation methodology, the term limitation will offer some incentives for developers and customers to consider the impacts of the location, design, and operation of DER on the electric system. Phase One NEM is subject to filing deadlines to ensure that it applies only to projects that are already in advanced stages of development and, for Community Distributed Generation (Community DG or CDG), to a limited capacity allocation to manage any impact on non-participants.

During this initial period, the Department of Public Service Staff (Staff) will engage with utilities and stakeholders to finalize recommendations to implement a new compensation mechanism. Once the recommendations have been filed and received public scrutiny, the Commission will take further action, as early as this Summer, to fully implement compensation for new projects that reflects the values created by those projects in a more accurate and granular manner, described in this order as Value Stack compensation. Recognizing the importance of continued clean energy development, the needs of the market, and the existence of values not yet identified, the Value Stack will include a Market Transition Credit (MTC) for CDG projects that provides compensation for initial projects that is substantially similar in value to compensation under NEM.

In this order, the Commission (a) adjusts the current interim floating ceiling on new Public Service Law (PSL) §66-j NEM projects by setting a new fixed ceiling that limits the level of new projects in favor of transitioning to a new regime; (b) establishes a VDER Phase One tariff consisting of two components, the Phase One NEM tariff implementing a new DER program similar to NEM with some exceptions, and the Value Stack tariff implementing a new, more comprehensive DER program based on monetary crediting for net hourly injections; (c) establishes capacity-based allocations for mass market and CDG projects intended to limit the potential impacts of the VDER Phase One tariff on non-participants to an incremental net annual revenue impact of approximately 2% for each utility; (d) allocates the costs associated with the VDER Phase One tariff to the customers who benefit from the savings associated with the compensated DER, or where the groups of benefitted customers have not been identified, to the customers within the same service class as

the beneficiaries; (e) allows participating customers to pair energy storage technologies with their eligible projects; (f) directs development of proposals for next steps that can be taken to reduce, eliminate, or mitigate market barriers, bill impacts, and CDG project costs; (g) directs NYSERDA to file new or revised Clean Energy Fund (CEF) investment chapters to support programs aimed to encourage and incentivize low-income customer participation in CDG projects, as well as to support the transition to the Value Stack; (h) directs Staff to consider options to encourage low-income customer participation in CDG including an interzonal CDG credit program and tailored approaches for CDG projects that comprise a majority of low-income off-takers; (i) directs Staff to develop an updated whitepaper on DER oversight provisions; (j) directs utilities to make specific filings to enable the full implementation of the Value Stack tariff; and (k) directs the commencement of VDER Phase Two.

LEGAL AUTHORITY

The PSL grants the Commission broad legal authority to prescribe regulatory requirements necessary to carry out the provisions contained therein. For instance, PSL Section 5(1) grants the Commission jurisdiction over the sale or distribution of electricity. Furthermore, PSL Section 5(2) permits the Commission to "encourage all . . . corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."

Pursuant to PSL Section 65(1), every electric corporation must safely and adequately "furnish and provide

[electric] service, instrumentalities, and facilities as shall be safe and adequate and in all respects just and reasonable." Section 66(1) extends general supervision to electric corporations having authority to maintain infrastructure "for the purpose of . . . furnishing or transmitting electricity." Pursuant to Section 66(2), the Commission may "examine or investigate the methods employed by. . . corporations . . . in manufacturing, distributing, and supplying . . . electricity," as well as "order such reasonable improvements as will best promote the public interest . . . and protect those using . . . electricity." Moreover, pursuant to Section 66(3) the Commission may prescribe "the efficiency of the electric supply system." Accordingly, the Commission has the jurisdiction over the electric utilities affected by this order to require them to comply with the requirements outlined herein.

In fulfilling its statutory mandate, the Commission has approved tariff provisions and established programs governing service, billing, and compensation for various DER, including distributed generation. For example, each electric utility's Commission-approved tariff includes standby rates, which govern service to large customers that meet a substantial part of their electric needs through on-site generation, and buy-back service, which governs the purchase of capacity and energy by the utility from qualifying customers.[2] Similarly, each electric utility has demand response programs, which offer incentives or compensation for reductions in peak demand,[3] and

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[2] See, e.g., Con Ed Tariff, Schedule for Electricity Service, P.S.C. No. 10 – Electricity, leaves 157-170 and 462-477.

[3] See, e.g., Case 14-E-0423, Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs, Order Adopting Dynamic Load Management Filings with Modifications (issued June 18, 2015).

several non-wires alternative (NWA) programs are under development, offering compensation to DER, including distributed generation, that supports elimination or deferral of costs associated with traditional infrastructure.[4]

As described in Appendix C, The History of NEM in New York, NEM was established by statute in 1997 and subsequent amendments have expanded eligibility and made other minor changes.[5] The NEM statutes govern compensation and terms of service for customer-generators that interconnect their eligible generating equipment with a utility's system before a rated generating capacity ceiling for that utility's service territory is reached.[6] Once the ceiling has been exceeded, customer-generators are no longer entitled to be provided service, billed, and compensated based on the terms of the statute. The Commission therefore has not only the authority but also the responsibility to define terms of service and compensation for those customer-generators.

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[4] See, e.g., Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn/Queens Demand Management Program, Order Establishing Brooklyn/Queens Demand Management Program (issued December 12, 2014).

[5] NEM of wind turbines is governed by PSL §66-l, while NEM of all other technologies is governed by PSL §66-j. The terms and conditions of NEM under the two statutes are essentially identical, except that wind is subject to a separately calculated statutory cap of 0.3% of 2005 electric demand for each utility, and therefore is not counted towards the cap that applies to all other technologies.

[6] Technically, the statutes do not create a cap, but rather require that each utility offer NEM to eligible customer-generators until the specified capacity is reached. PSL §66-j(3)(a)-(b). Because utility tariffs have always limited NEM based on the minimum capacity required, that capacity level has generally been described, and will continue to be described in this order, as a cap or a ceiling.

PSL §66-j sets initial ceilings of 1% of each utility's 2005 electric demand and provides the Commission with broad discretion to determine what level of NEM above these ceilings is in the public interest. The Commission raised the ceilings several times and ultimately directed that the ceilings float with interconnections.[7] However, in the Interim Ceilings Order, the Commission explained that the floating ceilings were a temporary measure and that, when a new compensation mechanism was developed, the ceilings would be set based on the existing capacity levels.

Where, as here, the Commission finds that additional NEM would no longer be in the public interest, we must determine what form of compensation for new DER projects is consistent with our statutory mandates to ensure safe and adequate service at just and reasonable rates consistent with the public interest and the efficiency of the electric system. Consistent with our statutory duties, with ratemaking principles, and with the goals of REV, in this order we create a compensation structure for those projects based on the benefits they create and the costs they impose.

PROCEDURAL HISTORY

As noted in the REV Track Two Order,[8] Case 15-E-0751 was established to provide a process for determining the value of DER, for both planning and transactional purposes. An extensive collaborative process was established that looked to

[7] Case 15-E-0407, Orange and Rockland Utilities, Inc. – Petition For Relief Regarding Its Obligation to Purchase Net Metered Generation Under Public Service Law §66-j, Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation (October 16, 2015) (Interim Ceilings Order).

[8] Case 14-M-0101, Reforming the Energy Vision, Track Two Order at 19.

market participants and stakeholders to develop proposals. Although there was active participation and collaboration by a wide range of stakeholders and market participants, it became necessary for Staff to offer straw proposals to facilitate the discussion. Staff provided a number of straw proposals intended to explore approaches that reflected the collaborative discussions. Participating parties provided input on the straw proposals at public, noticed collaborative conferences, as well as during smaller breakout groups established to address specific topics within the straw proposals. The process culminated in a Staff Report and Recommendations (Staff Proposal), filed on October 27, 2016.

The Staff Proposal presents several recommendations of general applicability and details the Value Stack as a proposed valuation and compensation methodology, along with when and how that methodology should apply to various market segments. It also describes several unique aspects for transitioning from NEM, including limited continuation of NEM for mass market customers consistent with our REV Track Two Order and an MTC that Staff proposes be made available to certain projects during the transition from NEM. In the context of developing a VDER Phase One methodology and tariff, Staff identified distinctions among four major market segments, including: 1) on-site, mass-market projects and customers, defined as customers that are within a jurisdictional electric utility's residential or small commercial service class and that are not billed based on peak demand; 2) CDG projects and customers, defined as consisting of an eligible generating facility located behind a non-residential host meter and a group of members located at other sites that receive credits from that facility to offset their bills; 3) remote net metered (RNM) projects and customers where non-residential customers, as well as residential customers who own

or operate farm operations, receive credits for excess generation by an eligible generating facility they own, lease, or operate at a site they own or lease, and where those credits are used to offset the bill for meters at one or more other properties that they own or lease; and, 4) large, on-site projects and customers, defined as customers within a jurisdictional utility's non-residential demand-based or mandatory hourly pricing (MHP) service classifications. Specific elements of the Staff Proposal related to decisions in this order are summarized in the Discussion section, below.

NOTICE OF PROPOSED RULEMAKING

On October 28, 2016, the Secretary issued a "Notice Soliciting Comments on Staff Proposal," which sought initial comments by December 5, 2016, and reply comments by December 19, 2016. Further, pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking (Notice) was published in the State Register on November 2, 2016 [SAPA No. 15-E-0751SP1]. The time for submission of comments pursuant to the SAPA Notice expired on December 19, 2016. In addition, a technical conference was held on November 28, 2016. Input was also solicited on process and areas of focus for Phase Two and a number of comments were received by December 23, 2016. Various initial and reply comments on the Staff Proposal were received, including thousands of comments from members of the public, as summarized in Appendix D and addressed below in where relevant. The first section of Appendix D contains short names for commenters; those names are used throughout this order to refer to the commenters.

SEQRA SUPPLEMENTAL FINDINGS

In February 2015, in accordance with the State Environmental Quality Review Act (SEQRA), the Commission finalized and published a Final Generic Environmental Impact Statement (FGEIS) that addressed the potential environmental impacts associated with two major Commission policy initiatives: REV and the CEF. On February 23, 2016, the Commission issued a Draft Supplemental Generic Environmental Impact Statement specifically relating to the CES and on May 19, 2016, the Commission adopted the Final Supplemental Generic Environmental Impact Statement (FSGEIS). In conjunction with the REV Framework Order, the Commission adopted a SEQRA Findings Statement prepared, in accordance with Article 8 of the Environmental Conservation Law (SEQRA) and 6 NYCRR Part 617, by the Commission as lead agency for these actions and attached to the Order. The SEQRA Findings Statement was based on the facts and conclusions set forth in the FGEIS.

In conjunction with the decisions made in this order, the Commission has again considered the information in the FGEIS and the SEQRA Findings Statement and hereby adopts a SEQRA Supplemental Findings Statement prepared, in accordance with Article 8 of the Environmental Conservation Law (SEQRA) and 6 NYCRR Part 617, by the Commission as lead agency for these actions. The SEQRA Supplemental Findings Statement is attached to this order as Appendix E. The actions adopted in this order do not alter or impact the findings statements issued previously. Neither the nature nor the magnitude of the potential adverse impacts will change as a result of this order. Rather, through this order, the Commission has taken concrete steps to transform New York's electric grid into a modern, distributed and increasingly clean system, consistent with the goals of the REV initiative.

SUMMARY OF DECISIONS

The Discussion Section offers a full explanation of the Commission's decisions in this order, including the reasons that recommendations from the Staff Proposal and from stakeholder comments are adopted, modified, or rejected. To ensure that the Commission's decisions are clearly identified for the benefit of Staff, active parties and interested stakeholders, the major decisions are summarized in this section.

This order directs an immediate transition from NEM to a VDER Phase One tariff. Projects interconnected prior to the date of this order will retain NEM compensation unless and until their owners opt-in to the VDER Phase One tariff. The VDER Phase One tariff includes two components: Phase One NEM and the Value Stack tariff. Mass market projects interconnected before January 1, 2020, subject to further limitations described below, will be compensated based on Phase One NEM. RNM, large on-site, and CDG projects for which, within 90 business days of this order, 25% of interconnection costs have been paid or a Standard Interconnection Contract has been executed if no such payment is required will be compensated based on Phase One NEM, with CDG subject to further limitations described below. RNM, large on-site, and CDG projects that do not qualify for Phase One NEM will be compensated based on the Value Stack tariff.

A. Transition from NEM to Phase One NEM

To effectuate an immediate transition away from NEM, NEM compensation under PSL §66-j will no longer be available to new projects after the date of this order. Projects that either are in service or that have completed Step 8 of the Standard Interconnection Requirements (SIR) for projects larger than 50 kW or Step 4 of the SIR for projects smaller than 50 kW by the close of business on March 9, 2017 will receive NEM based on existing

tariffs; all other projects will receive service based on the VDER Phase One tariff. In order to demonstrate that Step 8 of the SIR for large projects or Step 4 of the SIR for small projects was completed by March 9, 2017, customers must provide written notification of complete installation to the interconnecting utility, as required by Step 9 of the SIR for large projects and Step 5 of SIR for small projects, by March 17, 2017. New wind projects will be eligible to receive NEM pursuant to PSL §66-l until the caps described in that statute are reached, and will then be transitioned onto the then-applicable compensation mechanism. Projects compensated under NEM will be able to opt-in to the Phase One Value Stack tariff.

B. Phase One NEM

Phase One NEM will be available to projects that interconnect or make a defined financial commitment within 90 business days of this order. CDG projects eligible for Phase One NEM are further subject to the availability of by-utility MW capacity allocations, summarized below. New mass market, on-site projects will be eligible for Phase One NEM until the earlier of January 1, 2020 or a subsequent Commission order addressing such projects in this proceeding. The deployment of mass market projects under Phase One NEM will be monitored to ensure that these projects do not create the potential for unreasonable impacts on non-participants based upon a MW capacity allocation for each utility that provides for continued opportunity under the VDER Phase One tariff. Utilities will provide frequent and transparent reporting on the progress under the MW capacity allocation and will provide notice upon hitting 85% of the allocation amount so that the Commission may consider what action is appropriate.

Phase One NEM is identical to NEM, except that projects eligible for Phase One NEM will be subject to a

compensation term length of 20-years from their in-service date and will have the ability to carry-over excess credits to subsequent billing and annual periods, subject to further stipulations as detailed in the Discussion Section. Projects compensated under Phase One NEM will be able to opt-in to the Phase One Value Stack tariff. Projects, other than mass market on-site projects, compensated under Phase One NEM must be equipped with utility metering capable of recording net hourly consumption and injection.

C. The Value Stack

Under Phase One, the Value Stack tariff will only be available for technologies and projects that are eligible for NEM; other DER technologies will be addressed in subsequent Phases. The Value Stack tariff shall be based on monetary crediting for net hourly injections. Excess credits will be eligible for carry-over to subsequent billing and annual periods, subject to further stipulations as detailed in the Discussion Section. Projects eligible for the Value Stack tariff will receive compensation for a term of 25-years from their in-service date. Projects under the Value Stack tariff must be equipped with utility metering capable of recording net hourly consumption and injection.

Compensation under the Value Stack for net hourly injections will be calculated based on the value associated with: 1) Energy Value, based on the Day Ahead hourly zonal locational-based marginal price (LBMP), inclusive of losses; 2) Capacity Value, based on retail capacity rates for intermittent technologies and the capacity tag approach for dispatchable technologies based on performance during the peak hour in the previous year; 3) Environmental Value, based on the higher of the latest CES Tier 1 Renewable Energy Certificate (REC) procurement price published by NYSERDA or the Social Cost of

Carbon (SCC); and 4) Demand Reduction Value (DRV) and Locational System Relief Value (LSRV), based on a deaveraging of utility marginal cost of service (MCOS) studies, performance during the 10 peak hours, and further process as detailed in the Discussion Section. In addition, utilities are directed to develop options for a fee-based portfolio service under which DG projects can be aggregated into a virtual generation resource.

CDG projects compensated under the Value Stack tariff will be eligible for an MTC, equal to the difference between the "Base Retail Rate" and "Estimated Value Stack" as detailed below in the Discussion Section. CDG projects will receive a pro-rata MTC based on the portion of their project that is dedicated to serving small customers and shall not receive a DRV for that portion of their project. Eligibility for MTC compensation will be subject to the availability of MW capacity allocations in each utility that are derived from the incremental 2% net revenue impact limitation, summarized below.

MW capacity is further allocated to three distinct Tranche buckets as follows: Tranche 0 (Phase One NEM)/Tranche 1 (Value Stack plus MTC equal to 100% Base Retail Rate); Tranche 2 (Value Stack plus MTC equal to 95% Base Retail Rate; Tranche 3 (Value Stack plus MTC equal to 90% Base Retail Rate). The specific method and allocations to distinct Tranches is further detailed below under the Discussion Section and in Table 2. After 90 business days from the date of this order, any remaining capacity in Tranche 0 shall be rolled over to Tranche 1. Utilities will provide frequent and transparent reporting on the progress of Tranches and will provide notice upon hitting 85% of the total allocation amount so that the Commission may consider what action is appropriate. Eligibility for placement in a Tranche will be based on the time-stamp of a 25% advanced payment for interconnection upgrade costs or execution of a

Standard Interconnection Contract if no such payment is required.

D. Managing Potential Impacts on Non-Participants

To manage the potential impacts of the VDER Phase One tariff on non-participants, an incremental net annual revenue impact of approximately 2% for each utility will be established for all projects interconnected after the date of this order. The 2% upper bound will not result in a hard cap, but instead is used to design capacity-based allocations for mass market and CDG projects.

E. Cost Allocation Principles

Costs associated with compensation under the VDER Phase One tariff will be collected, proportionately, from the same group of customers who benefit from the savings associated with the compensated DER. For compensation that does not reflect a value that has been identified and calculated at this time, recovery will come from customers within the same service class as the beneficiaries.

F. Inclusion of Energy Storage

A Project that include energy storage paired with an eligible resource will be eligible for compensation under NEM, for mass market on-site projects, or the VDER Phase One tariff. As part of the development of the final Value Stack tariff, Staff will consider whether there are alternatives to their recommendation to base compensation on net monthly injections in order to better reflect actual storage configurations and value while still avoiding uneconomic arbitrage. The application of the Phase One tariff to stand-alone storage facilities will be addressed in subsequent phases.

G. Mitigation of Bill Impact and CDG Project Costs

Staff is directed to work with NYSERDA, the utilities, and market participants to develop and file a proposal for next steps that can be taken to reduce, eliminate or mitigate market barriers, bill impacts or CDG project costs. Topics include: development costs, consolidated billing, customer maintenance costs, and interconnection costs.

H. Enabling Participation of Low-Income Customers in VDER Programs and Tariffs

The Commission directs Staff to work with utilities and interested stakeholders to consider an interzonal CDG credit program designed to provide benefits from CDG projects interconnected in service territories and load zones other than that of the low-income participant. The Commission also supports NYSERDA's continued investigation into enabling low-income customer participation in CDG projects, and directs NYSERDA to file CEF investment chapters to support programs aimed to encourage and incentivize low-income participation in CDG projects. Finally, the Commission directs Staff to consider options to encourage low-income participation in CDG under the VDER Phase tariffs, including tailored approaches for CDG projects that comprise a majority of low-income off-takers.

I. Oversight of DER Providers

Given the advancement of this and other proceedings since the filing of the initial DER Oversight Staff Proposal on July 28, 2015, the Commission directs Staff to develop an updated whitepaper that will be issued for public comment within thirty days such that the Commission will be able to consider the DER oversight provisions at the same time as it acts on the implementation issues in this proceeding.

J. Further Process

To enable the full implementation of the Value Stack tariff, the utilities are directed to make specific filings,

following engagement with Staff and stakeholders, to enable public comment and Staff consideration such that the Commission may consider a Value Stack Implementation order as soon as Summer 2017. While a full listing of items appears in the Discussion Section, particular items of note include filing by each utility of: tariff leaves for implementing Phase One NEM; proposed implementation of cost allocation principles; proposed method and values for capacity; the most recent MCOS studies and workpapers followed by specific DRVs and LSRVs along with identification of specific locations and MW caps for LSRVs; MTC values; and a work plan and timeline for developing locationally granular prices to reflect the value to a utility's distribution system from DER additions.

K. Commencement of VDER Phase Two

Phase Two will commence in May 2017 with a procedural conference or other meeting of interested parties. An agenda will be issued at least five days in advance of the meeting. Specific topics to be addressed and prioritized in Phase Two are discussed further under the Discussion Section of this order.

DISCUSSION

I. THE NEED FOR TRANSITION

Through the REV initiative, the Commission has taken concrete steps to transform New York's electric grid into a modern, distributed, integrated, transactive, and increasingly clean system. This order addresses a fundamental requirement of building a distributed grid and offering fair and accurate compensation to all market participants: compensation of DER for the values they create. The REV initiative, through which the Commission is pursuing a consumer-centric, economically efficient, and environmentally sustainable energy future, demands accurate valuation of and compensation for DER. REV's

premise that clean energy deployed at scale will lead to increased consumer and third party engagement requires more precise price signals for DER products and services.

DER is a broad term that includes a range of technologies designed to interact with and affect the grid from the grid edge, generally from behind a utility meter, including DG, energy efficiency (EE) technologies, and demand response (DR) and reduction projects. Individual DER products and services number in the thousands, and more are developed all the time, but common examples include solar panels, energy storage, smart appliances, and learning thermostats.

In this diverse and growing marketplace, a compensation system must be value-based, rather than technology-based. Each DER will create different values for the electric system, and impose different costs on the electric system, depending on its individual characteristics and the nature of its use, including when and where the DER is operated. The values and services offered by DER are wide-ranging and will continue to be discovered and developed over time, but today include: reduced energy consumption, energy generation, green energy attributes representing reduction in emissions of greenhouse gasses and other pollutants, capacity, reduced system stress, displacement of the need for traditional grid infrastructure, increased reliability, load shifting, demand response, peak load reduction, voltage support, frequency management, and reactive power.

To achieve the energy future envisioned by REV, we must develop and implement mechanisms that identify these and other values and offer appropriate compensation. In order to incentivize customers and DER providers to install and operate DER in a manner that maximizes the benefits for themselves, the integrated electric system, and society as a whole, compensation

must accurately reflect the values created at a granular level. This requires the replacement of legacy compensation systems that do not and cannot accurately reflect these values, such as NEM. As a compensation mechanism, NEM is easy to understand and implement and, coupled with other incentive programs, proved an important and effective means to nurture the growth of New York's DG industry, particularly solar photovoltaic (PV) generation. However, especially when coupled with traditional volumetric rate structures, NEM does not provide sufficient information to serve as a basis of efficient investment decisions or to identify and compensate for the values that can be provided to the system. For most customers compensated under NEM, compensation reflects only the amount of energy generated and the customer's existing rate, and has little or no relationship to the actual values provided to or costs imposed on the system. For any individual DER, NEM may be over- or under-compensatory as compared to the actual values and costs that resource creates. Furthermore, to the extent that a failure to offer proper compensation by recognizing values leads to the installation of DER that creates lower benefits or greater costs for the electric system than would otherwise be the case, all utility customers, and in particular non-participants, suffer the impacts of those greater costs and lower benefits.

At relatively low levels of penetration, the inefficiencies of NEM could be tolerated. However, as both customer interest in and New York's need for clean and distributed generation increases, driven by initiatives including the CES and CDG, it has become increasingly vital for compensation and incentives to sufficiently encourage the deployment of DG and its location, design, and operation in a manner that maximizes values to the customer, the electric

system, and society. The continued success of New York's DG industry requires more efficient pricing mechanisms, without which the growth of these DER will be inhibited. While the market structure, products, and transactional mechanisms will evolve over time, a transition to a more precise mechanism to value and compensate DER must begin now in order to take full advantage of the opportunities.

The Staff Proposal, as informed by extensive collaborative work involving a multitude of stakeholders, offers a framework for compensation of NEM-eligible DER appropriately based on the values those DER create for the electric system, the Value Stack framework. Implementation of that framework will offer improved price signals for DER development while also ensuring the continued health of the DER market and managing potential impacts on non-participants. The extensive comments submitted on the Staff Proposal, fully summarized in Appendix D, offer general support for this framework and for many of the Proposal's elements, while also suggesting several modifications and arguing that various elements require further development. We agree that some modifications to the Staff Proposal are warranted and that, as discussed herein, some aspects of the methodology require further limited inquiry prior to full implementation of the Value Stack tariff. However, we believe that this further inquiry can be accomplished during the next several months, so that the Commission can consider a final implementation proposal, with stakeholder participation and commentary, as soon as Summer 2017. By adopting foundational policy decisions for a VDER Phase One tariff and its related elements in this order, including decisions regarding the Value Stack, we can offer clarity to DER customers and developers and identify what steps must be taken to finalize the Value Stack under Phase One.

Because we find that continuation of NEM is inconsistent with REV, Commission policy, and the public interest, we direct an immediate transition away from NEM to a new VDER Phase One tariff. To ensure that development activities can continue during the interim period while the Value Stack is finalized, the VDER Phase One tariff will include a new category of DER compensation, referred to as Phase One NEM, which offers equivalent compensation to NEM but manages NEM's imperfect incentives and impact on non-participants by including a limited term and limits on how many MWs of generation can be developed at this compensation level.

The following discussion begins with an explanation of the reasons for and the mechanisms required for transition from NEM to the first stage of the VDER Phase One tariff, Phase One NEM. The next section describes generally applicable policy decisions regarding the VDER Phase One tariff. Next, the order identifies the framework for Value Stack tariffs and describes the process for finalizing and implementing those tariffs. Finally, the order sets forth a roadmap for moving to the next stage of development in valuation and compensation of DER, both through VDER Phase Two and through work in related proceedings.

II. TRANSITION FROM NEM TO VDER PHASE ONE

A. Transition Away from NEM

1. Staff Proposal

The Staff Proposal recommends that projects in-service at the time of this order continue to receive compensation under existing NEM rules until 20 years from their in-service date. It proposes that new projects put into service after the order be compensated based on a new methodology, with limited exceptions.

Staff recommends that mass market and small wind projects interconnected prior to January 1, 2020 continue to

receive NEM compensation until 20 years from their in-service date. Staff recommends that RNM projects that qualify for monetary crediting pursuant to the Transition Plan Order[9] receive NEM compensation based on the terms of that Order until 25 years from their in-service date. In addition, Staff recommends that continued NEM compensation, for 20 years from in-service date, be available to a certain segment of projects put into service after the order subject to both a deadline and a capacity limit.

2. Comments

Many parties submitted comments discussing the proposed transition away from NEM as a compensation mechanism. Several parties, including Solar Parties, NYSEIA, CCSA, EDF/Policy Integrity, NRDC, Acadia, and Pace, emphasize the important role NEM has played in developing the solar industry but acknowledge the impetus for change and generally support Staff's proposed framework for a transition, subject to certain recommended modifications to elements of the new compensation framework and a transition that is gradual and predictable in nature. A number of parties, including AEEI, ACE-NY, NCEC, NY-BEST, and Bloom Energy, offer strong support for an expeditious transition away from NEM to a more accurate compensation methodology, as proposed by Staff. JU, IBEW, UIU, PULP, MI, and Nucor express concern that a failure to quickly transition away from NEM could lead to substantial impacts on ratepayers as the penetration levels of solar and other NEM-eligible technologies grow.

[9] Cases 14-E-0151 et al., Hudson Valley Clean Energy, Inc. - Petition for an Increase to the Net Metering Minimum Limitation at Central Hudson Gas & Electric Corporation, Order Granting Rehearing in Part, Establishing Transition Plan, and Making Other Findings (issued April 17, 2015) (Transition Plan Order).

Some parties, including EDA, NYCEJA/NYLPI, and several small solar developers express concern that transition away from NEM is premature. Over 700 individual comments were received supporting continuation of NEM, which they argue is one of the most basic foundations of renewable energy policy and energy democracy. Over 2,200 individual comments were received urging the Commission to reject proposed plans to impose caps on NEM and to set a goal of 100% renewable energy by 2035. In particular, commenters argue that NEM supports the expansion of residential clean energy and that New York State needs additional clean, distributed energy, not less.

3. Determination

NEM was instituted by statute, subject to a rated generating capacity ceiling in each utility territory equal to one percent of the 2005 electric demand for each utility, respectively.[10] However, the Commission was authorized to increase these ceilings as deemed necessary in the public interest. Consistent with this authority, the Commission raised those caps, as described above, through findings that permitting additional NEM would be in the public interest.

Since the Commission's decision to raise the caps to 6%, and subsequent adoption of temporary floating caps, circumstances have changed. First, progress in the REV proceeding has demonstrated that smarter planning, including the optimization of DER and their associated values, is both possible and necessary. Second, it is now clear that volumetric crediting, on which NEM is based, fails to reflect the full and accurate value that DER provide to the grid. Third, significant interest in the Commission's CDG policy is dramatically

[10] PSL §66-j(3)(a)(iii). NEM for wind generation projects has a separate rate generating capacity ceiling of 0.3% of the 2005 electric demand for each utility, respectively. PSL §66-l.

accelerating the level of DER that will be integrated on the system, such that associated costs to non-participants could significantly increase if prompt action is not taken to more accurately compensate these resources and fairly allocate the costs. When the Commission adopted the CDG policy, we noted the need to promptly develop a more accurate compensation method for these resources.

Based on these changed circumstances, further interconnection of projects under NEM is not in the public interest. Even applying a conservative estimate of projects in the current interconnection queue that will come to fruition, it is evident that continued application of floating NEM caps could result in substantial impacts for non-participant customers and a missed opportunity to incentivize those resources that will provide the most value to the system. A return to a 6% rated generating capacity ceiling, with a hard cut-off at that ceiling, would be inequitable, creating a sharp drop in compensation for customers interconnected once that ceiling was reached, and could limit our ability to create a transitional period while managing impact on non-participants. Limiting NEM at its current penetration level in each utility, while offering certain categories of projects, including those in advanced stages of development, the opportunity to receive equivalent compensation based on similar terms through Phase One NEM, will allow for a rational transition that balances the interests of participating and non-participating customers. Such a limit is also consistent with the intent expressed in the Interim Ceiling Order, which explained that the floating ceilings would be set at the level of penetration at the time of the implementation of a more accurate methodology.[11]

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[11] Case 14-E-0151, supra, Interim Ceilings Order.

We appreciate that NEM has served as an important mechanism to develop the solar market in New York and that it forms an important part of the business model of many developers. However, as even many of those developers and clean energy advocates recognize in their comments, progress beyond NEM is necessary to encourage development of DER consistent with REV goals while ensuring equity to all ratepayers. The purpose of this order is not to slow or limit the deployment of clean, distributed resources; rather, this order is necessary to drive achievement of New York's aggressive clean energy goals while also creating the grid of the future envisioned by REV. Those clean energy goals were established based on the State Energy Plan, and any recommendations to modify them or add further goals should be brought to that forum.

For the above reasons, NEM compensation under PSL §66-j will no longer be available to new projects after the date of this order. Projects that either are in service or that have completed Step 8 of the SIR for projects larger than 50 kW or Step 4 of the SIR for projects smaller than 50 kW by the close of business on March 9, 2017 will receive NEM based on existing tariffs; all other projects will receive service based on the VDER Phase One tariff. In order to demonstrate that Step 8 of the SIR for large projects or Step 4 of the SIR for small projects was completed by March 9, 2017, customers must provide written notification of complete installation to the interconnecting utility, as required by Step 9 of the SIR for large projects and Step 5 of SIR for small projects, by March 17, 2017. This will ensure that projects for which all development activity is complete will retain their expected compensation mechanism. Relying on the SIR milestones is appropriate because they provide clearly defined stages and will

avoid the potential for numerous factual disputes on projects' statuses.

As a replacement for NEM prior to the implementation of the Value Stack, the Commission adopts a mechanism called Phase One NEM that is identical to NEM, except that it is subject to a limited term length for each project. Phase One NEM will be available for projects interconnected after March 9, 2017 that either interconnect or make a defined financial commitment within 90 business days of this order, subject to defined limits consistent with the below discussion regarding impact on non-participants.

In addition, new mass market, on-site projects, as defined below, will continue to be eligible for Phase One NEM until the earlier of January 1, 2020 or a Commission order addressing such projects in this proceeding. Eligible new wind projects will receive NEM pursuant to PSL §66-l until the caps described in that statute are reached, and will then be transitioned onto the then-applicable compensation mechanism.

To implement this approach, each of the utilities will be required to record the total rated generating capacity of interconnected projects served under PSL §66-j in its service territory as of the close of business on March 9, 2017 and to file with the Secretary within seven days a preliminary letter stating that MW number. Each of the utilities must file a letter stating the final rated generating capacity of interconnected projects served under PSL §66-j, including projects that had completed Step 8 of the SIR for large projects or Step 4 of the SIR for small projects by March 9, 2017 and submitted notification of complete installation by March 17, 2017, by March 31, 2017, which will serve as the new ceiling for NEM for that territory. As projects served under PSL §66-j are taken out of service, the ceilings shall automatically decrease

to match the capacity of projects remaining in service. These decreasing ceilings should not be used to prevent customers served under PSL §66-j from repairing their system. Furthermore, the ceilings will not decrease below the 1% of 2005 electric demand level specified in PSL §66-j.

Projects not eligible for NEM compensation will be served under and compensated based on Phase One NEM or a subsequent tariff, as discussed below.

B. Managing Potential Impacts on Non-Participants

1. Staff Proposal

The Staff Proposal explains that both NEM and VDER Phase One tariffs are expected to result in net revenue impacts to utilities, which will be reflected on customer bills. The Staff Proposal includes a detailed, if preliminary, analysis of the potential net revenue impacts based on the identifiable and calculable values created for utilities by DER as compared to the costs imposed by compensating customers under NEM and through Staff's proposed Value Stack tariff. While the Proposal recognizes that the ongoing transition via REV towards more precise identification and quantification of value places certain limitations upon this analysis, Staff maintains that the analysis offers a useful tool for assessing the potential impacts of a VDER Phase One tariff on non-participating customers and that it is sufficiently informative to use as a guide in managing those impacts under Phase One.

The analysis estimated an incremental amount, based on revenue requirements embedded in existing rates, which would need to be collected from all customers as a result of the compensation methodologies proposed. Due to the highly speculative nature of predicting future rate levels and rate design changes, Staff adopted a simplified approach employing a snapshot of existing tariff levels, historical commodity prices,

and customer class structures and revenues. The analysis focused upon several DER deployment and compensation scenarios.

The Staff Proposal explains that while Phase One will have a meaningful impact on DER deployment and make positive steps towards more precise value of DER, the impacts will ultimately be bounded by the anticipated two-year period for application of the VDER Phase One tariff before moving to development and implementation of subsequent phases. To balance market opportunity and revenue impact during Phase One, the Staff proposal suggests, and bases its analysis on, a maximum incremental net annual revenue impact of 2% for each utility's residential customer class, inclusive of bundled and delivery-only customers, for all projects interconnected under the VDER Phase One tariff. The Staff Proposal explains that an incremental 2% impact reasonably balances the need for an upper boundary impact on non-participating customers while also establishing room for market growth in all utility service territories. The analysis focused upon technologies and project types that represent the vast majority of current market potential, as well as the largest potential net revenue impact (i.e., primarily solar CDG projects, as well as mass market on-site projects).

2. Comments

Commenters have divergent views and perspectives on Staff's approach and recommendations to balance cost impact with market opportunity. Solar Parties, CCSA, Acadia, NRDC, NYSEIA and CCR argue that a 4% net revenue impact is more appropriate in order to provide a more gradual transition from NEM as well as to provide sufficient opportunity for market participation and time for the market to mature. Many of the same commenters also posit that 4% is also more appropriate given that the Value Stack remains incomplete and imprecise, contributing to

uncertainty in calculation of an accurate net revenue impact. AEEI expresses concern about the approach used to calculate the net revenue impact, but nonetheless comments that a 3% bounding would be more appropriate for many of the same reasons articulated by Solar Parties. SolarCity supports a bounding on impact, but comments that utility-specific limits and revenue impact mitigation measures are more appropriately considered within the context of utility rate cases. Solar Parties point out that the net revenue impact estimate does not represent lost revenue for the utility since any differences in approved revenue requirement and actual revenues collected would be recovered through either a decoupling rider or an increase in base rates. Pace believes that there has not been sufficient basis established in the record for claiming detrimental impact on non-participants, and therefore argues that the 2% net revenue impact is inappropriate now. EDA similarly comments that there should not be any limitation on the program.

JU supports the spirit and principle of limiting impacts to Staff's recommended 2%, but disagree with the approach Staff has taken to calculate the precise impact. Instead, the utilities propose calculating the 2% target as the product of the three-year average of SC1 annual delivered kWh levels multiplied by the per kWh rates for delivery and three-year average of commodity rate. Further, JU claims that the approach would result in a customer bill increase of as much as 25% in some service territories, or $494 million statewide each year. JU is also concerned that Staff recommends that the 2% only apply to new projects instead of also including systems that are already interconnected. MI, PULP, and UIU also express concern that Staff's recommendation is only focused on incremental impact. Solar Parties respond to JU in reply comments stating that their approach to calculating net revenue

impact understates residential revenues, overstates impacts from mass-market PV exports, and does not account for any upward adjustment in DER value associated with future identification and quantification of DER benefits. TASC concurs that JU overstates impacts from mass-market PV exports.

MI expresses concern that Staff's 2% approach applies to total annual revenues as opposed to utility delivery revenues only, which MI argues would be more appropriate in this context. MI is also concerned about the context in which the 2% figure was selected and whether the full scope of other Commission-approved programs and initiatives that impose costs on customers were taken into consideration. PULP is similarly concerned and offers their assessment of aggregate impacts. Nucor is likewise concerned that the 2% net revenue impact bounding will not limit excessive cost shifts and recommends suspending any cost shifting elements of Staff's proposal upon hitting any cost impact boundary. UIU expresses concern that assessment of cost and benefits of DER has not been aided by a sufficiently detailed analysis and recommends imposing a hard cap on mass market projects and erring on the side of being conservative in calculating the 2%. PULP objects to the approach to set an artificial level of additional ratepayer support to justify the recommendations for subsidies to DER providers, and comments that the Staff Proposal fails to consider the cumulative effect of ratepayer increases already approved by the Commission or embedded in rate cases and other REV related proceedings.

3. Determination

Both NEM and the VDER Phase One tariff adopted in this order impact customer bills. NEM compensation results in reduced utility revenues and surcharge collections, which in some cases exceed the value of the benefits provided to the utilities by those projects. Because the utilities are

required, through revenue decoupling mechanisms, to bill customers at rates that result in net revenue equal to the approved annual delivery revenue requirement, any net revenue impact will be directly passed on to customers, with non-participating customers bearing the brunt of the impact since participating customers have offset much of their usage. Similarly, because most surcharges are designed to collect fixed total amounts based on Commission direction, reduced surcharge collections from NEM customers result directly in increased surcharge collections from non-participating customers.

Thus, the purpose of limiting the net revenue impact is not to protect overall utility revenues but instead to protect ratepayers, particularly non-participants, who are directly impacted as a result of revenue decoupling mechanisms and surcharge collections. Revenue decoupling mechanisms have been supported by environmental organizations and DER advocates as a method of ensuring that utilities are partners in, rather than opponents of, DER deployment and energy conservation. A significant portion of surcharge collections go to programs that support DER deployment. Phase One NEM compensation results in the same potential impacts as traditional NEM compensation, subject to a limited duration. While the Value Stack methodology manages and reduces these impacts, projects compensated under the Value Stack tariff that receive an MTC will still result in some net revenue impact.

The Commission is very aware of the compounding effect of bill impacts from various rate cases and initiatives approved by the Commission over the last several years as identified by PULP and expressed as a concern by UIU and MI. We note that while the list in PULP's comment appears long, the impacts of the items on the list are not all cumulative since many of the rate cases impact different geographic areas of the state.

While approval of a rate case or initiative has an immediate impact of a customer bill increase, the Commission balances those decisions with the underlying customer benefits to be produced. For example, rate case decisions are most often driven by the need to replace aging infrastructure, build new systems to meet increased demands, and adopt the latest technologies, all of which will benefit customers for many years to come. Similarly, the CES will attract billions of dollars in private investment for new renewable power, develop new jobs and new green choices for consumers, reduce carbon and other harmful pollutants, and allow New York to continue to maintain a diverse and reliable energy supply.

While, as the Staff Proposal acknowledges and several commenters maintain, some uncertainty exists in the precise calculation of the impacts of NEM and the potential impacts of the Value Stack, failing to address those impacts with as much precision as possible would represent an abdication of the Commission's responsibility to ensure just and reasonable rates for all customers. To mitigate impacts on non-participants during Phase One, both the availability of Phase One NEM and the inclusion of an MTC for certain projects in the Value Stack tariff will be designed with limits based on potential net revenue impacts. In calculating these net revenue impacts, we will consider all identifiable and calculable system values created by DER, including locational values and environmental values.

With those considerations, as well as other recent bill impacts and benefits, in mind, the Commission adopts Staff's recommendation of an upper bound for incremental net annual revenue impact of approximately 2% for all projects interconnected after the date of this order under the VDER Phase One tariff. The 2% upper bound will not result in a hard cap on

DER installation but instead, as described below, is used to design capacity-based allocations to limit the projected net revenue impact of mass-market and CDG projects under Phase One NEM and CDG projects under the Value Stack both through automatic transitions in CDG Tranches and through circuit breakers/triggers that inform the Commission that further action may be warranted.

Based on Staff's estimate of capacity-based allocations that can be accommodated under a 2% upper bound, this level reasonably balances the potential rate impacts with the need to provide market opportunity, and also takes into account the currently non-monetized benefits that these systems provide. The 2% level also ensures that there will be meaningful opportunities for customers in each utility service territory to install and invest in DER or participate in a CDG project. This order, coupled with the one billion dollar NY-Sun initiative, support for solar and other DG financing through the New York Green Bank, and other DG programs in the CEF, continues the Commission's support for aggressive DER deployment, while mitigating the potential bill impacts that would result from continued NEM and ensuring that continued DER development will, consistent with the goals of REV, take system needs into account and be compensated where it addresses those needs.

JU is correct that the approach proposed by Staff for calculating 2% in its Proposal was flawed. Because the calculation of 2% would vary each month based on commodity and other rate variations, the basic method proposed by JU is superior.[12] However, the list of rate elements proposed by JU excluded certain material elements. Because these elements vary

[12] Put simply, the JU approach is to multiply the average annual kWh for SC1 in each territory by a dollar per kWh rate to get a pro forma revenue estimate that is then multiplied by 2%.

from month to month, the JU approach of using three year averages is sensible.

With respect to the Phase One incremental CDG MW allocation, we also are persuaded by some of JU's comments. The 2% customer bill impact constraint is a useful target. However, the incremental CDG MW allocation should be defined by a number of MWs upfront, based on the percent of peak load that approximates such an impact. However, where JU proposes that the MW-based "cap" be set as a uniform 5% of each utility's peak load, we feel these two metrics could better balanced. By relying on the estimated MTCs discussed below, we find that the total number of incremental CDG MWs allocated to the Tranche system in Phase One shall be approximately equal to 4% of forecasted 2016 peak load for Consolidated Edison and Orange & Rockland. The total number of incremental CDG MWs allocated to the Tranche system in Phase One for Central Hudson, National Grid, New York State Electric and Gas, and Rochester Gas and Electric shall be approximately equal to 7% of forecasted 2016 peak load.

This conclusion was based on the following volumetric rate elements and calculation methods:

A. SC1 Tariffed Volumetric Delivery Rates per kWh. Calculated as the volumetric delivery rate element that is effective on the date of this order.

B. SBC Rates per kWh. Calculated as the weighted average per kWh SBC rate for the 36 months in the years 2014, 2015, and 2016. The weights used for calculating this average are the monthly kWh delivered to SC1 customers in the same months in 2014, 2015, and 2016.

C. MFC Rates per kWh. Calculated as in B.

D. Commodity Rates per kWh. Calculated as in B.

E. Calculating the 2% target for each utility. To derive total annual SC1 revenue estimates, the sum of these per kWh Rate elements are multiplied

by the average annual kWh delivered to SC1 customers, provided by JU with its comments. These averages are then multiplied by 2% to derive the target each utility.

F. The number of MWs of continuing onsite NEM growth, and the related revenue impacts, is estimated for the Phase One period and subtracted from the above 2% total. (Table 1)

G. The estimated remaining revenues are divided by the estimated revenue impact per MW of CDG to determine the approximate number of incremental CDG MWs consistent with the 2% target.

H. These MW estimates are compared to each utility's peak 2016 load as estimated by the NYISO, and a %-of-peak rule is set for each utility. (Table 2)

The number of MWs shown in the bottom row of Table 2 are the incremental CDG MWs for each utility.

TABLE 1. CALCULATING 2% REVENUE IMPACT, AND ALLOCATING TO CONTINUING ONSITE AND CDG

	CHGE	O&R	NGRID	NYSEG	ConEd	RGE
SC1 Load Weighted Rate	$0.1452	$0.1797	$0.1156	$0.1058	$0.2038	$0.1060
SC1 kWh/yr (3 yr avg)	2,070,088,000	1,578,881,333	11,340,042,826	4,871,585,653	13,849,333,333	2,597,630,513
Rate x kWh	$300,479,547	$283,738,460	$1,310,994,991	$515,208,388	$2,822,430,784	$275,242,570
x 2%	**$6,009,591**	**$5,674,769**	**$26,219,900**	**$10,304,168**	**$56,448,616**	**$5,504,851**
Continuing Onsite NEM						
kWh/MW	1,156,320	1,235,160	1,314,000	1,336,776	1,235,160	1,336,776
x 0.5	578,160	617,580	657,000	668,388	617,580	668,388
$ shift/kwh	$0.0737	$0.0942	$0.0457	$0.0470	$0.0919	$0.0487
$ shift/MW	$42,592	$58,177	$30,047	$31,427	$56,755	$32,532
MWs	**30**	**25**	**100**	**20**	**90**	**5**
$ for continuing onsite	$1,277,756	$1,454,425	$3,004,666	$628,541	$5,107,973	$162,662
Remainder for CDG	$4,731,835	$4,220,344	$23,215,234	$9,675,626	$51,340,642	$5,342,189
kWh/MW	1,271,848	1,358,128	1,444,159	1,472,145	1,357,414	1,473,426
$ shift/kwh	$0.0494	$0.0700	$0.0215	$0.0228	$0.0677	$0.0244
$ shift/MW	$62,865	$95,017	$31,039	$33,534	$91,842	$36,000
CDG MWs @ 100% NEM and no Tranche 0 REC retirements	**75**	**44**	**748**	**289**	**559**	**148**

TABLE 2. BALANCING 2% REVENUE IMPACT WITH % OF PEAK "RULE"						
	Central Hudson	O&R	NGRID	NYSEG	ConEd	RGE
2016 peak MWs	**1,104**	**1,164**	**6,776**	**3,192**	**13,705**	**1,591**
% of Peak						
4%	44	**47**	271	128	**548**	64
7%	**77**	81	**474**	**223**	959	**111**
CDG MWs Assuming: --2% bill impact (net of new rooftop) --100% NEM and no Tranche 0 REC retirements	75	44	748	289	559	148
INCREMENTAL CDG MWs	**77**	**47**	**474**	**223**	**548**	**111**

C. Limited Availability of Phase One NEM

The compensation available in Phase One NEM is equivalent to the compensation provided by NEM and will be offered according to the same rules, except that projects will only be eligible to receive Phase One NEM for a term of 20 years from the date of interconnection, as further discussed and explained in the section regarding compensation term lengths below.[13] Customers will be eligible for Phase One NEM where their DER project: (a) meets the eligibility rules for NEM; (b) is interconnected on or after March 10, 2017; (c) has a payment made for 25% of its interconnection costs,[14] or has its Standard Interconnection Contract executed if no such payment is required, within 90 business days of the date of this order;[15] and (d) for CDG projects, has a payment made for 25% of its interconnection costs, or has its Standard Interconnection Contract executed if no such payment is required, before the capacity limit for CDG projects under Phase One NEM is reached, which is established by this order for each interconnecting utility. In addition, all mass market, on-site DER projects will be eligible to receive Phase One NEM if those projects meet the eligibility rules for NEM and are interconnected before the earlier of January 1, 2020 or a subsequent Commission order. As described below, to manage potential impacts on non-participants, a capacity allocation has been established for

[13] Remote net metered projects eligible for monetary crediting grandfathering as established in the Transition Plan Order will receive Phase One NEM for a term of 25 years, consistent with that Order.

[14] A payment of 25% interconnection costs is a step established in the SIR and constitutes a sufficient level of financial investment to demonstrate that the project is advancing through the development process.

[15] As this order is dated March 9, 2017, this deadline will fall on July 17, 2017.

mass market Phase One NEM projects so that the Commission will receive notice and consider appropriate action if the number of mass market projects interconnected exceeds expected levels.

Phase One NEM is established to ensure that a compensation mechanism exists for projects interconnected after the date of this order and prior to the finalization of the Value Stack under Phase One to encourage continued market and development activity during that period. As discussed below, due to the maturity of the mass market and the fact that many mass market customers currently do not yet have sufficiently advanced metering for application of the Value Stack tariff, Phase One NEM will be available for mass market projects through January 1, 2020. While Phase One NEM continues the imperfect incentives created by NEM, it includes limitations to manage negative impacts. A fixed term of compensation is required to offer customers and developers the certainty they need to make investments, but must be limited in recognition of the imperfections of the current NEM compensation mechanism.

The eligibility rules for CDG under Phase One NEM, including the requirement of payment of a substantial portion of interconnection costs within a fixed period and the imposition of a rated generating capacity cap for each utility, will ensure that potential impacts on non-participating customers are properly managed. This approach will also ensure that Phase One NEM is only offered to CDG projects that have sufficiently advanced through the development process, while projects earlier in that process will be compensated based on the more accurate Value Stack tariff. The fixed period of 90 business days for payment of interconnection costs is consistent with the timeframes established in the SIR queue management process to ensure that only more mature projects that continue to advance through the necessary stages and meet all necessary financial

commitments are included. The capacity limits are established based on potential impacts on non-participating customers and are applied only to CDG projects. This is appropriate given that RNM and large on-site projects that are compensated based on volumetric crediting do not impose significant costs on non-participating customers under the current NEM construct, since those project types receive compensation for energy injected into the utility system based only on the commodity value of that energy.[16] Once the 90 business day period has passed or - for a CDG project - after the relevant capacity cap is reached, if a customer makes a payment for 25% of a project's interconnection costs or, if no such payment is required, executes a Standard Interconnection Contract, that customer will be compensated based on the Value Stack tariff, once that tariff has been implemented.

D. Transition from Phase One NEM to Implementation of Value Stack Tariff

In addition to making foundational policy decisions launching the transition towards more accurate valuation and compensation, this order begins the process of defining the Value Stack tariff and its components, while recognizing that further process is necessary before the tariffs can be implemented. The Commission is confident that, with the direction offered in this order, Staff and interested stakeholders can sufficiently develop the record for a

[16] As discussed in the Order Raising Net Metering Minimum Caps, Requiring Tariff Revisions, Making Other Findings, and Establishing Further Procedures, issued December 15, 2014 in Cases 14-E-0151 et al., RNM projects compensated based on monetary crediting may impose such costs; however, because grandfathering rules for those projects have already been established in the Transition Plan Order and customers have made investments in reliance on that Order, the eligibility of those projects for NEM-based compensation will not be modified here.

Commission decision finalizing and implementing the VDER Phase One tariffs as soon as Summer 2017. For that reason, the Phase One NEM CDG caps are designed to allow continued project development between the issuance of this order and Summer 2017.

III. FOUNDATIONAL POLICIES FOR NEM TRANSITION AND VDER PHASE ONE

A. Technologies and Projects Included

1. Staff Proposal

The Staff Proposal suggests that the VDER Phase One tariff apply to projects and technologies that are currently eligible for NEM under the PSL.[17] Those technologies were identified as either 1) intermittent and non-dispatchable, or 2) dispatchable, in recognition of their different characteristics.

The "Intermittent and Non-Dispatchable" category consists of technologies where the operator has no ability to control when the facility generates electricity or at what percentage of its capacity it generates, other than by limiting it or taking it out of service, once it has been put into operation, and includes solar photovoltaic generation, wind generation, and micro-hydroelectric generation. The "Dispatchable Technologies" category consists of technologies where the operator has a meaningful ability to control when, and at what percentage of its capacity, the facility generates, and includes farm waste generation, fuel cell generation, and micro-combined heat and power (CHP) generation.

The Staff Proposal notes that consistent with PSL §§ 66-j and 66-l, eligible projects must have a rated capacity of 2 MW or less, except for CHP projects, which must have a rated capacity of 10 kW or less. Projects must also meet certain other eligibility rules under PSL §§ 66-j and 66-l, including fueling requirements for farm waste generation and compliance

[17] PSL §§ 66-j and 66-l.

with relevant government and industry standards for construction and operation, including compliance with the SIR.

The Staff Proposal recognizes that while a variety of other DER technologies exist, further consideration is needed to determine whether and how the VDER methodology could be applied to compensate those technologies. Staff notes that a number of existing tariffs and programs govern the treatment and compensation of projects that are not eligible for NEM.[18] Specifically, Staff identifies the following categories that should not be eligible for the VDER Phase One tariff:

- Projects larger than 2 MW;
- CHP projects larger than 10 kW;
- Projects involving generation using non-eligible fuel sources, such as natural gas and diesel, other than eligible fuel cells and eligible CHP generators; and
- Non-Generation DERs, such as demand response and energy efficiency.[19]

However, the Staff Proposal recommends that the development of future phases of VDER tariffs prioritize inclusion of a broader array of DER.

2. Comments

Several commenters representing non-NEM eligible technologies recommend that the VDER Phase One tariff should apply to a broader category of projects, including some of the technologies that Staff recommends not be included under Phase

[18] For example, buy-back rates provide compensation for net injections and standby rates allow for the output of a generator, installed in-front of a customer's meter, to be netted against the usage of one or several buildings on the premises. In addition, the opportunity to earn compensation via a reliability credit under standby rates is now available.

[19] Customers that are otherwise eligible for participating in Phase One may, of course, also employ non-generation demand response and energy efficiency technologies without losing their eligibility.

One. Referencing the goal of technological neutrality, comments vary with the respect to the proposed timing for expanding eligibility for VDER. While NFG, NECHPI, and NFCRC recommend the inclusion of additional technologies under Phase One from the outset, AEMA, AEEI, NY-BEST, and DEC generally support Staff's recommendation to take up non-eligible technologies as part of the development of subsequent VDER phases and urge that this work commence expeditiously.

3. Determination

At this time, the VDER Phase One tariff will include only technologies and projects that are eligible for NEM. There is a pressing need to transition away from NEM, both to better target DER deployment to meet REV objectives and to manage impacts on non-participants. Many other types of DER, including demand management and response, energy efficiency and non-NEM-eligible DG, are eligible for participation in other existing tariffs and programs that reflect cost-benefit principles. In many cases, these programs have also been the subject of recent reforms to increase their ability to reflect more accurate price signals and compensation consistent with REV goals, including the addition of a reliability credit to standby rates, the expansion of demand response programs, and the development of the Clean Energy Standard. Adding the option to participate in the VDER Phase One tariff without further consideration could lead to overlapping compensation, opportunities for uneconomic arbitrage, and market confusion. Furthermore, as the Staff Proposal notes, technologies eligible for NEM share some basic similarities that not all DER possess, including the ability to produce electricity for on-site usage and for export to the grid, limitations on size, and environmental attributes. To permit other resources to participate in the VDER Phase One

tariff without sufficient consideration of their divergent attributes could lead to unintended consequences.

However, as commenters note, it is a key principle of REV that regulation and tariffs should be technologically neutral and focus on values provided and costs imposed by a DER and their behavior. Therefore, as part of Phase 2, VDER tariffs will be expanded beyond NEM-eligible DG technologies to all DER in a technologically-neutral, value-focused manner as soon as practicable.

B. Inclusion of Energy Storage

1. Staff Proposal

The Staff Proposal notes that energy storage technologies, such as batteries, are not addressed in PSL §§ 66-j or 66-l and recommends that storage be included in Phase One. Specifically, Staff recommends that: 1) projects that pair any energy storage technology with an eligible generation facility, including for the purposes of exporting stored energy, should be permitted to receive compensation under the Phase One tariff; 2) mass market and small wind systems that include storage should be permitted to retain NEM compensation; 3) for CDG, RNM, and large on-site systems, the installation of storage should require participation in the Value Stack, rather than NEM; 4) the presence of energy storage should not result in any change in compensation except that compensation for environmental value and the MTC should only be provided for net monthly exports; and; 5) while the use of system power to charge storage should be permitted, and even encouraged to the extent that it can support the system by reducing peak demand and variability, environmental and MTC compensation should not be provided for the export of stored system power.

The Staff Proposal also suggests that NYSERDA and the utilities examine solar-plus-storage intervention and

demonstration strategies that can help to further monetize system value, especially in high value locations of the distribution system, as VDER Phase One tariffs are implemented. Lastly, Staff recommends that projects that include energy storage but no eligible generator should not be eligible for the VDER Phase One tariff at this time but that a methodology for their inclusion should be developed for implementation at or before Phase Two.

2. Comments

Many commenters, including AEEI and NY-BEST, support Staff's recommendation to include energy storage paired with eligible generators under Phase One noting the importance of energy storage under REV. AEEI, Borrego and SolarCity also stress the importance of taking up consideration of stand-alone energy storage and recommend this topic as a priority; EDF/Policy Integrity suggest that a clear roadmap for doing so, with consideration by the Commission in 2017, is necessary. NY-BEST and TASC are particularly supportive of the solar-plus-storage intervention that is currently being considered by NYSERDA. SolarCity argues that solar projects paired with storage should be permitted to both provide on-site demand and load reduction and export under the VDER tariff. SolarCity also argues that large, on-site projects paired with energy storage should be able to charge on mandatory-hourly pricing even if the customer is not on this pricing scheme; AEEI agrees.

CORE, EDF/Policy Integrity, and Pace comment that Staff's recommendation to provide environmental value only to net exports from facilities paired with energy storage is insufficient to capture the full environmental values associated with energy storage, including the value of shifting load from dirty to less dirty generation on the bulk system. CORE suggests that the environmental value associated with energy

storage should be equivalent to how other clean generation is compensated for environmental value under VDER, which will help to encourage energy storage and further the State's clean energy goals.

3. Determination

The Commission adopts Staff's proposal to include energy storage when paired with an eligible VDER resource. Consistent with that proposal, mass market customers that include storage in their on-site systems will be permitted to retain NEM or Phase One NEM; however, customers that wish to pair storage with a CDG, RNM, or large on-site system will be required to receive compensation based on the Value Stack. While Staff's proposal limited the environmental and MTC compensation for energy storage to net monthly injections to avoid inappropriately providing compensation for those elements for non-green energy stored and then discharged, we recognize that such restrictions may not be reflective of expected storage installation configurations. Because of current federal tax credit rules, most energy storage systems are only charged with renewable power, and therefore the net monthly injection restriction may be unnecessary. Furthermore, the restriction could result in customers with significant usage, clean generation, and energy storage behind a single meter receiving compensation for less environmental value than they actually provide. Staff shall work with stakeholders to identify an alternate option for consideration by the Commission in implementing the Value Stack, such as a commitment by the customer to only charge using the eligible VDER resources, that still avoids uneconomic arbitrage while better reflecting actual storage configurations and value.

As the Staff Proposal and commenters acknowledge, energy storage is a key component of our energy future. The

integration of storage into DER deployments and the utility system has the potential to substantially enhance DER's capability to lower system costs and provide a variety of energy services. In addition to working to include stand-alone energy storage projects within the VDER Phase One tariff as expeditiously as possible, other methods of further encouraging integration of storage, including non-wires alternative projects and demonstration projects, are addressed in the Commission's order regarding Distributed System Integration Plans (DSIPs) considered at the same session as this order.

As noted in the Staff Proposal, NYSERDA is developing approaches to accelerating solar-plus-storage applications through the CEF. Staff shall work with NYSERDA and market participants to develop an Energy Storage Roadmap that identifies current and anticipated electric system needs that energy storage is uniquely suited to address, levels of energy storage that provide net benefit to ratepayers, and market-backed policies, consistent with REV objectives, to build energy storage in New York State.

While commenters' observation that projects that include energy storage could offer certain environmental benefits not recognized in the current Value Stack tariff, such as shifting energy consumption to a time of day when incremental generation is cleaner, is accurate, those benefits may not provide a cost savings to utilities and are not calculable at this time. As discussed further below, as part of Phase Two of this proceeding Staff and interested stakeholders should work to consider whether and how more granular values, including environmental benefits from time-shifted consumption, can be included in VDER tariffs.

C. Accurate Valuation and Compensation of DER

1. Staff Proposal

The Staff Proposal states that a move to monetary crediting is necessary in order to accurately reflect the values created by DER, including locational and temporal values. The Proposal explains that, in contrast to the volumetric crediting methodology currently used for most projects, monetary crediting permits the assignment of an individual value to each kWh based on when and where it is generated.

2. Comments

Several commenters acknowledge the practicality and usefulness of utilizing a monetary crediting structure for the Value Stack tariff. Acadia, EDF/Policy Integrity and Solar Parties specifically support Staff's proposal. SolarCity argues that volumetric crediting of CDG customers is a simpler tool then monetary crediting commenting that they are concerned with the utilities' ability to manage billing complexities.

3. Determination

A major goal of this proceeding, and of REV more broadly, is to develop a precise understanding of the value created and cost imposed by various interactions with the electric system and to then offer accurate compensation for such values, and charges for such costs, in order to provide appropriate incentives for customer and market behavior. At a minimum, accurate valuation and compensation requires the ability to recognize and account for the fact that the value of a kWh can vary greatly depending on where and when it is injected into or consumed from the grid; in other words, to recognize locational and temporal value granularity. As the Staff Proposal states, compensating DER based on locational and temporal granularity, as well as other specific values, requires monetary, rather than volumetric, crediting. For that reason,

compensation under the Value Stack tariff shall be based on monetary crediting.

D. Cost Allocation Principles

1. Staff Proposal

The Staff Proposal explains that, in order to avoid unnecessary reallocation of net revenue requirement between customer classes, recovery for each element of compensation should come from the same group of customers who benefit from the value that the compensation reflects. For compensation that does not reflect a value that has been identified and calculated at this time, including the MTC, Staff suggests that recovery should come from customers within the same service class as the beneficiaries in order to avoid revenue reallocation between service classes.

2. Comments

Many parties support Staff's principles and recommendations regarding cost allocation, including Acadia, JU, MI, Solar Parties, and UIU. Nucor states that cost allocation principles should explicitly state that cost allocation and cost recovery should be linked to and follow cost causation. MI and Nucor ask that additional clarity and specificity be offered for each specific cost allocation recommendation and its implementation.

JU points out that there are several mechanical issues with collection of costs related to various aspects of Staff's proposals, and that general accounting and cost allocation practices vary among the utilities. JU comments that further planning is necessary to implement the cost allocation proposal, and this work will be especially important as the penetration of DER increases.

3. Determination

The Commission adopts Staff's recommendation and directs that costs associated with compensation under the VDER Phase One tariff be collected, proportionately, from the same group of customers who benefit from the savings associated with the compensated DER, as determined in accordance with the Value Stack methodology. For compensation that does not reflect a value that has been identified and calculated at this time, including the MTC, recovery should come from customers within the same service class as the beneficiaries in order to avoid revenue reallocation between service classes.

In particular, compensation for energy and capacity values should be recovered from the same customers that benefit from reduced utility purchases of energy and capacity.[20] Compensation for environmental values should be recovered from the same customers that benefit from reduced utility purchases of Tier 1 RECs for CES compliance.[21] For DRV and LSRV compensation, utilities should identify what portion of the value results from avoided lower voltage level costs and what portion results from avoided higher voltage level costs. The portion of compensation reflecting avoided lower voltage level costs should be recovered from all lower voltage level delivery customers. The portion of compensation reflecting avoided

[20] As discussed below, some parties argue that the method chosen for capacity compensation may, at times, result in compensation for capacity within a given utility's territory being higher than the actual capacity value provided by the compensated resources. As part of the development of the Value Stack tariff, utilities should identify, and parties should consider and comment on, whether a method exists to collect any overcompensation from customers within the same service class, consistent with the principles laid out here.

[21] Tier 1 of the CES requires every load serving entity in New York State to procure RECs associated with new renewable energy resources.

higher voltage level costs should be recovered from all delivery customers. In addition, MTC compensation will be recovered from the service class of the project subscribers for CDG projects, with the total MTC for a project divided between service classes based on the percentage of the project serving subscribers from each class.

We recognize that, as JU states, implementing these cost allocation principles will require significant work, including determination of how to effectuate them within each utility's accounting and billing systems. For that reason, each utility shall make a filing by May 1, 2017 explaining their proposed implementation of these cost allocation principles. Those filings will be noticed for comment so as to enable Commission consideration as early as August 2017. While these principles are focused on the billing of costs associated with DER compensated under the Value Stack tariff, the utility filings should also discuss the practicality of allocating and collecting costs associated with DER compensated under Phase One NEM using these principles. Until the Commission has addressed these filings, recovery for compensation under Phase One NEM should continue to be based on current methods used for NEM.

E. Compensation Term Lengths

1. Staff Proposal

Staff recommends that projects retain the compensation methodology in effect at the time they are placed into service for 20 years after their in-service date.[22] The Staff Proposal observes that a twenty-year period is consistent with the term of contracts for Tier 1 RECs that NYSERDA will offer through

[22] Projects grandfathered under the Transition Plan Order should continue to maintain their compensation mechanism for 25 years from their in-service date.

auctions as part of the CES, as well as with policy trends in other jurisdictions.[23] The proposal also would provide an option for developers or customers to file petitions requesting a longer term than 20 years if pre-existing financing or other contractual arrangements contemplated a longer period. After the 20-year period ends, projects still in operation would be compensated based on the tariff then in effect.

2. Comments

Commenters' views and perspectives on length of compensation term vary. The majority of DER providers, solar developers, and advocates, as well as environmental advocates, including Solar Parties, CCSA, AEEI, DSUN, and EDA, argue that an appropriate compensation term would be equal to the life-of-system, and some argue that at the very least a term of at least 25 years is critical. CCSA posits that many project developers in New York have considered projects as 35-year investments, consistent with the estimated useful life of the current technology. CCSA also argues that Tier One REC contracts should not be determinative for overall compensation term length, which includes more than just compensation for environmental value. DSUN comments that other than already grandfathered RNM projects, NEM projects have not been subject to a term limit.

In the event that term length is shorter than life-of-system, several DER and solar developers, including CCSA and DSUN, are concerned about uncertainty related to the level of compensation after the term has expired, and request that the

[23] See, e.g., California Public Utilities Commission Rulemaking No. 14-07-002, Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering, Decision Adopting Successor to Net Energy Metering Tariff (issued February 5, 2016).

Commission adopt a clear statement on post-term compensation in order to appropriately support financing decision-making.

AEEI supports Staff's recommendation to provide an option for developers or customers to file petitions requesting longer terms if pre-existing financing or contractual terms contemplated a longer period. EDA and Grid comment that longer-term rates for CDG are essential to low-income participation.

JU recommends that Staff's recommended proposal of 20-year terms should be shorted to 15 years for mass market customers to reduce long-term risks to non-participants. JU also offers recommendations for term lengths associated with certain components of the VDER Phase One tariff.

MI expresses concern over locking in compensation for a term of 20 years, especially if more precise and accurate methodology is developed under Phase Two. MI also argues that if a 20-year term is adopted, DER developers and customers should not be afforded an opportunity to opt-in to compensation mechanisms under subsequent VDER phases. Other ratepayer advocates, including Nucor and UIU, are also concerned about the long-term locking in of DER compensation and impact on non-participants.

3. Determination

The Commission recognizes that project development requires a reasonable level of certainty in how that project will be compensated. The Commission also recognizes the increased costs and risks that long compensation terms can potentially impose on non-participating customers. However, due to their interconnection status under statutory authority, the Commission will not impose a limited compensation term on customers served under PSL §66-j or PSL §66-l.

For customers served under Phase One NEM, the Commission adopts Staff's recommendation that they receive Phase

One NEM compensation for a 20-year term from their in-service date.[24] As noted in the Staff Proposal, this is consistent with other programs and trends in other jurisdictions. As permitted in the Transition Plan Order,[25] developers or customers may file petitions requesting a longer term than 20 years based on pre-existing financing or other contractual arrangements that contemplated a longer period. After the 20-year period ends, projects still in operation will be compensated based on the tariff then in effect.

However, as some commenters note, a longer term can lower project costs, particularly with respect to financing, and thereby encourage development at lower levels of compensation, which benefits customers through increased DER deployment at reduced net revenue impacts. While the Commission is confident that the 20-year term length for Phase One NEM will serve as a sufficient incentive for continued project development, in order for projects to achieve economic viability under the Value Stack Tariff, additional support in lowering project costs and financing may be necessary. We therefore adopt commenters' suggestion for a compensation term of 25-years from the in-service date for projects that receive compensation under the Value Stack tariff. While the Commission recognizes the concerns raised by MI, UIU, and Nucor regarding the impacts of any fixed term, the terms established here balance the need for certainty associated with the development and installation of assets, like DER, with an extended productive life.

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[24] Projects grandfathered under the Transition Plan Order should continue to maintain their compensation mechanism for 25 years from their in-service date.

[25] Case 14-E-0151, supra, Transition Plan Order.

F. Environmental Attributes

1. Staff Proposal and Related Issues

The Staff Proposal addresses the treatment of environmental attributes associated with DER in discussing the Environmental Value component of the Value Stack. Staff's proposal that these matters be addressed here is consistent with the Commission's statement in the November 17, 2016 Order in the CES proceeding that "customer participation in the voluntary market and the question of a customer's ability to claim attributes associated with its voluntary projects are issues that are appropriate for further consideration by the Commission, in addition to and informed by the resolution of the transition of behind-the-meter resources from NEM to [a VDER] approach."[26]

Staff proposes that the generation attributes for which DER generators receive compensation under the Phase One tariff be ineligible from participation in the Renewable Energy Standard (RES) Tier 1 auctions administered by NYSERDA, and from participation in the separate sale of attributes certificates to LSEs or others for RES compliance or other purposes. Staff's proposal is based on the fact that the DER generator (customer-generator or CDG member) is being compensated for the environmental value the DER provides; therefore, the interconnecting LSE that pays for the value should receive a reduction of the obligation of that LSE for RES compliance purposes. Staff proposes that the New York Generation Attribute Tracking System (NYGATS) be used to track the transaction and create appropriate certificates for the account of the interconnecting LSE reflecting the transfer of the generation attributes. To the extent that the Commission determines that

[26] Case 15-E-0302, Clean Energy Standard, Order Providing Clarification at 5 fn.3 (issued November 17, 2016).

the Phase One tariff allows customers to claim generation attributes associated with energy consumed on-site for voluntary environmental and sustainability certification purposes, Staff proposes that NYGATS be used to track such on-site generation and to create appropriate certificates for the account of, and for retirement by, the customer. In such a case, the generation attributes retired would not provide any RES compliance credit for the interconnecting LSE, but would be recognized as contributing to the Statewide 50% by 2030 renewable resources goal.

2. Comments

JU comment that the creation of RECs should not be limited to exported generation only and states that generation consumed on-site should also contribute to LSE obligations under the RES. Bloom Energy also argues that generation consumed on-site should be eligible for RES participation. CORE comments that on-site generators should retain title to RECs regardless of the receipt of compensation for Environmental Value. As an alternative, CORE believes that customers should be able to forego payment for Environmental Value and receive fully tradable RECs.

CRS urges the Commission to clearly differentiate between the CES voluntary market and the RES compliance market and argues that no portion of the REC value should be decoupled from contractual REC ownership. CRS is particularly concerned about an automatic counting of renewable generation towards RES compliance without a stipulation that LSEs own RECs from this generation, in that it may erode the benefits of DER to the on-site customer. CRS argues that customers should be presented with a clear choice regarding the selling or transferring of RECs, along with clear articulation of REC ownership rights. NYPA also comments that this customer choice should be provided.

NFCRC is concerned about the lack of clarity around REC ownership.

Pace comments that RECs attributable to DER should not be counted towards either Tier 1 of the RES or the State's overall baseline unless the producer of the REC affirmatively makes a sale into compliance markets. Pace also opposes the restriction on receiving Environmental Value only for net monthly exports and believes that such a restriction will serve as a significant disincentive to customers installing storage.

NYC agrees with Staff's proposal to allow customers compensated under the Phase One tariff to claim the attributes for environmental and sustainability certifications. On the other hand, NYC opposes the restriction in the Staff Proposal that when a customer claims these attributes, the exported generation can be recognized as contributing to the State's overall Statewide 50% by 2030 renewable resources goal but not the RES Tier One obligation. NYC recommends that customer-retained attributes should be recognized as contributing to the RES Tier 1 obligation.

Comments concerning the treatment of DER were also submitted in response to the CES Phase 1 Implementation proposal filed by NYSERDA and Staff in Case 15-E-0302.[27] The Renewable Energy Parties (ACE-NY, American Wind Energy Association, Advanced Energy Economy Institute and Northeast Clean Energy Council) stated that further clarification was needed on the eligibility of DER to participate in the NYSERDA Tier 1 REC procurements and that no changes from the initial CES Order on eligibility with respect to DER should occur until the issues are resolved in the VDER proceeding.

[27] Case 15-E-0302, supra, Order Approving Phase 1 Implementation Plan (issued February 22, 2017).

IPPNY requested clarification on how DER projects funded by the NY-Sun and other customer-sited tier programs under the RPS would be counted toward the Statewide 50% by 2030 renewable resources goal.

Cypress Creek stated that RECs from DER resources that are recipients of net-metering and the phase one VDER tariff, proposed in Staff's White Paper in the VDER proceeding, be retained and retired by either the project owner or customer and, therefore, not count toward the mandated RES Tier 1 obligations of the LSEs. Instead, it remarked, that the RECs from these projects should be recognized as contributing to the overall Statewide 50% by 2030 renewable resources goal by reducing future LSE compliance requirements.

The National Fuel Cell Research Center and Bloom recommended that the Commission continue to include eligibility of net-metered DER resources in the RES Tier 1 REC solicitations unless and until the VDER proceeding has established appropriately structured REV market signals reflecting the true value of DER.

SRECTrade stated that DER should be allowed to participate in NYSERDA's RES Tier 1 REC procurements noting that solar PV should have access to additional incentives beyond the NY-Sun program.

As noted above, the JU supported the creation of RECs from DER and requested further clarification concerning metering arrangements for DER installations, noting that measurement and verification required for larger-scale installations could be cost prohibitive for many DER projects.

3. Determination

NYGATS was created to track the attributes of electric energy generated in or imported into New York State. Operation of the tracking system results in crediting to NYGATS accounts

and an output in the form of Certificates minted by NYGATS and deposited into the accounts of various NYGATS participants. NYGATS is capable of minting certificates for the attributes of electric energy as of January 1, 2016. Among other things, particular NYGATS Certificates may be designated as transferrable (tradable, sellable and/or monetizable) or non-transferrable (un-tradable, unsellable and non-monetizable), or may be eligible or ineligible to satisfy compliance requirements for governmental, utility, or voluntary market programs of various kinds.

However, even when particular NYGATS Certificates are designated as "non-transferrable," such Certificates may still be transferred in the following contexts and for the following purposes: (a) when the transfer is within sub-accounts of a single NYGATS account, so long as there is no remuneration of any kind associated with the transfer (for example, a company could not transfer credits or certificates to an affiliate, or from one affiliate to another, for remuneration); (b) when the transfer is associated with on-site mass market, small wind, remote net metering, or on-site large projects, the sale of energy or attributes in either a power purchase agreement, lease, or similar arrangement between contractual parties to the subject project to the degree such arrangements are allowed to qualify the customer or customers for participation in NEM, Phase One NEM, or Value Stack compensation and are necessary for the customer to obtain the generation attributes for retirement in the NYGATS account of the customer; and (c) for CDG projects, when the transfer is associated with the sale of energy or attributes in either a power purchase agreement, lease, or similar arrangement between contractual parties to the subject project to the degree such arrangements are allowed to qualify the customer or customers for participation in NEM, Phase One

NEM, or Value Stack compensation and are necessary either for the customer to obtain the generation attributes for retirement in the NYGATS account of the customer or for the interconnecting LSE to obtain the generation attributes for retirement in the NYGATS account of the interconnecting LSE.

The RES component of the CES is one program for which certain NYGATS Certificates will be eligible to satisfy the program's compliance requirements. For example, if the generation attributes meet the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificate that it is eligible to satisfy RES Tier 1 compliance requirements. If the NYGATS administrator does not indicate on each Certificate that it is eligible to satisfy RES Tier 1 compliance requirements, the Certificate will not be eligible for LSE compliance under RES Tier 1 regardless of the generation attributes stated on the Certificate.

The RES mandate imposes obligations on LSEs to financially support new renewable generation resources to serve their retail customers. LSEs may satisfy their obligation by either purchasing and retiring RECs in the form of NYGATS Certificates where the NYGATS administrator has indicated on the Certificate that it is eligible to satisfy RES Tier 1 compliance requirements, or by making Alternative Compliance Payments to NYSERDA. The RECs may be purchased from NYSERDA from the pool of RECs acquired through central procurement by NYSERDA or obtained through self-supply by direct purchase of RECs from generators or other market participants.

Various voluntary environmental and sustainability certification programs are another example of programs where certain NYGATS Certificates may be eligible to satisfy the program's compliance requirement. For these programs, it is often important to demonstrate that the claimant has acquired

resources that are not also being used to satisfy other mandates such that the claimant's actions evidence true incremental or "additionality" value by voluntary contribution. A Certificate retired in the claimant's account, for which the associated attributes are eligible under the certification program, is often the key indicator necessary to satisfy the compliance requirements of environmental and sustainability certification programs. Typically, those programs require the claimant to retire the Certificates to validate the claim. Given this background, the Commission fully understands the desire of many parties for a clear description of how the Commission will treat environmental attributes associated with DER.

a. Net Energy Metering

As a result of this order, most new DER projects going forward will not be eligible for NEM under the pre-existing NEM tariffs. Behind-the-meter projects that were previously eligible to bid in the Renewable Portfolio Standard (RPS) Main Tier solicitations conducted by NYSERDA will not hereafter be eligible to bid in RES Tier 1 solicitations conducted by NYSERDA unless they made the NEM cutoff established in this order and are actually enrolled in NEM under the pre-existing NEM tariffs. No other behind-the-meter projects of any kind will be eligible to bid in RES Tier 1 solicitations conducted by NYSERDA on a going forward basis. For the behind-the-meter projects that are eligible to bid into RES Tier 1 Solicitations conducted by NYSERDA, if any given the restrictions described above, if they are awarded a RES contract by NYSERDA, NYGATS will mint Certificates for the generator for delivery to NYSERDA's account. Similarly, NYGATS will mint Certificates that will allow generators to perform under all other RPS Main Tier and

RES Tier 1 contracts, beginning January 1, 2016, if appropriate and practicable.[28]

Customers enrolled in NEM under the pre-existing NEM tariffs, but without an RPS or RES contract, may desire NYGATS Certificates for their own voluntary market purposes. The Commission directs NYSERDA to authorize NYGATS to mint non-transferrable Certificates for deposit and retirement in these customers' accounts for the generation attributes ascribed to them. These customers will not receive any tradable Certificates from NYGATS. For these Certificates to be created, it may be necessary for the affected customers to register the project in NYGATS and provide generation data directly to NYGATS in accordance with the NYGATS operating rules, and possibly to provide NYGATS with a copy of the interconnection agreement. Because the generator attributes in this category are excluded from meeting the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificate that it is not eligible to satisfy RES Tier 1 compliance requirements and it will not count towards the interconnecting LSE's RES compliance mandates. The generation attributes of all renewable resource generation consumed by customers in New York State will however contribute towards the Statewide 50% by 2030 renewable resources goal, which relies on both mandatory and voluntary contributions for its ends to be achieved.

b. Phase One NEM

Any DER project that enrolls in Phase One NEM will be ineligible to bid in RES Tier 1 solicitations conducted by

[28] All pre-existing NEM projects that are eligible to bid into RES Tier 1 solicitations will be subject to a previous RPS Main Tier contract rule that prohibited simultaneous collections of both New York RPS incentive payments and production-based incentives from any other state or local source, including CST, NY-Sun, and CEF program incentives.

NYSERDA or to receive any tradable Certificates from NYGATS. For customers enrolled in NEM with On-Site Mass Market and Small Wind Projects, Remote Net Metering Projects, and On-Site Large Projects, the Commission directs NYSERDA to authorize NYGATS to mint non-transferrable Certificates for deposit and retirement in these customers' accounts for the generation attributes ascribed to them. These customers will not receive any tradable Certificates from NYGATS. Because the generator attributes in this category are excluded from meeting the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificate that it is not eligible to satisfy RES Tier 1 compliance requirements and it will not count towards the interconnecting LSE's RES compliance mandates. For customers enrolled in NEM with Community Distributed Generation Projects, the customers will be enrolled in a default Interconnecting-LSE-Option unless the customers make a joint non-revocable election at the time of interconnection to opt out and take a Customer-Retention-Option. Neither option involves any change in compensation for the customers, but the Interconnecting-LSE-Option would provide a social benefit to other ratepayers by reducing the cost of RES compliance for the interconnecting LSE. For the default Interconnecting-LSE-Option, the Commission directs NYSERDA to authorize NYGATS to mint non-transferrable Certificates for deposit and retirement in the account of the interconnecting LSE for the generation attributes ascribed to the energy received by the interconnecting LSE. If the generation attributes meet the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificate that it is eligible to satisfy RES Tier 1 compliance requirements and the generation attributes so retired in the interconnecting LSE's account will count towards the interconnecting LSE's RES compliance mandates. For the Customer-Retention-Option, the

Commission directs NYSERDA to authorize NYGATS to mint non-transferrable Certificates for deposit and retirement in these customers' accounts for the generation attributes ascribed to them. Because the generator attributes in this category are excluded from meeting the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificate that it is not eligible to satisfy RES Tier 1 compliance requirements and it will not count towards the interconnecting LSE's RES compliance mandates. As noted above, the generation attributes of all renewable resource generation consumed by customers in New York State will contribute towards the Statewide 50% by 2030 renewable resources goal, which relies on both mandatory and voluntary contributions for its ends to be achieved.

c. Value Stack

Any DER project that enrolls in Value Stack compensation will be ineligible to bid in RES Tier 1 solicitations conducted by NYSERDA or to receive any transferrable Certificates from NYGATS. All customers to be enrolled in Value Stack compensation will be enrolled in a default Interconnecting-LSE-Option unless the customers make a joint non-revocable election at the time of interconnection to opt out and take a Customer-Retention-Option. There is a difference in compensation for the customers depending on the option chosen. For the Interconnecting-LSE-Option, the customers will accept compensation for the Environmental Value component of the Value Stack. For the Customer-Retention-Option, the customers will be required to return that Environmental Value compensation to the interconnecting LSE in order to gain an opportunity to participate in voluntary market environmental and sustainability certification programs. These transactions would be conducted seamlessly by the

interconnecting LSE's billing system and the customer bills need only reflect the net result.

For the default Interconnecting-LSE-Option, the Commission directs NYSERDA to authorize NYGATS to mint non-transferrable Certificates for deposit and retirement in the account of the interconnecting LSE for the generation attributes ascribed to the energy received by the interconnecting LSE. If the generation attributes meet the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificate that it is eligible to satisfy RES Tier 1 compliance requirements and the generation attributes so retired in the interconnecting LSE's account will count towards the interconnecting LSE's RES compliance mandates. For the Customer-Retention-Option, the Commission directs NYSERDA to authorize NYGATS to mint non-transferrable Certificates for deposit and retirement in these customers' accounts for the generation attributes ascribed to them. Because the generator attributes in this category are excluded from meeting the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificates that it is not eligible to satisfy RES Tier 1 compliance requirements and it will not count towards the interconnecting LSE's RES compliance mandates. Again, as noted above, the generation attributes of all renewable resource generation consumed by customers in New York State will contribute towards the Statewide 50% by 2030 renewable resources goal, which relies on both mandatory and voluntary contributions for its ends to be achieved.

d. Conclusion

NEM, Phase One NEM, and Value Stack compensation are all linked to the environmental value of the generation attributes that make them eligible for these compensation methods. For NEM and Phase One NEM it is difficult to isolate the exact environmental value in the compensation equation, but

to the degree that those compensation methods allow for the avoidance of fixed costs, the full cost of such avoidance occurs as a consequence of recognizing the environmental value of the generation attributes. While the Commission previously allowed behind-the-meter resources to bid in the RPS Main Tier solicitations conducted by NYSERDA, that decision was made due to the difficulty of devising other viable alternatives for supporting biomass resources. However, continuing to allow dual participation in behind-the-meter compensation programs and RPS is inconsistent with the treatment of environmental attributes in those programs. Now that the Commission is fashioning a comprehensive revision of the NEM regime on the heels of a revision of the RPS regime, the Commission finds that this is an appropriate time to prevent simultaneous participation in both areas, particularly since new opportunities for compensation are being created that are more in tune with REV principles than the legacy solutions. In spite of that the Commission will also allow some small modicum of grandfathering for any behind-the-meter resources that made the NEM cutoff established in this order and are actually enrolled in NEM under the pre-existing NEM tariffs, in order to protect recent investments that may have been made.

Some of the categories being established allow for an element of customer choice as to how the customers will participate. To avoid unnecessary administrative complexities, it is the Commission's intention and requirement that such customer participation choices must be made no later than the time of interconnection so as to inform the interconnecting LSE how to implement the project without causing delay. Similarly, these irreversible decisions will only be allowed on a whole project basis and to all generation injected into the grid by

that project over its lifetime so as to make implementation manageable and predictable.

The platform utilized by NYGATS was originally created to support RPS-type programs, primarily involving large utility-scale generators injecting large quantities of energy into a unified electric transmission system with the quantity of most of the injections already being tracked by an Independent System Operator. The efficient "currency" that developed for such programs is the one-MWh certificate. Despite aggregation opportunities, or to make them possible, as a result of the issuance of this order in many cases it will be necessary to provide periodic certification to customers or to interconnecting LSEs of the generation attributes of quantities of energy measured in fractions of MWh. Therefore, the Commission directs NYSERDA to develop customer accessible monthly reports in NYGATS to include the balance of these generation attributes, inclusive of fractional MWh, in a form which will allow a customer to demonstrate, verify, and certify its claims and functionally satisfy compliance retirement requirements for governmental, utility, or voluntary market programs. NYSERDA is also directed to provide a report within 90 days of the issuance of this order detailing how the NYGATS platform can be used to generate information that will be used to support VDER Phase Two when substantially more tradability will be necessary.

For NYGATS to properly create certificates for a given project, the NYGATS administrator must know a significant amount of information about the project's classification pursuant to the interconnecting LSE's tariff, including the elections made

by the customer, and periodic data regarding the amount of energy generated and/or injected by the project.[29]

The most efficient method of ensuring that these designations are recognized by NYGATS is for the interconnection agreements to incorporate the required information. For pre-existing NEM or other projects, elections can be made by provision of the existing interconnection agreement along with written notice from the customer to the NYGATS administrator, with a copy to the interconnecting utility.

Until recently, NYGATS was not yet in operation and thus no Certificates were available. In acquiring, at the Commission's direction, the rights to generation attributes NYSERDA effectively claimed ownership of the rights to make environmental claims. In earlier years NYSERDA claimed those rights for a period of years. More recently the claims were made perpetual.

The effectuation of this important new policy requires a change to directions provided and past practice employed under the Customer-Sited Tier (CST) of the now expired RPS program and the more recent NY-Sun program. There, the Commission directed NYSERDA, as the central procurement agent, to acquire the renewable energy attributes for behind-the-meter projects to which it provided financial incentives. Emerging policy considerations and the evolution of REV make it necessary to take a new approach. Effective immediately, NYSERDA shall relinquish all rights to any environmental claims, certificates, attributes or other embodiments or memorializations of those claims for energy produced by any system to which it provided financial incentives under the CST and NY-Sun programs. This

[29] As was pointed out by JU in its comments, they do not have "gross production data" for these systems, but they do have data regarding energy injected into the system.

directive to relinquish rights applies both to Certificates minted in NYGATS and to all environmental claims, attributes or other embodiments or memorializations of those claims prior to the commencement of NYGATS tracking. NYSERDA should make reasonably practical efforts to alert past CST and NY-Sun participants of this change. NYSERDA should also work with Staff to consider and implement what changes to existing RPS, NY-Sun and CEF reporting requirements may be necessary to effectuate this change and provide appropriate guidance to all those who may be effected by this change of policy.

For further clarification of the Commission's treatment of generation attributes, a summary table is provided in Appendix B to this order.

G. Opt-In Availability

1. Staff Proposal

The Staff Proposal recommends that all projects that are entitled to continue to receive NEM based on the current policy should be allowed to elect to opt in for compensation under the VDER Phase One tariff instead. Mass market customers and CDG projects that opt in would be placed in the active Tranche at the time of their opt-in decision for the purpose of calculating an MTC. This opt-in would be irreversible and only available before the implementation of a Phase Two methodology. Compensation under the Value Stack requires a utility meter capable of reporting net hourly exported generation. While Staff suggests that utilities should make all reasonable efforts to install such meters for customers that wish to opt in, customers without such a meter would continue to be compensated through NEM mechanisms until such a meter is installed. Staff also recommends that customers compensated under NEM or the VDER Phase One tariff be permitted to opt in to any subsequent tariffs developed in further phases of this proceeding.

2. Comments

The majority of commenters that discuss this issue, namely solar and DER developers and advocates, express general support for Staff's recommendation. MI, however, is opposed to Staff's recommendation, arguing that this presents a "lose-lose" proposition for non-participants and imposes more of a cost impact. Nucor also characterizes the opt-in election as a windfall to developers at the expense of captive non-participants.

3. Determination

Consistent with Staff's recommendation, where a methodology that provides for more accurate valuation and compensation becomes available, customers served under a previous compensation methodology should be permitted to opt in. For this reason, while an opt-in for Phase One NEM is unnecessary because it provides identical compensation to NEM, customers served under either NEM or Phase One NEM will be provided a one-time opt-in to the Value Stack tariff once it is finalized. This allows those customers to access the more accurate compensation offered by that methodology. Furthermore, it will not impose any extra costs on non-participants during Phase One because projects that opt in will be counted towards any relevant caps, as appropriate.[30]

We will not decide at this time whether and under what conditions customers will be permitted to opt in to future tariffs developed in further phases of this proceeding. That question shall be left for orders related to those future tariffs.

[30] We anticipate that opt-in to future phases will similarly not result in additional costs to non-participants.

H. Metering Requirements

1. Staff Proposal

The Staff Proposal explains that a utility meter that can measure and record the net hourly consumption or injection of energy is needed in order to provide temporally granular compensation. Staff therefore proposes that the presence of such a meter be a precondition for Value Stack compensation. Staff notes that many large projects, particularly RNM and CDG projects, are already equipped with such advanced metering.

2. Comments

AEEI and Solar Parties express support for Staff's recommendation to require advanced metering as part of the VDER Phase One tariff. Digital comments that all DERs should be required to install such meters.

3. Determination

The Commission concludes that in order to be eligible for the VDER Phase One tariff, including Phase One NEM, all RNM, CDG, and large on-site projects must be equipped with utility metering with hourly recording capabilities. For new RNM and CDG projects, this metering must be installed at the time of interconnection. For large on-site projects, where an insufficient meter may already be present, the metering should be installed as soon as practicable. While mass market customers served under Phase One NEM are not required to have such meters installed, any mass market customer that opts in to the Value Stack must have such a meter installed before Value Stack compensation can be received.

I. Carryover of Credits

1. Staff Proposal and Related Issues

The Staff Proposal explains that, in any given billing period, a customer may create, or a subscriber may receive, more credits in compensation than the amount of their bill. In such

cases, Staff recommends that the amount will be carried over to the next billing period and applied as a credit on that bill. There would be no limit to the amount carried over by a customer or subscriber, nor would carried over credits be paid out at any time.

In its petition filed on October 21, 2016, SolarCity seeks clarification of how excess credits associated with CDG projects and held by project sponsors will be treated at the end of each annual period. SolarCity asserts that the CDG program rules are unclear insofar as they do not specify whether excess project credits accruing to a project sponsor at the end of the annual period expire, or may be monetized. According to SolarCity, this ambiguity is problematic for project developers because it risks compensating them for less than the full amount of generation produced. This creates uncertainty for financiers, SolarCity continues, which makes it more difficult to secure project financing.

In its petition, SolarCity requests clarification that the interconnecting utility must pay the system average locational marginal cost (LMP) to CDG project sponsors for their year-end excess generation credits. SolarCity argues that PSL §66-j(4)(c) requires utilities to pay CDG sponsors in this manner and, therefore, the "forfeiture" provisions of utility tariffs which effectuate the expiration of excess sponsor credits are incompatible with the PSL and Commission precedent.

SolarCity further argues that federal law also requires that CDG sponsors be compensated for year-end excess generation credits. Specifically, SolarCity explains that the federal Public Utility Regulatory Policies Act (PURPA) requires utilities to buy energy and capacity from a Qualifying Facility (QF) at the utility's avoided cost rate. According to SolarCity, the Federal Energy Regulatory Commission (FERC) has

determined that a QF – including a NEM facility – that makes a net sale to a utility must be compensated at an avoided cost rate. SolarCity asserts that the State's CDG program should be aligned with the federal rules implementing PURPA, as well as the PSL.

2. Comments

No comments on the Staff Proposal substantially discussed this issue or objected to Staff's recommendation.

Pursuant to SAPA §202(1), a Notice with respect to the SolarCity petition was published in the State Register on November 16, 2016 [SAPA No. 15-E-0082SP5]. The SAPA §202(1)(a) period for submitting comments in response to the Notice expired on January 3, 2017. Comments were received from JU and Cypress Creek.

JU opposes the petition. JU asserts that the central goal of the CDG program is to expand customer access to clean, distributed generation. It argues that the Commission required the distribution of all CDG project credits to its members in order to achieve this goal, and appropriately specified how the credits should be allocated or redistributed to project members. This requirement, JU continues, is critical to the CDG program and should be retained. JU argues that the contrary result urged by SolarCity would undermine the Commission's goal of expanding customer access to clean, distributed generation by reducing the amount of clean energy that utilities may resell from the CDG project. According to JU, allowing CDG sponsors to monetize their excess credits: (i) would create an arbitrage opportunity between fixed price contracts with customers and the utility's avoided cost rate; and (ii) could create an incentive for sponsors to spend fewer resources maximizing the project's customer value so that the sponsor may accumulate more excess credits to sell.

CDG developers, JU continues, may elect to sell energy and capacity directly into the wholesale markets rather than enrolling the project in the CDG program. JU argues that, if developers want the benefit of compensation as a QF under PURPA, they should forego the CDG program in favor of participation in the wholesale market. If, however, the project developer prefers to seek compensation for project output under the state-jurisdictional CDG program (and at the higher retail avoided cost rate), then it should accept the CDG program rules as they were established by the Commission.

JU asserts that the CDG program is "in its infancy," with little deployed capacity but a substantial quantity of CDG project capacity under development. JU asserts that it is unclear what effect the year-end excess credit monetization proposed by SolarCity would have on the design, financing, and implementation of the projects under development, or whether SolarCity's proposal would create a competitive advantage for certain resources. JU further notes that SolarCity failed to provide any specific example of the potential harm it describes.

Finally, JU argues that two additional considerations warrant rejecting the Petition. First, to the extent that the Petition suggests that the Commission erred by requiring CDG sponsors to forfeit year-end excess credits, the deadline for rehearing petitions passed more than a year before SolarCity filed its Petition. Accordingly, JU asserts, the Petition is untimely and should not be granted. Second, JU explains that they have made significant investments in billing solutions to implement the CDG program under the rules challenged by SolarCity. The Petition, if granted, would require further investments of unknown amount or difficulty to modify the billing systems. JU contends that the CDG program should be allowed to mature further under the existing program rules,

particularly in consideration of potential changes that may be required by the pending Value of DER proceeding.

Cypress Creek, a community- and utility-scale developer, owner, and operator of solar projects, supports the Petition. Cypress Creek notes that the CDG Order acknowledges that CDG sponsors may not be able to avoid accumulating excess generation credits under certain circumstances. Cypress Creek agrees that sponsors must be compensated for the full value of their generation to enable financing and reduce the risk posed by customer defaults or unexpected terminations. According to Cypress Creek, this creates a minimum value that sponsors may rely on as a backstop, thereby enabling shorter, more flexible subscription lengths and more onerous customer credit requirements. Cypress Creek alleges that it would be difficult for CDG projects to serve low-income customers without the relief requested by SolarCity.

3. Determination

The Commission adopts the Staff Proposal as it relates to the carryover of credits; for a project compensated under the VDER Phase One Tariff, unused credits may be carried over to the next monthly billing period, including over the end of annual periods, with the exception of credits held by CDG sponsors. However, in order to ensure that projects are sized appropriately for the load they are intended to serve, at the end of a project's compensation term,[31] any unused credits will be forfeited.

With respect to the SolarCity petition, we are persuaded that some additional flexibility may be necessary for

[31] As discussed above, Phase One NEM projects, other than RNM monetary crediting projects, will have a compensation term of 20 years; RNM monetary crediting projects will have a compensation term of 25 years; and VDER Phase One projects will have a compensation term of 25 years.

project sponsors, particularly with respect to a situation where a large customer drops its membership shortly before the end of an annual period. However, the fundamental purpose of CDG is to expand access to DER to customers who might not otherwise have such access. The restriction on carryover of credits by the sponsor was intended to ensure that CDG projects served customers, rather than serving to produce credits for the sponsor's own use, as well as to avoid the potential for arbitrage.

Compensating sponsors for unused credits, as SolarCity suggests, would improperly allow CDG projects to operate for an extended term without full subscription. Neither PSL §66-j(4)(c), which applies only to a limited category of projects, nor PURPA mandates any such payment. Rather than supporting SolarCity's claim, the FERC case cited in the petition demonstrates that state commissions have broad authority to determine the terms of service for net metered projects.[32] As JU states, developers are free to build projects that act as a QF selling energy into the wholesale market, rather than participate in CDG programs, if they prefer PURPA compensation to the terms of those programs.

In order to provide additional flexibility to CDG sponsors while retaining the incentives to keep projects fully subscribed and without creating opportunities for uneconomic arbitrage, CDG sponsors will be given a two year grace period beyond the end of an annual period to distribute any credits they retain at the end of the annual period. If at any time during the grace period the CDG sponsor has distributed all credits in its account, no credits will be forfeited; however, if the CDG sponsor has credits in its account throughout the

[32] MidAmerican Energy Co., 94 FERC ¶ 61340.

grace period, then at the end of the grace period it will be required to forfeit a number of credits equal to the smallest number of credits that were in its account at any point during the grace period, since that represents the number of credits that were held over from the previous period. To further ensure that projects are appropriately focused on serving customers, rather than generating credits for later distribution, CDG sponsors will only be permitted to retain credits for distribution during the two year grace period if those credits remain after the sponsor has distributed as many credits as practicable to members, such that each member's consumption in the final month of the annual period is fully offset by the credits provided.

This result addresses SolarCity's petition and also JU's concerns; JU's argument that the petition is untimely does not suggest a different result because consideration of petitions for rule modifications is always within the Commission's discretion and because of the relevance of the issue to this proceeding.

J. Determination of Applicable Compensation Methodology and Transfer of Ownership

1. Staff Proposal

The Staff proposal explains that for mass market, small wind, and large on-site projects, the project is closely tied to the underlying property and the customer as its owner or lessor. Staff concludes that modifying the compensation methodology when a property is sold may impair the value of that property. Furthermore, any transfer of such a property would involve the actual customer moving their residence or business location, and therefore would no longer be able to take advantage of credits generated by the project. For that reason, the compensation methodology of a mass market, small wind, or large on-site project should be determined at the time it pays

25% of its interconnection costs, consistent with the requirements in the SIR, or at the time of the execution of a Standard Interconnection Contract if no such payment is required, and should not change during the 20- or 25-year term based on changes in ownership.

For RNM projects, in some cases the project is on land where the customer also has a residence or business location. In other cases, the project may be on a site with no other use and the transfer of a project may not involve a customer moving their home or business. However, in either case, the value of the project is tied with the land once it is put into service. Furthermore, the payment of 25% of interconnection costs reflects a significant investment in the project. For that reason, the Staff proposal recommends that the compensation methodology of an RNM project be determined at the time that it pays 25% of its interconnection costs, consistent with the requirements in the SIR, or at the time of the execution of a Standard Interconnection Contract if no such payment is required, and will not change during the 20- or 25-year term based on changes in ownership.

For CDG projects, the Staff proposal recommends that subscribers may be added or removed regularly, consistent with current CDG rules, both during the planning and development phases of a project and during the operation of the projects. Using different compensation methodologies for different subscribers would lead to significant complications for the utility and developer and confusion for the subscribers. Furthermore, changing compensation methodologies when there is a change in the owner or operator, where that owner or operator may be the anchor subscriber, the developer, or another entity, would unreasonably change the compensation for subscribers. Therefore, the Staff proposal recommends that the compensation

methodology of a CDG project be determined at the time it pays 25% of its interconnection costs, consistent with the requirements in the SIR, or at the time of the execution of a Standard Interconnection Contract if no such payment is required, and will not change during the 20- or 25-year term based on changes in ownership or subscription.

2. Comments

No comments substantially discussed this issue or objected to the Staff Proposal.

3. Determination

Staff's proposal presents a rational solution for determining treatment of ownership transfers and therefore it is adopted.

K. Other DER Incentives

1. Staff Proposal

The Staff Proposal notes that DER technologies eligible for the Phase One tariff may also be eligible for a number of other incentives, including federal and state incentives and incentives offered by NYSERDA. Staff recommends that the receipt of any of these incentives not impact eligibility for compensation under NEM or the Phase One tariff.

2. Comments

MI disagrees with Staff's recommendation and argues that receipt of these other DER incentives combined with compensation under NEM or VDER would represent double compensation for the same attributes, in particular environmental attributes. Solar Parties and SolarCity, on the other hand, agree with Staff's recommendation.

3. Determination

The Commission adopts the Staff Proposal as it relates to other DER incentives. It is important to draw a distinction between compensation and incentives. Compensation, including

NEM and the VDER Phase One tariff, is designed to offer DER owners a return for the value that their projects create for the system. Incentives are intended to be additive to, rather than a replacement for, compensation, and reflect a variety of goals and values. To reduce compensation based on the receipt of incentives would subvert the purpose of those incentives and could not be rationally related to the value provided. To the extent that improvements in compensation methodologies, coupled with possible soft cost reductions and continued decreases in system costs, result in a reduced need for incentives, modifications to those incentives can be considered in the appropriate forums.

L. Future Rate Changes

1. Staff Proposal

The Staff Proposal explains that customers that receive NEM have always been subject to changes in rates and in rate design, including increases and decreases in fixed customer charges, allocations between service classes, use of time-based or demand-based rates, and allocation of costs between various billing categories. Staff therefore recommends that customers compensated under NEM or the VDER Phase One tariff should similarly remain subject to such changes. For projects involving multiple sites, such as CDG and RNM projects, this should apply to all sites and meters. Similarly, Staff notes that customers were not and should not be protected from changes in the price of fuel or electricity.

2. Comments

Solar Parties commented in general support of Staff's recommendation. No other comments substantially discussed this issue.

3. Determination

The Commission adopts the Staff Proposal. All customers are subject to changes in rates and rate design, as well as changes in the price of fuel and electricity. The setting of a fixed term for compensation does not freeze other elements of a customer's bill.

IV. APPLICATION OF THE VDER PHASE ONE TARIFF TO THE FOUR MAJOR MARKET SEGMENTS

A. On-Site Mass Market Projects and Small Wind

1. Staff Proposal

The Staff Proposal defines mass market customers as customers that are within a jurisdictional electric utility's residential or small commercial service class and that are not billed based on peak demand. On-site mass market projects include eligible generating facilities connected behind a mass market customer's meter. Staff recommends that on-site mass market projects placed into service before January 1, 2020 continue to receive NEM based on the current compensation methodology. That is, their kWh usage and generation is netted each billing cycle; if their usage exceeds generation, they pay only for the excess usage; and if their generation exceeds their usage, their excess generation becomes kWh credits that offset their usage in the next billing cycle.

For projects put into service after January 1, 2020, Staff recommends that they receive compensation based on the mechanisms to be developed in Phase Two. Should a new compensation methodology not be in place by January 1, 2020, projects put into service after that date would receive NEM compensation only until the new compensation methodology is developed and implemented and would then be transferred to the new compensation methodology.

In addition, for each service territory, Staff proposes a MW trigger reflecting the estimated growth of on-site mass market projects during Phase One. The MW allocation was calculated to sustain activity based on levels and approximate growth trends from 2014-2016. Staff suggests that the rated capacity of all eligible mass market generation interconnected after the date of this order be counted towards this MW trigger, with the exception of wind interconnected before the PSL 66-l cap is reached. If growth in mass market installations results in this MW trigger being reached prior to the implementation of a new compensation methodology, Staff proposes that the Commission determine what action is appropriate under all the facts and circumstance then applicable. However, reaching the MW trigger would not have any effect on projects put into service prior to any Commission action.

To enable timely awareness of the potential for reaching the MW trigger, Staff recommends that the utilities should be required to provide monthly public reports on the number and capacity of mass market projects as compared to the MW trigger. Furthermore, Staff suggests that the utilities should provide public notice, including notice to Staff, when mass market installations reach 85% of the MW trigger and when the trigger is reached. In addition, Staff proposes that the utilities should expeditiously develop unbundled values, as described below, such that before the MW trigger is reached they can propose new compensation methodologies for consideration.

The Staff Proposal also considers whether other requirements should be imposed on this sector, such as the installation of smart inverters or mandatory participation in Time-of-Use Rates. As noted therein, discussion of smart inverters reflects consideration of how best to address the growth of the installed base of on-site systems compensated

through NEM and of how the value to the system can be maximized. The Proposal recognized that further questions remain regarding smart inverters and recommended that Staff, in consultation with interested parties, present a report and recommendations regarding this topic by July 1, 2017. Topics that could be included, at a minimum, involve the definition of a smart inverter, including operating parameters, and the circumstances under which any requirement should be imposed.

2. Comments

Commenters representing DER technologies, particularly solar companies and advocates, universally support the continuation of NEM for mass market customers as recommended by Staff. Acadia, Pace, NYSEIA, Solar Parties, and TASC all support Staff's recommendation. Many comment that real-time tracking of development under the MW triggers is critical. AEEI cautions that the Staff proposal for continuation of NEM for mass market and its proposal for CDG create a disparity between these two markets segments and customer value propositions.

NYC argues that the MW trigger is not necessary, in particular for the Con Edison territory, and that it introduces material uncertainty into mass market project development, which is especially problematic in New York City where the market is still in early stages. NYSEIA and SolarCity posit that the MW trigger may be hit in some service territories within months after any Commission order and well in advance of the January 1, 2020 date.

While JU does not oppose the Staff recommendation for continuation of NEM for mass market, it argues that any MW triggers should result in concrete and definitive actions as opposed to review by the Commission as Staff recommends. MI and PULP oppose continuation of NEM for mass market and argue that the recommendation carries the concept of grandfathering too far

at the expense of non-participants. Nucor also expresses concern over the impact of continuation of NEM on non-participants.

3. Determination

The Commission finds that continuation of NEM under Phase One NEM for new mass market projects installed before January 1, 2020 is appropriate. Maturation of this market segment and appropriate business models will require notice and a more gradual evolution to a new compensation methodology. In addition, the application of the Value Stack will necessitate more advanced metering than most mass market customers currently have. The rollout of more advanced metering in each utility's territory has been subject to substantial development in other proceedings, including rate cases; attempting to quickly transition mass market DER customers to the Value Stack would disrupt the schedules established in those proceedings. Transition of this sector onto a new compensation methodology will be a component of the Phase Two deliberations, and influenced in part by utility plans and actions to unbundle values.

However, as the Proposal suggests, monitoring will be necessary to ensure that mass market projects do not create the potential for unreasonable impacts on non-participants. Staff's recommendation of a MW capacity allocation, with regular reporting by the utilities and explicit notice when 85% of the allocation is reached, is adopted. Analysis subsequent to the Staff Proposal and informed by comments has resulted in modifications of the capacity allocation sizes. The resulting capacity allocations, as well as the 85% levels, are shown in Table 3, below. The notice at 85% of a utility's allocation will offer the Commission sufficient time to determine whether action is necessary and, if so, what further action should be

taken to manage impact on non-participants. This could result in a variety of possible outcomes, including an accelerated transition to a new compensation methodology, the development of cost mitigators such as grid access charges or non-bypassable fees, or no immediate action if impacts on non-participants do not require further action.

Table 3. Phase One NEM Mass Market MW Capacity Allocation

	CHGE	O&R	NGRID	NYSEG	CE	RGE
MWs	30	25	100	20	90	5
85% of MWs	25.50	21.25	85.00	17.00	76.50	4.25

B. Community Distributed Generation Projects

1. Staff Proposal

The Staff Proposal defines CDG projects as consisting of an eligible generating facility located behind a nonresidential host meter and a group of members located at other sites that receive credits from that facility to offset their bills. CDG projects may include both mass market customers and large customers as subscribers. CDG projects are subject to further eligibility rules as described in the Commission's CDG Order.[33] It's expected that most CDG projects will export 100% of their generation to the grid to earn credits to provide to subscribers, but some may be behind the meter of a member and include some on-site usage.

Staff recommends that CDG projects put into service after the issuance of this order should receive compensation based on limited continuation of NEM or the VDER Phase One tariff. These projects are either behind new meters and export 100% of their generation to the grid, like RNM projects, or are

[33] Case 15-E-0082, Policies, Requirements and Conditions For Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015).

behind the meter of a large customer, like on-site large projects.

2. Comments

A few commenters, including EDA and smaller DER and solar developers, argue that it is inappropriate at this stage of the CDG market to dramatically shift to a new compensation scheme due to the nascent stage of the market and newness of such Phase One compensation mechanisms. EDA suggests that at the very least, that during Phase One, projects should be afforded the choice to select between NEM and the Value Stack tariff.[34]

3. Determination

The Commission adopts the Staff Proposal that CDG projects be compensated based on a limited continuation of NEM compensation, authorized in this order as Phase One NEM, or on the Value Stack tariff, based on the applicable policy when 25% of a project's interconnection costs are paid or the Standard Interconnection Contract executed if no such payment is required.

CDG offers an important opportunity to expand access to DER in New York State, particularly to low-income customers and other customers who otherwise might not have the opportunity to install DG on their premises and participate in DER programs. However, the CDG market in New York State is nascent, with CDG authorized by the Commission less than two years ago and with many projects in the interconnection queue under various stages of development. The Commission is cognizant of the need to avoid taking actions or creating uncertainty that could harm

[34] NYC submitted a separate petition requesting waiver of the CDG 10-member minimum, and references that petition in its comments. Case 15-E-0082, supra, Joint Request for Waiver (filed September 1, 2016). That petition is addressed in a separate order.

this market's development, and at the same time recognizes that these projects will be managed by CDG developers, anchor members, or subscriber organizations that have the capability to manage a more accurate compensation mechanism. In recognition of the gap that some projects may face between expected compensation under NEM and under the Value Stack and the need for certainty in the development of the CDG market, the Commission adopts an MTC for CDG projects, which will be divided into Tranches. The calculation of the MTC and capacity allocations for the Tranches are detailed below; as with mass-market projects, the utilities will provide regular reporting on progress in the Tranches and explicit notice when 85% of the allocation is reached.

Because the projects authorized in the separate order addressing NYC's petition for limited waiver of the 10-member minimum are CDG projects and share the necessary characteristics of those projects for Value Stack compensation, including metering capable of recording net hourly injections, they will be compensated in the same manner as other CDG projects.

C. Remote Net Metering Projects

1. Staff Proposal

The Staff Proposal explains that non-residential electric customers, as well as residential customers owning farm operations, may designate net metering credits created by an eligible generator at one property they own or lease to the meters of other properties they own or lease. This process is commonly referred to as remote net metering (RNM). Under the volumetric crediting system adopted in the RNM Volumetric Crediting Order,[35] the excess kWh generated at the host site are

[35] Case 14-E-0151, supra, Order Raising Net Metering Minimum Caps, Requiring Tariff Revisions, Making Other Findings, and

transferred to the Satellite Account as volumetric credits, which then offset the Satellite Account's kWh charges, thereby reducing their bill. Staff notes that volumetric crediting results in very low credit value for many customers because a large portion of their delivery bill is a demand charge, which volumetric crediting does not reduce. Therefore the VDER Phase One tariff offers the opportunity to increase compensation for those customers to a more accurate value based on monetary crediting without causing net utility revenue impact. Staff therefore proposes that RNM projects placed into service after the issuance of this order, and not eligible for NEM, should receive compensation based on the Phase One Value Stack tariff.

2. Comments

Several commenters, including Borrego, CORE, and Bloom express concern that under the Staff Proposal large commercial customers, due to their ineligibility for an MTC, will be at a disadvantage as compared to CDG and that current retail rates have proved challenging for DER investment in this market segment.

3. Determination

The Commission adopts the Staff Proposal that RNM projects be compensated based on a limited continuation of NEM compensation, authorized in this order as Phase One NEM, or on the Value Stack tariff, based on the applicable policy when 25% of a project's interconnection costs are paid or the Standard Interconnection Contract executed if no such payment is required. These types of projects, which involve large, sophisticated businesses as customers, are well-suited for a more accurate and detailed compensation system. The Value Stack tariff may reenergize this segment, which has struggled to

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Establishing Further Procedures (December 15, 2014) (RNM Volumetric Crediting Order).

develop new projects under volumetric crediting. Because, as discussed above, new RNM projects are not expected to cause significant impact on non-participants regardless of whether they are compensated under Phase One NEM or the Value Stack, any project that has a payment made for 25% of its interconnection costs, or has its Standard Interconnection Contract executed if no such payment is required, within 90 business days of the date of this order shall be placed on Phase One NEM, with no capacity limit applied. Projects that do not meet this deadline will be compensated under the Value Stack.

D. On-Site Large Projects

1. Staff Proposal

The Staff Proposal defines large customers as customers within a jurisdictional utility's non-residential demand-based or mandatory hourly pricing (MHP) service classifications. On-site large projects are eligible generating facilities connected behind a large customer's meter and not used to offset consumption at any other site. Staff recommends that on-site large projects put into service after the issuance of this order that are not eligible for continuation of NEM should receive compensation based on the VDER Phase One tariff for their net hourly exported generation. Generation consumed on-site would not be metered by the utility and would, as is the current practice, directly reduce metered usage and therefore reduce bills rather than resulting in compensation. To the extent that an eligible generating facility that would be subject to the VDER Phase One tariff is interconnected on a site without a meter capable of providing data on net hourly imports and exports, that project should be provided with compensation based on NEM methodology until such a meter is installed.

Staff notes that, to the extent that a customer who has built or builds a project on-site prefers to receive

compensation based on the VDER Phase One tariff mechanisms for all generation, rather than consuming some generation on-site, that customer may arrange for that project to be separately interconnected and metered, such that no generation it produces is consumed on-site but instead all generation is exported to the grid. In that case, as with an RNM project, the customer should receive compensation for all exported generation based on the Value Stack.

2. Comments

Several commenters representing non-solar DER, including AEEI, Bloom, CORE, NFCRC, and OGS express particular concern over the Staff Proposal's treatment of behind-the-meter generation under Phase One. These commenters argue that generation produced and consumed behind-the-meter, as is the case with many large-scale commercial applications, offers many of the same values that the Staff Proposal identifies for net injections. AEEI, for example, urges the Commission to apply the DRV and LSRV to all behind-the-meter generation regardless of whether it is instantaneously consumed or exported. CORE argues that that non-exporting, behind-the-meter generation creates multiple benefits including: 1) avoided or deferred distribution investments; 2) avoided distribution energy losses; 3) reduced wear and tear on the distribution system; 4) avoided environmental impacts associated with transmission and distribution facilities; 5) displacement of diesel generators; and, 6) enablement of grid isolating capabilities.

3. Determination

The Commission adopts the Staff Proposal and directs that large on-site projects be compensated based on a limited continuation of NEM compensation, authorized in this order as Phase One NEM, or on the Value Stack tariff, based on the applicable policy when 25% of a project's interconnections costs

are paid or Standard Interconnection Contract executed if no such payment is required. These types of projects, which involve large, sophisticated businesses as customers, are well-suited for a more accurate and detailed compensation system. Similar to RNM projects discussed above, new large-scale, on-site projects are not expected to cause significant impact on non-participants regardless of whether they are compensated under Phase One NEM or the Value Stack tariff. Any project that has made payment for 25% of its interconnection costs, or has its Standard Interconnection Contract executed if no such payment is required, within 90 business days of the date of this order shall be placed on Phase One NEM, with no capacity limit applied. Projects that do not meet this deadline will be compensated under the Value Stack.

As commenters note, reducing consumption from the grid by one kWh in a particular location at a particular time through consumption of on-site generation offers identical values to the system as injecting one kWh in the same location at the same time. For that reason, under the principles of REV, a customer should receive equal overall compensation for generating 1 kWh for on-site usage which reduces demand on the grid as for generating 1 kWh for injection as soon as the transition to that end-state can be practicably accomplished. However, a method has not yet been developed to ensure that such customers receive the exact same overall compensation for on-site generation and consumption as for injected generation. Until those methods are developed, customers who currently generate and consume energy behind a meter will get the benefit of bill reductions under existing rate designs.

Therefore, in VDER Phase One, compensation under the Value Stack tariff will only be available for generation injected into the grid, and no compensation beyond the existing

benefit of bill reductions through reduced metered consumption will be offered for energy generated and consumed on-site until VDER Phase Two. To the extent that any customers believe that this results in potential under-compensation for their projects, they can arrange for their DER to be separately metered. In that case, it would not directly reduce their usage; instead, substantially all generation would be injected into the grid and receive compensation based on the full Value Stack leaving them in the same overall financial position as they will be in Phase Two. In order to achieve the technology neutrality and focus on value envisioned by REV, rate design issues will be taken up in Phase Two of this proceeding in order to develop and implement a method for offering equal compensation for reductions in consumption as for generation.

V. THE VALUE STACK

Staff proposes that the VDER Phase One mechanism should compensate customers using a tariff based on calculations (and proxy calculations) of specific value sources as applied to hourly net injections at a utility meter.[36] When considered together, these values comprise the Value Stack, with each stated value serving as a component of the stack. Some of the Value Stack's components will be fixed for a given project, while some components will vary with fluctuations in energy markets. The following sections explain each value identified by Staff and Staff's recommended methodology to reflect that value and make determinations accepting or modifying Staff's recommendations. The Value Stack tariff approach results in

[36] In addition, and as discussed above, Staff recommends consideration of an initial tranche that would provide limited opportunity for projects put into service after the date of this order to receive compensation based on Phase One NEM.

monetary bill credits that are applied to a customer's or project subscriber's account in each billing cycle, with any excess credit carried over month-to-month, as described above. In order to avoid disruption in New York's nascent CDG market, Staff recommends, and we direct, that the Value Stack tariff also include an MTC that is stepped down over time.

Although commenters offer a wide range of perspectives on particular aspects of Staff's proposed Value Stack mechanism, many parties express general support for the structure of the Value Stack as a strong first step based upon the underlying objectives to transition DER compensation to a more accurate and granular framework. Many parties, including JU and many solar providers, DER providers, and environmental advocates, comment that the overarching structure of the proposed Value Stack tariff would serve as an appropriate step forward from NEM with some critical modifications and if implemented in an appropriate manner, as detailed in prior and subsequent sections of this order.

While consumer advocates express general support for more accurate and precise compensation based on the unique performance characteristics of DER, they articulate concern that the overall Phase One proposal includes too much subsidization for certain types of DER, particularly resulting from the continuation of NEM for mass market and the MTC for CDG projects.

A. Energy Value

1. Staff Proposal

Staff recommends that both the value and the compensation for the energy that eligible generation facilities inject into the system, and the reduction in utility energy purchases resulting from that injection, take the form of actual day-ahead NYISO hourly zonal LBMP energy prices at the time of

generation. Staff suggests that this compensation be calculated in the same way as charges for mandatory hourly pricing (MHP) customers are calculated and, thus, would include avoided losses.[37]

Staff states that employing hourly zonal LMBP for energy compensation increases the temporal granularity of compensation and has the potential to increase location granularity. It also precisely reflects the costs that utilities are avoiding based on the injected generation. Furthermore, this method of compensation will recognize that some generation technologies, such as solar, may provide electricity at the most valuable time of the day.

2. Comments

There is general acknowledgement by commenters of the logic of this approach. JU, however, argues that injections to the distribution system will not always avoid the loss levels reflected in MHP tariffs. JU suggests that further study be undertaken to analyze and better understand how losses at levels of the system are impacted with the increased use of DG. In the meantime, JU proposes that a lower line loss adjustment be provided considering that most projects injecting into the system under VDER will not achieve the same line loss benefit as behind-the-meter resources. PULP challenges the assertions that DG provides benefits related to reduction in line losses.

Solar Parties, Borrego, EDF/Policy Integrity and OGS support Staff's recommendation and argue for the inclusion of

[37] Staff indicates that, to the extent that MHP kWh charges contain adders to collect costs in addition to LBMP and related losses, such as uplift and ancillary services, these adders should not be credited to net injections, as injections do not reduce these costs at this time. These are the types of costs that should be considered for further unbundling, as discussed below, and included in the discussions among DER companies, the utilities, and the NYISO, noted above.

components related to energy, congestion and losses. AEEI and CCR also argue that losses should be included in the valuation of energy.

DSUN argues that the methodology should establish a floor price in order to provide greater certainty under VDER. Solar Parties also note the significant shift that moving from energy value under NEM versus day-ahead LBMP entails. SolarCity comments that it would be appropriate to utilize MHP values as a proxy for energy values under Phase One.

3. Determination

Staff is correct that, at this time, the Day Ahead hourly zonal LBMP, as used in the MHP tariffs, is the appropriate value for crediting DER injections. The Commission notes that JU's Supplemental DSIP filings describe a process wherein the NYISO initiated a pilot project to include a limited number of sub-zonal buses in the calculation of LBMPs which have been published on the NYISO website since late June 2016. We encourage the utilities, Staff, and stakeholders to continue to work on methods to reflect more local and real-time energy valuation mechanisms to provide beneficial price signals to the marketplace.

With respect to avoidable distribution losses, JU would have us treat injections of electricity at specific locations in the distribution system differently from how withdrawals of power are treated at these exact same locations. For withdrawals (i.e., commodity purchases), utility tariffs all provide for increasing bulk commodity costs by a factor to reflect distribution losses. Yet, JU recommends injections be treated asymmetrically — that is, to not increase the bulk energy price by such same level of losses to reflect their avoidance — until studies have been conducted. The Commission disagrees with this approach. Absent a more granular

disaggregation of distribution line losses, it is sensible to conclude that a one kWh injection of power would avoid, on average, the same amount of losses that would be caused, on average, by a one kWh withdrawal.

B. Installed Capacity Value

1. Staff Proposal

The NYISO requires utilities to purchase capacity based on the MW demand on their system during the statewide peak hour of the previous year. Consequently, the actual installed capacity value that eligible generation facilities provide each year depends on their performance during the peak hour in the previous year. Staff notes that the Phase One tariff could base compensation for installed capacity on this value by compensating eligible generation facilities each month with a lump sum equal to their MW performance during the peak hour in the previous year, sometimes referred to as a customer's "capacity tag," multiplied by the actual monthly generation capacity spot prices from NYISO's ICAP market that month.

Staff maintains that dispatchable technologies, as well as intermittent technologies paired with storage, should be able to target performance during this peak period; while the hour itself is not known in advance, it will likely occur during an afternoon on a hot summer day, though it has occurred as late as September. Thus, Staff recommends this form of value calculation and crediting for dispatchable technologies, as well as intermittent technologies that opt in, for example after installing storage.[38] Staff argues that any alternative approach

[38] Dispatchable technologies, and intermittent ones that opt in, would "be compensated each month with a lump sum equal to their MW performance during the peak hour in the previous year multiplied by the actual monthly generation capacity spot prices from NYISO's ICAP market that month. In a project's first year, it would receive capacity compensation based on an

to crediting dispatchable technologies would not properly incentivize those technologies to perform during peak hours and would undercompensate those generators who do perform during those hours. Staff acknowledges the difficulties this approach can present and its imperfect match to actual costs and suggests continued engagement with NYISO's processes to improve billing and compensation methods for capacity.

Staff then discusses intermittent technologies not paired with storage, which generally have no control of when they generate. While solar generation, in particular, will generally be producing during summer peak hours, any given project may miss the one particular hour of the year due to uncontrollable, purely random events, such as a poorly timed local cloud.

If credited for ICAP as described above, this would result in substantial variability for intermittent technologies, which could present issues for project financing. In recognition of this challenge, Staff proposes alternative compensation methodologies for intermittent technologies. Staff asserts that intermittent technologies should receive more stable per kWh compensation based on the capacity portion of the utility's full service retail market supply charges. The two specific alternatives proposed by Staff are:

1) The capacity portion of the supply charge for the service class with a load profile most similar to a solar generation profile could be used for each kWh of generation all year; or,
2) Alternately, that capacity portion could be assigned to specific summer hours to better reflect system needs. For this method, each

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average generation profile for a project of its technology and rated capacity in its service territory."

June, the prior 12 months of Service Class 1 monthly capacity statements would be used to determine the $/kW per year. The $/kW/year amount would then be credited to the 460 peak summer hours: hours 14:00 through 18:00 each day in June, July and August. Compensation for the ICAP value would be calculated for kWh generation during those hours, and none during other hours. This would result in a similar potential capacity value as providing smaller compensation for each kWh generated all year but would encourage project siting and design focused on peak summer hours.

2. Comments

Commenters submitted wide-ranging viewpoints on Staff's recommendations and alternatives. On the one hand, many commenters, including Solar Parties, Acadia, Borrego, CCR, CCSA, NYSEIA and SolarCity comment that capacity value based upon a single peak hour during the year presents far too much uncertainty and variability and is thus inappropriate for intermittent technologies under Phase One. These parties support Staff's alternative recommendation to base capacity value on the more stable capacity component of a customer's supply charge. Solar Parties, Borrego and SolarCity recommend that SC 1 rates be used as the rates to establish this value and comment that further investigation of appropriate service class load profiles for determining DER capacity value should be taken up under Phase Two. DSUN suggests setting a floor price for the value of capacity.

JU supports Staff's recommendation to link capacity value to performance and are opposed to fixed capacity payments based on a retail supply charge because such compensation may

not accurately reflect the installed capacity value provided to the utility, and its retail customers, by the injections from these resources.

AEEI supports Staff's recommendation to base capacity value on 460 summer hours, indicating that it more appropriately encourages performance in line with system needs. Solar Parties and Borrego support this alternative as an option but not the default approach under Phase One.

AMP says that the capacity value in Staff's proposal will place hydro at a disadvantage considering that, despite having a far higher capacity factor than wind or solar, it often produces the lowest output during the summer months. AMP therefore suggests calculating capacity value based on both a summer and winter peak, or alternatively consider the highest LBMP price as a supplementary peak measurement.

EDF/Policy Integrity comment that the NYISO cost allocation for capacity to LSEs is not aligned with cost causation and is thus a hindrance to efficient DER compensation, which should be further addressed with the NYISO. In the meantime, EDF/Policy Integrity support Staff's second alternative to assign capacity credit to 460 summer hours.

MI and Nucor oppose Staff's alternative recommendations for intermittent technologies, arguing that they unnecessarily subsidize DER developers and customers and are not sufficiently tied to performance. NFG and Nucor comment that the Commission should reject the alternative compensation methodology for intermittent technologies, especially for capacity value, and instead consider a requirement that these technologies pair with energy storage to receive compensation.

Pace expresses concern about the recommendation to link capacity payments for dispatchable resources to ex-post measured performance. SolarCity similarly comments that the ex-

post element of Staff's proposal does not offer sufficient visibility into when to operate in line with system peak.

3. Determination

As JU notes, the compensation recommended by Staff for intermittent technologies may not accurately reflect the installed capacity value provided to the utility, and its retail customers, by the injections from these resources. However, as Staff notes, compensating these technologies through the capacity tag approach could provide a highly variable and uncertain revenue stream to these facilities. That, in turn, could be a serious impediment to the maturation of this nascent market, especially during Phase One of the transition from NEM. Thus, we agree that one of the more stable mechanisms proposed by Staff, both of which rely on retail capacity charges, should be used for intermittent technologies. Alternative 1, above, mirrors the capacity credit currently provided under NEM and thus would be the least disruptive during this transitional phase. Therefore, Alternative 1 should be the default capacity compensation methodology for intermittent resources. Because it focuses the compensation on the 460 peak summer hours, Alternative 2 should be offered as an option to intermittent resources. Finally, intermittent resources should also be permitted to employ the capacity tag approach used for dispatchable technologies. A project may move from compensation under Alternative 1 to Alternative 2 or from compensation under Alternative 1 or Alternative 2 to the capacity tag approach by submitting a request to the utility; however, a project compensated under Alternative 2 may not switch to Alternative 1, and a project compensated under the capacity tag approach may not switch to Alternative 1 or Alternative 2.

The utilities shall work with Staff and other stakeholders to propose, for consideration by the Commission as

soon as Summer 2017, a specific method to implement these approaches. This initial method will include filing of values by May 15, 2017 and filing of updated values by May 15 of each year in Phase One. For this method to provide an incentive over the simple monthly average, the value of capacity in the 460 hour period in the initial filing shall reflect the rate per kWh of collecting all retail customers' (for example, all SC 1 customers') annual capacity costs in those 460 hours. Parties shall work to recommend an improved approach for Phase Two.

Because any approach other than the capacity tag method may credit these facilities for more or less than the ICAP value that their actual exports provide, the utilities are ordered to keep tracking accounts of the comparison of credit amounts to actual ICAP purchase reduction benefits, as those data become available. This will ensure that any net benefits or costs of this compensation methodology can be assigned to or collected from ratepayers in the same service class as the projects creating those net benefits or costs.

For dispatchable technologies, the Phase One tariff shall base compensation for installed capacity on actual performance during the peak hour in the previous year (the capacity tag method). Compensation shall be a lump sum equal to the generator's MW performance during the peak hour in the previous year multiplied by the actual monthly generation capacity spot prices from NYISO's ICAP market that month.

The Commission acknowledges and agrees with the points raised by Staff and some commenters regarding the imperfection of the current processes for billing for capacity and endorses Staff's recommendation for continued work through the NYISO to improve those processes. In addition, Staff and stakeholders should consider other ways to improve capacity valuation and compensation as part of Phase Two.

C. Environmental Value

1. Staff Proposal

Staff recommends that the Commission find that the Environmental Value of eligible behind the meter generation is at least equal to the SCC as calculated by the U.S. Environmental Protection Agency. However, Staff recognizes that, starting in 2017, the CES will require the purchase of Tier 1 RECs by LSEs. They further note that energy sources included in this proposal are eligible to produce such Tier 1 RECs.[39] The CES includes a state goal for clean energy consumption that will be achieved by a combination of mandatory purchases by LSEs and voluntary actions.[40]

The energy exported by eligible DER can provide Environmental Value to LSEs by offsetting the LSE obligation to purchase Tier 1 RECs from NYSERDA or other large-scale generators. The value of that reduction will be equal to the cost of one REC per MWh, or one-thousandth of a REC per kWh. The cost of Tier 1 RECs will be published by NYSERDA as they

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[39] Staff notes that there are several exceptions. First, CHP generators using non-renewable fuels are not eligible to produce Tier 1 RECs and therefore will not receive compensation for Environmental Value at this time. The eligibility of technologies to produce RECs will continue to be reviewed as part of the ongoing implementation of the CES. In addition, compensation for any Environmental Value provided by technologies that do not produce Tier 1 RECs will be part of Phase Two of this proceeding. Energy storage is not eligible to produce NYGATS Certificates. To compensate projects that combine storage with eligible generation for environmental values for kWh produced by that generation and exported to the grid but not for kWh imported from the grid, stored, and then exported back from the grid, those projects should receive environmental compensation based on their monthly net injections instead of all injections.

[40] Case 15-E-0302, supra, Order Adopting a Clean Energy Standard (issued August 1, 2016) (CES Order).

procure them. Staff believes that, since the purposes of the CES include capturing the benefits of carbon reduction, the Tier 1 REC value should be considered as a substitute for, rather than an addition to, the SCC. While Staff anticipates that the Tier 1 REC price will remain higher than the SCC, it is possible that NYSERDA's latest published sale price of a Tier 1 REC may fall below that amount. Therefore Staff recommends that the Phase One tariff include environmental compensation as the higher of the applicable Tier 1 REC price per kWh generated or the net SCC per kWh value, as calculated by Staff consistent with the BCA Framework Order.[41] Because the NYSERDA CES auctions will procure Tier 1 RECs under long term contracts, Staff would set the Environmental Value per kWh for a given project at a fixed level for a twenty-year period based on the higher of the Tier 1 REC price most recently published by NYSERDA at the time of interconnection or the SCC per kWh value as most recently calculated by Staff at the time of interconnection.

2. Comments

Many commenters, including Acadia, Borrego, CCR, NRDC and Solar Parties support Staff's recommendation to base Environmental Value on NYSERDA's published Tier 1 REC prices and for this value to be fixed for the compensation term. AEEI and EDF/Policy Integrity argue that compensation for Environmental Value should be consistent regardless of whether clean generation is consumed on-site or injected into the system. EDF/Policy Integrity comments that while using the REC price is practical that these prices could be substantially different from the actual damage costs of carbon emissions depending on market outcomes.

[41] Case 14-M-0101, supra, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016) (BCA Framework Order).

MI comments that the Tier 1 REC price is reflective of economic subsidies as opposed to environmental costs or benefits, and thus should not be utilized in any DER valuation methodology that is striving for accuracy. NFG asserts that the Commission should refrain from compensating for the Environmental Value of renewable technologies since all DER technologies, including CHP using non-renewable fuels, should be treated equally under Phase One.

3. Determination

Staff's approach is the most consistent with our prior BCA Framework Order and the intended structure of the CES. Hourly metered injections to the distribution system from eligible facilities receiving Value Stack compensation should receive compensation for Environmental Value based on the latest Tier 1 procurement price published by NYSERDA.[42] This credit value shall be fixed for the term of compensation for all Value Stack-eligible projects. In turn, these injected MWhs shall reduce the respective utility's Tier 1 REC compliance obligation on a one-for-one basis the customer elects the Customer-Retention option described in the Environmental Attributes Section above, in which case the customer will receive the minted Certificates and will be required to return that Environmental Value compensation received. As discussed above,

[42] As recommended by Staff as a transition mechanism, Phase One resources shall receive the higher of the Tier 1 REC price or the Social Cost of Carbon, net of the expected Regional Greenhouse Gas Initiative (RGGI) allowance values, as calculated by Staff per the BCA Framework Order. NYSERDA recently published the weighted average price as $24.24 per MWh for its latest main tier solicitation (https://www.nyserda.ny.gov/main-tier). As this is higher than the net SCC, this is the value that would be used here until a subsequent solicitation is conducted and price published.

Environmental Value compensation, like the rest of the Value Stack, will be offered only for net hourly injections.

D. Demand Reduction Value and Locational System Relief Value

1. Staff Proposal

Staff states that the Value of DER process has not produced a valuation methodology that identifies and includes all potential distribution system values and this is an area where significant evolution is expected during Phase Two. It notes that further work is required in both data calculation and modeling. As a result, Staff recommends the MTC approach for eligible CDG projects, discussed further below.

However, since, under Staff's proposal, many projects would not receive the MTC, Staff believes these projects should receive an approximate credit for their contribution of value to the local distribution system. Staff proposes to base a DRV credit on the marginal cost of service (MCOS) studies developed by utilities to value peak demand reductions in the Dynamic Load Management proceeding. Currently, compensation for providing this value is available to demand response resources. Unfortunately, participation in those demand response programs is difficult or impossible for most projects that will be compensated under the Phase One tariff, either because the resource is intermittent and therefore cannot respond to calls in the same way as the dispatchable demand response assumed by the programs, or because the resource is in operation most of the time and therefore acts as "baseload" rather than "response." Staff believes that, while not a perfect match, these can provide a basis for a Phase One DRV credit.

In recognition of the different characteristics of these technologies, a separate method for determining compensation is proposed by Staff. Staff recommends that the MCOS study dollar per kW-year values used for Demand Response

tariffs should be "deaveraged" to enable the calculation of two values for delivery cost savings from demand reduction: the DRV that applies across the service territory and an additional LSRV that would apply to high value areas for a limited number of MWs. Staff proposes that the resulting calculated dollar per kW year will be distributed across the ten highest usage hours in a utility's territory and generators will be compensated based on their performance during those hours. As discussed further below, Staff proposes that, to the extent possible, the values found in the MCOS study be disaggregated to offer more granular locational compensation; furthermore, where that is done, the ten hours chosen would be based on the local peak to the extent possible and appropriate. This compensation would take the form of a monthly lump sum based on the project's kW performance during those ten hours in the previous year. In a project's first year, it would receive DRV and LSRV compensation based on an average generation profile for a project of its technology and rated capacity in its service territory.

Furthermore, Staff proposes that the utilities be required to identify high-value locations, as well as any limitation in the number of MW that are required in those locations, to set LSRVs. A dollar per kW-year compensation would be identified for those areas to reflect the higher value. Staff explains that this compensation represents the value provided in these locations in excess of the DRV, and would therefore be credited to eligible facilities that locate in those areas and are within the required number of MW as additional compensation on top of the MTC or DRV compensation. The higher dollar per kW value identified by the utility would be locked in for the first 10 years for those high-value locations. For all other areas, the dollar per kW value would be subject to modification based on updates to MCOS studies,

increased locational granularity, and deaveraging to reflect the separation of the high-value areas.

As with capacity compensation based on performance during the peak hour, Staff asserts that this compensation mechanism results in uncontrollable quantity variability for intermittent technologies not paired with storage, though the use of 10 hours, rather than one, offers some mitigation. To provide greater compensation stability and further reduce risk, Staff believes the utilities should develop a fee-based portfolio service under which DERs are aggregated into a virtual generation resource with an average nameplate capacity based on the overall capacity and types of resources in the portfolio. The utility would then manage the portfolio to maximize system value and compensate the participants based on that value.

2. Comments

Staff's recommended methodology for DRV and LSRV elicited a range of comments from parties. Solar Parties and Borrego are opposed to DRV as currently proposed, commenting that it is based on incomplete information and requires much more scrutiny and process to properly evaluate and base compensation. These commenters are particularly concerned about financeability. Solar Parties recommend a flat kWh value per utility service territory informed by MCOS studies. Similarly, Solar Parties comment that development of LSRV requires additional and transparent processes, and that developing a proxy value would be appropriate in the interim. Solar Parties and Borrego support an LSRV term of 10-years, but argue that 25-years aligns better with system value.

Commenting that DRV and LSRV are far too uncertain to adopt for Phase One, Borrego recommends basing the DRV off of a 5-year, utility-wide rolling average of similarly performing DERs. Borrego further recommends basing the approach on a

period of greater than 10 peak hours and to permit projects the ability to opt out of the portfolio average. For LSRV, Borrego is also concerned about the process to derive LSRV and their respective locations, and suggests using a proxy value in the meantime based on a multiple of DRV and available for a certain percentage of a utility territory. Solar City shares many of the concerns of Solar Parties and Borrego.

Acadia, NRDC and Pace share similar concerns about the proposed methodology to calculate DRV and LSRV, commenting that the approach will not accurately compensate for distribution values, especially for non-MTC eligible projects. Pace recommends an explicit process to further investigate these values.

While JU is supportive of Staff's proposal to develop location-based compensation, based in part on value to the distribution grid, JU expresses concerns and offers several recommendations. Specifically, JU is concerned about the proposal to subsume distribution value into the MTC for CDG projects, commenting that it locks in a value for far too long and removes any performance incentive for this value component. Alternatively, JU recommends calculating specific DRVs and LSRVs for all DER projects including CDG. JU also comments that any deaveraging to provide an incremental LSRV must also be paired with a corresponding decrease in value to projects outside of the targeted areas. JU recommends unbundling DRV and LSRV and setting for 5 years, with a reset every 5 years using the most recently approved MCOS values.

Non-solar DER developers and advocates, including AEEI, OGS, and NY-BEST recommend that DRV and LSRV compensation should be offered in a consistent manner for both exported energy and generation that is consumed behind-the-meter. These parties comment that failing to do so will significantly

undervalue distribution value offered by behind-the-meter technologies.

MI and Nucor comment that these value components should be explicitly based upon performance and only offered in situations where DER provide a benefit that is sufficient in nature for a utility to rely upon when making system investment decisions and considering potentially avoided costs.

3. Determination

An important aspect of the compensation methodology being adopted is the recognition of locational value, specifically that related to the distribution system. The Commission's goal is to have a methodology that balances per kWh price signals with kW price signals aligned with the system peak, kW signals aligned with local peaks, and price differentials to reflect temporal and locational differences in value. Under this approach, as DER providers work to maximize compensation, they will also maximize benefits to the system. In order to implement a more granular and accurate compensation system, we must move expeditiously so that each individual kWh is assigned an individual value based on when and where it is generated. For this reason, we adopt the DRV and LSRV as part of the Value Stack.

The Commission recognizes that utilities are at the beginning stage of calculating all potential distribution system values. We do note that many distribution system values already exist. While some data is available to determine these values, other data is not yet available for more accurate and granular calculations. Other value streams, such as the benefits of local reactive power or the valuation of quick local response, are currently not modeled in either the wholesale or retail markets. As such, development of DER is constrained due to the

inability to recognize precise values of avoided distribution costs.

However, that does not mean that no value should be credited for contributions to the distribution system. Although Staff's MTC proposal would address this for CDG facilities receiving the MTC, this does not solve the issue for non-CDG projects receiving Value Stack compensation or for CDG facilities with non-mass market CDG members. We are particularly concerned with utility efforts in this area. The utilities, in the first instance, have the most in-depth knowledge of their systems and have access to the planning and operational data necessary to perform such analysis. With unilateral access to the primary data and knowledge of the portions of their systems where load relief would be more or less beneficial, they are gatekeepers of the information. Their comments seem to indicate their acknowledgement of the value of locational specificity, but their lack of progress in developing locationally specific price signals seems to imply a degree of indifference to where, specifically, these facilities will be built during Phase One.

This is not the first time the utilities have been asked to develop methods for determining the granular locational value of DER penetration to their distribution systems. In our Order Instituting Proceeding Regarding Dynamic Load Management and Directing Tariff Filings, issued December 15, 2014 in Case 14-E-0423, we directed the utilities to design programs that reflect the marginal costs of avoided T&D investments, granular to the network or substation level, if possible, as well as granular load information at the same disaggregated level. In our Order Adopting Distributed System Implementation Plan Guidance, issued April 20, 2016 in the REV proceeding, we noted that the utilities' data processes need to recognize that more

granular data and forecasts will be needed in the future to identify beneficial locations for DER. In the Benefit Cost Analysis Framework, issued January 21, 2016, in the REV proceeding, we directed the utilities to include sufficient information in their DSIPs and BCA Handbooks to inform the developing DER market of system conditions, needs, and granular marginal values so that any solicitations for alternative solutions will be robust. This Value of DER proceeding also requires an examination of granular marginal costs which largely focuses on identifying precise methods in valuing DER benefits and costs as well as new rate designs and valuation mechanisms.

Currently, all utilities have Commission-approved marginal cost of service (MCOS) studies that identify, at the very least, Transmission and Primary Distribution marginal costs at a system-wide level, with some including marginal costs for Secondary Distribution. However, the underlying detail supporting each MCOS study lacks consistency across utilities. Furthermore, system-wide marginal costs simply do not provide the granular price signals needed to achieve value-based and targeted DER penetration. Central Hudson may be closest to meeting the need for a more granular, both spatially and temporally, MCOS study. Central Hudson filed marginal cost studies in the DLM and DSIP proceedings, which include granular estimates for 54 of its 70 substations, as well as Distribution Substation and Transmission at a system-wide level for 2016-2025. Central Hudson's estimates are developed using probabilistic load forecasting at the substation level, essentially providing confidence intervals around capital investments needed to maintain reliability and resiliency. Central Hudson also acknowledges that not all substations or networks are experiencing load growth which would trigger investments. Such an implication suggests that load relief of

any kind (for example energy efficiency, demand response, or DER investment) is more valuable to the extent it relieves constraints associated with a particular substation or Load Area.

Con Edison similarly acknowledges the importance of more granularity and identifies marginal costs separately by identifying six network areas and one non-network area. Although not granular at the substation level, Con Edison's MCOS study developed in its recently completed rate case produced marginal costs by the following regions: Manhattan, Brooklyn, Bronx, Queens, Staten Island, Westchester, and non-network areas. Con Edison then combines those values to arrive at Transmission, Primary Distribution, and Secondary Distribution avoided costs at a system-wide level for 2016-2024. Orange and Rockland's MCOS study methodology is essentially the same as Con Edison's, producing Transmission, Primary Distribution, and Secondary Distribution system marginal costs. However, Orange and Rockland's marginal costs are only presented at a system-wide level for 2016-2032. Similarly, National Grid includes Transmission, Primary Distribution, and Secondary Distribution marginal costs at a system-wide level for 2016-2035. The NYSEG/RG&E MCOS study also includes Transmission, Primary Distribution, and Secondary Distribution marginal costs. However, the NYSEG/RG&E costs are only presented at a system-wide level, and only for 2016.

Although Orange & Rockland, NYSEG/RG&E, and National Grid MCOS studies include granularity of MCOS components (i.e. meter costs, lighting, upstream substation, distribution substation, trunk line feeder, etc.), the studies do not reveal granular, location specific values. Though planned investments due to load growth at particular substations and feeders provide the cost inputs for all the utilities' MCOS studies to date, Con

Edison, O&R, NYSEG/RG&E, and National Grid do not publish the marginal costs by load area or substations. Also, a more probabilistic approach, such as used by Central Hudson, requires load and capacity rating data for each substation. Even Central Hudson only has this information for 54 of its 70 substation areas. National Grid and NYSEG/RG&E are considerably behind in this respect.

The forum for developing marginal T&D cost studies has traditionally been utility rate cases. In recent rate cases, the possibility of modifying MCOS study methodologies to produce more granular and forward looking marginal costs that could be useful for carrying out the objectives of REV have been addressed. This has resulted in a number of rate case joint proposals (JPs) which require collaborative discussions between Staff, utilities, and stakeholders regarding the methodology of MCOS studies for future filings.

Con Edison's JP stipulates that the Company convene with Staff and stakeholders to develop and apply more granular marginal cost studies for not only rate filings, but for other Commission objectives as well. The language in the O&R JP is less prescriptive, but rather states that the Company initiate discussions with Staff and interested parties to identify an agreed upon methodology for future electric marginal cost studies. The NYSEG/RG&E JP charges the Companies to initiate discussions with Staff and any interested parties to review and identify up to three specific methodologies for conducting future electric marginal cost studies, with one of the methodologies reserved solely for the Companies. Neither National Grid nor Central Hudson have language in their respective JPs stipulating a new or updated marginal cost study. It is expected that new marginal cost study information will be included in the Companies' next rate case filing.

Due to the considerable benefit to customers when DERs receive granular price signals, the current misalignment of marginal cost methodologies with the needs of the system has become untenable. The development of granular prices to reflect locational distribution value has not progressed at a pace consistent with the reality of the DER marketplace. Locational indifference now can lead to unnecessary stranded costs in the future, as rapidly improving distributed generation technology outpaces traditional utility response.

The Commission's DSIP Guidance Order required utilities to address the development of tools needed to develop a uniform methodology for calculating the locational value of DERs.[43] While the utilities recognize that value assessments that quantify the full set of benefits and services from DER require the development of new data, analytical tools, methods, and a deeper understanding and characterization of salient value metrics driving such analyses, the Commission finds that a more detailed schedule for the development of the valuation methods and tools is necessary for achieving these objectives.

Since a significant portion of the distribution locational benefits are derived through long-run avoided costs of incremental distribution system upgrades, we will require development of those values first. This will form the basis of the information to develop the DRV and LSRV necessary for determining compensation for avoided distribution costs as part of the Phase One Value Stack.

As several parties have recognized, there is a need for much more information, review and process before actual values can be determined. As commenters note, DRVs and LSRVs

[43] Case 14-M-0101, supra, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016) (DSIP Guidance Order).

are critical to our implementation of the Value Stack, and therefore we direct utilities to file their most recent MCOS studies and workpapers in this proceeding within 10 business days to enable parties to become familiar with the data and information. This shall be followed by the filing of utility Implementation Proposals developed in consultation with Staff and stakeholders, which shall include specific DRVs and LSRVs, by utility, by May 1, 2017. This filing shall include the identification of specific locations and MW caps for the LSRVs. Staff shall establish a process for stakeholder review and comment of the MCOS and Implementation Proposals to enable Commission action by Summer 2017.

Realizing other sources of distribution value - such as the marginal value of distribution voltage and reactive power or the short-run marginal value of distribution constraint management - present increasing complexity and will require continued investment to implement increasingly sophisticated solutions, the Commission requires a detailed schedule from each utility for unlocking those values. Therefore, within forty-five days of the effective date of this order, each utility shall file a work plan and timeline for developing granular locational prices and values to their distribution systems from DER additions. This plan is intended to provide addition transparency and to facilitate third-party contributions to determination of values. This work should be coordinated with the comparable work underway in the DSIP and BCA implementation processes. A process for review and Commission action on these plans shall be established in as part of the implementation of the Value Stack.

An important feature of the DRV and LSRV approach is the generator performance period. We find that the 10 peak hour approach recommended by Staff appropriately balances the need to

provide certainty to the utility to be able to rely upon the DER when making system investment decisions, with the ability for the DER facility to control its performance.

As for the duration of the DRV and LSRV, we find that the DRV and LSRV shall be determined every three years. The five years suggested by JU is too long of a period given the pace of DER installations and the ongoing infrastructure investments by the utilities. Any project that receives a LSRV shall receive that compensation for a period of ten years as Staff proposes and Solar Parties and Borrego support. Also in accordance with Staff's recommendation, the LSRVs shall have corresponding MW caps associated with them to avoid providing compensation without corresponding benefits. DRVs shall not be fixed, but instead change as they are updated by the utility on the three-year basis.

As Staff proposes, DRV compensation shall not be offered to projects with regard to that portion of the project that receives an MTC, since the MTC, among other purposes, is intended to compensate for unidentified distribution system values. Customers that receive the MTC will remain eligible for the LSRV, since it compensates for defined locational values. For CDG projects that include both small and large customers, as described in the CDG Order,[44] as members and therefore receive an MTC for only part of the project, DRV compensation should be provided for the portion of the project not receiving an MTC. For those CDG projects that include a mix of both small and large customers, the utility shall value the monthly kWh output of the CDG facility by applying the Value Stack to the percentage of the output allocated to large customers by the developer and applying the Value Stack, plus the MTC but without

[44] Case 15-E-0082, supra, Order Establishing a Community Distributed Generation Program and Making Other Findings.

the DRV, to the percentage of output allocated to the small customers. The total dollar compensation will then be allocated to the large customers and the small customers using those same percentage allocations.

While we recognize that a performance requirement related to DRV and LSRV compensation presents risk as commenters have stated, Staff's proposed fee-based portfolio service under which DER are aggregated into a virtual generation resource with an average nameplate capacity based on the overall capacity and types of resources in the portfolio should mitigate those risks. Therefore utilities shall develop such options and have them available in time for our implementation of the Value Stack.

We reject comments of non-solar DER developers and advocates, including AEEI, OGS, and NY-BEST, that suggest that DRV and LSRV should be offered for both exported energy and generation that is consumed on-site. As stated earlier, compensation under the Value Stack tariff will only be available for generation injected into the grid, and no compensation will be offered at this time for energy generated and consumed behind a single utility meter. To the extent that any customers believe that this results in potential under-compensation for their projects, they can arrange for their DER to be separately metered and receive compensation under the Value Stack for all generation.

E. Potential Values Not Included

1. Staff Proposal

Staff’s Report states that several potential values were discussed during the collaborative process but not included in its proposal. These values include: distribution system values not reflected by the locational demand reduction value, as discussed above; reduced SO_2 and NO_x emissions, to the extent that their damage costs are not already embedded in the LBMP

through existing programs; non-energy benefits, including reductions in CO_2 emissions for reasons other than reduced electric generation, land and water impacts; environmental justice impacts, including reduced local emissions; and wholesale price suppression. Staff also notes that its proposal does not address the ability of customers with behind-the-meter generation to avoid contributing to societal benefits embedded in utility rates or otherwise recovered through per kWh charges, such as low-income discounts and the System Benefit Charge.

Some of the values not included, including currently uncalculated distribution system values and reduced SO_2 and NO_x emissions, will be considered through the Phase Two process. Others, Staff argues, such as non-energy benefits, are not properly addressed through a Value of DER tariff for the reasons noted in the BCA Framework Order.[45]

Finally, for some, no compensation should be offered. In particular, as recognized in the BCA Framework Order, wholesale price suppression is simply a transfer payment, not a resource or societal benefit. When it does occur, it is appropriately recognized as a mitigator of bill impacts, but likely to be an ephemeral one, evident only until the supply side of the market adjusts and prices fall back to sustainable levels. Staff goes on to argue that, in this case, New York State's goals under NY-Sun, the State Energy Plan, and the CES have been broadcast so publicly, and so far in advance of the resource impact, the supply side of the market's planning has already been affected, and will clearly have completely adjusted to the effects of these resources by the time they are in place. Thus, there will not be any market price suppression from adding these clean resources - they will instead simply replace the

[45] Case 14-M-0101, supra, BCA Framework Order.

fossil-based resources that, otherwise, would have been provided in the market in the future.

2. Comments

Several parties comment on various values that have not been included in Staff's Proposal. Many solar and DER providers, as well as environmental advocates, comment that it will be essential to evaluate and address values that are not identified or calculable at this time as soon as possible. Acadia and NRDC comment that of most particular concern are values related to distribution system value and wholesale price suppression. Cow Power urges consideration of Environmental Value that is unique to anaerobic digestion. EDA argues for the inclusion of additional valuation for reduced particulate air pollution, other contaminants and toxins, reduced water use, environmental justice benefits, reduced energy burden for low-income customers, local job creation, increased resiliency, and ensuring of geographical equity. Other commenters, including Bloom, also comment that Environmental Value related to criteria pollutants should be included in Phase One.

3. Determination

As Staff notes, and consistent with the BCA Framework Order, non-energy benefits are not appropriately addressed through a VDER tariff.[46] We adopt the Staff proposal on this issue. A process for moving forward on uncalculated distribution system values is described in the appropriate section above; in the work plans required in those sections, the utilities should also include a plan to develop a proposal for identifying and compensating for the value of reduced SO_2 and NO_x emissions.

[46] Case 14-M-0101, supra, BCA Framework Order.

F. Market Transition Credit and Tranches

1. Staff Proposal

Staff states that some projects are likely to receive equal or greater compensation under its proposed Phase One tariff as compared to what they would receive under current NEM mechanisms. It points to many volumetric NEM and dispatchable technologies as examples. For such projects, Staff recommends that their compensation be set at the Value Stack for Phase One, with a collaborative being created in Phase Two to improve the accuracy of that compensation.

However, other projects, such as CDG solar with no storage, are likely to receive lower compensation under the proposed Phase One tariff as compared to what they would receive under current NEM mechanisms. For those projects, moving immediately to the Value Stack could result in market disturbances. Also, Staff considers the Value Stack to be imprecise in terms of total value provided by generators because it does not reflect full identification of distribution system values. Thus, Staff argues that it is appropriate to provide an additional Market Transition Credit to such projects, bounded based on utility net revenue impact and divided into tranches so that there is a gradual transition to the new compensation mechanisms for CDG solar projects.

Under Staff's proposal, Tranche Zero constitutes those projects compensated under Phase One NEM. CDG solar projects that are compensated under the Value Stack would be eligible to receive an MTC, intended to make their estimated compensation equal to NEM in a first tranche (Tranche 1), 10% less than NEM in a second tranche (Tranche 2), and 20% less than NEM in a third and final tranche (Tranche 3). Further, Staff would apply the MTC to 80% of the generation of eligible CDG projects. The MTC would not be applied to 100% of the generation because the

MTC is based on comparing the value stack to the retail rate for residential customers, while up to 40% of the generation may be assigned to large non-residential subscribers, who may pay a substantially lower per kWh rate. While Staff acknowledges that this may over- or under-compensate a project depending on its actual mix of small and large customers, Staff states that "compensating at 80% reasonably limits any imbalance in compensation while also providing greater certainty and simplicity in Phase One." In addition, Staff explains that this methodology is consistent with the principle that the value of energy should not depend on project membership.

Staff provides illustrative spreadsheet calculations for the MTC for each utility, using data for SC1 customers. In summary, it equated the MTC to the difference between its pro forma calculation of SC1 "NEM" Rates and a similar pro forma calculation of "Value Stack" rates. For its SC1 "NEM" rate estimate, Staff includes the currently effective tariff rates for per kWh delivery charges, SBCs, and MFCs, as well as multi-year averages of per kWh energy and capacity commodity charges. For its "Value Stack" estimate, Staff uses multi-year averages of wholesale LBMP and ICAP values (when applied a pro forma 2 MW solar output curve), and an estimate of the Tier 1 REC value.

Staff proposes the following details for MTCs and Tranches:

1. The MTCs for each tranche should be calculated by each utility and set one time following the issuance of this order.
2. An initial tranche, Tranche Zero, will not require an MTC calculation because projects in Tranche Zero will receive full NEM compensation, as described above. If capacity remains in Tranche Zero after the end of the ninety

business day eligibility period, remaining capacity will roll over into Tranche One.

3. The MTC for Tranche One will be calculated by subtracting the estimated value stack from the current total residential retail rate. However, Tranche One will consist only of capacity rolled over if Tranche Zero is not filled; if Tranche Zero is filled, Tranche Two will follow it.
4. No amount representing the Demand Reduction Value will be included in the Value Stack for the purposes of this calculation because the MTC is intended to subsume the values the DRV represents. Staff states that the use of a fixed kWh MTC rather than a peak-performance-based DRV to compensate certain projects will, among other purposes, respond to developer concerns that application of the DRV methodology would create too much risk and uncertainty because a given year's peak coincident performance is based on factors outside of a developer or customer's control. However, if a project that would be eligible for an MTC wishes to accept the uncertainty of the DRV in exchange for the chance of higher compensation, Staff would allow it to opt out of the MTC and be compensated based on the value stack, including the DRV. This opt-out would be irreversible.
5. The MTC for Tranche 2 will be calculated by subtracting the estimated value stack from 90% of the residential retail rate.
6. The MTC for Tranche 3 will be calculated by subtracting the estimated value stack from 80% of the residential retail rate.
7. If the MTC calculation for a given tranche results in a negative number or zero, there will be no such tranche, and instead prior tranches will be larger.

8. After the final tranche is filled, projects will be compensated based on the value stack associated with the Phase One methodology, including the DRV, and the MTC would no longer apply.

2. Comments

Most parties offered comments on Staff's Proposal to develop and utilize an MTC during Phase One. While the majority of solar developers and advocates support inclusion of the MTC on the basis as a placeholder for values not yet fully identified or quantified, they express concerns over the approach for calculating the MTC along with its applicability under Phase One.

Solar Parties are specifically concerned about the Staff proposal to offer MTC to only 80% of the generation from an MTC-eligible project, commenting that this combined with the compensation tranche step downs will result in anemic CDG growth. NYC comments that this approach would result in an inappropriate and immediate reduction in value as compared to on-site rooftop solar. CCSA comments that an 80% MTC combined with the proposed tranche step downs will not support CDG development upstate and may not support development in later tranches downstate.

Solar Parties argue for step down from the retail rate of 5% per tranche as opposed to Staff's recommendation of 10%. Solar Parties further comment that the MTC should be applied to 100% of generation because the value to the distribution system from a CDG project will be the same regardless of CDG customer composition.

With respect to the calculation of the MTC, Solar Parties, Borrego and CCSA suggest that LBMP data from 2016 should be used to calculate the MTC in that historical data does not accurately represent the commodity prices that CDG projects

will be exposed to. The majority of these parties also support setting the MTC at one time at the beginning of Phase One and recommend that this should be conducted by Staff in a transparent manner.

JU comments that the MTC should only be offered for a period of 10-years as opposed to the 20-year term recommended by Staff. JU also asserts that there needs to be significant improvements made in the accuracy of data and inputs used to calculate the MTC, including using the same values for LBMP and capacity in both the Value Stack and calculation of MTC to avoid unnecessary distortions. JU is concerned that an 80% MTC would lead to payments greater than current NEM compensation for some customers, including large-commercial customers. Alternatively, JU recommend that the MTC be applied based on the actual mix of CDG customers. JU is also concerned that given CDG project economics, the MTC will impose more cost impact on non-participants than is necessary to stimulate market development. Solar Parties along with many solar developers and advocates object to the JU claim of excessive profit margins.

MI and Nucor are opposed to the concept of an MTC, commenting that the approach perpetuates unnecessary subsidies for DER and is inconsistent with the objective of the VDER proceeding to develop more accurate and granular valuation.

CORE comments that the MTC should apply uniformly to all commercial-scale projects, not only CDG.

3. Determination

We find that the general approach of gradually declining MTCs, associated with fixed-MW-size Tranches based on limitations of impacts on non-participants as discussed above, to be an appropriate transition mechanism. However, to avoid the possibility of a cliff or market interruption, similar to the mass market trigger, when 85% of the total MW capacity

allocated to all Tranches is reached in any utility territory, that utility shall provide notice to the Commission so that the Commission can consider what further steps should be taken and until further Commission action, projects that interconnect will continue to be placed in Tranche 3.

Further, the tariff elements and general method of calculating the MTC described in Staff's Report are sensible, with the following changes. Consistent with our decision above regarding the calculation of the 2% revenue impact target, three-year averages should be used for all but the per kWh delivery tariff element. The latter shall be based on the currently effective level. However, in this case, all averages shall be weighted by the output levels in the pro forma photovoltaic profiles filed with the Staff Proposal, as these better represent average values that would be received under NEM. Thus, the volumetric delivery elements and calculation methods for MTC calculation shall be:

A. SC1 and Small (i.e. non-demand-metered) Commercial Tariffed Volumetric Delivery Rates per kWh. Calculated as the volumetric delivery rate element that is effective on the date of this order.

B. SBC Rates per kWh. Calculated as the weighted average per kWh SBC rate relevant to each service class for the 36 months in the years 2014, 2015, and 2016. The weights used for calculating this average are the monthly kWh produced by the pro forma PV profiles for a 2 MW system in each service territory, provided by E3 and filed with Staff's October Report.

C. MFC Rates per kWh. Calculated as in B.

D. Capacity Rates per kWh. The portion of the retail commodity charge designed to collect NYISO capacity costs for each of the two services classes. Calculated as in B.

E. Retail Energy Charges per kWh. The retail commodity charge minus the capacity portion described in D. Calculated as in B.

The sum of elements A through E, above, will establish the pro forma "Base Retail Rate." For the purpose only of setting the MTC, the following elements and calculation methods shall be used to calculate the "Estimated Value Stack":

F. Environmental Rates per kWh. Based on the most recent NYSERDA Tier 1 REC procurement, this shall be set at $0.02424 per kWh.

G. Capacity Rates per kWh. Calculated exactly as in D, above.

H. DA LBMP Rates per kWh. The hourly Day Ahead Locational Based Marginal Prices for all hours in the years 2014, 2015, and 2016. Calculated as the hourly PV kWh weighted average price for all hours in the above years.[47] (For the purposes here, the prices for February 29, 2016 shall be ignored to comport with the pro forma PV curves.)

The MTCs shall be the difference between the above "Base Retail Rate" and "Estimated Value Stack." A table showing estimates of these values for each utility for SC1 is attached as Appendix A to this order. Utilities shall file by May 1, 2017 the final calculations of these MTCs, for both SC1 and small non-demand metered commercial customers, following the methods above.

Although the value of a CDG project ultimately should not be based on the rate class of members, we find that Staff's proposal to credit the MTC to 80% of a project's exported output, regardless of the actual makeup of its member customers, is too prone to over- or under- compensation. The MTC compensation shall reflect the actual mix of mass market customer members, as reflected by their percent entitlement to

[47] For Central Hudson and Orange and Rockland, NYISO Zone G DA LBMPs shall be used. For Rochester Gas and Electric, Zone B DA LBMPs shall be used. For Consolidated Edison, an hourly average of Zone J, Zone H, and Zone I DA LBMPs shall be used. For New York State Electric and Gas, an hourly average of Zones A through G DA LBMPs shall be used. For National Grid, an hourly average of Zones A through F DA LBMPs shall be used.

output credits. Because mass market members may be either residential or small (i.e. non-demand metered) commercial customers, two MTCs, one for each service class, shall be defined and calculated for each utility to reflect each of these rate classes. As described above, DRV compensation will not be provided for the portion of any project that receives an MTC, but will be provided on a pro-rata basis for the portion of any project that does not receive an MTC.

To create a gradual transition from 100% NEM to more value-based compensation, the total capacity allocated to CDG projects built during Phase One, as shown in Table 2 above, shall be made available according to the compensation Tranches shown in Table 4, described here. Tranche 0 constitutes the capacity allocation available in Phase One NEM for CDG projects. Any capacity remaining in Tranche 0 after the 90 business day deadline for determining eligibility for Phase One NEM will be allocated to Tranche 1. Projects in Tranche 1 will receive Value Stack compensation with a per kWh MTC derived by subtracting the Estimated Value Stack from the Base Retail Rate, as described above, such that compensation in Tranche 1 is approximately equal to compensation under Phase One NEM.

Once the Tranche 1 allocation has been reached, projects will be placed in Tranche 2 and receive Value Stack compensation with a reduced MTC. We agree with the commenters that argue that Staff's 10% reduction in compensation from Tranche 1 to Tranche 2 is too large and instead adopt a 5% reduction. Thus, the per kWh MTC for projects in Tranche 2 will be derived by subtracting the Estimated Value Stack from a number equal to 95% of the Base Retail Rate.

Finally, when the Tranche 2 allocation has been exhausted, projects will be placed in Tranche 3, which will receive Value Stack compensation with an MTC intended to result

in a further 5% reduction in total compensation. The Tranche 3 per kWh MTC will be derived by subtracting the Estimated Value Stack from a number equal to 90% of the Base Retail Rate.

The total capacity allocated to CDG projects built during Phase One, as shown in Table 2 above, was allocated among these Tranches as follows: For utilities with a total capacity allocation for CDG projects greater than 100 MWs, 25% of that allocation was placed in Tranche 0. For utilities with a total capacity allocation for CDG projects less than 100, 50% of the total incremental MWs were placed in Tranche 0. The portion of the Tranche 0 capacity allocation that is not exhausted during the 90 business day period for determining eligibility for Phase One NEM, if any, shall be assigned to Tranche 1. The remaining capacity allocation is allocated approximately evenly to Tranche 2 and Tranche 3, rounded to even MW numbers. As noted, these represent, respectively, 95% and 90% of expected compensation in Tranche 1.

Table 4. INCREMENTAL CDG MWs BY TRANCHE

	CHGE	O&R	NGRID	NYSEG	ConEd	RGE
Total Incremental CDG MWs	77	47	474	223	548	111
Tranche 0/1	39	23	119	56	137	28
Tranche 2	19	12	178	84	206	42
Tranche 3	19	12	177	83	205	41

Table 5, below, shows the estimated annual net revenue impact in each service territory of the VDER Phase One Tariff, if the capacity allocations for Phase One NEM for mass market projects and all three tranches are filled. Table 5 demonstrates that the estimated impact is approximately 2% or less in all service territories.

Table 5. Estimated Revenue Impact Given Ordered Tranches

	CHGE	O&R	NGRID	NYSEG	ConEd	RGE
Continuing On-site	$1,277,756	$1,454,425	$3,004,666	$628,541	$5,107,973	$162,662
Tranche 0/1	$3,052,905	$2,563,976	$5,776,581	$2,877,094	$14,836,244	$1,508,026
Tranche 2	$1,016,400	$993,677	$4,153,361	$2,153,150	$15,901,750	$1,178,239
Tranche 3	$838,369	$847,153	$2,766,065	$1,471,689	$12,821,527	$824,366
Total	$6,185,430	$5,859,232	$15,700,673	$7,130,475	$48,667,495	$3,673,292
Total SC1 kWh Revenues	$300,479,547	$283,738,460	$1,310,994,991	$515,208,388	$2,822,430,784	$275,242,570
% of kWh Revenues	2.06%	2.07%	1.20%	1.38%	1.72%	1.33%

NOTES

1. Tranche 0/1 conservatively assumed to consist entirely of Tranche 0 projects
2. 50% of Tranche 0/1 RECs are assumed retired, thus not offsetting compliance

What Tranche a project falls in, including whether it is eligible for Phase One NEM as part of Tranche 0, shall be determined at the time it submits its payment for 25% of interconnection costs, or at the time it executes a Standard Interconnection Contract if no such payment is required. Utilities should provide frequent and transparent reporting on the progress of the Tranches so that CDG developers can make informed decisions with respect to pursuing tranche eligibility. This is especially the case for Tranche 0, Phase One NEM, which will be open and available soon after the effective date of this order. To ensure an orderly allocation of Tranche 0 capacity in each service territory during the ninety business day period, each utility shall file, within 7 days, the number of CDG projects and the MW of capacity represented by those projects that, at the time of this order, had already paid 25% of their interconnection costs. The utilities shall expeditiously develop a method for providing real-time updates on the capacity left in each Tranche; until such a method is developed and implemented, each utility shall confer with Staff to determine the appropriate frequency of reporting based on local market conditions and shall periodically file letters stating the current amount of capacity left in each Tranche based on those conditions. Each utility shall also immediately file a letter when any Tranche is filled.

Similar to the mass market trigger, when 85% of the total MW capacity allocated to all Tranches is reached in any utility territory, that utility shall provide notice to the Commission. The Commission will then consider what further steps should be taken. Until further Commission action, projects that pay for 25% of their interconnection costs, or has execute their Standard Interconnection Contract if no such payment is required, will continue to be placed in Tranche 3,

even if the capacity allocation established for Tranche 3 is exceeded.

VI. IMPLEMENTATION OF VDER TARIFF AND FURTHER PROCESS

As described above, this order directs that all projects interconnected after the date of its issuance, with limited exceptions, be served under the VDER Phase One tariff rather than currently existing tariffs. To effectuate that, each utility is directed to file tariff amendments to be effective on April 1, 2017 on not less than 5 days' notice consistent with the decisions regarding NEM and Phase One NEM in this order.

To enable the full implementation of the VDER methodology through the Value Stack, the Commission intends to issue a Value Stack Implementation Order as soon as Summer 2017. To ensure the Commission has the necessary information to do so, we direct utilities to make specific filings and to develop an Implementation Proposals in consultation with Staff and stakeholders and file those Proposals for public comment, which will enable the Commission may consider and act on the relevant matters no later than Summer 2017. Staff should work with the utilities and stakeholders to organize consultative meetings in advance of and, as necessary, following the issuance of the Implementation Proposals.

In order to ensure that activity under the VDER Phase One tariff meets stakeholder expectations and New York State's needs for aggressive DER deployment, as well as to monitor for unintended consequences, Staff shall conduct a review of initial progress and file a report on that progress within six months of the issuance of this order.

Utilities are required to make the following filings:

1. Each utility shall file tariff leaves implementing the transition from NEM to Phase One NEM, as part of

the VDER Phase One tariff to be effective on April 1, 2017 on not less than 5 days' notice. Newspaper publication of these compliance tariff filings shall be waived.

2. Each utility shall file a letter within seven days recording the total rated generating capacity of interconnected projects served under PSL §66-j in its service territory as of the close of business on March 9, 2017.

3. Each of the utilities must file a letter stating the final rated generating capacity of interconnected projects served under PSL §66-j, including projects that had completed Step 8 of the SIR for large projects or Step 4 of the SIR for small projects by March 9, 2017 and submitted notification of complete installation by March 17, 2017, by March 31, 2017, which will serve as the new ceiling for NEM for that territory.

4. Each utility shall file, within 7 days, the number of CDG projects and the MW of capacity represented by those projects that, at the time of this order, had already paid 25% of their interconnection costs, as well as the number of CDG projects and the MW of capacity represented by those projects that paid 25% of their interconnection costs between the issuance of the order and the filing of the letter. The utilities shall expeditiously develop a method for providing real-time updates on the capacity left in each Tranche; until such a method is developed and implemented, each utility shall confer with Staff to determine the appropriate frequency of reporting based on local market conditions and shall file regular letters stating the current amount of capacity left in each Tranche based on those conditions. Each utility shall also immediately file a letter when any Tranche is filled.

5. Each utility shall file their most recent MCOS studies and workpapers within 10 business days.

6. Within forty-five days of the effective date of this order, each utility shall file a work plan and timeline for developing locationally granular prices to reflect the full value to their distribution systems from DER additions.

By May 1, 2017, each utility shall file an Implementation Proposal for public review and comment, followed by Commission consideration. The utility Implementation Proposals shall include, at a minimum:

1. Calculation and compensation methodologies for DRV;
2. Identification of, compensation for, and MW caps for LSRV zones;
3. Proposed methods and values for providing Capacity Values using Alternative 1 and Alternative 2;
4. Identification of average generation profiles for capacity and DRV compensation in projects' first year of operation;
5. Cost allocation and recovery methodologies implementing the principles adopted in this order for each component of the Value Stack, with particular attention to issues associated with capacity compensation;
6. The practicality of allocating and collecting costs associated with DER compensated under Phase One NEM using the principles adopted in this order;
7. Proposed accounting transactions and ratemaking treatment related to the implementation of this order;
8. Utility processes for managing billing and tracking bill credits;
9. Reporting procedures for tracking progress in Tranches and any other necessary reporting;
10. Draft tariffs stating the Market Transition Charge for the residential and small commercial classes, for each tranche, as described in the body of this order. This filing should include rules on how the MTC, DRV and LSRV will be applied to CDG projects.

A. Commencement of VDER Phase Two

At the outset of the collaborative meeting, the parties agreed that recommendations for a Phase Two of the VDER methodology would be developed as soon as practical following

the completion of the Phase One deliberations. The Staff Proposal recommends the development of Phase Two methodology by the end of 2018.

The Commission endorses that timeframe. Request for comments addressing the design of the Phase Two process was issued on November 18, 2016 and comments were received on December 23, 2016. The Commission recognizes that it is important that work begin immediately. Therefore, a procedural conference or other meeting of interested parties will be convened during May 2017 to commence Phase Two. The meeting should include consideration of the process for Phase Two, which should give due consideration to the comments filed on December 23, 2016. We anticipate that the scope of Phase Two will include, at a minimum, the following topics: 1) inclusion of DER projects in VDER tariffs on a technology-neutral basis; 2) development of methods to provide equal compensation for reduced consumption and injected generation; 3) a framework for the development and consideration of grid access charges, non-bypassable fees, or other methods to mitigate costs imposed on non-participants; 4) potential changes to default rate design and development of optional rates for VDER participants; 5) improvements and modifications to the Value Stack, including components related to the bulk system, distribution system and societal values; and, 6) transitioning of mass market projects to VDER. An agenda will be issued at least five days before the meeting. We anticipate that these topics may be further refined, either through the agenda or another notice issued prior to the first meeting or thereafter as a consequence of further input from stakeholders.

Commission action on recommendations developed during Phase Two need not wait until the completion of consideration of all topics. Rather, the Commission will entertain

recommendations as they are available. In particular, consideration of 1) project and bill impact cost mitigation initiatives that are not presented as part of the implementation order and 2) inclusion of DER projects in VDER tariffs on a technology-neutral basis should be given priority such that they can be brought to the Commission while other Phase Two proposals are still under development.

B. Enabling Participation of Low-Income Customers in VDER Programs and Tariffs

Maintaining the commitment to promote affordability of electric service and opportunities for low-income customers to participate in clean DER, the Commission's adoption of a CDG policy was premised in part on broadening access to renewables, including serving low-income customers. In adopting CDG, the initial Phase 1 of the program included a project eligibility option of 20% low-income off-takers for a given project. While, there was no uptake or development of projects under this stipulation, we stand by our commitment to pursue solutions to encourage low-income customer participation as discussed below.

In addition, as part of CDG adoption, we directed a CDG Low Income Customer Collaborative to investigate barriers and solutions for low-income customer participation in the anticipated CDG market. While we appreciate the work of the Collaborative, it did not result in viable solutions or recommendations for supporting and/or removing barriers to low-income customer participation in CDG.

We finally note that NYSERDA's low-income solar program for low-income, single family residences under CEF is currently being reevaluated due, in part, to the modest uptake under this program. We appreciate and support NYSERDA's investigation into new program options, including ways to encourage and incent low-income customer participation in CDG

projects. Their efforts are critical in order to ensure successful market intervention in this sector.

While recognizing the various ongoing efforts focused on this important topic, consistent with our underlying objectives in REV and our continued commitment to broaden access to clean energy for low-income customers, the Commission directs near term actions as well as additional process to continue these critical investigations. We acknowledge the comments of the EDA and agree with them that CDG continues to offer great potential for broadening access to clean energy to low-income customers. Our actions in this order recognize both the critical need to address these issues with near-term intervention as well as the fact that there remain persistent challenges in this market segment despite the efforts discussed above.

First, consideration should be given to an interzonal CDG credit program designed to provide benefits to interested low-income customers from CDG projects interconnected in service territories and load zones other than their own. Such a program could offer the potential to serve low-income customers in areas, such as New York City, that have proven challenging for development of larger scale CDG projects that benefit from economies of scale. While we acknowledge the added administrative challenges of implementing an interzonal CDG credit program, including those associated with utility billing and crediting mechanisms, we believe it merits serious consideration at this time. We therefore direct Staff to work with NYSERDA, the utilities, and other stakeholders to develop a report on the feasibility of an interzonal CDG credit program.

In recognition that the interzonal CDG credit program will require deliberate development and consideration, the Commission will take the following two actions, which hold the

potential to have more immediate impact. First, the Commission directs Staff to work with NYSERDA as they continue their investigation into alternative program design options for their low-income solar programs, and specifically directs consideration of whether reallocation of CEF funding dedicated to encouraging and incentivizing low-income participation in CDG projects is appropriate and whether additional funding should be dedicated to those areas, balancing the consequences and foregone benefits of these reallocations and considering the required adjustments to CEF outcomes. Upon a determination that program changes are warranted, we anticipate that NYSERDA will file a new or revised CEF investment plan with Staff, as appropriate.

As we adopt this suite of measures to address barriers to low-income customer participation in CDG, it will be essential to also consider financing solutions and credit issues related to these customer segments. The Commission therefore directs Staff to work with NYSERDA to continue to explore New York Green Bank options, including but not limited to developing solutions to lower the cost of capital and provide credit support for CDG projects that are either fully or proportionally comprised of low-income customers. In particular, the investigation of options through the Green Bank should include consideration of solutions that can support local community-based investment into CDG projects.

To help overcome additional financial barriers for low-income customer participation in CDG projects, during the implementation phase for VDER Phase One tariffs, consideration will be given to other options to incentivize and encourage low-income customer participation in CDG, including tailored approaches for CDG projects for which low-income customers compose a majority of off-takers.

In consultation with stakeholders, Staff shall develop and file, by September 1, 2017, a Low-Income CDG Proposal, which shall include, at a minimum, information developed through the CDG Low Income Customer Collaborative, a report on the feasibility of an interzonal CDG credit program, and discussion of the other options to encourage and support low-income customer participation discussed above. That Proposal will be filed for public comment followed by Commission consideration and action.

C. Oversight of DER Providers

The Commission recognizes the comments of UIU related to DER oversight. Specifically, UIU comments that in conjunction with the VDER proceeding, it is important to formally recognize parallel proceedings regarding consumer protections, including establishing a set of Uniform Business Practices for DER providers and considering DER performance bonds as a consumer protection measures.

The Commission's DER Oversight proceeding was initiated in the Order Adopting Regulatory Policy Framework and Implementation Plan, issued February 26, 2015 in the REV proceeding, and advanced through a Staff Proposal filed on July 28, 2015. The DER Oversight proceeding has focused on the design, structure, and level of supervision of DER providers that will be appropriate to ensure consumer protections, while at the same time enable markets to develop through fair competition. Staff has conducted a substantive discussion with stakeholders regarding the advantages, benefits, detriments, and other aspects of various approaches to DER oversight. With the anticipation of CDG development and broader DER markets, there is a need to refresh the work that has been accomplished to date.

Therefore, the Commission directs Staff to file within 30 days an updated whitepaper on DER oversight for public comment so that the Commission will be able to consider the DER oversight provisions at the same time as it acts on the implementation issues in this proceeding.

D. Mitigation of Bill Impact and DG Project Costs

While this order establishes a control on bill impacts resulting from the implementation of VDER Phase One, other mechanisms may be available to reduce project development costs, enabling a reduction in the MTC. Such actions can also have the effect of enabling additional projects within a utility service territory without exceeding the bill impact ceilings established by this order. For example, the Green Bank may be able to offer financing of DG projects that enables a project to accept compensation from a higher Tranche, and therefore lower the MTC and resulting bill impacts. Other actions can have the effect of lowering CDG project development costs, thereby enabling additional projects to proceed within the Tranche size limits established here.

The following are examples of barriers to development that can be addressed to expedite soft cost reduction as the market scales. Addressing these barriers could meaningfully reduce soft costs to New York's CDG industry. To promote soft cost reductions in the CDG market, Staff is directed to work with NYSERDA, the utilities, and market participants to develop and file a proposal or proposals for steps that can be taken to reduce, eliminate, or mitigate market barriers. To the extent feasible, proposals should be developed for consideration by the Commission as early as Summer 2017 as part of the Phase One implementation order. Otherwise, proposals will be addressed by the Commission as they are ready for consideration.

To ensure continuous activity and growth in the DER market as these options are developed, the Commission directs NYSERDA to develop and file CEF investment chapters as soon as feasible that can provide additional support as determined necessary by NYSERDA in consultation with Staff, with specific consideration of providing support to Tranches 2 and 3. The purpose of these investments will be to ensure the viability of the solar market during the Phase One transition, while transitioning the market to align with underlying goals of the VDER process.

a. Development costs:

i. Project size: DER projects, and CDG projects in particular, benefit substantially from economies of scale. Allowing projects larger than 2 MW to participate in the VDER program could significantly lower per-MW costs. This should be a priority item in the Phase Two process and should be presented to the Commission as expeditiously as possible.

ii. Financing costs: New York Green Bank, in consultation with NYSERDA and DPS Staff, shall explore and seek to offer to financing to developers who voluntarily opt into higher tranches that has more efficient terms which can help offset some of the economic effects of opting into those higher tranches.

iii. NY-Sun incentives: NYSERDA, in consultation with DPS Staff, shall explore adjustments to the current and future blocks of the MW Block Design that continue existing incentive levels for longer, and correspondingly decrease future incentive levels on the basis of future improved

economics of solar projects as a result of the cost-reducing actions being advanced in other parts of this order.

iv. Use of utility property: Staff, utilities, developers, and other stakeholders shall consider options for leasing or other arrangements allowing the installation of DER on utility property.

b. Consolidated Billing:

i. Staff shall confer with utilities and market participants and evaluate and report to the Commission whether utilities should be required to offer consolidated billing for CDG subscriptions, to improve the customer experience and reduce collections costs. This evaluation should include consideration of the appropriate roles for the utility and the developer, including in calculations, communications, and collections, with particular attention to relevant provisions of the Home Energy Fair Practices Act (HEFPA). The utility may be permitted to charge CDG providers for these services, creating a new revenue stream for the utility.

c. Customer maintenance costs:

i. Staff shall confer with utilities and market participants to and report to the Commission regarding what actions can be taken to provide efficient two-way electronic communication between CDG providers and utilities regarding subscriber lists and bill credit calculation and

application to customer bills to enhance customer experience and reduce customer management costs.

d. Interconnection costs:

i. Cost sharing: An initial, limited cost-sharing proposal was adopted by the Commission in Docket 16-01984 on January 24, 2017 that will apply to projects moving forward under the. A more robust cost sharing policy including the potential partial utility funding for upgrades is being considered in that proceeding. Recommendations will be presented to the Commission by the end of 2017.

ii. Cost containment: DPS Staff and NYSERDA should work together to track interconnection upgrade costs throughout 2017, and thereafter provide the Commission with any recommendations that may be appropriate to address industry concerns about transparency and the alignment of costs with neighboring states, the Commission should take action to contain costs within reasonable bounds.

E. Utility Development of Virtual Generation Portfolios

1. Staff Proposal

The Staff Proposal recommends the Commission direct development by utilities of virtual generation portfolios through which they work with customers and DER providers so that DER are installed and operated in a way that best supports the overall system.

2. Comments

AEEI comment that the virtual generation portfolio concept closely resembles the role that the Distribution Service Providers are expected to serve. SolarCity supports the virtual generation portfolio concept, and comments that an initial set

of services should be detailed and filed by the utilities by July 1, 2017. SolarCity further suggests modeling on the existing Con Edison demonstration project.

3. Determination

As described above, we recognize that a performance requirement related to DRV and LSRV compensation presents risk and therefore adopt Staff's proposed fee-based portfolio service under which DER are aggregated into a virtual generation resource for the purpose of DRV. As directed above, utilities shall develop such options and have them available in time for our Summer 2017 implementation of the Value Stack.

F. Unbundling of Values

As described earlier under the discussion of DRV and LSRV, we require the utilities to file a work plan and timeline for developing locationally granular prices to reflect, as much as feasible, the complete value to their distribution systems from DER additions. This filing shall include a plan with milestones for the unbundling of those values and services embedded in rates. As noted previously, the identification of more precise valuation is essential to the implementation of REV and thereby providing value to the system and its customers. Moreover, the absence of that information results in the need to constrain DER and CDG deployment to limit bill impacts, when such information could demonstrate better methods of doing so. If a utility does not proceed with all appropriate speed to achieve such unbundling, the Commission may consider other strategies such as increasing the MW development limits in a utility territory while potentially disallowing the recovery of the impacts associated with the additional development as a means to mitigate bill impacts.

G. Coordination with DSIP and BCA Handbook Proceedings

The Commission recognizes the importance of coordinating the decisions and outcomes in this proceeding with those happening under other REV initiatives, in particular the DSIP and BCA Handbook proceedings. As described earlier, the VDER tariff initiative will complement these efforts to enable more precise pricing and valuation and the optimization of DERs.

The REV Framework Order began a transition from the historic model of a unidirectional electric system serving inelastic demand, to a dynamic model of a grid that encompasses both sides of the utility meter and relies increasingly on DER and dynamic load management.[48] To guide this transition of the utility model, the Commission defined a set of functions of the modern utility that are called, collectively, the Distributed System Platform (DSP). DSP functioning combines planning and operations with the enabling of markets. The vehicle by which improved planning and operations will be defined and implemented is DSIP.[49] The DSIPs contain (among other things) proposals for capital and operating expenditures to build and maintain DSP functions, as well as the system information needed by third-parties to plan for effective market participation.

As the DSP, utilities will play a leading role in animating markets by creating consistent platforms for the buying and selling of products and services among a broad set of market actors. Tools, processes, and protocols will be developed jointly or under shared standards to plan and operate a modern grid capable of dynamically managing distribution resources and supporting retail markets.

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[48] Case 14-M-0101, supra, REV Framework Order.

[49] Case 14-M-0101, supra, DSIP Guidance Order.

The information that the DSIPs provide is essential to the development of retail markets that accurately and fully price the value of DERs to the grid and electric consumers. The DSIP process is envisioned to be a multi-year plan, subject to public comment and regular updates. Accordingly, the DSIPs will document utility plans over a five-year period, with updated DSIP filings required every two years. The first formal updates to the DSIP filings will be June 30, 2018.

The Commission recognizes that many of the operating tools and functionalities required to incorporate and rely on large scale DER deployment to promote public policy outcomes, including the requisite algorithms and software solutions to price the marginal value of DER as efficiently as practicable, are either immature or incomplete and need to be developed. The DSIP filings include a high level plan to reveal potential distribution system values on a granular basis. Additionally, the plans identify specific areas in the utility footprint where DERs would provide benefits to the distribution system. However, in this order we require the filing of more detailed workplans and timelines for the development of locationally granular prices to reflect the full value to their distribution systems from DER additions. Therefore, as required above, within forty-five days of the effective date of this order, each utility shall file a work plan and timeline for developing granular locational prices to reflect the full value to their distribution systems from DER additions.

As the Commission recognized in the BCA Framework Order, the interests in sustaining a stable investment environment to support the DER market should be balanced with remaining flexible and adaptive so that the valuation process

does not become outdated or inaccurate.[50] Over time, developing more dynamic and granular methods will require a continuous process, rather than a single decision. The BCA Framework Order served as the first step in forming a robust and long-lasting BCA Framework.

The BCA Framework provides a means for evaluating DER alternatives as substitutions for traditional utility solutions, and against each other on a static basis. Additionally, the BCA Framework supports the development of tariffs that place a value on DER and in fact forms the basis of the Value Stack we are adopting in this order. Through these processes, the BCA Framework will be updated in coordination with the DSIPs.

H. Summary Calendar for Future Actions in VDER and Related Proceedings

a. March 2017

i. Filing of utility tariffs implementing Phase One NEM

ii. Staff initiates stakeholder engagement related to development of Implementation Order

iii. Utilities file existing MCOS studies with workpapers

b. April 2017

i. Utilities file work plan and timeline for developing locationally granular prices to reflect the full value to their distribution systems from DER additions

ii. Stakeholder process to develop implementation of recommendations continues

iii. Staff issues DER Oversight Report

iv. Staff initiates stakeholder engagement for BCA Handbooks

[50] Case 14-M-0101, supra, BCA Framework Order.

c. May 2017
   i. Procedural Conference or other meeting to initiate VDER Phase Two
   ii. Utilities file Implementation Proposals
d. Summer 2017
   i. Commission consideration of recommendations related to VDER Implementation and DER Oversight
   ii. Implementation of VDER Value Stack
   iii. Commission consideration of actions to mitigate bill impacts and CDG project costs
   iv. Staff issues CDG Low Income Proposal, including interzonal crediting proposal
   v. Informal update to DSIPs filed by June 30, 2017, as required by March 2017 DSIP Order
e. Q4 2017 – Q1 2018
   i. Commission consideration of any initial recommendations arising from VDER Phase Two process and review of utilities' plan and timeline on locationally granular pricing
f. Q3 2018
   i. Formal update to DSIPs to be filed by June 30, 2018 per Commission DSIP Guidance Order
g. Q4 2018
   i. Report and Recommendations for VDER Phase Two presented to Commission
h. Q4 2018 – Q1 2019
   iii. Commission consideration of Report and Recommendations for VDER Phase Two
   iv. Commission consideration of utility capital expenditure plans related to DSP functions and capabilities presented in rate case filings

The Commission orders:

1. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (collectively, the Joint Utilities or the utilities) are directed to file, in conformance with the discussion in the body of this order and the below Ordering Clauses, tariff leaves implementing the transition from net energy metering (NEM) to a Value of Distributed Energy Resources (VDER) Phase One Tariff on not less than 5 days' notice to become effective on April 1, 2017.

2. Pursuant to Public Service Law (PSL) Section 66-j(3)(b), the Commission determines that it is in the public interest to set the limit for NEM under PSL §66-j in the territory of each utility, respectively, to a total rated generating capacity equal to the total rated generating capacity of generating equipment interconnected and served under PSL §66-j in that utility's territory as of the close of business on March 9, 2017 plus the total rated generating capacity of generating equipment for which Step 8 of the Standard Interconnection Requirements (SIR), for projects larger than 50 kW, or Step 4 of the SIR, for projects smaller than 50 kW, has been completed by the close of business on March 9, 2017. In order to demonstrate that Step 8 of the SIR for large projects or Step 4 of the SIR for small projects was completed by March 9, 2017, customers must provide written notification of complete installation to the interconnecting utility, as required by Step 9 of the SIR for large projects and Step 5 of SIR for small projects, by March 17, 2017.

3. Furthermore, it is in the public interest for those limits to decrease as projects served under NEM PSL §66-j

are taken out of service to match the capacity of projects remaining in service. These decreasing ceilings should not be used to prevent customers served under PSL §66-j from repairing their system. The ceilings will not decrease below the 1% of 2005 electric demand level specified in PSL §66-j.

4. Each utility shall file a letter by March 16, 2017 recording the total rated generating capacity of interconnected projects served under PSL §66-j in its service territory as of the close of business on March 9, 2017.

5. Each of the utilities shall file a letter stating the final rated generating capacity of interconnected projects served under PSL §66-j, including projects that had completed Step 8 of the SIR for large projects or Step 4 of the SIR for small projects by March 9, 2017 and submitted notification of complete installation by March 17, 2017, by March 31, 2017, which will serve as the new ceiling for NEM for that territory.

6. The tariff leaves filed by each utility shall include amendments to the existing NEM provisions limiting eligibility for service under those provisions to projects that were interconnected and served under PSL §66-j in that utility's territory as of the close of business on March 9, 2017 and projects that had completed Step 8 SIR, for projects larger than 50 kW, or Step 4 of the SIR, for projects smaller than 50 kW, by the close of business on March 9, 2017 and provided written notification of complete installation by March 17, 2017 and to wind turbines interconnected under PSL §66-l before the 0.3% cap is for NEM under PSL §66-l is reached.

7. The tariff leaves filed by each utility shall include new provisions for Phase One NEM, which shall have the same eligibility rules as NEM under PSL §66-j, shall offer compensation using the same methodology as NEM, and shall apply the same policies except that Phase One NEM shall be limited to

a term of 20 years from generator interconnection and credits created under Phase One NEM will be carried over indefinitely, as described in this order, rather than being paid out at any time. The tariff leaves shall offer Phase One NEM to all mass market on-site projects, defined as projects interconnected behind the meter of a customer within a utility's residential or small commercial service class and not billed based on peak demand and not used to offset consumption at any other site, interconnected before the earlier of January 1, 2020 or a Commission order directing modification. The tariff leaves shall also offer Phase One NEM to large on-site projects, defined as projects interconnected behind the meter of a customer within a utility's non-residential demand-based or mandatory hourly pricing (MHP) service class and not used to offset consumption at any other site, and remote net energy metering projects for which 25% of interconnection costs have been paid, or a Standard Interconnection Contract has been executed if no such payment is required, within 90 business days of the issuance of this order. The tariff leaves shall also offer Phase One NEM to community distributed generation projects that for which 25% of interconnection costs have been paid, or a Standard Interconnection Contract has been executed if no such payment is required, within 90 business days of the issuance of this order and before the total rated generating capacity specified in Ordering Clause No. 9 has been reached. Wind turbines shall not be included in Phase One NEM until the 0.3% cap is for NEM under PSL §66-l is reached.

8. The tariff leaves filed by each utility shall include provisions for Phase One NEM for remote net metered projects entitled to monetary crediting grandfathering under the April 17, 2015 Order Granting Rehearing in Part, Establishing Transition Plan, Making Other Findings in Cases 14-E-0151 and

14-E-0422 and interconnected after March 9, 2017, which shall offer compensation using the same methodology as NEM and shall apply the same policies except that Phase One NEM of grandfathered remote net metered projects shall be limited to a term of 25 years from generator interconnection.

9. The total rated generating capacity of Phase One NEM offered to community distributed generation projects in each utility shall be:

a. For Central Hudson Gas & Electric Corporation, 39 MW;
b. For Consolidated Edison Company of New York, Inc., 137 MW;
c. For New York State Electric & Gas Corporation, 56 MW;
d. For Niagara Mohawk Power Corporation d/b/a National Grid, 119 MW;
e. For Orange and Rockland Utilities, Inc., 23 MW; and
f. For Rochester Gas and Electric Corporation 28 MW.

10. The tariff leaves filed by each utility shall establish a two year grace period for carryover of credits by community distributed generation project sponsors consistent with the discussion in the body of this order.

11. Each utility shall file, within 7 days of the effective date of this order, the number of CDG projects and the MW of capacity represented by those projects that, at the time of this order, had already paid 25% of their interconnection costs, as well as the number of CDG projects and the MW of capacity represented by those projects that paid 25% of their interconnection costs between the issuance of the order and the filing of the letter. The utilities shall expeditiously develop

a method for providing real-time updates on the capacity left in each Tranche; until such a method is developed and implemented, each utility shall confer with Staff to determine the appropriate frequency of reporting based on local market conditions and shall file regular letters stating the current amount of capacity left in each Tranche based on those conditions. Each utility shall also immediately file a letter when any Tranche is filled.

12. Each utility shall file their most recent marginal cost of service (MCOS) studies and workpapers within 10 business days of the effective date of this order.

13. Within 45 days of the effective date of this order, each utility shall file a work plan and timeline for developing locationally granular prices to reflect the full value to their distribution systems from DER additions.

14. By May 1, 2017, each utility shall file an Implementation Proposal for public review and comment. The utility Implementation Proposals shall include, at a minimum, the items specified in the body of this order.

15. Department of Public Service Staff (Staff) shall file an updated whitepaper on oversight of Distributed Energy Resources within 30 days of the issuance of this order.

16. Staff shall work with the utilities and stakeholders to organize consultative meetings in advance of and, as necessary, following the issuance of the Implementation Proposals.

17. In consultation with stakeholders, Staff shall develop and file, by September 1, 2017, a Low-Income CDG Proposal, which shall include, at a minimum, information developed through the CDG Low Income Customer Collaborative, a report on the feasibility of an interzonal CDG credit program,

and discussion of the other options to encourage and support low-income customer participation discussed above.

18. Consistent with the discussion in the body of this order, the New York State Energy Research and Development Authority (NYSERDA) shall file new or revised Clean Energy Fund (CEF) investment chapters to support programs aimed to encourage and incentivize low-income customer participation in CDG projects, as well as to support the transition to the Value Stack.

19. NYSERDA shall operate the New York Generation Attribute Tracking System (NYGATS) and procurements consistent with the discussion in the Environmental Attributes Section of this order.

20. NYSERDA shall provide a report within 90 days of the issuance of this order detailing how the NYGATS platform can be used to generate information that will be used to support VDER Phase Two.

21. NYSERDA shall relinquish all rights to any environmental claims, certificates, attributes or other embodiments or memorializations of those claims for energy produced by any system to which it provided financial incentives under the Customer-Sited Tier and NY-Sun programs consistent with the discussion in the body of this order.

22. Staff is directed to work with NYSERDA, the utilities, and market participants to develop and file a proposal or proposals for steps that can be taken to reduce, eliminate, or mitigate market barriers.

23. The requirements of §66(12)(b) of the Public Service Law and 16 NYCRR §720-8.1 concerning newspaper publication of the tariff amendments described in Ordering Clause No. 1 are waived.

24. The petition filed by SolarCity on October 21, 2016 is granted to the extent discussed in the body of this order and is otherwise denied.

25. In the Secretary's sole discretion, the deadlines set forth in this order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least one day prior to the affected deadline.

26. These proceedings are continued.

By the Commission,

(SIGNED)

KATHLEEN H. BURGESS
Secretary

Commissioner Diane X. Burman, concurring:

As reflected in my comments made at the March 9, 2017 session, I concur on this item.

APPENDIX A. ESTIMATED MTCS

(to be replaced by utility compliance calculations)		All Averages are PV Load Weighted Averages				
	CHGE	O&R	NGRID	NYSEG	Con Ed	RG&E
Estimated "Base Retail Rate"						
MFC	$0.0042	$0.0072	$0.0021	$0.0042	$0.0051	$0.0064
SBC	$0.0081	$0.0045	$0.0053	$0.0061	$0.0045	$0.0068
Deliv	$0.0607	$0.0785	$0.0476	$0.0368	$0.1016	$0.0379
ICAP	$0.0184	$0.0288	$0.0125	$0.0114	$0.0408	$0.0121
Energy+	$0.0559	$0.0608	$0.0392	$0.0488	$0.0638	$0.0447
subtotal 1	$0.1473	$0.1798	$0.1067	$0.1073	$0.2158	$0.1079
"Estimated Value Stack"						
E	$0.0242	$0.0242	$0.0242	$0.0242	$0.0242	$0.0242
ICAP	$0.0184	$0.0288	$0.0125	$0.0114	$0.0408	$0.0121
DA LBMP	$0.0490	$0.0489	$0.0400	$0.0400	$0.0515	$0.0365
subtotal 2	$0.0916	$0.1020	$0.0768	$0.0757	$0.1166	$0.0728
Estimated MTC (subtotal 1 - subtotal 2)	$0.0558	$0.0778	$0.0299	$0.0317	$0.0993	$0.0350
VoD (estimated)	$0.0063	$0.0078	$0.0084	$0.0089	$0.0316	$0.0106
Net Revenue Onsite Mass Market Impact	$0.0737	$0.0942	$0.0457	$0.0470	$0.0919	$0.0487
Net Revenue CDG Impact*	$0.0494	$0.0700	$0.0215	$0.0228	$0.0677	$0.0244
	* CDG impact < Onsite Mass Market impact due to E credit					

APPENDIX A CONT.						
	Note: O&R and CE "Delivery" =					
	PV load weighted avg. of					
	tail block rates					
	Note: NGRID's VoD offset is double the					
	average VoD for all other upstate utility VoD					
	estimates. Upstate average will be used					
	instead for trancheing purposes					
	CHGE	O&R	NGRID	NYSEG	Con Ed	RG&E
Tranche 1 Compensation	$0.1473	$0.1798	$0.1067	$0.1073	$0.2158	$0.1079
times 0.95	$0.1400	$0.1708	$0.1014	$0.1020	$0.2050	$0.1025
times 0.90	$0.1326	$0.1618	$0.0960	$0.0966	$0.1943	$0.0971
MTC 1.00 (Tranche 1)	$0.0558	$0.0778	$0.0299	$0.0317	$0.0993	$0.0350
MTC 0.95 (Tranche 2)	$0.0484	$0.0688	$0.0246	$0.0263	$0.0885	$0.0297
MTC 0.90 (Tranche 3)	$0.0410	$0.0598	$0.0192	$0.0209	$0.0777	$0.0243
Rev Shift 1.00	$0.0494	$0.0700	$0.0215	$0.0228	$0.0677	$0.0244
Rev Shift 0.95	$0.0421	$0.0610	$0.0162	$0.0174	$0.0569	$0.0190
Rev Shift 0.90	$0.0347	$0.0520	$0.0108	$0.0120	$0.0461	$0.0136

APPENDIX B. SUMMARY TABLE OF DISTRIBUTED ENERGY RESOURCE CATEGORIES AND TREATMENT OF GENERATION ATTRIBUTES

		DER Category	Options	Is the project allowed to bid into RES Tier 1 Solicitations conducted by NYSERDA if otherwise eligible?	Will NYGATS create a transferable Certificate in the account of the generator?	Will NYGATS create a non-transferable Certificate in the account of the customer (indicates retirement by the customer)?	Do the attributes of the generation count towards the interconnecting LSE's RES Compliance Mandate?	Do the attributes of the generation count towards the Statewide 50% by 2030 renewable resources goal?
Pre-existing NEM Tariffs	Net Energy Metering	All Projects (Prior to Cut-Off)	RES Tier 1 (if eligible and awarded a contract by NYSERDA) *	Yes	Yes**	No	No	Yes
			Customer Retention	No	No	Yes	No	Yes
VDER Phase One Tariffs	Phase One NEM	On-Site Mass Market Projects and Small Wind Remote Net Metering Projects On-Site Large Projects	None	No	No	Yes	No	Yes
		Community Distributed Generation Projects	Interconnecting-LSE-Option	No	No	No	Yes	Yes
			Customer-Retention-Option	No	No	Yes	No	Yes
	Value Stack	On-Site Mass Market Projects and Small Wind (by opt-in, no longer net metering) Community Distributed Generation Projects (no longer net metering) Remote Customer Projects (no longer net metering) On-Site Large Projects (no longer net metering)	Interconnecting-LSE-Option	No	No	No	Yes	Yes
			Customer-Retention-Option	No	No	Yes	No	Yes

Note: The generation attributes of all renewable resource generation consumed by customers in New York State will contribute towards the Statewide 50% by 2030 renewable resources goal, which relies on both mandatory and voluntary contributions for its ends to be achieved. Voluntary market contributions do not count towards compliance with the Load Serving Entity mandates of the Renewable Energy Standard (RES).

* All pre-existing NEM projects that are eligible to bid into RES Tier 1 solicitations are subject to a previous RPS Main Tier contract rule that prohibited simultaneous collections of both New York RPS incentive payments and production-based incentives from any other state or local source, including CST, NY-Sun, and CEF program incentives.

** The Certificates will be transferable to NYSERDA pursuant to contract who may then transfer them to Load Serving Entities.

APPENDIX C. HISTORY OF NET METERING IN NEW YORK

In 1997, the Public Service Law (PSL) was amended to add §66-j, which provided net energy metering (NEM) for residential solar electric generation sized at no more than 10 kW.[51] Over the following two decades, the PSL was expanded to include other forms of electric generating equipment, including farm waste, wind, micro-hydroelectric, fuel cell, and micro-combined heat and power systems along with other arrangements and project sizes, in particular to accommodate commercial customers.[52]

Pursuant to statutory NEM provisions implemented through utility tariffs, customer-generators receive a bill from their electric utility based on their net energy consumption over the course of their billing period. For residential customer-generators and other customer-generators billed on a volumetric basis, each kWh of energy injected into the grid, when their generation exceeds their usage, provides an offset on their bill, equal to one kWh of energy, for when they draw energy from the grid during times when their usage exceeds their generation. Compensation for injected energy is therefore equal to the entire per kWh retail rate, including the portions of that rate that reflect supply charges, delivery charges, and other charges that are billed on a per kWh basis, such as taxes, the System Benefit Charge (SBC), and the Merchant Function Charge (MFC.

Demand-billed customers and mandatory hourly pricing (MHP) customers, a group generally made up of non-residential customers characterized by energy demand above a certain threshold established in each utility's tariff, are similarly

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[51] Laws of 1997 ch. 399 (effective August 13, 1997).

[52] PSL §§66-j and 66-l. NEM of wind turbines is governed by PSL Section 66-l, while NEM of all other technologies is governed by PSL 66-j.

billed for net energy consumption with regard to the volumetric kWh portion of their monthly bill, which includes the supply charge and some other charges, including the SBC and MFC. However, because their delivery charge is based on their peak monthly kW demand, injections of energy do not reduce their delivery charge.

If a customer-generator's net energy consumption over the course of a billing period is negative, credits are carried over to the next month. Depending on the class of the customer-generator and the type of generation, the value of those credits is equal to either the per kWh retail rate or the utility's avoided cost rate, which is set based on the utility's cost for electric supply alone. Over the annual billing period, if a residential or farm non-residential customer-generator employing solar PV, wind, or anaerobic digester generation has negative net energy consumption, the utility issues a check for excess credits based on the utility's avoided costs. For other customer-generators and generation types, the credits continue to carry over into the next annual period.

In 2012, remote net metering (RNM) was authorized by the legislature and provided for a minor variation on the above formula. Specifically, a non-residential or farm-based residential customer-generator with a solar PV, wind, anaerobic digester, or micro-hydroelectric system may participate in RNM if it has two or more utility meters in the same utility territory and load zone.[53] A customer-generator participating in RNM may designate net metering credits created by an eligible generator at one property they own or lease (the Host Meter), to the meter or meters of other properties they own or lease (Satellite Meters). Some participants in RNM have minimal electric usage at their Host Meter and therefore inject almost

[53] PSL §§66-j(3)(e)-(h).

all of the energy generated into the grid to offset usage at the Satellite Meters; others have significant usage at the Host Meter and inject a smaller portion.

For most of the history of RNM, the value of credits was calculated by converting the kWh of excess generation at the Host Meter to monetary credits based on the per-kWh charges applicable to the Host Meter's service class. The bill for the Satellite Meter or Meters was then reduced by that monetary amount. This is often described as monetary crediting. In many cases, the per kWh charges at the Host Meter can be significantly larger than at the Satellite Meter because the Host Meter can be within a non-demand service class while the Satellite Meter can be within a demand-metered service class.

In order to avoid uneconomic arbitrage and unreasonable promotion of RNM over on-site net metering, the Commission modified the method of calculating the credit value.[54] Under the RNM volumetric crediting system adopted by the Commission, the excess kWhs generated at the Host Meter are transferred to the Satellite Meter as volumetric credits, which then offset the Satellite Meter's kWh charges and thereby reduce their bill. The Commission subsequently provided for the grandfathering under monetary crediting to permit existing RNM projects, and certain other RNM projects under development, to continue monetary crediting for 25 years.[55]

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[54] Cases 14-E-0151 et al., Petition of Hudson Valley Clean Energy, Inc. for an Increase to the Net Metering Minimum Limitation at Central Hudson Gas & Electric Corporation, Order Raising Net Metering Minimum Caps, Requiring Tariff Revisions, Making Other Findings, and Establishing Further Procedures (issued December 15, 2014).

[55] Cases 14-E-0151 et al., supra, Order Granting Rehearing in Part, Establishing Transition Plan, and Making Other Findings (April 17, 2015).

On July 17, 2015, the Commission issued an order instituting a Community Distributed Generation (Community DG or CDG) program (the Community DG Order) in response to the growing interest in access to DG from customers that, for a variety of reasons, could not participate in traditional NEM or RNM.[56] Like RNM, the Community DG rules permit credits to be accumulated through injections of energy from a generator installed behind a Host Meter. The credits may be either volumetric credits or monetary credits, depending on whether the Host Meter is served at non-demand rates or demand rates, respectively. Those credits are then distributed to members of Community DG project in order to offset the kWh charges at their meters. Among other requirements, Community DG projects must serve at least ten members and no more than 40% of the facility's kWh credit output must be distributed to large customers, defined in the order as customers with a demand above 25 kW.

The Community DG Order included several policies to promote participation in Community DG by low-income customers, including limiting participation in the six month initial phase to projects that either included a significant number of low-income customers or were located in an area where they would provide locational benefits to the utility and instituting a Low-Income Customer Collaborative. The Community DG Order also recognized the need for transition of DG compensation from NEM to a more accurate methodology, called in that order LMPD.[57] Staff was directed to promptly commence the development of a

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[56] Case 15-E-0082, Policies, Requirements and Conditions For Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015).

[57] Representing of its combination of the value of energy based on locational marginal price (LMP) with other distribution (D) values.

report and recommendations on valuation of distribution system benefits provided by DER in consultation with stakeholders.

The Commission has repeatedly addressed the ceilings applicable to the amount of generation entitled to statutory NEM in each utility service territory.[58] In conformance with provisions of PSL §66-j that allow the Commission to increase the statutory ceiling caps if deemed to be in the public interest, in October 2012 and June 2013, the Commission issued orders in Cases 12-E-0343 and 12-E-0485, respectively, raising the ceilings to 3% of the Utilities' 2005 electric demand, three times the statutory cap of 1%.

Subsequently, on December 15, 2014, the Commission issued an order in Case 14-E-0151 setting the ceiling on the amount of NEM generation that the state's investor-owned electric utilities must interconnect to 6% of 2005 electric demand, 6 times the statutory cap. The Commission found in the December 2014 Order that a 6% ceiling was in the public interest because it was necessary to accommodate further DG development while methods of more accurately valuing DER were developed through REV and that a 6% ceiling would not impose unreasonable impacts on ratepayers.

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[58] The ceilings discussed here, which appear in PSL §66-j, apply to all NEM-eligible generation technologies other than wind generation, which is governed by a separate provision, PSL §66-l. The terms and conditions of NEM under the two sections are essentially identical, except that wind is subject to a separately calculated statutory cap of 0.3% of 2005 electric demand for each utility, and therefore is not counted towards the cap that applies to all other technologies. The 0.3% cap has not been modified by the Commission and has not yet been reached in any service territory. For that reason, statutory NEM will continue to be available for wind turbines in each service territory until the 0.3% cap is reached; once the 0.3% cap has been reached in a utility's service territory, that utility should treat all NEM/VDER eligible generators, including wind turbines, identically.

In response to concerns that one or more utilities might reach the 6% ceiling prior to the implementation of a new DER compensation policy, in an order issued on October 16, 2015 in Case 15-E-0407, the Commission found that a floating ceiling, whereby utilities were required to accept all interconnection applications and to continue to interconnect NEM without measuring the DG capacity against an artificially set ceiling level, was appropriate and in the public interest for an interim period. However, the Commission explained that the floating ceilings would be applied until a more accurate DER valuation methodology was ready for implementation, at which point the ceilings would be automatically set "based on the PV and other DG generation that is actually installed in the service territory." The Commission recognized that the development of this more accurate methodology would require consideration both of the distribution system benefit issues discussed in the Community DG Order and of other costs and benefits associated with NEM and DER. The Commission directed the development of a report and recommendations by December 31, 2016, through a Staff-led collaborative process, presenting "more precise interim methods of valuing DER benefits and costs, as well as the appropriate rate designs and valuation mechanisms . . . , to serve as a bridge while the complete "value of D" tools and methodologies are developed."

In the context of the Commission's action in this Order to establish the critical and necessary foundation for transitioning to more accurate valuation and compensation for DER, it is useful to recognize that dozens of other jurisdictions have been wrestling with similar issues that we are addressing here. Whether prompted by regulatory or legislative initiative, over the past several years an increasing number of jurisdictions have been grappling with issues related to NEM and valuation of DER. Notably, the

motivations and objectives of other jurisdictions for addressing NEM compensation and value of DER are wide ranging, as are the outcomes and their respective progress.

Broadly speaking, actions taken in other jurisdictions to address these issues range from comprehensive assessments around valuation and optimization of DER, such as those in California[59] and our current undertakings here in New York, to rate design approaches explicitly impacting NEM compensation (e.g., mandatory time-of-use, increased fixed or customer charges), such as those in Arizona and Nevada. Approaches and initiatives have similarly ranged depending on the particular market segment being addressed, such as rooftop solar or off-site, CDG facilities and arrangements. In recent years, states including Massachusetts, Colorado and Minnesota have specifically taken actions related to their emerging CDG markets.

[59] CPUC, California's Distributed Energy Resources Action Plan: Aligning Vision and Action, November 2016.

Frequently, decisions and developments regarding these issues are often informed and aided by factual analysis or studies, whether directed by the decision-making body or put forth by an interested or active party. For instance, a recent report references upwards of 20 "value of solar" studies over the past several years.[60] New York's deliberations have similarly been informed by preliminary analyses, the importance of which was recognized by the State legislature when they directed an analysis into the benefits and costs of NEM, completed in December of 2015.[61]

[60] Barbose, Galen L. Putting the Potential Rate Impacts of Distributed Solar into Context, January 2017. Lawrence Berkeley National Laboratory.

[61] PSL § 66-n, resulting in Energy and Environmental Economics. The Benefits and Costs of Net Energy Metering in New York, December 2015. Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service.

APPENDIX D. SUMMARY OF COMMENTS

LISTING OF PARTIES THAT SUBMITTED COMMENTS

Acadia Center and Natural Resources Defense Council (Acadia)

Advanced Energy Economy Institute, Alliance for Clean Energy New York, Inc, and the New England Clean Energy Council (AEEI)

Advanced Energy Management Alliance (AEMA)

Azure Mountain Power Company (AMP)

Bloom Energy Corporation (Bloom)

Borrego Solar Systems, Inc. (Borrego)

Center for Resource Solutions (CRS)

City of New York (CNY)

Coalition for Community Solar Access (CCSA)

Coalition of On-Site Renewable Users (CORE)

Cypress Creek Renewables (CCR)

Digital Energy Corp (DEC)

Distributed Sun LLC (DSun)

Energy Democracy Alliance (EDA)

Environmental Defense Fund and Institute for Policy Integrity at NYU School of Law (EDF, NYU)

Grid Alternatives

IBEW, New York State Utility Labor Council, International Brotherhood of Electrical Workers, Local Union 10 (IBEW)

Joint Utilities (JU) – Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric and Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation (JU)

Multiple Intervenors (MI)

National Fuel Cell Research Center (NFCRC)

National Fuel Gas Distribution Corporation (National Fuel)

New York Battery and Energy Storage Technology Consortium (NY BEST)

New York City Environmental Justice Alliance, New York Lawyers for the Public Interest (NYCEJA)
New York Solar Energy Industries Association (NYSEIA)
New York State Office of General Services (OGS)
New York Power Authority (NYPA)
Northeast Clean Heat and Power Initiative (NCHPI)
Nucor Steel Auburn, Inc. (Nucor)
NY Cow Power Coalition / Cayuga Marketing
Pace Energy and Climate Center (Pace)
Public Utility Law Project of New York, Inc. (PULP)
SolarCity Corporation (SolarCity)
Solar Parties (Solar Energy Industries Association & Vote Solar)
The Alliance for Solar Choice (TASC)
Utility Intervention Unit, Division of Consumer Protection, Department of State (UIU)

INITIAL COMMENTS

Acadia

Acadia strongly supports the overall framework recommended by the Staff Report for the Phase One methodology of (1) monetary net metering credits based on locational and temporal values applied to net hourly injections, (2) unlimited carryover of credits, and (3) cost allocation following the group of customers that benefits from the savings. Acadia also supports the key measures to make this transition a gradual one, including grandfathering for legacy projects and projects that qualify within 90 business days of the Phase One Order, "Tranche Zero" for CDG projects, and continuation of current net energy metering structures for mass market solar and small wind. Acadia generally supports the major elements of the Phase One crediting methodology, but has previously recommended a more stable and gradual approach and has concerns about the recommended values for delivery, particularly for projects that

do not qualify for the market transition credit. It is also crucial that key missing values are evaluated and addressed as soon as possible, including avoided transmission costs, and bill impacts due to reduced electricity and natural gas prices.

Acadia and NRDC

Acadia and NRDC offer general support for the overall framework and transition elements recommended in the Staff Report. With respect to the Phase One Compensation Methodology, Acadia and NRDC applaud the thoughtful approach taken in the Staff report which attempts to balance tradeoffs between efforts to accurately value distributed energy resources in a technology neutral manner, and the principles of simplicity and gradualism. Acadia and NRDC offer several recommendation which are intended to improve the Phase One Compensation Methodology. First, Acadia and NRDC support the proposed environmental value and MTC for CDG projects. Second, Acadia and NRDC, suggest that the recommendations with respect to avoided energy and capacity value are overly complex and provide uncertainty for customers and developers. With respect to installed capacity value, Acadia and NRDC recommend adoption of options that lean toward simplicity.

Next, Acadia and NRDC note that benefits associated with avoided transmission costs are not explicitly reflected in the value stack recommendations and recommend a full examination of transmission and sub-transmission value. With respect to distribution system value, Acadia and NRDC find the Staff proposal inadequate for projects that are not eligible for the MTC.

Acadia and NRDC also believe that the proposed methodology basing the demand reduction value across a service territory on the ten highest usage hours for the service territory and valued based on marginal cost of service studies

that will be updated over time is flawed because, among other reasons, the ten hour limit is arbitrary and ex-post evaluation does not give customers and generators a clear price signal when to act. Acadia and NRDC instead propose establishing a predictable delivery value credit that applies across a service territory, based upon a portion of the values shown in marginal cost of service studies for transmission and distribution. Finally, Acadia and NRDC oppose the recommended revenue impact cap and the proposed methodology for calculating such impacts. Acadia and NRDC support a 4% revenue impact cap as a more appropriate limit that will better facilitate achievement of the State's clean energy goals without posing an undue burden on utility customers.

AEEI

AEEI concerns surround the uneven treatment of different technologies and how BTM benefits of DERs are treated. AEEI cautions that the focus on solar should not detract from the central purpose of VDER to develop accurate pricing for DERs. AEEI encourages the Commission to incorporate flexible DERs, including stand-alone energy storage, clean dispatchable generation, demand response, and demand side management more broadly and more quickly. AEEI explains that these technologies had been receiving support from NYSERDA programs that were phased out with the expectation that a technology neutral LMP+D that included grid and societal benefits would compensate them, but the Phase One proposal leave a gap until the Phase Two inclusive compensation mechanism is developed.

AEEI advises that technologies eligible for the MTC will receive financing at a lower cost than projects that are ineligible for the MTC that will instead receive the demand reduction value. AEEI states that Phase One compensation fails to provide signals for demand reductions that can avoid the need

for future utility investments and does not differentiate between clean and conventional generation consumed behind the meter. AEEI argues this goes against established treatment of CES-eligible technologies that were previously able to sell RECs into the Main Tier of the RPS. AEEI urges the Commission to apply the DRV and LSRV to all BTM generation regardless of whether it is consumed behind the meter or exported. AEEI illustrates that a solar plus storage customer may receive a reduction in demand charges for dispatching its solar plus storage to meet system peaks, but only on the off chance that the customer's peak demand is coincident with system demand.

AEEI recommends expanding eligible technologies to those not included in PSL §§66-j and 66-l. AEEI encourages the Commission to set a timeline for adapting the Phase One compensation methodology to include standalone storage well in advance of the Phase Two methodology timeline.

AEEI advises that compensating only for net monthly exports does not accomplish the intended purpose, and as an alternative, the environmental compensation should be provided for the net output of the DER rather than the customer. AEEI notes that this recommendation requires the use of a separate meter, but says that BTM DER is likely to have separate metering for a variety of reasons. Furthermore, AEEI instructs that the full DER output should be separately metered to quantify and compensate the full benefits.

AEEI suggests that projects in service on the date of the Phase One Order should receive compensation under existing NEM rules for 25 years, rather than 20 years as proposed in the Staff Report. Additionally, AEEI believes the Commission should respect contracts with terms greater than 25 years that were signed prior to the Commission's Phase One Order.

AEEI argues that because of the way the market supply charge is calculated, customers that are not on mandatory hourly

pricing are likely to be inaccurately compensated for the capacity they provide to the wholesale market through the generation that they produce and consume behind the meter. AEEI requests clarification of whether compensation is based on net export during the hour or on MW performance, and recommends that it should be based on net exported generation. AEEI suggests technology-specific first year values be published to facilitate financing, and that capacity payments be allocated based on performance during the 460 summer hours.

AEEI advises that a methodology to convert the table of social cost of carbon costs into $ per kWh price, since the EPA measures this in $ per metric ton. AEEI believes the REC certificates associated with customer generation should either be counted toward the customer's sustainability certification or the CES goal, but not both. AEEI states that the Staff Report was not clear with respect to the relationship between the overall CES goal and the Tier One obligation, and requests more information. AEEI proposes that customers have the choice to forgo receiving the E value as part of the LMP+D stack, and instead receive title to fully tradable RECs for their eligible generation.

AEEI points out that the Staff Report leads to the conclusion that clean energy produced on behalf of CDG subscribers provides different environmental value than the same clean energy produced by individual customers where the energy is consumed onsite instead of being exported. AEEI suggests that all clean energy produced by DERs should be valued consistently and compensated at either Tier One rates or SCC rates. AEEI asserts that allowing non-exported energy to be used to reduce LSE obligations would result in the DER providing an economic benefit to the utility without receiving compensation, and amounts to double counting into the CES. AEEI complains that if on-site clean generation is claimed for

compliance in the manner proposed by Staff, a company's investment in clean energy will decrease the LSEs obligation to procure RECs, in effect transferring the benefit of a company's private investment in clean generation to the ratepayers of New York without compensation while eliminating the ability of that company to produce clean energy that is incremental to state targets.

AEEI advises that eliminating RECs for non-exported generation is a substantial departure from the previous RPS policy, and a change of this magnitude should have had greater stakeholder discussion. AEEI characterizes distribution costs as underrepresented because the proposed tariff neglected to include avoided losses. AEEI requests the Commission clarify that projects whose MTC is reduced to zero will receive the DRV.

AEEI recommends that parties be given sufficient time to review proposed values and the input calculations prior to Phase One tariffs going into effect. AEEI notes that the virtual generation portfolios seem very similar to the distributed system providers' role in the REV proceeding, and demonstrations are prudent.

AEEI prefers a revenue shift impact cap of 3% instead of the 2% cap in the Staff Report. AEEI suggests that the Commission should be prepared to adjust the tranche size if the market is not responding, particularly in utility service territories like NYSEG and RG&E, which have significant flexibility.

AEEI concludes by noting that Central Hudson and O&R are the most constrained by the Phase One proposal, and the Commission should establish a transparent process for managing interconnection queue management and SIR complaints.

AEMA

In its comments, AEMA expresses concern that different technologies will be compensated differently for providing similar, if not identical, services. AEMA comments that technologies that receive inferior compensation, but offer the same services, will be placed at a competitive disadvantage over the next two years while Phase Two is developed. In order to address this competitive disadvantage, AEMA proposes that the Commission: 1) Provide non-export demand response customers the option to lock in the 2017 dynamic load management program pricing in Con Edison's programs for 10 years; 2) include the environmental value that is available to NEM technologies to payments for the all dynamic load management programs prior to summer 2017; 3) limit the number of customers that can participate in the Phase One tariff until all technologies are compensated more equally; and, 4) act expeditiously to level the playing field and resolve all differences in compensation between technologies that provide similar grid services.

AMP

AMP supports NEM programs, but submits several concerns. AMP advises that the current RNM program requirement that a generator and off-take site be located in the same utility territory and load zone greatly restricts certain hydroelectric generators' participation. AMP explains that in some upstate areas the load zone and utility territory overlap is small, and it is hard for generators in these sparsely populated areas to find off-takers. AMP suggests that given the granularity of the value stack, it would be logical to lift the restriction that the two sites be within the same LBMP zone. AMP requests that if fully lifting the restriction is not feasible, the requirement be loosened for smaller load zones

such as Zone D, so that participation between contiguous zones or throughout the individual service territory be allowed.

AMP states that how the value stack elements will be calculated for existing facilities who may already be contributing to grid strength and reduce the cost of maintenance is unclear. AMP asks the Commission to consider how best to value the contributions of existing generators as well as new facilities, particularly with respect to calculating the LSRV.

AMP argues that it is vital for an existing renewable facility that enters into a DER agreement also be able to vest its RECs with the DER customer, and requests clarification that this will be permitted. AMP also seeks clarity regarding what effects this will have on the renewable baseline and/or the Tier One purchase obligations of the serving utility.

AMP claims that while hydroelectric generators operate at a far higher capacity factor than wind or solar, hydro generators are often at their lowest output during summer load peaks. AMP believes this may lead to unfair hydro compensation based on certain methods of calculating capacity value, and requests that the Commission consider this when determining how best to calculate the capacity portion of the value stack. AMP suggests calculating both a summer and winter peak may be equitable, and alternatively recommends considering the highest LBMP price as a supplementary peak measurement.

AMP urges the Commission to consider that new renewable resources should be intended to displace natural gas if GHG reduction goals are to be met. AMP advises that legacy hydro and natural gas are compensated at the same rates, and any negative impact of natural gas generators acts equally upon legacy hydro generators, which AMP claims are vulnerable to retirement.

Bloom Energy

Bloom Energy commends the Staff Proposal for proposing a workable solution and transition plan for moving from net metering to DER valuation. However, Bloom Energy believes that the Staff Report deviates from the goal of REV by restricting REV markets exclusively to net excess generation, by excluding behind the meter resources from traditional incentive programs before any REV market signals are in place. Bloom Energy urges the Commission to clarify that these exclusions will not be solidified in establishment of a methodology and process for determining the full value of DER for the larger purposes of developing DER compensation mechanisms built upon an LMP+D approach. Bloom Energy opposes the Staff Reports apparent recommendation that non-exporting behind the meter generation be effectively excluded from the CES. Bloom Energy comments that non-exporting, behind the meter generation creates multiple benefits including: 1) avoided or deferred distribution investments; 2) avoided distribution energy losses; 3) reduced wear and tear on the distribution system; 4) avoided environmental impacts associated with transmission and distribution facilities; 5) displacement of diesel generators; and, 6) enablement of grid isolating capabilities.

Borrego

Borrego is a member of the SEIA and the NYSEIA, and supports those organizations' comments, in addition to the following comments. Borrego supports Staff's proposal to grandfather RNM and CDG projects, but suggests several additions. Borrego expresses concerns with Staff's proposed capacity limitation on grandfathering CDG projects, and cautions against adopting an arbitrary cap. Borrego strongly recommends the Commission expressly state that the cap on grandfathering is justified because of the unique circumstances affecting the

present distributed solar market, but is not an appropriate precedent for future transitions. Borrego also requests the Commission order the access to each Tranche, including Tranche Zero, be based on the date on which each project makes its 25% interconnection payment. Borrego claims that older projects that are subject to the old SIR face a higher bar to achieve grandfathered status than more recent projects subject to the new SIR that only need to make 25% payment secure a position in Tranche Zero. Borrego requests the Commission specify that projects under the old SIR may make 25% payment within 30 days of the Commission Order allowing these projects to opt into the new SIR, and guarantee these older projects access to Tranche Zero.

Borrego advises that since a project's economics may hinge on successfully reserving a place in a particular Tranche, the Commission should direct the utilities to provide real-time information on progress toward the Tranches. Borrego believes the utilities should provide written confirmation of a project's Tranche assignment by the business-day after the project developer makes 25 % interconnection payment. Borrego proposes that the Commission direct utilities to release the number of MW that have been reserved in each Tranche in real time, as soon as practicable after the effective date of the Commission's order. Additionally, Borrego proposes that any projects that make 25% payment before this MW data is published automatically be placed in Tranche Zero, even if this placement exceeds Tranche Zero's size. Borrego favors a user-friendly interface, such as the NYSERDA MW Block Dashboard, to display each utility's progress towards each Tranche. Borrego explains that under the current proposal, key elements of the value stack will not be determined until after a Commission order. Borrego contends that the Commission should modify its CDG grandfathering proposal allow projects access to Tranche Zero until all elements of the

interim VDER tariff have been developed. Borrego maintains that unless the Commission identifies the DRV, LSRV, and Capacity values in its order, the Commission should specify that projects may qualify for Tranche Zero until those values are identified. Borrego explains that a workable interim tariff is strongly preferable, but if the Commission does not identify the methodology for calculating all elements in the value stack, it should extend the time period for grandfathering to well-beyond the 90-day period proposed by Staff.

Borrego generally supports the use of the zonal hourly LBMP as the energy component of the value stack, and notes that this this value should include all three components of the NYISO price – energy, congestion, and losses. Borrego requests the Commission clarify that projects under the interim VDER tariff will receive energy compensation equal to the full zonal LBMP price.

Borrego supports the use of the capacity element of the retail supply charge as the capacity component of the value stack. However, Borrego is concerned that Staff is proposing to leave the determination of which retail rate class to use for this calculation until the implementation phase, and recommends that the SC1 rate be used for the interim tariff. Borrego submits that the question of which service class load profile should be used for the capacity portion of the value stack is more appropriately resolved through Phase Two VDER tariff discussions. Borrego requests that Staff's alternative proposal for compensating projects for their capacity contribution during the 460 peak summer hours should not be adopted as the default approach for all DERs, but should be preserved for DERs that are able to design their systems to provide more capacity during the 460 peak summer hours.

Borrego believes the NYSERDA REC price is an acceptable default value for the environmental component (E) of

the interim value stack, but advises E should be revisited during Phase Two tariff discussions. Furthermore, Borrego states the E value and any other fixed values for CDG and non-CDG projects, should be determined at the time projects make their 25 % interconnection payment. Borrego strongly supports Staff's proposal to fix the E value for at least 20 years, and explains that a longer time is more appropriate because the NYSERDA REC value does not capture the full environmental value that DERs provide over time. To account for the increasing value DERs have on the state's GHG reduction goals over time, Borrego advises that projects under the interim VDER tariff should be allowed to opt into using annual values of the Social Cost of Carbon on a one-time basis. Borrego goes on that to facilitate this option, Staff should publish these values on a kWh basis for the full term of the DER tariff.

Borrego strongly supports including a market transition credit (MTC) for CDG projects, and recommends that the MTC be adopted for commercial and industrial (C&I) off-taker projects. Borrego explains that although revenues for C&I projects will likely increase slightly under the new tariff, the increase is unlikely to revive the "C&I market in New York that is currently dead." Borrego recommends the Commission use LBMP data from 2016, because comparing 2016 LBMP rates to 2016 residential NEM rates would provide the best comparison for determining the MTC. However, if the Commission decides to retain a multi-year average approach for projecting the LBMP, Borrego advises adopting a seven-year average, including 2016. Borrego notes that the Commission should use the same capacity value when calculating the MTC as the capacity value used for providing compensation under the interim tariff. Borrego further requests that the Commission calculate and announce the value of the MTC for each utility one time for all projects, including the stepped-down value in later Tranches.

Borrego proposes several clarifications to the VDER Staff Report, in order to set appropriate production curves to simulate DER generation over time. Borrego recommends that the MTC be calculated by reference to separate utility and NYISO zone-specific annual production models, with industry input. Borrego specifically requests the Commission assume that almost all projects will be roof-mounted in Con Edison's service territory, and that the Commission employ a production model that reflects this assumption; Borrego goes on to recommend specific assumptions for generating the production curves in other utility territories. Borrego states that the Commission should use a 2% annual escalator to the MTC to reflect the historical increase in retail rates over time in order to align compensation under the new tariff with market expectations and requirements.

Borrego supports including a DRV in the interim tariff, and suggests that the best interim solution is to base the DRV on the current, publicly available MCOS figures included in the Staff Report. Borrego states that each project's DRV value should be based on a 5-year, utility zone-wide rolling average of performance for similar DERs during the applicable peak hours. To address significant inter-annual variability in the peak demand hours' timing across utilities, Borrego says the Commission should modify Staff's proposal such that the DRV is based on a minimum of 25 hours per year.

Borrego strongly urges the Commission to adopt a proxy value for the interim locational distribution value for projects located in high-value areas, rather than leaving the locational value determination until implementation. Borrego continues that a more granular value should be developed in Phase Two.

Borrego concludes by expressing strong support for unbundling retail rates, developing a separate tariff for stand-

alone electricity storage systems, and applying these concepts to projects larger than 2 MW.

CCR

CCR supports the proposal that projects currently under development that pay 25% of their interconnection costs or execute an interconnection contract within 90 days of the Phase One Order should receive NEM compensation. However, CCR proposes extending the NEM compensation period for those projects from 20 to 25 years. CCR also proposes a similar extension of the Phase One tariff compensation period.

CCR recommends that, in order to reduce complexity, avoid the creation of unintentional inequities, and serve a compelling public purpose, the MTC should be set for consistency and transparency, and 100% of the production from a CDG facility should be granted the MTC in lieu of a DRV. Additionally, CCR proposes that recovery of the MTC should come from both residential and commercial service classes at a pre-defined ratio, and the step down between CDG tranches should be reduced from 10% to 5%. Further, CCR offers that a shorter, more relevant averaging time of 12 months for the energy value should be used in setting the MTC.

CCR comments that the cap for cumulative annual revenue impact from all projects under NEM continuation and the Phase One tariff should be set at 4% instead of the current 2%. CCR avers that a 4% Limited Net Revenue Impact more accurately balances the needs of gradualism with respect to regulatory changes, and is not likely to actually result in a 4% impact on ratepayers because Phase One value stack is likely underestimating the value of solar.

With respect to intermittent technologies, CCR supports the Staff Report's option #1 for deriving the capacity value from the retail supply rate, and proposes that the

capacity value be made more readily transparent. CCR also supports the proposed environmental value approach, and recommend that this value be fixed for the term of the compensation methodology. Next, CCR comments that that current approach for setting the DRV is likely to cause volatility and uncertainty and recommends adopting an alternative methodology which should be locked in for the duration of the compensation methodology.

Finally, CCR offers that there are several important logistical issues that should be addressed including: the creation of an online dashboard for tranche reservations and circuit breaker progress; a standard metric for tranche reservation; and, the requirement for key information including the details of the value to be communicated on customer bills.

CCSA

CCSA expresses concerns that without changes to certain provisions of the Phase One tariff proposal, the Staff Report does not provide for a robust CDG program that would create equitable access to local clean energy. CCSA argues that CDG should be prioritized for expansion, not targeted for curtailment.

According to CCSA, projects compensated with the Phase One tariff should be able to lock-in this compensation structure over the lifetime of the project. CCSA advises that a Phase One 4% utility net revenue impact would strike a better balance between utility impacts and providing meaningful opportunities for customers to install DG or participate in CDG. CDG projects that are sufficiently advanced in development to meet Tranche Zero criteria within 90 business days of the Order should be awarded capacity in that tranche, CCSA asserts. CCSA advises that the MTC should be applied to 100% of the generations from CDG projects, since the MTC encompasses benefit values not yet

quantified in Phase One. Further, CCSA believes the inputs to the MTC will need to be carefully calibrated to transition smoothly from Tranches One, Two, and Three. In order to accomplish this, CCSA advises that the tranche step downs should be no more than 5% increments, and a reservation system should be created with timely reporting of public data.

CCSA suggests that legacy projects in-service at the time of the issuance of the Phase One Order should receive compensation under existing NEM rules for the useful life of the system. CCSA explains that only two or three legacy projects will be in-service, and those project developers made investment decisions on these projects at a time when the standard term for net metering was life of system. Additionally, CCSA advises that solar project developers in New York have considered projects as 35-year investments, consistent with the estimated useful life of the system. CCSA says investment decisions were made under the assumption that the project could continue under net metering or a similar structure for as long as the system could operate. CCSA argues that Staff's basis for the 20-year term, Tier One REC contracts, should not dictate the term of the overall compensation. At the very least, CCSA requests the Commission include a clear statement that projects would move to a compensation structure other than simply defaulting to the wholesale energy market.

CCSA cautions that the most significant CDG development activity has occurred in the two utility territories with the smallest proposed tranche size for continuing NEM and the Phase One tariff, and Tranche Zero must be managed closely in these territories. In light of this, CCSA recommends that all projects meeting the proposed threshold requirements for Tranche Zero within 90 days of the Order be included in Tranche Zero.

The benefits associated with a stable and reliable revenue stream for project financing purposes outweigh the purported benefit associated with added precision in the determination of the capacity value contribution during specific peak hours, CCSA emphasizes in its support for Staff's recommendation to provide intermittent technologies per kWh compensation based on the utility's full service market supply charges.

CCSA states that the E value should be determined and set as a floor for the project, and the higher E value should apply if different than at the time of interconnection.

Regarding MTC calculation, CCSA notes that requiring each utility to complete final MTCs for each tranche may result in the utilities implementing the approved methodologies inconsistently given different utility interpretations. Therefore, CCSA recommends the Staff calculate the MTCs and tranches using utility data, transparently with input from all stakeholders. When it comes to tranching, CCSA suggests Staff implement a transparent communication platform to facilitate developer decision-making in order to ensure that tranche capacity is allocated in an orderly manner.

Finally, CCSA proposes that existing NEM projects that opt-in to the Phase One tariff in any tranche should not impact the availability of that tranche for new projects.

CORE

In its comments, CORE recommends that storage by treated like all other eligible renewable energy and be paid the value of "E," contrary to the proposal in the Staff Report. Core offers that paying Phase I pricing to energy storage facilities linked to on-site renewable energy projects will encourage such projects and further the state's clean energy goals.

CORE supports the proposed transition plan that grandfathers existing projects based on their settled expectations at the time that they entered into their contractual and financial arrangements, but opposes the recommendation to limit grandfathering of NEM to 20 years. CORE recommends at a minimum, NME grandfathers should last for 25 years. CORE also opposes the proposed milestone requirements to be eligible for grandfathering as they would place eligibility for grandfathering within the hands of the interconnecting utility.

Next CORE proposes that the framework for the value of E should adhere to the BCA Order principles to ensure that on-site generators can make the renewable energy claims to which they are entitled. With respect to the primary categories of carbon and other air pollution emissions, CORE recommends that the Commission retain its approach adopted in the BCA Order, rather than adopt the Staff Report's proposed approach that would value E based on RECs. CORE also urges the Commission to clarify that on-site generators own the environmental attributes associated with their projects, including on-site renewable NEM projects. Further, CORE comments the on-site generators should retain title to RECs regardless of the receipt of the value of E, and that such values should be set based on proper analytical inputs without reference to RECs. Alternatively, CORE believes that on-site generators should be able to forego payment of E and receive fully tradable RECs.

With respect to CDG, CORE comments that the Commission should: 1) raise the 2MW cap to 5MW; 2) allow both the host commercial customer(s) and the subscribing mass market customers to retain their voluntary claims to the project's RECs; and, 3) not require the project developer to provide the interconnecting utility with competitive information regarding its subscribing customers and the allocation of project benefits. With respect

to billing, CORE recommends a strategy wherein credits from DER projects can be assigned to offset any related customer energy expense.

Next, CORE comments that the MTC should not be limited only to CDG projects because doing so inappropriately favors CDG at the expense on on-site projects. CORE proposes that he MTC should be made available to all commercial renewable projects.

Cow Power

Cow Power believes that ADG green power on dairy farms across the state should be valued to establish sustainability and incentivize the growth of on-farm ADGs throughout New York. Cow Power explains that electricity generated by ADG is cleaner and greener than energy produced by other renewable power sources because in addition to supplanting the negative attributes of fossil fuel generated electricity, anaerobic digestion directly improves air and water quality by treating manure storages. Cow Power points out that diverting inedible food waste to ADGs is an additional opportunity for the State to provide a rational and beneficial diversion of organic material from landfills.

Cow Power advises that an ADG capital investment must offer a predictable, amortizable rate of return in order to pass the long-run profitability and return on investment perspectives. Cow Power states existing ADG operators have significant, justifiable concerns regarding how the market for their energy will evolve and if reasonable long-term recompense will be earned for their investments of capital, labor, maintenance and operational costs, and opportunity costs. Cow Power cautions the current net metering program's valuation model does not provide a fair or sustainable valuation level. Cow Power explains on-farm ADGs have evolved to become significant base load power producers, which net substantial

amounts of energy to the grid. However, Cow Power elaborates, their demand based commercial service class relegates the value of the exported energy to the utility's avoided cost of generation rate, which is further reduced by non-representative demand charges. Cow Power argues that a farm's monthly demand charge is determined when the engine-generator set is briefly shut down for maintenance, which results in a disproportionately high demand charges. Additionally, Cow Power says that farms conduct scheduled engine-generator set maintenance when the overall utility demand is not being realized, resulting in farms with ADGs being over charged for demand in two ways. As a result, Cow Power advises that some generator sets are being taken out of operation because the major overhaul expense cannot be justified based on the net metering price of exported electricity.

Cow Power suggests using a value of E that reflects the actual value of ADGs would incent dairy farms with ADGs to increase biogas production, associated electric generation, and combined CO_2 equivalent reductions. Cow Power strongly disagrees with adopting different DER compensation policies for existing ADG operations and future operations, and cautions that future investment in ADGs by dairy farmers or outside investors should not be expected if visionary ADG pioneers are not compensated appropriately.

Cow Power recommends that the E component of the value stack include a value for the carbon equivalents destroyed as a function of electricity generation, and that other non-energy benefits be included in future proceedings. Furthermore, Cow Power includes an accurate way to value CO_2 equivalents destroyed through the process of generating power as Appendix B, and requests the value stack reflect this significant element of E as an adder at $0.082 per kWh.

Cow Power submits that an MTC that closes the gap between the value stack and the retail market rate is appropriate for large on-site projects, which will receive a comparable price for energy valued under the value stack as they currently receive through NEM. Cow Power believes that a floating, market oriented pricing system is the best approach because project developers would have the benefit of increasing values of environmental benefits. Cow Power asserts the SCC is a more appropriate value of E for ADG technology than the REC value, as it would compensate technologies for their full impact on GHG reduction. However, Cow Power states a policy change that will allow legacy ADG RECs to be utilized in the E value stack. Cow Power claims that the benefit ADGs and other base load producers bring to the grid can and should be recognized within the calculation of the demand reduction value. Cow Power emphasizes that RNM should continue to be values at the retail consumer rate, and DERs should have the option of remaining under RNM or opting into the value stack. Cow Power states that depending on the DER, E, and time values, ADGs can be modified to provide dispatchable electricity, and ADG exports should have the option to be valued in a time of use system.

Cow Power concludes that ADG technology is unique, and it may be appropriate for the Commission to explore a separate rate class for ADG.

CRS

CRS strongly encourages the Commission to clearly differentiate between the CES voluntary market and the CES compliance market. CRS states that no portion of the value of the REC should be decoupled from contractual REC ownership. To avoid double-counting, CRS advises that if the tariff compensation transfers the environmental and other generation attributes to the LSE, the REC should also be transferred to the

LSE. Furthermore, CRS recommends that RECs be transferred to the state of the LSE when the state or LSE intends to use the renewable energy towards compliance with the CES.

CRS cautions against automatically counting renewable energy generation from DER towards CES compliance, by not requiring that LSE's own the RECs from this generation. CRS points out that a policy that automatically counts DER generation towards the CES erodes the benefits of DER to the on-site customer, is likely to reduce future investments in DER, and implicitly allows double counting of attributes.

CRS asserts that customers should be presented with clear choices regarding selling or transferring RECs, and fair compensation for the environmental attributes when the LSE receives the RECs. CRS continues that nothing precludes DER customers from selling RECs out-of-state for a voluntary purchase or for usage towards another state's compliance market. To avoid this double count, CRS recommends two choices for DER customers in the tariff: either allow the customer to provide regulatory surplus by the customer keeping the REC, or by the customers receiving appropriate compensation from the LSE; or, CRS suggests the DER customer should retain unequivocal ownership rights.

Digital

Digital requests that the full value of CHP be recognized and included at the earliest opportunity. Digital asserts that the Staff Report metering requirements are inadequate for providing high quality data about the performance of DERs. Digital argues that the meter costs should be recovered through the tariff and all DERs should be required to install these meters. Digital believes an exemption to the metering requirements may be appropriate for smaller nameplate capacity generation.

DSUN

DSUN comments address potential disruptors to the CDG market including RNM grandfathering, compensation terms, MTC compensation to projects with 100% retail subscriber base, and the variability in value stack component credits.

DSUN recommends extending the time RNM requirements have to make 25% Advance Payment from 90 business days to 150 business days following a Commission Order on VDER. Distributed Sun cautions that combining grandfathered RNM projects (Tranche Zero) and Tranche One into one Tranche sets an inordinately low capacity for projects. According to DSUN, the capacity limit on RNM is not based on cost recovery, but on Staff fears that grandfathering RNM would effectively prevent applying Phase One methodology in some or all utility service areas. DSUN claims that changing from NEM to the Phase One methodology will result in halting many projects and stranding significant developer investments in the state. DSUN suggests not counting Tranche Zero projects against the Tranche One capacity limit and only limiting RNM grandfathering by the 25% payment date within the Commission-established timeframe.

DSUN disagrees with migrating the compensation methodology from a consumer-focused tariff to a generation-focused tariff within such a short timeframe. DSUN claims that the precise value of energy and capacity in Phase One compensation presents significant challenges in projecting long-term revenues for a project. DSUN suggests that varying the MTC to mitigate the financial impact of changes in NEM compensation could provide greater certainty for Tranche One projects during the market transition. DSUN recommends the Commission set a floor price for the value of energy and the value of capacity equal to current rates when each project commits 25% advance interconnection payment.

DSUN advocates for extending NEM and Phase One projects' compensation term to 20 years. DSUN notes that other than the 25 year crediting methodology for NEM projects under the monetary crediting methodology, NEM-based projects in New York have not been subject to a term limit. DSUN advises that neighboring states do not impose do not impose term expiration limits for net-metering, and provide higher incentives and higher utility rates. DSUN cautions that limiting the net-metering term to 20 years while changing revenue streams on projects that have commenced development, would be unfair and cause huge uncertainties in the term of the revenue. DSUN requests the Commission clearly articulate a compensation methodology after the expiration of the compensation term.

DSUN concludes by advising that 100% MTC credit should be available to projects that certify a 100% residential subscriber mix. Distributed Sun believes this would provide a stronger business case to support including Low and Moderate-Income subscribers.

EDA

On behalf of 18 member organizations of EDA and 80 signatory allies, including elected officials, policy experts, small businesses, community-based organizations, and grassroots organizations, EDA submits concerns that Staff's proposal is likely to slow the development of much needed shared renewable energy, while creating anxiety and uncertainty in areas of renewable energy development not included in the initial transition. EDA respectfully insists that the transition away from NEM toward a VDER tariff include all the benefits and costs of renewables, not only those valued by utilities.

EDA advises that the Staff proposal is too complex given how little will change within the next two years in terms of real value paid to solar developers and solar customers. EDA

suggests that in light of the Community Solar NY Program, the Commission should avoid making it harder for people to be confident investing in solar, and simplify the policy so that there are only a few rules that can be quickly explained. EDA states that one important way to simplify would be to eliminate the 20-year timeframe proposed for the duration of a project's tariff, because providing compensation for only 20 years will leave a customer wondering what will happen for the remainder of the life of their system. EDA claims that four important benefits would be gained by allowing projects to choose between net metering and the Phase One tariff until the Phase Two tariff is developed, or for two years, whichever is greater. EDA advises that this would have a similar effect as the MTC Staff proposed, but is much simpler, would be in effect for a longer period of time, and would apply equally across utility regions. Furthermore, EDA recommends extending the option of net metering into Phase Two.

EDA maintains that the tranches combined with the flawed value stack Staff proposed would limit the new capacity of distributed energy that can be developed economically. EDA states that the predictability of renewable energy costs can make financing renewable energy projects easier, but that stability cannot be attained if the compensation mechanism for the value of solar is volatile. EDA recommends fixing the VDER tariff for the life of the system, like the Value of Solar in effect in Minnesota.

EDA believes VDER should result in improved solar access for all communities, and cautions against costly rules that favor large developers. EDA advises the Staff Report's Value Stack does not include all benefits of DERs, but excludes those benefits that most directly and immediately benefit communities. EDA states in both the BCA and Staff Report, those quantifiable benefits are left for the future. EDA recommends

VDER contain additional values for: reduced particulate air pollution, other contaminants, and toxins; reduced water use; EJ benefits; reduced energy burden for low-income people; local job creation; increased resiliency; and, ensuring geographical equity. EAD concludes by claiming that the Staff Report recommendations would throttle the transition to a decentralized energy system by placing caps on the number of shared renewable energy projects that could be economically viable any given time.

EDF/Policy Integrity

EDF/Policy Integrity appreciates the Staff Report and efforts to realize the REV vision by requiring DERs to be compensated for the full value they contribute to the grid. EDF/Policy Integrity advises that accurate compensation requires unbundled price signals that can value generation and transmission, distribution, ancillary services, as well as environmental benefits, separately, and that are granular with respect to time and location. EDF/Policy Integrity suggests the Commission lay out a clear roadmap to including environmental benefits not reflected in the current methodology, including air pollutants other than carbon and potential environmental value streams of energy storage. Furthermore, EDF/Policy Integrity advises that these environmental attribute valuations should be consistent across all Commission orders and technologies.

EDF/Policy Integrity cautions that the NYISO cost allocation for capacity and charges for ancillary services to LSEs is not aligned with cost causation, and is a hindrance to efficient DER compensation. EDF/Policy Integrity states that discussions with DER companies, the utilities, and the NYISO are needed to address issues that arise due to market design. EDF/Policy Integrity advises that the Phase One methodology

should establish a valuation and compensation foundation that can evolve as new knowledge and capabilities evolve.

EDF/Policy Integrity points out that using REC prices to value the environmental attributes of energy storage systems based on net exports is insufficient to estimate the full environmental value of currently eligible energy storage systems. EDF/Policy Integrity continues that the proposed methodology focuses only on net exports of energy storage that is paired with a clean generator, which cannot be used to accurately compensate energy storage systems for the environmental value they bring when they shift load from dirty to less dirty generation on the bulk system.

EDF/Policy Integrity supports Staff's proposal to move from volumetric crediting to monetary crediting based on locational and temporal values, and states that monetary crediting is necessary to reflect the dynamic nature of the values created by DER. EDF/Policy Integrity advises Staff's suggestion to keep NEM for small onsite DER that enters service before Jan. 1, 2020, is a simple solution. EDF/Policy Integrity also recommends using a MW trigger that would prompt new analysis and Commission consideration of appropriate action to avoid potential negative consequences if DER penetration accelerates. In contrast, EDF/Policy Integrity advises that for distributed generation that is not co-located with load, the more time- and location-granular approach away from traditional net metering should occur more quickly. EDF/Policy Integrity explains that any locational benefit associated with these systems cannot be expected to offset any system needs created by the customer's usage, which undermines a key rationale for treating NEM as a reasonable first-order estimate of the value of DER that are co-located with load. EDF/Policy Integrity believes that Staff's proposal to subject CDG and RNM to the Phase One methodology from the outset makes sense, and submits

that large scale onsite projects are also worth the investment in advanced metering and should therefore also be put on the Phase One methodology.

EDF/Policy Integrity strongly supports Staff's recommendation to use a bottom up value stack approach for the Phase One methodology. EDF/Policy Integrity also supports Staff's suggestion of using LBMP as the energy value.

EDF/Policy Integrity agrees that using the proposed installed capacity value approach is reasonable because it is consistent with NYISO's current approach for allocating the cost of installed capacity to the various utilities. EDF/Policy Integrity notes that the second of Staff's two proposed crediting alternatives for intermittent technologies is better aligned with underlying system costs and would encourage efficient project siting and avoid future costly capacity investments. EDF/Policy Integrity encourages the Commission to adopt Staff's second approach. Additionally, EDF/Policy Integrity recommends that if Staff's discussions with the NYISO result in an ICAP cost allocation approach that is more aligned with cost causation, the crediting approach for ICAP under the Phase One methodology should be updated.

EDF/Policy Integrity agrees with Staff that the SCC should be the floor price of the E component, but recommends that environmental attributes of reduced SO_2 and NO_x emissions should be added to the value stack. EDF/Policy Integrity recognizes that using the Tier One REC price is practical, but highlights that the REC prices could be substantially different from the actual damage costs of carbon emissions depending on the market outcomes. Moreover, EDF/Policy Integrity points out, using a REC price to distinguish between the environmental value of generation from emitting vs. non-emitting DERs will be unhelpful. Therefore, EDF/Policy Integrity encourages the

Commission to adopt a methodological framework that can be used for all resources consistently.

EDF/Policy Integrity supports developing a demand reduction value and locational system relief value. However, EDF/Policy Integrity stresses the importance of making the value of D and the associated credits as granular as possible with respect to both time and location.

EDF/Policy Integrity emphasizes that implicitly incorporating the D value of CDG projects in the MTC as Staff suggests does not provide sufficient incentives for locating and designing projects to provide high value to the distribution system. EDF/Policy Integrity proposes making part of the MTC conditional on project performance during some number of the highest usage hours in a particular distribution network or circuit. Alternatively, EDF/Policy Integrity suggests making a higher Demand Reduction value part of the criteria for qualifying for higher value tranches of the MTC. EDF/Policy Integrity supports Staff's suggestion that the utilities should offer fee-based portfolio service for intermittent renewables to provide compensation stability and reduce risk, but maintains that fees charged for such a service must be just and reasonable and have regulatory oversight.

EDF/Policy Integrity notes that LIM issues were not brought up during collaborative discussions or mentioned in Staff's Report. EDF/Policy Integrity advises that LMI participation in CDG is important but poses challenges, and recommends additional incentives for developers that enroll LMI customers as part of CDG projects. EDF/Policy Integrity describes one approach as a greater MTC for CDG projects that have a significant share of LMI subscribers.

EDF/Policy Integrity concludes by agreeing that gradualism is important, but cautions that if an MTC is also designed capture some of the values currently un-monetized in

the value stack, using the full value of the revenue impact of an MTC as a limiting mechanism may be inefficiently restrictive.

GRID

GRID requests that benefits to LMI communities be included in the valuation of solar for CDG. GRID advises that a predictable, long-term CDG rate is essential to LMI participation, and requests Staff integrate a LMI valuation of solar into the calculation some way so that the LMI customer base is prioritized. GRID claims that New York is a difficult market low-income solar because the state has lower differential incentives for low-income solar than other markets. GRID advocates for preserving full retail NEM credit for CDG projects that can demonstrate meaningful savings for LMI participants; alternatively, GRID promotes ensuring an adder, external incentive, or other market signal to deliver meaningful savings through low-income CDG.

JU

The JU express support for the expansion of customer choice and the growth of DER, but recognize that not all DERs provide the same benefits and comments that it is essential to develop a policy that will set the stage for future economically-efficient development of DER, and to be able to differentiate the value of differing DER characteristics. Along those lines, the JU offers strung support for the reforming and or replacement of NEM.

The JU support the Staff Report's goals of limiting annual bill impacts to 2%, compensating DER based on the benefits it provides, and providing a fair and appropriate transition to more sustainable compensation levels using a modified tranche structure. On the other hand, the JU opposes the assumptions in the Staff Report that would result in levels

of DER growth that cannot be sustained within a two percent customer bill impact, but instead would result in annual total bill increases of up to 25% in some utility service territories. The JU also notes that the Staff Report would improperly provide compensation to all projects, irrespective of whether the project attributes are valuable to deferring generation or distribution system investments and, would in some cases, lock in these DER payments at levels greater than the current NEM construct for 20 years, thereby shifting significant risks and costs to electric customers for decades to come. The JU believe that the customer Staff Report likely understated the customer bill impacts to be expected and cites a number of inaccuracies and mistaken assumptions in the Staff report, to which the JU provides corrections. The JU propose that existing data be updated with more accurate information to create a transition formula that will better approximate and limit incremental customer bill increases.

With respect to the 2% cap on customer bills, the JU proposes that the Commission also establish a more robust circuit breaker mechanism that monitors actual bill increases on a quarterly basis and will initiate immediate and predetermined actions (instead of mere Commission review) if that cap is projected to be reached. The JU comment that this approach would provide both visibility and certainty to the market, allowing developers foresight into the growth of the market and allowing them to plan their businesses accordingly. Additionally, the JU recommend that the grandfathering period for new and existing mass market residential and small commercial DER be shortened from the 20 years proposed in the Staff Report to 15 years in order to reduce costs and long-term risks to all customers and provide for a more effective transition to a more granular Phase Two valuation methodology.

With respect to wholesale ICAP payments and value, The JU propose using an actual ICAP valuation that will encourage peak demand reduction as opposed to the Staff Reports proposed volumetric usage-based ICAP credit that will reward projects that can reduce peak demand, and will increase customer bills without any commensurate benefit. The JU also propose that energy and ICAP payments should be recovered on the supply side of the bill instead of being included as part of the energy delivery charge.

With respect to the value of DER to the distribution system, the JU suggests that instead of using NYISO wholesale system peak coincidence as an estimate for distribution coincidence, location-based compensation should be utilized. The JU propose that both positive and negative LSRVs be developed based on the identification of high-value locations, which would be an additional value or a reduction in value on top of the MTC compensation for all projects based on the location of the project and the corresponding distribution benefit detailed within each utility's MCOS study.

Next, the JU notes that the Staff Report assumes that DER distribution value will result in near-term avoided costs for utility customers. However, the JU comments that due to the long lead time required to plan and install distribution infrastructure, these benefits will phase in over time, leading to a reduction in the near-term avoided costs and therefore to larger near-term bill increases without commensurate benefits. The JU also suggest using the same values for energy and capacity in both the retail rate and the value stack calculations to avoid understating or overstating of actual energy and capacity market prices, which may result from using the snapshot of current retail rates which includes utility hedges.

Turning to the tranche structure, the JU proposes that DER compensation levels be stepped-down in even increments over five tranches instead of three. Additionally, the JU propose to allocate the budget dollars evenly across all tranches, rather than concentrating 60 percent of the budget in the most expensive tranche, so that more resources can be built for the same customer dollars. The JU also suggest establishing an upper limit on the total MW of CDG that can be installed under Phase One in order to recognize operational limits and allow room for industry development following the conclusion of Phase One.

The JU recommend avoiding increasing compensation above current NEM rates unless the DER's value to the electric system warrants such compensation. The JU comment that the compensation level provided for in the Staff Report is not necessary to achieve the State's policy goals of bringing more CDG to New York, and will lead to fewer clean energy resources being built for the same customer dollars. Additionally, the JU notes that, in addition to overcompensating CDG, the Staff Report increases compensation over current levels by assuming that 80% of subscribers are residential, and therefore eligible for the MTC, when it is more likely that only 60% of subscribers would be residential customers. The JU also propose to include a reasonable limit on CDG development in any utility's service territory to account for operational limits that will be reached with high penetration of solar resources. The JU recommends limiting the total incremental distributed solar load in a utility's service territory to 5% of peak load. According to the JU, such a limit would allow the DSP to develop and provide price signals to competing technologies (such as demand response, energy storage, and other forms of clean generation) that may provide similar or identical beneficial attributes. The JU support the recommendation to require projects to have

paid 25% of the interconnection costs determined by the utility, or to have signed an interconnection agreement in the event that no such costs exist, within 90 days of the Order to receive Tranche Zero designation.

Turning to the MTC, the JU proposes that the period over which the MTC is paid should be shortened to 10 years, with a proxy for distribution benefits set for 5 years, to limit the long-term shifting of risk from developers to customers. The JU also recommends that a portion of the MTC be performance-based to encourage DER to align their output with electric distribution system needs. Doing so, the JU comment, would create a price signal for DER and could be achieved by using Staff's concept of weighting actual production at the time of the 10 highest distribution load hours.

Finally, with respect to cost recovery, the JU comments that several key questions remain unanswered, the answers to which will have a significant effect on the actual bill increases that any given customer class experiences. As an example, the JU comment that allocating energy and capacity payments to DER only to those customers within the service class of the DER customer may result in undue impacts to residential and small business customers, when the benefits from that energy and capacity may actually benefit all customers.

The JU also note that the Staff Report will lead to new implementation costs, including improved metering to implement hourly energy payments and billing system modifications, which will need to be carefully considered so that costs are properly assigned to those benefited by them. In addition, the JU points out several mechanical issues with collection of costs as accounting and cost allocation practices vary among Utilities and will require further focus as the quantity of these resources grows on the system. The JU propose that the monetary credits should be allocated on a percentage

basis, based on the MWhs generated by the project each month in order to provide transparency for the CDG subscriber and provide a link to any future service class cost allocations and allow potential CDG subscribers to compare prices between competing CDG projects and provide a better comparison to their existing utility bill.

MI

MI comments that the Staff report seems to have a conflict between a desire to accurately price DERs and promoting DER penetration. MI recommends that it is of the upmost importance that valuation of pricing of DER be accurate and precise. MI supports the cost-effective development of DERs and cautions that overvaluing DERs can lead to uneconomic choices, misallocated resources, and higher customer rates. MI advocates that DERs be facilitated, and barriers be addressed, but that the Commission refrain from utilizing the valuation process as a means to subsidize DER developers and/or owners at customer expense.

MI proposes that, as a way to address the barrier that mass market delivery rates are not sufficiently granular to facilitate DER investment, the focus should be on implementing accurate delivery rates and DER values, and not on the subsidization of DER developers and/or owners to overcome this barrier. MI also comments that the Staff Report focuses on the benefits of DERs, but does not explore the costs associated with increased DER penetration, such as increasing demand on certain ancillary services. With respect to timing, MI disagrees with the proposal to begin Phase Two immediately after the development of Phase One methodology and suggests waiting so that all parties, can benefit from Commission guidance in resolving issues pertaining to the interim methodology prior to beginning work on a longer-term valuation methodology.

With respect to energy storage, MI comments that: 1) energy storage should be evaluated on its own merits and the value that it provides should be calculated accurately and applied where utilized; 2) the addition of energy storage, in and of itself, should not warrant disparate treatment among otherwise comparable DER projects; and, 3) energy storage provides another example of the need for an accurate pricing methodology for DERs.

Next, MI opposes that recommendation that projects entitled to receive NEM may elect to opt-in for compensation under the Phase One methodology. MI argues that allowing project to elect to switch is a "lose-lose" proposition for non-participating customers because it will allow a project to elect to utilize which ever valuation methodology is more lucrative, instead of keeping the project on NEM; the methodology that the project had a reasonable expectation that they would continue to receive.

With respect to cost allocation, MI urges that cost allocation be determined in accordance with cost causation principles and recognizes that the Staff Report generally appears to be consistent with this approach, but that additional clarity is needed. MI supports the recommendation that compensation for energy and capacity values be recovered from the same customers that benefit from reduced utility purchases of energy and capacity so long as this principle means that when DER project reduces the amount of capacity that a utility is obligated to procure, the beneficiaries of such reduction are the utility's commodity customers and not large, nonresidential retail access customers who have their capacity obligations set based on their peak loads, or capacity tags, and do not benefit similarly. MI also concurs, strongly, with the recommendation that compensation for environmental values be recovered from the same customers that benefit from reduced utility purchases of

Tier One RECs because if compensation for environmental values were recovered from all customers, retail access customers would be double-charged; once for DER compensation to reduce utility REC obligations and a second time to cover their own ESCO's REC obligations. MI also strongly concurs with the recommendation that:

For demand reduction and locational system relief values, utilities should identify what portion of the value results from avoided lower voltage level costs and what portion results from higher voltage level costs. The portion of compensation reflecting avoided lower voltage level costs will be recovered from all lower voltage level delivery customers. The portion of compensation reflecting avoided higher voltage level costs will be recovered from all delivery customers.

MI agrees that the recommendation that MTC compensation be recovered from the service class of the project subscribers for CDG, with the total MTC for a project divided between service classes based on the percentage of the project serving subscribers from each class, is consistent with cost causation principles. However, MI opposes the use of a MTC because it believes that the MTC represents an economic subsidy in excess of the actual and calculated value provided by DERs.

With respect to revenue impacts, MI expresses concern with respect to the recommendation that a 2% upper bound be placed on the revenue impacts for all projects interconnected after the date of the Phase One Order. MI comments that: 1) this 2% figure appears to apply to annual revenues, while MI proposes that utility delivery revenues would be more appropriate in this context; 2) limiting application to projects interconnected after the date of the Phase One Order ignores the impacts of NEM projects implemented prior to that date; 3) it is not clear whether the 2% figure was deemed "reasonable" in vacuum, or in the context of the myriad of other Commission-

approved initiatives that are placing upward pressure on rates and prices; and, 4) the 2% figure appears to have little practical meaning because hitting that threshold apparently would not result in the cessation of additional customer impacts or even a meaningful reduction in prospective compensation.

MI also expresses concern with the recommendation that new DER projects retain the compensation methodology in effect at the time they are put into service for 20 years after their in-service date. Such a term, MI avows, will make customers responsible for excess payments for potentially 18 years if a more precise and accurate valuation methodology is developed and approved approximately two years after the Phase One order is issued, and results in less total compensation for some or all DER projects implemented under that order. On the other hand, MI comments that if a 20-year term is adopted, DERs should not also be afforded to opportunity to opt-in for compensation under the new tariffs or mechanisms developed in Phase Two.

Next, MI disagrees with the recommendation that the receipt of other incentives (including incentives offered by NYSERDA and federal and state tax incentives) not impact their eligibility for or compensation under NEM or the Phase One tariff. MI comment's that to do so would be wrongfully compensating those projects twice for the exact same attributes. MI recommends that DER projects already receiving RPS incentives or subsidies be declared ineligible for any environmental adder based on the SCC or Tier One REC price because such additional compensation would be duplicative.

MI opposes extending the availability of NEM based on the current compensation methodology to all mass market and small wind projects interconnected after the issuance of the Phase One Order and before January 1, 2020. MI contends that extending NEM to DER projects that have yet to be developed and

which may not be interconnected until 2019, carries the concept of grandfathering too far.

With respect to installed capacity value, MI opposes the recommendation that intermittent technologies will receive the per kWh compensation based on the capacity portion of the utility's full service market supply charges and claims that this approach makes no sense, is not based on a DER project's actual performance, and serves merely to subsidize DER developers and/or owners at the expense of customers. MI proposes that all DERs should be compensated for ICAP based on their actual performance, without customer-funded subsidies.

With respect to valuing environmental benefits, MI comments that the proposals on this issue serve primarily to subsidize DERs at the expense of customers and thus fail to accurately value DERs. MI offers that the Tier One REC price is reflective of economic subsidies, not environmental costs or benefits and, as such, should not be utilized in any DER valuation methodology that is striving for accuracy.

Next, MI comments that intermittent DERs should not be paid the Demand Reduction Value because they cannot respond to calls to reduce demand during system peak periods and, therefore, do not provide comparable benefits. MI reiterated that DERs should be compensated based on actual performance. MI also opposes the recommendation that Locational System Relief values be calculated and then fixed for ten years because this could subject customers to increased risks and costs, and may overcompensate DERs. Instead, MI proposes that such values should be adjusted annually based on utilities' actual costs. Furthermore, MI comments that DERs should not be afforded the option to select between Demand Reduction Value and MTC. According to MI doing so places excessive emphasis on DERs concerns and not enough on customer concerns and effectively

allows the DERs to choose the option that benefits it the most and thus maximizing customer payments and rate impacts.

MI also expresses concern with the recommendation that the Phase One Order not apply to any on-site mass market projects because the maturation of the segment and business models requires notice and a more gradual evolution to a new compensation methodology. MI comments that this assertion is not bolstered any explicit analysis or supporting facts and ignores the considerable notice provided previously regarding this proceeding. MI maintains that this exclusion for mass market DER projects benefits mass market customers only at the expense of other customer classes.

MI agrees with the recommendations that remote net metering projects, on-site large projects, and CDG projects placed into service after issuance of the Phase One Order and not eligible for continuation of NEM be subject to the Phase One Order valuation methodology, provided that the outcome of this proceeding is the development of a valuation methodology that truly is accurate and not one that unduly subsidizes this type of DER project at the expense of customers.

Finally, with respect to framing the analysis, MI recommends that the Commission focus on the total delivery rate impacts associated with its NEM-related policies, as well as with its future rulings herein because this would provide more useful information about the likely delivery rate impacts that have been borne by customers. MI also comments that the Commission should refrain from evaluating such customer rate impacts in a vacuum as there are numerous other initiatives already in effect that are placing upward pressure on delivery rates.

NECHPI

NECHPI supports the inclusion of micro CHP (less than 10 Kw) in Phase One of the proceedings, but comments that there is very little activity surrounding micro CHP in the market, and since CHP greater than 10 KW have been omitted from phase One, CHP is essentially ignored in these proceedings. Accordingly, NECHPI offers the following recommendations: 1) CHP greater than 10 KW should be allowed to opt-in for compensation under Phase One methodology; 2) the recommendations for cost allocation should be made applicable to CHP greater than 10 KW; 3) CHP Projects greater than 10 KW should be allowed to retain the compensation methodology in effect at the time they are put into service for20 years after their in-service date. After the period ends, the projects should still be compensated based on the tariff than in effect; 4) the compensation methodology should be determined at the time it pays 25% of the interconnection costs or at the time of execution of SIR contract, if no such payment is required; 5) the value and the compensation for the energy the eligible generation facilities inject into the system, and the reduction in the energy utility purchases because of the injection should take the form of actual day ahead NYISO hourly LBMP energy prices at the time of generation; 6) CHP technologies that opt in after installing storage, should be compensated each month with a lump sum equal to their MW performance during their peak hour in the previous year multiplied by the actual monthly generation capacity from NYISO's ICAP market; 7) separate method for determining the compensation for the demand reduction value that is created by CHP greater than 10 KW keeping in mind the unique characteristics of a CHP system. Alternately, the methodology that is currently proposed for intermittent technologies and dispatch able technologies should be extended to CHP systems greater than 10 KW; 8) in order to recognize locational system

relief values, a dollar per Kw-year compensation should be identified for those areas to reflect higher value; 9) market transition credit should be made available to CHP projects greater than 10 KW and should be made available in tranches; 10) for calculating the MTC that must be made available in each tranch, no number representing the Demand Creation Value (DRV) should be included in the value stack for the purposes of this calculation as the purpose of MTC is to subsume the value DRV represents; and, 11) in those utility areas, where the tranches are zero or negative, there should be no tranches and instead, the previous tranches should be larger.

Additionally, NECHPI proposes that the capacity payment should not be linked to the single hour performance, when the weather is known only after the fact because doing so may create a disincentive toward storage and prevent the development of hybrid systems. Finally, NECHPI comments that there should be a time limit on carrying over credits month-to-month because to do otherwise would likely create likely a bias against large systems.

NFCRC

NFCRC advises that BTM technologies, like fuel cells, are an essential component of a truly distributed grid and should be fully and fairly valued in both the interim and long-term methodologies for valuing DER. NFCRC argues that the current order of events does not support the intention of an uninterrupted transition to a Phase One tariff. NFCRC expresses concern that fuel cells will be adversely affected in the critical time between the traditional incentives and the REV market signals, when projects that have already secured financing may be deterred.

NFCRC states there are several features of the Staff Report that do not provide adequate certainty and/or incentive

to promote non-solar technology development. NFCRC asserts that while the Staff Report is required to take into account existing legislation such as PSL §§66-j and 66-l, the Staff Report runs counter to a core REV tenant for neutrality and fuel and resource diversity.

NFCRC claims the year-to-year variability in MCOS creates uncertainty that will hinder project development and investment, since the demand reduction value compensation of on-site large projects would be derived from each utility's MCOS. NFCRC points out that contrary to technology neutrality, solar technologies such as CDG and mass market will be afforded revenue stream predictability in Phase One. NFCRC believes calculating the compensation for the ICAP value from dispatchable technologies using the NYISO ICAP spot price will expose investors to spot price volatility.

NFCRC seeks clarification on which "MW performance" will be used for the installed capacity value. NFCRC requests the Commission clarify that "MW performance" is in fact the installed capacity of the generating asset and not the net MW exported to the grid.

NFCRC reiterates the eligibility requirements and compensation rates for VDER should include BTM, as well as utility side resources. NFCRC continues that there is additional value delivered to the grid that is not addressed in the Staff Report. NFCRC illustrates that all of the values described in the BCA are met by BTM technologies, yet there will be no capacity signal or environmental signal in rates in the interim period. NFCRC explains that the lack of clarity regarding ownership of environmental attributes should be in the Phase One report to avoid a significant shortcoming and future inconsistency. NFCRC recommends Phase One mimic the recent policy movements of ISO-New England, PJM, and FERC and compensate generators for the full value of BTM resources.

NFCRC suggests a MTC for on-site large projects in lieu of the uncertain environmental attribute ownership approach. NFCRC says on-site large projects should have an irreversible opt-out option. Furthermore, NFCRC believes it is vital important that all project development receive an equal level of certainty, regardless of technology.

NFCRC claims there is inconsistency since the Commission originally included non-exported BTM generation as an eligible Tier One REC, but the Staff Report indicates there is not Tier One REC for separate sale. NFCRC explains that there has been inconsistent communication and cross-referencing between proceedings, resulting in unjustified exclusion of BTM DER. NFCRC believes that such an impactful decision requires a public record of decision, which is missing from the VDER docket and has not been decided if it is included or excluded in the CES proceeding. NFCRC states that because there is no detailed record of collaborative conferences and working groups, some of the outcomes were not included in the Staff Report. NFCRC also says that cross-referencing proceedings leads to unclear precedent.

NFCRC concludes that the content that remains to be developed on the valuation of DER far outweighs that which has been completed. NFCRC requests the Commission include specific Phase Two guidance in the Phase One Order.

NFG

NFG suggests that electric retail pricing must provide efficient value signals, as respects compensation earned by customers for the value that natural gas-fired DG, energy management, and other DER technologies provide. NFG advises that it is key that energy markets serving customers in western New York be structured to take advantage of the unprecedented and unique opportunity that NFG's close proximity to Marcellus

and Utica Shale production offers, perhaps exclusively to western New York. NFG urges the Commission to acknowledge the significant societal benefits of natural gas in New York, as a cleaner and more affordable fuel currently available to customers using propane, fuel oil, or diesel.

NFG points out that while the Staff Report cites technology neutrality, the recommended methodology is not technology neutral. NFG asserts that developing an exclusionary methodology that selects "winner" and "loser" DER technologies is not technology neutral, is inconsistent with the REV rate design principles in the Track 2 Order, and is inappropriate. NFG argues that Staff should have filed an extension request if additional time was necessary to complete a full analysis and put all DER technologies on a level playing field. NFG continues that the failure to install the capabilities of some DER types represents a lost opportunity, yet Staff has not contemplated or presented a compensation methodology to all New York ratepayers that may result from adopting Staff's incomplete compensation methodology.

NFG remains concerned about the recommended proposal to develop a Phase Two methodology in this proceeding. NFG claims that the current proposal would establish a two-year competitive advantage in the REV market, which would shut-out certain DER providers and market actors that can provide valuable benefits to the electric grid. NFG questions the value of perpetuating a two-year dialogue over content that has not been identified, across a timeline that does not exist. NFG urges the Commission to direct Staff to complete their analysis with input from the parties instead of adopting Staff's Phase Two proposal.

NFG notes that aside from limited eligible applications under PSL §§66-j and 66-l, natural gas is missing from Staff's list of technologies. NFG requests that the

Commission recognize natural gas a dispatchable DER technology that can provide valuable benefit to the electric grid, and allow natural gas DERs to receive the same compensation methodology as other dispatchable DER technologies identified by Staff. NFG claims that natural gas can backstop intermittent technologies, and the Commission should allow natural gas to backstop intermittent technologies in a non-discriminatory manner that is not different than energy storage.

NFG takes issue with Staff's assertion that applying the dispatchable compensation methodology to intermittent technologies that are not backstopped may present issues for project financing. NFG points out that Staff offers no analysis or support that a single DER compensation methodology would limit project financing, and states that project financing variability is actually because intermittent technologies are inferior resources compared to dispatchable technologies like natural gas. NFG advises that the Commission should reject the alternative compensation methodology for intermittent technologies that are not backstopped, and consider requiring natural gas or energy storage backstopping in order for intermittent technologies to receive compensation and ensure value is brought to the electric grid.

NFG claims Staff's Report does not include any outreach plans to make customers aware of their opportunities to opt-in to new compensation methodologies, and suggests that the Commission should require an outreach and education initiative for customers. NFG argues that Staff's recommendation to not pay credits to customers at any time will give customers a disincentive to generate more than their own usage, since they will never be able to be compensated. NFG proposes that customers be paid out credits in an administratively easy way such as annually, when they reach a certain dollar threshold, or upon customer request.

NFG asserts that the Commission should refrain from compensating the environmental benefits of renewable technologies because all DER technologies, including CHP generators using non-renewable fuels, should be treated equally. NFG goes on to point out that energy storage is not currently eligible for NEM, and is not eligible to produce credits in NYGATS. NFG also states that Staff's recommended plan is inconsistent with the benefits of natural gas stated by the Commission in a November 30, 2012, Order. Furthermore, NFG claims that the detrimental environmental impacts of manufacturing renewable technologies are undisclosed and not accounted for, and suggests DER technology manufacturers should be required to meet similar disclosure, disposal, and water treatment requirements that natural gas exploration companies must perform.

NFG suggests the Commission reject Staff's MTC proposal, until Staff's claims can be validated with numerical support and an appropriate compensation level can be calculated. NFG continues that rejecting the MTC will also eliminate the need for overly complicated tranches and the contentious and administratively burdensome issue of estimating the composition of community distributed generation projects.

NFG concludes by saying the Commission should reject the arbitrary cap on the developing REV market, which could be counterproductive to Commission policy objectives. Alternatively, NFG proposes to allow electric utilities to defer balances associated with compensation methodology revenue requirement impacts by either establishing a surcharge, or addressing deferred balances during rate proceedings.

Nucor

Nucor cautions that the cumulative weight of the REV suite of programs and mandates is particularly challenging in

economically strained Western and Central New York. Nucor asserts that as solar investments grow in size and significance, and DER scales increase, NEM produces an unacceptable cost shift of the utility's embedded revenue requirement to non-participating customers.

Nucor argues that the Phase One tariff proposal is not justified and would impose substantial additional costs and risks on New York consumers above what NEM now provides. Nucor points out two basic principles that are missing from the Staff Report: compensation should match DER performance; and, cost allocation and cost recovery should follow cost causation. Because NEM-based compensation is tied to bundled embedded cost-based rates, it does not in any way represent DER attributes and would only coincidentally approximate a DERs true value, Nucor claims.

Nucor criticizes the Staff Report muddling of considerations that produced several valuation method proposals that are thinly veiled compensation adders and unsupportable revenue stream guarantees. Nucor asserts this is apparent in the proposed generation capacity ICAP valuation method for intermittent resources, the Distribution Value element, and the proposed MTC for CDG installations. Furthermore, Nucor strongly maintains that estimating system or societal value of DERs is a distinct issue from the level of compensation and revenue guarantees that certain project developers need.

Regarding the Phase One MTC, Nucor opines that it largely negates efforts to develop a more precise value of DER since the compensation offered is simply a slight discount from NEM with the further complication of a long term fixed MTC. Nucor claims the Staff Report does not link CDG compensation to the value of DER, is not technology neutral, and favors CDG and solar PV development. Nucor argues that is imperative the Commission correct the imbalanced Staff Report that promotes CDG

above basic ratemaking and State policy considerations, and relies on key assumptions that lack basic factual support.

To better align the interim DER valuation and compensation in Phase One, Nucor proposes that the tariff not be technology specific by providing an alternative capacity payment to non-dispatchable intermittent resources, but assess value stack elements based on common criteria reflecting performance in providing system benefits consistent with NYISO requirements instead. In other words, Nucor proposes a technology forcing incentive for intermittent resources to pair with storage or otherwise improve their value as capacity resources. Nucor believes excluding DERs that may be more cost-effective or offer more reliable system benefits is a basic error. Additionally, Nucor asserts that neither value stack elements, nor the MTC should be fixed for long term periods. Nucor requests clarification regarding the specific cost allocation recommendations for reduced utility purchases of energy and capacity and environmental attributes. Furthermore, Nucor recommends a hard cap target of dollars or MWs applicable to all NEM and Phase One tariff projects.

Nucor characterizes an opt-in or other transition mechanism as a windfall to developers that unreasonably shifts normal developer business risk to captive ratepayers. Nucor argues it is premature to recommend all NEM and Phase One tariffs should be allowed a one-time opportunity to opt-in to a subsequent tariff, which should be addressed when subsequent DER tariffs are established. Regarding cost allocation, Nucor requests clarification that "the same customers" noted in the Staff Report recommendation to recover energy and capacity value compensation from the same customers that benefit from reduced utility purchases of energy and capacity refers to a utility's commodity sales customers. Nucor asserts that allocation of the cost of environmental values should remain with the customers

for whom a utility provides commodity service, not allocated to MHP or other delivery-only customers, if the Tier One REC acquisition runs with that bundled service.

Staff's proposal with respect to the net annual revenue impact limit raises multiple concerns for Nucor. Primarily, Nucor claims it will not halt excessive MTC-related cost shifts, and it does not limit mass market NEM-related cost shifts. Additionally, Nucor points out that pricing distortions caused by a fixed MTC could overwhelm the subsequent tranche discounts from the full NEM compensation if underlying energy prices increase as projected in the CES docket. Nucor recommends restructuring the proposed tranches, and suspending cost shifting elements of the proposed compensation method once the upper boundary of the Phase One tariff is met.

Regarding demand reduction value, Nucor argues it should only be offered to resources that provide a benefit sufficient for a utility to rely on when making system investment decisions, not simply a compensation adder that inflates the value stack.

NY-BEST

NY-BEST advocates that energy storage is a key enabling technology for the state to achieve REV, the State Energy Plan, and the CES goals. NY-BEST urges the Commission to adopt the Staff Report recommendation to allow storage paired with an eligible generating facility to participate in the Phase One program. NY-BEST also requests that the Commission work with the NYISO and distribution utilities to develop the most accurate market signals aligned with the peak cost hours in the tariff so that DERs have the information necessary to dispatch for maximum grid value.

NY-BEST encourages Staff and the Commission to work with NYSERDA to develop a solar plus storage intervention to

more fully capture the value provided by the combination solar and energy storage technologies. NY-BEST also supports the Staff Report recommendation that utilities should be required to develop unbundled tariffs that will increase granularity regarding the values and services, such as energy, capacity, ancillary services, and environmental impacts, currently embedded in average bundled rates.

NY-BEST requests the Commission consider amending the proposed Phase One tariff to include non-exporting, BTM storage immediately. NY-BEST claims that the system capacity value and local delivery value could be calculated and compensated with the Phase One tariff immediately, while the other values that storage can provide are further evaluated. NY-BEST advises that if the Commission does not change this in the Phase One tariff, then the Commission should address standalone storage as early as possible in 2017, and not wait to address this as part of the Phase Two tariff. NY-BEST states that in the absence of such action, private investment will continue to be held back from the state.

NY-BEST expresses concern with the Staff Report assumption that the retail rate is sufficient compensation for benefits related to energy and demand reductions BTM. NY-BEST explains that retail rates, whether volumetric or based on non-coincident peak demand, do not value reductions of energy consumption at system peak differently from reductions that take place when demand is low, despite the fact that reductions at peak can reduce costs. NY-BEST continues that clean generation that causes reductions in energy imports from the utility is of higher value than conventional generation that reduces imports from the utility in the same way. NY-BEST believes both of these concerns should be addressed as part of this proceeding.

NY-BEST concludes that their primary concern is that appropriate interim measures be put in place to ensure that New

York's grid is able to realize all of the benefits provided by storage.

NYC

NYC's comments offer several recommendations for improving the Phase One tariff as proposed in the Staff Report. First, NYC recommends that the proposed value stack be expanded to include additional value streams including avoided costs of local air pollution, land and water use impacts, and resiliency, and that locational adders should be adopted in Phase One to be applied to project compensation for projects serving customers in high-value public policy locations. NYC also advocates for increasing the value stack for high-value public policy locations, like NYC, where vulnerable customers (particularly low-income customers) have historically faced barriers to implementing renewable generation.

Next, NYC disagrees with the proposal to continue NEM for grandfathered on-site mass market projects while at the same time requiring CDG projects put into service after the issuance of the Phase One Order to receive compensation based on the Phase One tariff. NYC recommends treating load-modifying CDG projects equally to on-site mass-market projects and allow such projects to continue receiving NEM during Phase One.

NYC opposes the Staff Report's proposal to apply the MTC to 80% of generation from an eligible CDG project and believes that this 80% threshold will have a detrimental impact on CDG projects, particularly those comprised principally of residential and small commercial customers. Instead, NYC recommends that the MTC be applied based on a project's actual customer makeup, with the MTC applying to 100% of the generation allocated to residential and small commercial subscribers, and 50% of the generation allocated to large commercial and industrial subscribers.

With respect to RECs and other environmental attributes, NYC agrees with the proposal to allow customers compensated under the Phase One tariff to claim the attributes produced by NEM-eligible projects for the purpose of environmental and sustainability certifications. On the other hand, NYC opposes the restriction in the Staff Report that when a customer claims these attributes, the exported generation can be recognized as contributing to the state's overall CES goal but not the CES Tier One obligation, and NYC recommends that customer-retained attributes should be recognized as contributing to the CES Tier One obligation.

Next, NYC offers comments citing issues needing clarification with respect to cost recovery mechanisms in Phase One. NYC notes that the Staff Report appears to recommend that all Phase One costs should be recovered within utility service territories, but requests that the Commission confirm this point. NYC also requests clarification as to whether the Staff Report is referring to utility sales customers when it discusses recovering costs from the same customers that benefit from reduced utility purchases of energy and capacity and Tier One RECs. Additionally, NYC supports the proposal to determine the value of demand reduction and locational system relief by the portion of the value results from avoided lower voltage level costs and what portion results from avoided higher voltage level costs, but asks the Commission to clarify the threshold for lower and higher voltage. With respect to the Staff Report recommendation that MTC compensation be recovered from the service class of the project subscribers for CDG projects, NYC requests clarification as to whether it will be the utilities who track subscriber composition on a project by project basis.

With respect to the recommendation that projects entitled to continue receiving NEM have a one-time right to opt into the Phase One compensation, NYC requests clarification in

regard to whether the project will receive the compensation level available at either the time of opt-in, the project's in-service date, or some other date. Next, NYC opposes the proposed MW trigger that could result in mass-market projects transitioning to Phase One earlier than January 1, 2020 and recommends that the Commission reject this proposal. Finally, NYC that the Commission establish procedures to ensure the NYPA customers, like NYC, can participate in Phase One projects by the July 2017 implementation date, including addressing issues surrounding cost allocation.

NYLPI and NYC-EJA

NYLPI and NYC-EJA represent the REVitalize coalition, which includes PUSH Buffalo, UPROSE, and The Point. REVitalize submits their comments to highlight the concerns and interests of economically underserved and environmental justice (EJ) communities that may benefit from CDG. REVitalize cautions that the current VDER proposal will make CDG projects in LMI and EJ communities uneconomical to implement.

REVitalize advises that the VDER proposal should include additional value credits for social benefits, economic benefits, EJ siting, local workforce engagement, and use of local manufacturing base or materials. Additionally, REVitalize recommends an additional value credit if the project includes a community ownership component. REVitalize advises that the Social Cost of Carbon is not robust enough to capture additional benefits that should be valued. REVitalize suggests that the proposal primarily addresses the costs and benefits of distributed generation on how the grid functions, from the economic perspective of utility companies.

REVitalize claims that the current proposal discourages widespread renewable energy penetration by: establishing a Tranche system that caps the amount of energy

produced that can receive a higher valuation; and, by creating a VDER that is less than what a project would receive under the current net metering approach. REVitalize recommends revising or removing the Tranche system, and allowing LMI customers more time to pay interconnection costs than other projects. REVitalize proposes allowing a project to choose the net metering value, or opt-in to the VDER scheme, depending on what is more economically beneficial for the project. REVitalize favors phasing in VDER over a period time when it is voluntary and financial returns may be measured. REVitalize concludes by suggesting that the value rate determined at the time of project development should be locked in for the entire life of the project.

NYPA

NYPA supports the recommendation that compensation to DER projects should come from the same group of customers who benefit from the utility savings. Flowing from that recommendation, NYPA comments that Con Edison distribution system customers should be allocated costs when they benefit from NYPA-customer DER located within the Con Edison service territory because all Con Edison delivery customers will benefit from distribution and locational system relief provided by those DER projects. NYPA believes that that the granular approach proposed will allow Con Edison tariffs to unbundle the components of the value stack to ensure that Con Edison ratepayers only compensate NYPA customer projects for the services that ratepayers benefit from. NYPA comments that to deny NYPA customers compensation for the delivery of benefits to the distribution system, while providing those benefits to other Con Edison delivery customers would result in rates that unduly discriminate against NYPA customers with DER.

NYPA also recommends that the Commission should 1) explicitly recognize that the energy exported from a qualified renewable DER facility creates Tier One RECs for CES compliance or other purposes; and 2) empower customers to choose whether to be compensated for the environmental value of such exported energy or retain the associated REC for disposition as the customer sees fit. To do otherwise, NYPA avows, may reduce the incentive for certain customers to invest in DER, which could lead to a chilling effect on the DER market.

Finally, NYPA supports the recommendation that renewable generation consumed on-site be tracked in NYGATS, in order to allow certificates to be retired for the purpose of environmental and sustainability certifications. NYPA asks the Commission to that renewable generation consumed on-site will be tracked in NYGATS in a manner that allows customers to comply with environmental and sustainability certifications including, but not limited to, the U.S. Green Building Council's Leadership in Energy & Environmental Design criteria, and New York State Executive Order 88.

NYSEIA

NYSEIA supports the Solar Parties' comments and emphasizes the importance of gradualism and stability as the state shifts away from NEM. NYSEIA recommends increasing the program size to 4% net utility revenue impact for DER deployment, because the 2% cap will trigger an arbitrary and abrupt deceleration in development in specific utility territories. NYSEIA emphasizes that this is especially true in the on-site mass market segment, which may breach the control mechanism in some territories within months after a Commission Order.

NYSEIA advises that the MTC should apply in full to 100% of CDG project output, with a more gradual 5% step down in

Tranches Two and Three. NYSEIA believes the proposed 10% decreases from retail rate net metering for the MTC by Tranche results in a steep decrease in value rather than a gradual shift away from NEM.

NYSEIA cautions that under the proposal, C&I and RNM customers will not receive full and fair compensation, but they should be compensated for all grid values. NYSEIA recommends a proxy Demand Reduction Value be assigned to C&I and RNM projects to approximate the delivery value not accounted for.

NYSEIA supports compensation based on the capacity portion of the utility supply charge, not the proposed peak hour options in the Staff Report. NYSEIA states that capacity compensation based on a set of peak hours would not capture the full value of distributed energy resources to the grid.

NYSEIA encourages Staff to lengthen the duration of the applicable compensation methodology to 25 years for all NEM eligible, in-service, and in-development projects. NYSEIA requests a consistent metric for locking in tranche reservations and an easily accessed and regularly updated web interface tracking progress with the tranches.

NYSEIA concludes by requesting gradual and transparent implementation. NYSEIA claims that to date, little information has been provided on how Phase One will be billed and tracked.

OGS

OGS argues that every kW and KWh of eligible generation should be valued and compensated equally based on the locational and temporal value of the project to the grid, and without regard to how the project is interconnected or how the output is consumed. OGS claims that all DERs should be compensated equally and fully based only on that DERs value to the grid. OGS claims that under the proposal in the Staff Report, resources defined as belonging to the on-site large

projects and customers will be significantly undervalued and undercompensated, especially compared to CDG projects. OGS suggests that a BTM MHP project is used to offset existing load, and is essentially guaranteed to provide system relief.

OGS believes the LBMP for energy compensation correctly recognizes the value of exported energy. OGS takes issue with the fact that the value stack applies only to net exports from a DER hosts account on an hourly basis, so a large BTM MHP project is unlikely to see the same recognition of its ICAP value as a CDG project. Similarly, OGS points out that a CDG project and a BTM MHP project would have equal demand reduction value and locational system relief. However, OGS states that because the BTM MHP project would not export any generation, it would receive no compensation for its contribution. OGS suggests that the MTC is inappropriate because a large BTM MHP project provides as much value as, if not more than, an equivalent CDG project and they should be compensated equally.

Pace

In its comments, Pace offers general support for the proposal to create limited value stack, coupled with a Market Transition Credit elastically linked to the retail rate, which is offered through a series of tranches that limit the sum of all non-value compensation to a 2% bill impact. Further, Pace supports the recommended structure for tranches 0 and One. Next, Pace supports the proposed intention to unbundle the values and services currently embedded in average bundled rates, and believes this will be a valuable exercise that will complement the efforts undertaken in the VDER proceeding.

Pace criticizes the Staff Report in that in assessing the five distinct areas of DER value, the Staff Report borrows existing market values, or leaves the value undefined for future

development. While this may be appropriate in some cases, Pace comments that this does not represent a methodologically sound approach, particularly for environmental and locational value. Pace opposes several aspects of the proposed MTC tranche structure and does not believe a basis has been established for claiming ratepayer impact, and thus does not support the 2% cap on bill impacts proposed in the Staff Report.

Next, Pace comments that RECs attributable to DER should not be counted towards either Tier One of the CES or the state's overall baseline unless the producer of the REC affirmatively makes a sale into compliance markets. Pace further disagrees with the proposal to allow RECs attributable to power produced and consumed on-site and RECs related to net exported power to be recognized as contributing to the state's overall CES goal. Pace also opposes the restriction on receiving environmental value only for net monthly exports and believes that such a restriction will serve as a significant disincentive to customers installing storage.

Pace is also unsupportive of the proposal that capacity payments for dispatchable resources be linked to ex-post measured performance during their utility's highest demand hour of the previous year. Pace also disagrees with the recommendation that excess credits be carried over each billing cycle and not paid out at any time because doing so may create an incentive against larger DER systems that cannot net their total generation against the customer bill.

With respect to the proposal to apply the MTC to only 80% of the generation of eligible CDG projects, Pace recommends that those project be eligible to receive the DRV for the remaining 20%. Pace supports the structure by which mass market systems will receive NEM moving forward, as well as the notice requirements for utilities to alert market participants of their proximity of the cap, but encourages the Commission to provide

more guidance on the process by which mass market compensation will be determined after the caps have been reached.

Next Pace recommends that a process involving public participation be utilized to establish LSRV and urges the Commission to be specific in establishing a process by which utilities will identify LSRV. Pace also recommends measuring and accounting for wholesale price suppression in Phase Two. Finally, Pace offers that non-energy benefits identified in the Staff Report should be accounted for in the DER valuation methodology.

PULP

PULP offers comments opposing the proposal to continue NEM for projects until 2020 because NEM have been acknowledged to be imprecise and the Staff Report offers little justification for grandfathering projects in such a manor. Additionally, PULP comments that the Commission should not adopt delivery service rates that are imbued with pricing values that are primarily designed to support an unregulated and profit-making business model based on values that have neither been definitively demonstrated in the marketplace, nor have been placed in this record and supported by objective facts. Additionally, PULP asserts that there is a lack of evidence that the assumptions about any of the wholesale market and distribution or delivery related benefits cited in the Staff Report which would justify the subsidy provided. Further, PULP challenges the assertions that rooftop and community solar programs provide benefits to the distribution system associated with line losses and avoiding future distribution service investments, and states that such benefits rely on hypothetical avoided distribution service costs and have not been shown to actually avoid the essential services included in delivery rates.

PULP also comments that it is inappropriate to compare the approach to arriving at the NEM value stack to how efficiency programs are approved for cost recovery from ratepayers because the latter function is delivered by regulated entities or subject to the oversight of regulated entities and the former is performed by unregulated entities. PULP comments that the Staff Report does not include any information on the costs and bill impacts associated with the current net metering policy and further that, by nature, NEM shifts costs unpaid and unavoided essential distribution services from solar customers to non-participants, who are often lower-income customers.

Next PULP comments that the subsidies provided to DER programs by all ratepayers should not be based on a predetermined and hypothetical set of values assigned to DER, but instead, rates should reflect prudent costs incurred by utilities and rates for market based products and services like DER should be based on market-based pricing principles. Further, PULP rebuke's the Staff Report for failure to consider the least cost benefits of solar generation in its pricing methodology.

Finally, PULP comments that the Phase One Value Stack repeats the defects of the existing NEM policy in that it requires customers to pay unregulated entities for a hypothetical value subsidy in distribution rates. PULP states that the Staff Report does not identify this bill impact in terms of overall costs that might be imposed on residential ratepayers under either the current net metering policy or its proposed Phase One compensation methodology. PULP recommends that the Commission require utilities to undertake a fact-based analysis of the actual benefits any DER project might deliver to regulated ratepayers prior to justifying payments to such providers, and that such payments should be based on actual performance in achieving those benefits.

SolarCity

SolarCity generally supports the proposals set forth in the Staff Report, but cautions that market growth forecasts and total market size allocated to the on-site mass market segment may result in triggering the market control mechanism well in advance of the Jan. 1, 2020, date. SolarCity suggests Staff examine reforms that are needed within existing policies and programs, such as available time-of-use rates and demand response, which would remove barriers to energy storage adoption and unlock the value of storage to the grid and to customers.

SolarCity proposes that Staff outline an initial set of services and impose a July 1 deadline for utilities to develop proposals for virtual generation resource and fee-based portfolio. SolarCity continues that successful implementation of a smart energy home rate is crucial to develop a Phase II tariff.

SolarCity signals that the proposal to continue NEM treatment for existing projects for 20 years would give customers and investors confidence that their financial decisions based on existing policies may not be abruptly betrayed in the future.

SolarCity advises that stakeholders should have visibility into the utility methodology of what portion of the reduction of demand and locational relief value benefits are allocated to lower and higher voltage customers. SolarCity suggests the Commission give an opportunity to comment on these allocations of costs and benefits across service classes.

SolarCity generally supports a 2% cap on revenue avoided by participating customers, but proposes Staff and utilities develop utility-specific caps and revenue impact mitigation measures in individual utility rate cases.

SolarCity favors volumetric crediting of CDG customers as a simpler tool than monetary crediting. SolarCity expresses

concern in the utilities' ability to manage the bill complexity of Staff's proposal. SolarCity stresses the Commission and Staff should closely observe customer credits to verify correct calculations and allow for a streamlined customer complaint resource.

SolarCity submits that customers should be compensated for carried-over credits, and advises that the year-end compensation should be modeled on the NEM statute.

SolarCity agrees with Staff's proposal to not modify rebates or incentives within this proposal, but points out several designs within the NY-Sun Commercial MW Block Program that may be incompatible with Staff's Phase One tariff proposal. SolarCity advises resolution of this and other discrepancies.

SolarCity believes a limited continuation of the existing CDG policy in Tranche Zero is appropriate due to the extremity of the interconnection queue, but otherwise disagrees with retroactive policy making. SolarCity comments that the Commission should note the extremity of the situation and commit to limit any other retroactive policy changes.

Generally, SolarCity supports the value stack approach. SolarCity notes that mandatory hourly pricing (MHP) values as a proxy for energy value generated by a project is appropriate, and proposes that large onsite projects with storage be able to charge on MHP even if the customer is not on this pricing scheme. SolarCity cautions that the current proposal to credit customers for wholesale capacity and capture ICAP value offers aggregators and customers no visibility into when to operate to be in line with system peak. SolarCity advises requiring day ahead notification to customers and aggregators to maximize system value. SolarCity believes that more work is needed to quantify and value omitted externalities in the renewable energy attribute auction price. SolarCity disagrees with Staff's assertion that attributes generated by

energy used on-site must be retired, thus ineligible for compensation. SolarCity limits support for using a proxy value for demand reduction and locational system relief based on the Commercial System Relief Program only as an interim. SolarCity believes this method is not adequate to represent locational value, should consider 20 years instead of 10, and that there should be stakeholder input on utility-developed locational relief values.

SolarCity believes the Commission should allocate additional capacity to the residential segment and increase the 2% revenue requirement shift to give the industry a more gradual transition. SolarCity argues that PV projects with storage should be able to provide either on-site demand and load reduction or export for the VDER tariff, not be limited to one function. SolarCity labels Staff's proposal to provide MTC to 80% of export as inadequate, and suggests MTC should be allocated to 100% of export. SolarCity fully embraces developing virtual generation resource and fee-based portfolios in every IOU territory, and says they should model the existing Con Edison demonstration project.

SolarCity concludes by requesting the Commission its Petition filed October 21, 2016, at the same time as the order resulting from the Staff Report.

Solar Parties

Solar Parties support the recommendation to continue NEM for projects in service at the time of the Phase One Order. Solar Parties also agree with the proposal to allow NEM customers to opt in to the Phase one tariff, but further recommend that customers also have to opportunity to opt out in order to encourage customers to experiment with the new tariff.

Solar Parties do not support to proposed 2% cap on net annual revenue impacts and instead recommend a 4% cap. Solar

Parties aver that a 4% limit is more reasonable when proper cost allocation and recognition of the benefits delivered by solar systems is considered. Additionally, Solar Parties believe that 4% upper bound will allow the market to scale at an early stage in development, will ensure that residential customers who cannot participate in the onsite mass market have an opportunity to participate in the CDG market, and will better facilitate achieving the Governor's solar objectives and the state's clean energy goals.

With respect to the 20 year term for the Phase One tariff, Solar Parties disagree with placing a limit such as 20 years and instead recommend allowing projects to maintain net metering, or the subsequent VDER tariff as applicable, for the life of the project. Alternatively, Solar Parties recommend adopting, at the minimum, a 25 year term.

Solar Parties support the following recommendations in the Staff Report: 1) utilization of monetary crediting; 2) the hourly metering requirement; 3) carrying over credits on a monthly basis; 4) keeping projects on their current rate in the case of project transfer or subscriber turnover; 5) projects on NEM or the Phase One tariff remain eligible for NYSERDA incentives; 6) changes in underlying rates for DER customers; 7) treating behind the meter generation as load reduction, and to apply the Phase One Tariff to net injections only; 8) fixed locational value based on the MCOS and values put forward by the utilities; 9) maintaining NEM for projects in service until 2020; 10) launching an initiative reviewing smart inverter requirements; 11) considering time of use rates in Phase Two; 12) application of Phase One tariff to new CDG projects;

Solar Parties also support the recommendation regarding grandfathering, but note that this type of capacity-limited grandfathering is not an appropriate precedent for future policy transitions. Further, Solar Parties recommend

establishing increased transparency regarding project eligibility.

Solar Parties accept the recommended approach to use the actual day-ahead NYISO hourly LBMP energy price for the energy value, but believe that this should include all of the components of zonal LBMP, including energy, congestion, and losses. Solar Parties caution however that this approach also creates more uncertainty and complexity for developers, which ultimately makes financing more difficult and erodes the value proposition for customers.

With respect to the value of installed capacity, Solar Parties support the recommended approach to valuing capacity, and further request that Staff identify a rate class to be used as soon as possible, stating that SC1 should be used. Solar Parties also support the use the higher of the REC value based on the NYSERDA published price and fixed for a term consistent with grandfathering and tariff term length, or the social cost of carbon when determining the economic value.

Turning to the proposed DRV, Solar Parties oppose the recommendation as structurally flawed and based on incomplete information. Solar Parties comment that it would be very difficult to finance around the DRV, resulting in lost value from the overall stack, and that it is critical that a strong foundation be set for each component in the value stack, as the foundation established in Phase One will inform the later phases. Solar Parties propose adopting a proxy DRV based on the full territory-wide MCOS value, a greater number of hours, and a multiyear average for the interim tariff, and recommend leaving further development of the DRV to Phase Two.

Solar Parties support the recommendation concerning the MTC, but have concerns with respect to the proposals for its application. Solar Parties oppose the proposed step downs between tranches and recommend a 5% step down instead.

Additionally, Solar Parties recommend that CDG generation be paid 100% of the residential MTC for each tranche, rather than 80% proposed in the Staff Report. Solar Parties also propose that tranche sizes should be derived assuming that MTC compensation will be recovered from the residential class commensurate with the assumed residential subscription rate, as well as a number of adjustments for calculating the MTC. Next, Solar Parties comment that while the Staff Report proposes the MTC as a placeholder value, it does not recommend a similar placeholder for C&I/RNM projects. The Solar Parties urge the Commission to adopt a proxy DRV and LSRV values to account for the delivery value of DERs that has yet to be established through a more granular approach.

Solar Parties support the recommended approach to the MW trigger, but are concerned that it is based on an overly conservative projection of market growth. Finally, with respect to the net revenue impact estimated in the Staff Report, Solar Parties comments that the Staff Report's analysis does not represent revenue losses to the utility, because any difference between revenues and costs would be recovered through either a decoupling rider or an increase in base rates. Additionally, Solae Parties continues, the net revenue impact does not represent the shift in revenue recovery from CDG participants to non-participants, since it would be recovered from all ratepayers in proportion to each ratepayer's energy usage.

TASC

TASC supports the recommendation that all projects in service as of the date of the Phase One Order will continue to be compensated based on the applicable Net Energy Metering methodology. TASC also supports the recommendation to continue NEM for mass market customers. TASC supports the recommendation to continue mass market growth during Phase One, and proposes

that a MW trigger for Commission review of mass market activity be adopted, and that any trigger provide continuity with Commission timelines regarding the development of Phase Two.

With respect to time of use rates, TASC supports the recommendation to consider time of use rates under Phase Two, and welcomes Staff's recommendation regarding a review of smart inverter requirements. TASC supports the recommendations regarding storage in section 2.2 of the Report, but notes that the economics of storage are still challenging in many applications and thus supports the proposed "solar plus storage" incentive program to be developed by NYSERDA in 2016.

Finally, TASC supports the recommendation to treat instantaneous on-site consumption as load reduction. TASC comments that treating instantaneous on-site consumption of generation as load modification similar to energy efficiency, or other methods of instantaneous load reduction is the defining feature of the net metering construct and is key to customer adoption. Similarly, TASC supports the application of the Phase One Tariff to net injections only.

UIU

UIU proposes that it is equally important to formally recognize parallel proceedings regarding consumer protections that will affect DER providers as it is to move towards a more accurate DER valuation. UIU requests that the Commission formally acknowledge the ongoing proceeding to establish a set of UBP regulations for DER providers. UIU cautions that insufficient customer protections may enable inexperienced developers to inadvertently harm customers or attract bad actors, and advises that DER contracts extending for twenty years or more may compound the resulting customer harms.

As UIU proposed for ESCOs, UIU suggests the Commission establish a DER performance bond process to insure ratepayers'

investment in the DER market. UIU acknowledges that a performance bond may make it more difficult for some DERs to enter and remain in the market, but believes this consumer protection is prudent.

REPLY COMMENTS

Acadia and NRDC

Acadia and NRDC filed joint reply comments, whereby they oppose the comments of the JU as those comments offer several radical changes to Staff's proposal never before discussed in the collaborative. Acadia and NRDC comment that the JU analysis that is difficult to follow and impossible for other parties to comprehensively evaluate at this stage of the proceeding and that the JU projections appear on their face illogical. Acadia and NRDC urge the Commission not to rely on supplied by the JU, but instead to rely on the methodology in the Staff Report, which was shared in detail with the various collaborative participants and developed throughout the collaborative process.

AEEI

In response to the comments of the JU, the AEEI offers that the results of the JU calculations diverge significantly from those contained in the Staff Report. The AEEI cites three problems with the JU suggestion to base DER compensation on modeled output of solar during the last five years. First, solar production profiles do not represent other eligible DER technologies. Second, this method would hinge upon modeled output for a single sample year, as opposed to the more accurate Staff proposal which is based on actual, metered data during the prior year's peak. Third, the JU's proposed modeling suffers from an analytical problem because it relies on solar irradiance data collected from the wrong days. Thus, the AEEI supports the

Staff proposal to used technology-agnostic metered data rather than solar-only modeling results.

The AEEI also comments that the JU made an error in calculating the customer bill impacts; the JU did not properly interpret the results of their analysis and thus reached two conflicting conclusions. The AEEI also notes that both the Staff Report and the JU analysis calculated the revenue impacts assuming that all
DERs would be solar, producing output for this technology only, and that other technologies may have significantly better capacity factors in the top 10 load hours.

Next, the AEEI propose that utilities should increase the granularity of the MCOS studies to more accurately reflect distribution value, and that incremental LSRV may reflect either an increase or decrease in value. The MCOS studies, the AEEI continues, are critical to the quantification of distribution value and should be open to public review of data and methods.

The AEEI strongly disagrees with the JU calculation that shows community solar projects achieving an 80% profit margin and the implication that the Staff proposal would result in a windfall for developers. The AEEI cites two major flaws with the JU calculation; 1) they assumed a discount rate of only 2%, which is unrealistic and lower than the cost at which the U.S. Government can currently borrow; and 2) the analysis ignored many of the expenses that the CDG would incur, including customer acquisition costs and ongoing administrative costs.

The AEEI shares the concerns of other commenters that the Phase One Tariff will leave two critical values, capacity and environmental benefits, without compensation for energy that is produced and consumed behind the meter. With respect to achieving a more accurate compensation mechanism for storage, the AEEI supports the proposal by SolarCity to storage be allowed to charge using the Mandatory Hourly Pricing tariff,

providing a way for storage to participate in economically beneficial arbitrage.

With respect to the proposed treatment of environmental attributes, the AEEI shares the concerns expressed by other parties with the method proposed in the Staff report. The AEEI supports the proposed solution by Pace for clarifying the ownership of RECs, protecting against double counting, formulating reasonable and meaningful baselines, and ensuring that the critical concept of regulatory surplus is protected. The AEEI recommends that all generation from an eligible generator, regardless of whether it is consumed onsite or exported, should generate RECs if the customer forgoes environmental compensation.

With respect to distribution capacity, the AEEI opposes MI's suggestion that the Locational System Relief Value should vary annually like the Demand Reduction Value, instead of fixing the value over a 10-year period as failing to recognize a key distinction between these two distribution system values. AEEI instead supports the Staff proposal.

Next, the AEEI agrees with Pace that for any project that receives the MTC for any portion of its generation, the DRV should apply to the portion of the generation that does not receive the MTC. Additionally the AEEI supports the proposal that the calculations for translating the acceptable cost increases to customers into tranche sizes should be carried out by Staff and be open for public review and comment.

The AEEI recognizes the possible market distortions and unintended consequences within the Staff Report presented by CORE, including increasing the prevalence of CDG projects and leaving otherwise viable on-site DER opportunities undeveloped. Additionally the AEEI challenges MI's concern with allowing NEM customer the option to opt-in to the Phase One tariff and notes that a project is only likely to switch from NEM to the Phase

One tariff if there is a high LSRV available, meaning that the project would be fulfilling a specific grid need. Finally, the AEEI supports AEMA's recommendation that payments for dynamic load management programs should reflect the environmental benefits that demand response provides.

AEMA

In its reply comments, AEMA reiterates the list of issues that were deferred during Phase One discussions, but that it believes should be addressed immediately during the first quarter of 2017 in order to level the playing field as much as possible between technologies that were considered in Phase One and those that were not, resolving differences in compensation between technologies that provide similar grid services. With respect to Phase Two, AEMA urges to the Commission to avoid delay in deciding Phase Two issues and recommends that the Commission: 1) design tariffs that are standardized across technologies, applications, and services to provide the same compensation for similar services, no matter the method of delivery; 2) Allow for consumers to access multiple benefits streams of DER technologies, applications, and services; and, 3) Develop consistent and transparent planning and procurement processes so that all DER can participate competitively and on an equal playing field. Finally, with respect to the format of subsequent phases, AEMA recommends that the Commission: 1) encourage rich engagement with stakeholders during subsequent phases and build a foundation of credible analysis to model innovative solutions; and, 2) coordinate with the NYISO as it works through integration of DER into the wholesale market, to ensure that both entities are inclusive and consistent.

Bloom Energy

Bloom Energy supports the comments of other parties who propose to include energy consumed behind the meter in the Phase One value stack. Bloom Energy comments that excluding behind the meter projects is adverse to the foundational principles of REV and would have a serious chilling effect on the development of customer sited distributed generation.

Next Bloom Energy recommends including the values associated with criteria pollutant reductions like SO_2, and NO_x in the Phase One values stack instead of waiting until Phase two. Finally, Bloom Energy supports the comment of parties who recommend maintaining the eligibility of traditional incentive programs, like CES, for behind the meter resources.

CCR

In its reply comments, opposes the assertions made in other party comments with respect to the scale and cost of solar in New York, the Value of DER being less than retail rate, and the regressive nature of NEM. CCR challenges the JU's revenue impact analysis and the conclusion that customer impacts as high as 25% will result. CCR also challenges the assertions that solar developers are making excessive profits in an overly incentivized market, and that the assertion of 90% gross profit margins should be disregarded in its entirety. CCR also oppose the recommendations to shorten the grandfathering term for mass market NEM customers. CCR recommends retaining the proposal in the Staff Report and that the grandfathering term be no less than 20 years.

CCR further disagrees with the recommendation of MI to reduce the compensation period under the Phase One methodology, and instead supports the comments of several solar parties that the compensation period should be extended to 25 years. CCR also opposes the recommendation by MI to eliminate the option

for DER projects to opt-in to the new valuation methodologies both for projects eligible for NEM and those under the Phase One tariff.

With respect to the changes proposed by other parties to the components of the value stack, CCR comments that many are either inadequately supported or more appropriate to consider in the development of the Phase Two methodology. Specifically CCR recommends that; 1) losses should be included in the valuation of energy; 2) the capacity value should be derived from the SC1 supply rate for the Phase One tariff and then worked on gradually to more accurately reflect the contribution of solar; 3) there should be no assumption about the impact of DER on ancillary services at this time; 4) the calculation of the DRV should be modified to improve its accuracy and limit its volatility; and, 5) that the solar generation profiles should be standardized on a realistic set of real-world conditions for each service territory including the impact of near-field shading and snow.

Additionally, CCR urges the Commission to reject the recommendations for the elimination of a value stack credit for the environmental benefits of solar or the use only of the Social Cost of Carbon. CCR supports the Staff Report's proposal to use the higher of the REC value based on the NYSERDA annual published price for compliance or the social cost of carbon from the BCA Framework Order.

With respect to the comments concerning the MTC, CCR opposes, as inconsistent with the intent of current transition, the proposals to: 1) eliminate the MTC; 2) shorten the timeframe for the MTC; 3) increase the number of MTC tranches and/or create steeper step-downs from NEM between tranches; and, 4) allocate the MTC to only 60% of generation from CDG Facilities.

Finally, CCR supports the Staff Report's proposal that RECs for NEM and Phase One Tariff projects be retained and

automatically retired by the customer. CCR offers that these RECs should not count toward the Tier One obligations of the LSEs, but can still being tracked and recognized as contributing to the overall State CES goals.

CCSA

CCSA offers reply comments to those filed by the JU and UIU. First, CCSA asserts that the profit margins for CDG presented by the JU are based on a faulty and incomplete model that bears no relation to the reality of solar project development in New York. Along those lines, CCSA notes that the JU model; 1) improperly utilizes a 2% discount rate when calculating a CDG project's profit margin; 2) fails to accurately represent project costs; 3) does not reflect the reality that CDG project developers must provide a discount to customers from the value of the VDER credit; 4) does not account for the federal investment tax credit; 5) includes several errors in inputs, including double-counting the value of the NY-Sun incentive and using historical rather than current values for LBMP and ICAP in the value stack; and 6) omits entire categories of costs beyond financing.

Next, CCSA challenges the JU's use of raw total of interconnection applications in the queue, stating that it is not reflective of actual anticipated development. Additionally, CCSA comments that the JU analysis of the bill impacts of other policies adopted thus far is one-side in that it does not reflect any benefits of those policies. CCSA supports the comments by the Solar Parties with regards to the utilities' rate impact analyses. With respect to the comments filed by UIU, CCSA shares UIU's concerns with consumer protections and comments on the multiple industry initiatives that demonstrate those shared goals.

CORE

In its reply comments, CORE requests that the Commission ensure: 1) that the on-site renewable energy generators own the environmental attributes associated with their projects; and, 2) on-site and remote net metered renewable energy projects are compensated for the value of their generation on a nondiscriminatory basis with CDG and irrespective of whether the generation is consumed on site or exported to the grid. CORE echoes the concerns of other parties that Staff's proposal may unduly tilt the field in favor of CDG to the economic and competitive disadvantage of other DER. CORE urges the Commission to expressly affirm that on-site generators/customers have the right to register their renewable projects in NYGATS and own, retain, and trade the RECs associated with their projects' output.

DSUN

In its reply comments, DSUN challenges the JU's calculations which suggested that developers would be overcompensated, resulting in gross profit margins of 80%. DSUN instead calculates developer gross profit margins to be -14%. DSUN cite several flaws with the JU calculations, including: 1) erroneous sampling; 2) underestimating interconnection costs; 3) incorrect discount values for NPV calculations; 4) miscalculation of the value of incentives available under the NYSERDA MW Block program; 5) utilization of a calculation of gross profit margin inconsistent with industry norms; and, 6) the use Tranche One values to represent the revenue streams for investors while at the same time calling for a reduction in Tranche One sizing.

In order to address the challenges faced by developers by the proposed VDER compensation rates, DSUN recommends that the utilities be directed to help developers reduce costs by

ensuring interconnection fees for CDG projects average $0.03/$W_{DC}$, as indicated by their own model of developer costs, and by providing transparency in cost estimates, open cost book, a commitment to variability of no more than 10%, and post-COD comparison of actuals to estimated costing.

DSUN supports the comments of SEIA and Vote Solar, CCSA, Cypress Creek, and Pace suggesting a longer term for the Phase One Compensation stack. DSUN supports extending the Phase One Compensation stack to 25 years, with 25-year fixed terms for the MTC and the Value of "E". DSUN also recommends that the Commission clarify that volumetric NEM will not be limited to any specific term. DSUN also supports increasing the term for the compensation for projects grandfathered into NEM to 25 years.

DSUN supports applying 100% MTC credit to projects declared as 100% residential as a way to relieve the burden on residential imposed by projects with a low residential to commercial mix that receive an inordinately high level of MTC, and provide the foundation for inclusion of more low-to-moderate-income subscribers.

DSUN also supports the comments from SEIA, NYSEIA, CCSA, and Cypress Creek calling for a 5% step down in compensation between tranches rather than the 10% recommended in the Staff Report. Additionally, DSUN supports the comments from Borrego Solar on real-time updates to the tranche statuses.

JU

It its replies, the JU reiterates several of its initial comments, including the suggestion to replacing the 2% bill impact cap with an alternative approach that would consider limiting incremental CDG growth to a number of MWs corresponding to five percent of each utility's forecasted, weather-normalized 2015 peak load at the time of the NYISO peak. The JU oppose the

proposal in several comments to develop utility caps and cost recovery mechanisms in individual utility rate cases as such an approach could have the unintended effect of adding to market uncertainty and delaying the transition to a more value-based compensation mechanism for several years, as utilities may not have imminent rate case filings.

The JU agree with parties who support the Staff Report's inclusion of a wholesale energy and capacity values in the compensation structure. Additionally, the JU support comments favoring a performance-based capacity payment, and disagree with parties who advocate for a fixed capacity payment based on the SC1 residential capacity charge for CDG projects.

As stated in its initial comments, the JU supports modifying the methodology to compensate for distribution value by applying the Staff Report's DRV methodology CDG projects receiving the MTC, and having a portion of the MTC be valued with the DRV 10 peak-hour mechanism as a proxy for system-wide distribution benefits. The JU opposes other parties' suggested changes to the Staff Report's DRV proposal. The JU reiterates its support for the Staff Report's recommendation to use future marginal cost studies to determine locational performance based CDG credits and again offers proposes to shorten the compensation period to five years.

Next, the JU oppose parties who comment that argue that using RECs as the mechanism for valuing the environmental attributes of clean DER does not aligns with past Commission policy. Further, the JU agree with party recommendations that the creation of RECs should not be limited to exported generation. The JU shares other parties concerns with the potential double counting of RECs and propose that customers should be able to choose whether they will retain their RECs without compensation, or sell them and receive payment for them from the utility.

The JU oppose party suggestions to modify the approach to gradually transition to more value-based compensation by using the MTC based on concerns regarding unintentionally harming projects that would exclusively target residential and small commercial customers. It believes this concern could be resolved through the JU's recommendation to provide the MTC for 100% of projects that certify and maintain 100% residential and small commercial subscribers, while all other projects would receive the MTC for 60 percent of output. The JU generally support the approach to use five-year average LBMP data to establish the expected average energy rate that a solar installation would earn and disagree with parties who argue that this differential should be calculated using 2016 numbers only. Additionally, the JU argue that this approach could be improved by simply ignoring this differential for the purposes of calculating the MTC.

The JU clarify its initial comments with respect to the potential that Tranches Zero and One may lead to higher than necessary levels of compensation for CDG projects. The JU note that they do not know the net profit margin or net income for these projects, or for the companies and individuals who develop them and that the JU analysis does not account for all costs, including financing costs. The JU comment that the purpose of offering such an analysis is to highlight the need to consider that costs of CDG are lower than the costs of mass-market rooftop installations, and are declining.

With respect to grandfathering, the JU support parties who favor establishing a fixed grandfathering period and MTC payment period and oppose comments suggesting that grandfathering and MTC payments should continue for the life of the project. The JU again recommend that the grandfathering period should be limited to 15 years, and the MTC payment period

limited to 10 years, with the distribution component guaranteed for only five years.

The JU also support comments advocating for including low- and moderate-income customers within the development of the Phase One tariff. To achieve this goal, the JU proposes that either: 1) CDG projects could be required to reserve a small portion of its output for low- and moderate-income customers; 2) CDG projects could be allowed access to Maintenance Tier funding under the CES, which could be expanded to provide additional assistance to low- and moderate-income CDG projects demonstrating a financial need; or, 3) tranche allocations could be prioritized to accommodate projects serving low-income customers.

NFCRC

NFCRC supports the comments of other parties stating that the numerous attributes of power generated and used onsite should be appropriately valued, consistent with REV principles. On the other hand, NFCRC disagrees with the SEIA assertion that behind-the-meter generation should be treated only as load reduction, and that the Phase One Tariff should apply to net injections only. With respect to the economic and environmental value created by onsite generation, TASC supports the comments by other parties that the lack of price signals for self-consumed generation that avoids emissions or that provides capacity relief will negatively impact New York's ability to achieve its system efficiency and carbon reduction goals.

NFG

In its reply comments, NFG states that, although the Staff Report claims to be technology neutral, it has the outcome of manipulating the REV market by creating barriers of entry, dictating which market actors can viably participate. Instead

of adopting the Staff Report, NFG recommends establishing broad policy applicable to all technologies, especially natural gas, which would allow market actors to develop innovative ideas, strategies, techniques and products to fulfill those objectives.

Next, NFG comments that there is no merit to the claims that price volatility exists in the natural gas markets. NFG explains that the volatility experienced in the winter of 2013 to 2014 was the result of a shortage in pipeline capacity, not a shortage of natural gas supplies. NFG asks the Commission to reaffirm its commitment to support the expansion of natural gas pipeline infrastructure.

Next, NFG opposes the recommendation by the JU to establish an upper limit on the amount of CDG that can be installed under Phase One. NFG comments that an arbitrary cap on CDG development does not allow room for industry development, and does not send signals that significant development opportunities exist. Additionally, with respect to the JU's concern with intermittent renewable technologies, NFG notes that CDG does not need to be fueled solely by renewables and that CDG projects could be fueled entirely by natural gas, which is dispatchable, and available on demand immediately.

NFG also opposes the recommendation that the Commission should give Staff clear authority to make an independent evaluation of the social cost of carbon, given the uncertain future of the federal process. NFG notes that there is significant disagreement amongst parties in this proceeding and that the Commission should not delegate its decision making authority to Staff. Finally, NFG reiterates its suggestion that the Commission refrain from adopting compensation for environmental benefits at this time for several reasons, including the fact that the Staff Report proposal fails to account for detrimental environmental impacts that can be caused

by the manufacture of renewable technologies such as solar panels.

NYC

In its reply comments, NYC oppose the recommendation by the JU to adjust the Phase One tranche sizes. NYC comments that the JU proposal is a significant departure from the Staff Report and urges the Commission not to utilize the JU calculations. Additionally, NYC recommends that the Commission reject the JU proposal to reduce the MTC payment period to 10 years, and continues to support the proposed 20 year period as it will provide certainty to developers and customers transferring to the new Phase One compensation methodology. With respect to the JU's recommendation to require quarterly filings by the utilities reporting on bill impacts resulting from the Phase One tariff, NYC supports such transparency, but opposes taking short-term actions based on such quarterly reports, and instead, recommends that the Commission only act upon the utility bill impact reports once a full year's worth of data has been reported. Finally, with respect to Phase Two, NYC recommends that Phase Two commence with a Staff Straw Proposal and that working groups which focus on discrete topic areas should be established.

NYSULC and Local 10

NYSULC and Local 10 offer reply comments in support of those filed by the JU. NYSULC and Local 10 agree that NEM fails to accurately compensate DER compared to the value provided to electric grid stakeholders, and believes that if proper tariffs are not applied to DER, it will place an unfair, higher rate burden on all electric consumers. NYSULC and Local 10 share the JU's concern that the Staff Report: 1) is based on inexact data and assumptions that result in levels of DER growth that cannot

be sustained within a 2% customer bill impact; and, 2) appears to provide compensation to all DER projects irrespective of whether the project attributes are valuable to deferring generation or distribution system investments. NYSULC and Local 10 cite a number of issues in the Staff Report that still need to be fully explored in order to develop policy and standards that will guide the development of future economically-efficient resources through the placement of a value on each of the differing DER characteristics including time-based, locational and operational values.

OGS

OGS offers reply comments in response to the comments submitted by the JU. OGS concurs with the conclusion drawn in the JU comments that the methodology proposed in the Staff Report will result in disparate compensation for different resources, despite those resources supplying identical, and occasionally superior, benefits to the grid. Further, OGS agrees with the JU assertions that the proposed Phase One methodology will result in excessive compensation levels that are unnecessary to meet the stated policy objectives, and would instead result in excessive profit margins for CDG developers. OGS comments that behind-the-meter mandatory hourly-priced are a better vehicle to effectuate the Commission's policy of increasing DER penetration, while achieving greater value for consumers at decreased costs as compared to CDG.

Pace

In its reply comments, Pace states that several party comments seem to walk back the productive agreements that the collaborative reached over the last year and are counter to the progress of the collaborative effort. While Pace does not comment on the merits of the JU's modeling critiques, it does

note that the JU comments seem to underscore one of Pace's concerns with the Staff Report – that for the sake of exigency, the collaborative and Staff Report adopted existing market values as proxies for the different time and locational values that DER can provide to the grid, thus leaving a great deal of uncertainty around the actual value of DER to the grid. Pace suggests leaning toward preserving the status quo until a full analysis can be performed.

Pace disagrees with the JU proposal for a 5% of peak load cap on incremental distributed solar capacity, and claims that such a limit is not supported by any specific analysis of the bill impact at 5% incremental penetration, or the reliability concerns attendant that level of solar penetration. Additionally, Pace comments that the proposal by the JU to shorten the application of the MTC to 10 years does not reflect the life of the DER asset or the value that it will provide to the grid over that period. Pace also opposes the JU's proposal to reset the tranches and reweight them towards increasingly lower compensation levels. To do so, Pace continues, would on the whole steer a greater portion of the market towards a discounted compensation rate that is not based on actual value analysis, but merely an arbitrary, round rate of discount from current net metering compensation.

Next, Pace disagrees with the UIU proposal to require DER developers to post performance bonds. Pace avers that this recommendation i short-sighted because DER is not being compensated for the 20-year, deferred transmission and distribution value of its generation under the Phase One tariff.

With respect to the comments offered by MI, Pace disagrees with the assertion that the VDER proceeding is driven by need to replace NEM because that approach overcompensates certain DERs. Pace comments that the purpose of the VDER proceeding is not to reduce compensation to DER projects, but

instead to more accurately compensate DERs for the value they provide to the distribution system and society. Finally, with respect to the MI comments that suggest DER should not have the option to opt-out of the MTC in favor of DRV, Pace disagrees and comments that to the extent project developers wish to forego the assurance associated with the MTC in favor of developing where they can provide greater grid benefits, they should be encouraged to do so.

PULP

In its reply comments, PULP notes that many stakeholder focus on the use of non-market based support from ratepayers to promote the DER market, instead of implementing market based approaches to encourage the reliance on distributed generation. PULP opposes this approach and asserts that any proposals for ratepayer subsidies should rely on proven, documented ratepayer benefits that outweigh any subsidies. PULP also expresses concern with the analysis in the Staff Report of bill impacts on residential and other ratepayers. In light of the comments filed by the JU expressing that bill impacts may be understated in the Staff Report, PULP recommends that Staff be required to revise and reissue its Report for additional public comment and response before new ratepayer subsidies are placed before the Commission for determination. Additionally, PULP objects to the apparent approach to set an artificial level of additional ratepayer support to justify the recommendations for subsidies to DER providers and comments that the Staff Report fails to consider the cumulative effect of ratepayer increases already approved by the Commission or embedded in rate cases and other REV related proceedings.

PULP supports the UIU comments urging the Commission to adopt robust oversight and regulation policies with respect to the business practices and disclosures for certain DER

providers. Additionally, PULP agrees with the observation and concern raised by AEMA – that the Staff Report appears to forward discriminatory policies that appear to favor certain types of demand side management and other technology-based solutions in its recommended compensation methodologies. Along those lines, PULP comments that the Staff Report does not reflect market based solutions and would continue the unfair structure that favors solar programs.

Next, PULP opposes comments, mainly submitted by solar advocates, that continue to request ratepayer support for their programs and policies instead of relying on market based solutions. PULP supports ratepayer support through performance based incentives only when actual ratepayer benefits – lower rates and better service – are documented. PULP comments that including vague and unsupported "values" in any determination of what ratepayer support should be approved harms ratepayers and runs the risk of overvaluing DER.

SolarCity

SolarCity, in its rely comments to the JU initial comments, states that the JU's submission was permeated with new arguments and assertions, issues pertinent only to Phase Two, and matters that are completely irrelevant. SolarCity comments that the JU comments do not align with the efforts of the collaborative to discuss positions and substantive concerns in good faith among the stakeholders. SolarCity notes that the JU comments seem to be targets toward the final end state tariff, not the interim approach under discussion in Phase One comments. Additionally, SolarCity avers that several of the JU comments contradict the terms of the Solar Progress Partnership agreement; a joint proposal on a DER compensation mechanism framework entered into by SolarCity and other solar companies with the members of the JU. Therefore, SolarCity urges the

Commission not to rely on the arguments or evidence submitted by the JU for the Phase One Order, and instead to consider those comments in Phase Two of the VDER proceeding.

Solar Parties

In its reply comments, Solar Parties offer that the comments provided by the JU rest on inaccurate and incomplete information, and disruptive policy proposals that are counter to the goals of the proceeding. Solar Parties comment that the JU comments ignore the work of the collaborative and has the potential to derail the proceeding.

Solar Parties oppose the approach proposed by JU for determining the value of ICAP and continue to support the approach proposed in the Staff Report. Additionally, Solar Parties comment that the JU proposal for a performance-based MTC directly contradicts the purpose of the MTC and the principles upon which it is based, and thus should be rejected. Solar Parties also oppose the JU recommendations to limit the eligibility for the MTC to 10 years and to limit distributed solar in Tranche Zero and under the Phase One Tariff to 5% peak load. The JU comments, Solar Parties continue, also rely on flawed analysis of revenue impacts by, among other things: understating residential revenues; 2) overstating the estimated revenue impacts from mass-market PV exports; and, 3) focusing on one downward adjustment to the VDER valuation methodology and ignoring other adjustments that would increase the values of DER.

Next, Solar parties recommend dismissing the JU's analysis of CDG profit margins as based on unfounded assumptions and flawed modeling. Solar parties also comment that the data relied on by the JU with respect to the interconnection queue has been acknowledged in the collaborative to be inaccurate and

unreliable information that cannot be reasonably relied upon to make policy determinations in this proceeding.

With respect to the comments filed by Borrego, the Solar Parties support the recommendation to implement a proxy locational value based on Central Hudson's DSIP study and the framework the Commission already established in the CDG Order. Further, Solar Parties Borrego's recommendations to leave determination of de-averaged MCOS studies to Phase Two implementation, and the recommendation to use the SC1 rate for capacity. Solar parties also share the concern expressed by Borrego the Staff's proposal would make it more difficult for projects subject to the old SIR to achieve grandfathering status as compared to more recent projects subject to the new SIR. Finally, Solar Parties urge the Commission to approve the queue management and interim cost sharing proposals alongside the VDER tariff.

TASC

In its reply comments, TASC notes its support for and concurrence with the reply comments submitted by SEIA and Vote Solar. TASC further comments that the comments of the JU are a departure from the extensive work that has been done as part of the collaborative process. Specifically, TASC notes that the circuit breaker mechanism proposed by the JU is at odds with the iterative and data-driven approach that was laid out in the Staff Report and recommends that this proposal be rejected. Finally, TASC comments that the JU greatly overstate the revenue impact of mass market exports.

UIU

In their reply comments, UIU express support for imposing a hard cap on customer bill impacts with a robust circuit breaker mechanism similar to JU's recommendation, in

order to limit the shifting of DER costs onto non-participating customers. UIU recommends a hard ceiling on DER mass-market projects in each utility's service territory to limit the cost shift to 2% because a hard cap with a pre-defined circuit breaker mechanism will both give the market regulatory certainty and help mitigate the rate shock to non-participants. Further, UIU comments that the Commission should adopt a conservative approach to calculating the 2% cap that limits harmful cost shifts during the development of a more accurate value stack, as opposed to the methodology proposed in the Staff Report which appears to err on the side of underestimating cost-shifts.

With respect to grandfathering of projects connected during Phase One, UIU recommends that such projects should be grandfathered for as short a term as possible to ensure customers pay the most accurate available value of DER, and supports the shorter 15 year period proposed by the JU. Additionally, UIU supports the Staff Report's cost allocation principles, but further recommends distinguishing the benefits and costs between participants and non-participants within each service class. Finally, UIU proposes addressing the concept of an LMI value adder in Phase Two.

LISTING OF INDIVIDUALS OR ENTITIES THAT SUBMITTED PUBLIC COMMENTS

ALLAN HARARI

COMVERGE, INC.

DAIRY FARMERS OF AMERICA

DENNIS PHAYRE

ENERGY STORAGE ASSOCIATION

GRAVITY RENEWABLES

HIGH PEAKS

SOLITUDE DEVELOPMENT, LLC

SOLAR POLICY FORUM

STRATEGAIN, LLC

SUNRISE SOLAR SOLUTIONS

TOM KACANDES

VANGUARD RENEWABLES

PUBLIC COMMENTS

ALLAN HARARI

Mr. Harari comments that Staff's proposal perpetuates market uncertainty, especially for CDG, and that the lack of foundational data and empirical evidence further challenges the justification to transition to a new paradigm. Mr. Harari further comments that it would be more appropriate to base a transition on a percentage of operational projects as compared to state goals, such as the CES, and at the very least should extend implementation of the program to a five-year period. Mr. Hariri is also concerned about thresholds for project maturity requirements and that the new paradigm may only benefit a handful of development interests.

COMVERGE, INC.

Comverge expresses concerns that Staff's proposal would result in unintended consequences. Specifically, Comverge is concerned about a crowding out of the market under Phase One as a result of the focus on NEM-eligible technologies. Comverge is also concerned about the lack of performance requirements and the overlap of market opportunity for value of "D" aspects with markets in which non-solar DER resources participate. Comverge recommends placing a specific MW cap until methodology for all DER solutions can be sufficiently developed. Additionally, Comverge recommends that DRV for purely intermittent resources be suspended until all resources are evaluated and that environmental value also be applied to DER and NWA programs to ensure a more level playing field.

DAIRY FARMERS OF AMERICA

The Dairy Farmers of America offer support for other commenters who focused on properly recognizing the benefits of anaerobic digester technology, including capturing the variable environmental value associated with this technology and that this technology offers value through destroying of carbon equivalents.

DENNIS PHAYRE

Mr. Phayre offers comments on aspects of the valuation of DER in the context of values offered to the distribution system. Mr. Phayre argues that the value of "D" should comprise not only deferred grid costs but also strategic locational values. Mr. Phayre further comments that NEM does not work well for large-commercial customers under a volumetric crediting system and that with the appropriate decisions, the Staff Proposal offers the potential to support this market segment. In particular, Mr. Phayre argues for returning to a monetary crediting system, and considering large projects as both energy producers and capacity providers.

ENERGY STORAGE ASSOCIATION

ESA offers support for the comments of NY-BEST. Specifically, ESA calls for immediate work on determining valuation and compensation for stand-alone storage systems and to also establish concrete goals or targets for the deployment of storage in New York. ESA further supports Staff's recommendation to immediately unbundle values associated with DER.

GRAVITY RENEWABLES

Gravity offers support of other commenters on the following points: that any renewable generation used for CES

Tier 1 compliance should receive environmental value and that the definition of environmental value be more inclusive. Gravity is also concerned about Staff's propose for capacity valuation and support AMP's comments in this regard. Gravity also argues for a more inclusive MTC that would be available to RNM projects.

HIGH PEAKS SOLAR

High Peaks Solar expresses concern regarding the future growth of the solar industry in New York and that the Staff Proposal will hinder the market, especially the growing CDG market. In particular, High Peaks is concerned about the recommendation to move to monetary crediting and challenges it will pose for customer acquisition and understandability.

SOLITUDE DEVELOPMENT, LLC

Solitude comments in support of the proposal to include an MTC for CDG projects as well as Staff's recommendation for environmental value. Solitude shares others concerns that moving to monetary crediting will cause customer and market confusion as well as administrative billing complexities for the utilities. Solitude offers several suggestions including options for making sure the credits are bankable and sufficient terms to support and increase project financability. Finally, Solitude recommends a MTC approach that would be weighted by utility territory as well as by load zone.

SOLAR POLICY FORUM

The Solar Policy Forum is concerned about the complexity and policy instability that they argue would result from Staff's proposal. The Solar Policy Forum argues for a 4% net utility revenue impact to establish program size and to take a much more gradual approach in moving away from NEM.

STRATEGAIN, LLC

Strategain applauds Staff's work and proposal towards a full understanding of the value of DER and the proposed move to increased granularity of values and services. At the same time, Strategain comments that they remain concerned about the final recommendations for valuation and integration of DER into the grid. Strategain also urges Staff and the Commission to consider the interconnectedness of the various REV initiatives and linkages and the need to ensure greater consumer insight and understanding into these complex decisions.

Specifically, Strategain recommends:

1. Immediately initiate a top-down, strategic renovation of REV policy reviews.
2. More accurately quantify environmental, reliability, and resiliency values.
3. More accurately quantify temporal and locational distribution values and work towards greater data collection and dissemination to the DER marketplace.
4. Align state utility pricing and revenues with utility costs.
5. Encourage the DER growth, including proper standby rates and fast & accurate interconnection procedures.
6. Promote a diverse mixture of DER technologies.
7. Staff's use of day-ahead LBMP value for energy excludes the use of DERs for dynamic grid management. Customers that want to use their DER to manage loads in the real time market or ancillary service markets should be rewarded for doing so. Staff's value stack should include this value.
8. NYSERDA research studies into the Value of DERs are peculiarly absent from Staff's report. The Commission should take steps to ensure the delivery of study and research on this topic in a timelier manner and with more impactful results.

SUNRISE SOLAR SOLUTIONS

Sunrise Solar focuses its comments on Staff's Proposal for CDG, and argues that it is unworkable in its current form. In particular, Sunrise is concerned about the move to monetary crediting and the challenges that this will present for customer acquisition and simplicity as compared to the NEM paradigm. Sunrise further comments that the 10% step-downs for the MTC are too significant given the early stages of this market segment and instead suggest step-downs of 2%. Sunrise also argues for a longer compensation term for grandfathered systems and suggests that 25 years would be more appropriate than the 20 years as proposed by Staff. Finally, Sunrise offers comments on the requirements for project maturity (i.e., 25% of interconnection costs or an executed interconnection contract), arguing that these requirements are not equivalent.

TOM KACANDES

Mr. Kacandes submits comments from the perspective of a small CDG developer. Mr. Kacandes is concerned about Staff's proposal and the uncertainty that it will bring to the emerging CDG market. He believes that if adopted as proposed, New York's CDG market will come to a halt. Specifically, Mr. Kacandes is concerned about market disruption from monetary crediting, access to market opportunity for smaller, local developers and that the Value Stack will not sufficiently support the economics of CDG.

VANGUARD RENEWABLES

Vanguard focuses its comments on the environmental value associated with DER, and recommend that the environmental value should be variable rather than fixed over the life of the projects, and that environmental value should include not only

carbon offsets, but carbon equivalents destroyed through the anaerobic digestion of manure.

PUBLIC COMMENTS FROM INDIVIDUALS

Over 2,200 individual comments were received urging the Commission to reject proposed plans to impose caps on net energy metering (NEM), and to push towards 100% renewable energy by 2035. In particular, commenters argue that NEM supports the expansion of residential clean energy and that New York State needs additional clean, distributed energy, not less. Commenters further argue that the state's NEM program should credit customers at retail electricity rates and should not impose any surcharges.

Over 700 individual comments were received expressing concern about the Staff proposal, which commenters characterize as reducing the compensation for CDG energy. Commenters argue that the proposals undermine NEM, which they argue is one of the most basic foundations of renewable energy policy and energy democracy, especially for enabling access for LMI customers. Commenters further argue to maintain NEM, for at least the next two years, as a simple form of compensation, and to reject the new proposals. Commenters suggest that the Commission should account for all the benefits that renewable energy provides including values not accounted for on the Staff proposal including: reduced air pollution, reduced water usage, new jobs, lower and stabilized energy bills, storm resilience, and energy independence. Lastly, commenters argue that the proposed policy changes are confusing and complicated, and will significantly impair this important market.

Over 200 individual comments were received in support of expanding access to solar energy for New York State residents through CDG. Commenters urge the Commission to design the proposed program in a way that supports products and services

that are on par with that of rooftop solar. Commenters further argue for a program of sufficient size in order to ensure maximum participation as possible.

APPENDIX E. STATE ENVIRONMENTAL QUALITY REVIEW ACT SUPPLEMENTAL FINDINGS STATEMENT

March 9, 2017

Prepared in accordance with Article 8 - State Environmental Quality Review Act (SEQRA) of the Environmental Conservation Law and 6 NYCRR Part 617, the New York State Public Service Commission (Commission), as Lead Agency, makes the following supplemental findings.

Name of Action: In the Matter of the Value of Distributed Energy Resources (Case 15-E-0751) Order On Net Energy Metering Transition, Phase One Value of Distributed Energy Resources, and Related Matters.

SEQRA Classification: Unlisted Action

Location: New York State/Statewide

Date of Final Generic Environmental Impact Statement: February 6, 2015

Date of Final Supplemental Generic Environmental Impact Statement: May 23, 2016

FGEIS available at:
http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101

FSGEIS available at:
http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=48235&MNO=15-E-0302

I. Purpose and Description of the Action.

An order of the Public Service Commission addressing the development of and prompt transition to more accurate valuation and compensation mechanisms for Distributed Energy Resources (DER), particularly distributed generation (DG) projects currently compensated through Net Energy Metering (NEM). The transition involves new compensation methods based on new tariff provisions. To effectuate this transition, NEM-eligible DG projects not interconnected into the utility grid as of the date of the order will receive compensation based on new tariff provisions developed in Phase One of the Value of Distributed Energy Resources (Value of DER or VDER) proceeding. Projects interconnected as of the date of the order will

continue to receive NEM compensation unless and until the project owner chooses to opt-in to a new compensation methodology.

During an initial period, new projects will continue to receive compensation based on NEM methodologies, except that those projects will be limited to receiving such compensation to 20 years before transitioning to new compensation mechanisms.

II. Facts and Conclusions in the FGEIS Relied Upon to Support the Decision

In developing this findings statement, the Commission has reviewed and considered the Final Generic Environmental Impact Statement(FGEIS) in Case 14-M-0101 – Reforming the Energy Vision (REV) and the Final Supplemental Generic Environmental Impact Statement, issued on May 23, 2016 (FSGEIS) in Case 15-E-0302. The findings are based on the facts and conclusions set forth in the FGEIS and the FSGEIS.

The actions described above do not alter or impact the SEQRA findings issued previously. Neither the nature nor the magnitude of the potential adverse impacts will change as a result of the actions described in this order. Rather, in this order, the Commission has taken concrete steps to help further transform New York's electric grid into a modern, distributed, and increasingly clean system, envisioned in the REV Proceeding (see, SEQRA Findings Statement issued in conjunction with the Order Adopting Regulatory Policy Framework and Implementation Plan issued on February 26, 2015, at Appendix B).

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 15-M-0127 - In the Matter of Eligibility Criteria for Energy Service Companies.

CASE 12-M-0476 - Proceeding on Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-residential Retail Energy Markets in New York State.

CASE 98-M-1343 - In the Matter of Retail Access Business Rules.

NOTICE OF EVIDENTIARY AND COLLABORATIVE TRACKS AND DEADLINE FOR INITIAL TESTIMONY AND EXHIBITS

(Issued December 2, 2016)

When the Commission first opened up the energy services market to retail competition, the intended purpose of allowing Energy Service Companies (ESCOs) to serve residential and small non-residential customers (mass-market customers) was to spur innovation in the creation of value-added products, particularly energy efficiency services that regulated rates may not provide, and to create commodity price competition that would result in efficiencies. It was believed that robust competition would result in efficiencies that would be beneficial to customers and would produce just and reasonable rates for commodity service better than would monopoly regulation. The Commission accordingly exercised its ratemaking authority to effectuate competitive access to utility systems by unbundling utility rates into monopoly (transport) and competitive (energy commodity) portions. The Commission's planned policy of regulatory forbearance, under which market pressures set rates for competitive electric commodity suppliers, was upheld based on continued Commission oversight of

the commodity market to ensure that market rates were just and reasonable.[1]

Although often necessary, the regulation of monopoly services can be imperfect, administratively burdensome and untimely, and can lead to inefficient pricing. Competitive markets tend to efficiently distribute and allocate resources in society because customers consider their own benefit when choosing how much to consume or to pay for a good or service. The actions of such consumers in a functioning competitive market generally drive prices to a state where marginal benefits equal marginal costs, since customers are not willing to purposefully pay any more than the minimum necessary to obtain the benefits they desire. Similarly, competitive markets tend to be efficient at encouraging sellers to produce goods and services for the lowest cost so as not to lose market share to their competitors. Robust competitive markets typically have the following characteristics: (1) sufficiently large enough number of buyers and sellers to prevent individuals or groups from exclusively influencing the market price; (2) products that can be readily compared; (3) complete information about prices and supplies for both producers and consumers; (4) sellers that face significant elasticity of demand around the market price such that, if a seller charges a higher price, demand will significantly drop because buyers will switch suppliers, and if a seller charges a lower price (below market cost), it will receive significantly less net revenue than if it charged the market price; and (5) few barriers to entry to the market for both buyers and sellers.

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[1] Matter of Energy Assn. of New York State v Public Serv. Commn. of the State of N.Y., 169 Misc. 2d 924, 936-37 (Albany County 1996), affd on other grounds, 273 A.D. 2d 708 (3d Dept 2000).

After considerable experience with the offering of retail service to mass market customers by ESCOs, the Commission has determined that the retail markets serving mass-market customers are not providing sufficient competition or innovation to properly serve consumers.[2] Despite efforts to realign the retail market,[3] customer abuses and overcharging persist, and there has been little innovation, particularly in the provision of energy efficiency and energy management services. Commodity price differentiation has not worked, and the market for differentiated services is immature or non-existent. If ESCOs were truly living up to the promise of their function as innovators, it is expected that there would be much greater variety and transparency in the market for goods and services that supply real consumer energy value, insistence from serious participants on rules that govern against consumer fraud, maturity beyond door to door selling, and a consumer base with a much greater degree of satisfaction. While a well designed market could offer these consumer opportunities, it simply does not exist today. Accordingly, the Commission continues to examine measures that must be taken to ensure that these customers receive valuable services and pay just and reasonable rates for commodity and other services. Among the measures to be considered are: (a) whether ESCOs should be completely prohibited from serving their current products to mass-market customers; (b) whether the regulatory regime, rules and Uniform

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[2] Case 12-M-0476, et al., Retail Access, Order Taking Actions to Improve the Residential and Small Non-residential Retail Access Markets (issued February 25, 2014).

[3] Case 12-M-0476, et al., supra, Order Granting and Denying Petitions for Rehearing in Part (issued February 6, 2015); and Case 15-M-0127, et al., Eligibility Criteria for Energy Service Companies, Order Resetting Retail Energy Markets and Establishing Further Process (issued February 23, 2016).

Business Practices (UBP) applicable to ESCOs need to be modified to implement such a prohibition, to provide sufficient additional guidance as to acceptable rates and practices of ESCOs, or to create enforcement mechanisms to deter customer abuses and overcharging, including whether the Commission decision not to subject ESCOs to Article 4 of the Public Service Law should be revisited; and (c) whether new ESCO rules and products can be developed that would provide sufficient real value to mass-market customers such that new products could be provided to them by ESCOs in the future in a manner that would ensure just and reasonable rates.

Please take notice that in furtherance of these efforts, two procedural tracks are established in these proceedings for the consideration of measures "(a)", "(b)" and "(c)" described above. Track I shall be for the consideration of measures "(a)" and "(b)" and shall include an evidentiary hearing at which sworn testimony and exhibits will be subject to cross-examination, followed by the filing of post-hearing briefs prior to Commission action. Track II shall be for the consideration of measure "(c)" and shall include collaborative meetings of interested parties, collaborative or party reports or proposals, and the opportunity to comment in writing prior to Commission action.

Please take further notice that Track I initial pre-filed testimony and exhibits must be filed on or before April 7, 2017. An Administrative Law Judge will be assigned to conduct and oversee the evidentiary hearing process of Track I. The assigned Administrative Law Judge will work with the parties to establish other Track I milestones and set the schedule for them, including the date for the evidentiary hearing and the schedule for post-hearing briefs.

It is anticipated that Staff of the Department of Public Service will provide testimony and exhibits in Track I along with the testimony of ESCOs, regulated utilities, consumer groups, and other interested parties. All parties to these proceedings may be subject to discovery regarding Track I issues. Parties submitting Track I testimony and exhibits should address the following topics where relevant to their positions:

1. Whether ESCOs should be prohibited in total or in part from serving their current products to mass-market customers, or whether ESCOs should be required to offer value-added energy efficiency and energy management services as a condition to offering commodity services.

2. Whether the regulatory regime of how the Commission applies the Public Service Law to ESCOs should be modified to ensure that customer abuses and overcharging by ESCOs is deterred. In particular, the Commission has not applied Article 4 to ESCOs, based on a construction that Public Service Law §66(1) only applies to utilities with plant in public streets.[4] Is that construction justified today? Would it be appropriate to revisit that construction in light of subsequent events, such as the adoption of the 2002 amendments to the Home Energy Fair Practices Act? If the construction is revisited, would it be appropriate and beneficial to customers and in the public interest to apply the restrictions of Public Service Law §65 to ESCOs?

3. Whether the regulatory regime of how the Commission applies the Public Service Law to ESCOs should be modified to ensure adequate enforcement mechanisms, including penalties, to deter customer abuses and overcharging. In this regard, please comment on whether it is possible for the Commission to seek penalties against ESCOs under the current regime, pursuant to which they are only regarded as "gas" and/or "electric" corporations under PSL Article 1, or if it is necessary to also regulate ESCOs under Article 4 to seek penalties against ESCOs? If Article 4

[4] Case 94-E-0952, Competitive Opportunities Regarding Electric Service, Opinion No. 97-17 (issued November 18, 1997), mimeo p. 34.

regulation is deemed necessary, then what burdens would such regulation impose? For instance, would it be possible for ESCOs to obtain "incidental" regulation under Public Service Law §66(13) and would such "incidental" regulation serve the public interest? Would ESCOs also be subject to undue burdens if they needed to obtain approval for stock issuances under Public Service Law §69 or the transfer of stocks, plant or franchises under Public Service Law §70? Should ESCOs be further regulated as to credit worthiness?

4. Whether the regulatory regime of how the Commission applies the Public Service Law to ESCOs should be modified to guide ESCOs toward acceptable rates and practices and deter customer abuses and overcharging. In particular, if the Commission decides that Public Service Law Article 4 applies to ESCOs, should the Commission use the discretionary authority of Public Service Law §66(12)(a) to require filing of tariffs by ESCOs in order to ensure that ESCO bills be no greater than utility bills? If so, should the Commission require filing of tariffs by all ESCOs, just ESCOs offering commodity-only service, or just ESCOs that have been determined to charge prices in excess of utility bills? Should the Commission take steps to void existing ESCO contracts if it tariffs ESCO services?

5. Whether the rules applicable to ESCOs should be modified to ensure that customer abuses and overcharging by ESCOs are deterred. If so, then should the authority be imposition of Public Service Law Article 4 and/or other requirements created by Public Service Law Article 6?

6. Whether the Uniform Business Practices (UBP) applicable to ESCOs should be modified to ensure that customer abuses and overcharging by ESCOs are deterred.

7. Whether door-to-door and outbound telemarketing practices of ESCOs to mass market customers should be prohibited, and whether other ESCO marketing practices should be prohibited?

8. Whether the purchases of receivables system regarding mass market customers should be modified in any way, including but not limited to imposing "purchase with recourse" provisions or tiered discount rates so that ESCOs with abusive practices bear more financial risk from such practices?

9. The prices for retail gas and/or electric service charged to and paid by mass-market customers of ESCOs in the recent past, including, at a minimum, calendar years 2014 and 2015 and as much of 2016 as may be available, and the prices those customers would have paid for comparable utility service. If different products are offered (e.g., fixed vs. variable), the prices by product offering. In addition to annual data, seasonal (summer and winter) and monthly data should be provided where possible and relevant. Data for residential and small commercial customers should be provided separately. Data for electric and natural gas products should be provided separately. Where an ESCO product has been offered for more than five years, the last five years of historical data should be provided. Parties providing significant quantities of data should consult with Staff as to providing the data in a useful electronic format.

10. Data setting forth the number of customers served by ESCOs, by ESCO, for 2014, 2015, and so much of 2016 as is available.

11. Data setting forth the volume of sales in total dollars and in kWh, by ESCO, for 2014, 2015, and so much of 2016 as is available.

12. Evidence that an ESCO has, in fact, in recent years offered or is currently offering lower prices on an annual basis compared to the incumbent utility consistently, including number of customers served and total volume of sales in both dollars and kWh. Such evidence should also include an analysis of whether that price offering has been profitable or resulted in a loss to the ESCO.

13. Whether, given the current retail market structure, it is possible for an ESCO to profitably offer lower prices on an annual basis compared to the incumbent utility consistently and, if possible, how it can be done.

14. The number and nature of customer complaints regarding i) retail prices and bills and ii) sales and marketing practices from a) customers directly to ESCOs, b) from customers to utilities about ESCOs, by ESCO, and c) customers to the Commission about ESCOs, by ESCO during calendar years 2014 and 2015 and as much of 2016 as it is available.

15. ESCO marketing and sales practices, including printed materials, customer contracts, scripts for telephone or

door-to-door solicitations, and other training materials for ESCO sales people for practices in effect during calendar years 2014, 2015, and 2016. Such evidence should include all efforts by ESCOs to ensure that they and their personnel comply with the Uniform Business Practices (UBP) and that they otherwise avoid any deceptive marketing practices.

16. The ability of mass-market customers to obtain information about relative prices and offerings of ESCOs and regulated utilities and to understand such information, including evidence regarding the transparency of the retail market for mass-market customers and the level of knowledge in that market.

17. Tools that are available in the public domain that customers can use to do comparison shopping.

18. Specific customer surveys that shed light on customers' understanding about retail choices available and how to make informed choices.

19. Actions by state agencies or consumer advocacy groups to protect customers, to monitor the state of the retail market customers, to provide information, or to lodge complaints or impose discipline in the case of improper ESCO practices, including specific concrete steps the group has taken and any results obtained from those actions.

20. Actions that have been taken or that could be taken to strengthen the retail market or otherwise to provide consumer protections sufficient to protect mass-market customers from overcharges or deceptive marketing practices. For instance, if the Commission decided to subject ESCOs to Article 4 of the Public Service Law would it be appropriate to require ESCOs to obtain Certificates of Public Convenience and Necessity under Public Service Law §68 in order to provide commodity service?

Track II activities shall be initiated by Staff of the Department of Public Service upon notice to all parties in these proceedings.

(SIGNED) KATHLEEN H. BURGESS
Secretary

Staff Report to the Secretary on Electricity Markets and Reliability

August 2017

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1 Introduction

On April 14, 2017, Energy Secretary Rick Perry issued a memorandum requesting a study to examine electricity markets and reliability. With this document, Department of Energy (DOE) staff are delivering a study that seeks not only to evaluate the present status of the electricity system, but more importantly to exercise foresight to help ensure a system that is reliable, resilient, and affordable long into the future. Therefore, while carefully acknowledging history, this study focuses on the present trajectory of trends that are of particular concern in meeting those long-term goals.

Specifically, the April 14 memo directed a study that explores the following three issues:

- The evolution of wholesale electricity markets, including the extent to which Federal policy interventions and the changing nature of the electricity fuel mix are challenging the original policy assumptions that shaped the creation of those markets;
- Whether wholesale energy and capacity markets are adequately compensating attributes such as on-site fuel supply and other factors that strengthen grid resilience and, if not, the extent to which this could affect grid reliability and resilience in the future; and
- The extent to which continued regulatory burdens, as well as mandates and tax and subsidy policies, are responsible for forcing the premature retirement of baseload power plants.

The U.S. electricity industry is facing unprecedented changes. Last year, for the first time in history, natural gas replaced coal as the leading source of electricity generation. In 2015, a record-high amount of generating capacity retired. Over the course of the last decade, overall growth in electricity consumption at the national level has stalled, while many generation sources—particularly natural gas, wind, and solar—frequently hit new record levels of penetration.

The stakes are high around these issues because electricity is crucial to modern society and economic activity, and because of the physical and financial magnitude of the industry. As noted in the report, *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (QER 1.2):

> The United States has around 7,700 operating power plants[1] that generate electricity from a variety of primary energy sources; 707,000 miles of high-voltage transmission lines;[2] more than 1 million rooftop solar installations;[3] 55,800 substations;[4] 6.5 million miles of local distribution lines;[5] and 3,354 distribution utilities[6] delivering electricity to 148.6 million customers. The total amount of money paid by end users end for electricity in 2015 was about $400 billion.[7] This drives an $18.6 trillion U.S. gross domestic product and significantly influences global economic activity totaling roughly $80 trillion.[8]

Recognizing how vital electricity is to our society and the health of the U.S. economy, the April 14 memo asked staff to "provide concrete policy recommendations and solutions." It also offered principles for policy formulation: "the Trump Administration will be guided by the principles of reliability, resilience, affordability, and fuel diversity—principles that underpin a thriving economy." To that end, this report concludes by outlining policy recommendations to advance those principles.

Section 2 of this study offers a summary of findings. Sections 3 through 6 provide the analytical framework, relevant data, and research. In addition, each of these sections concludes with a "looking forward" note, as many of the issues raised in the April 14 memo are of growing importance. Section 1

presents policy recommendations available—to DOE and others—to address the issues identified in this study. Section 8 outlines potential areas for further research.

Data Used in This Study

This study uses data collected by the Energy Information Administration (EIA) for the years 2002 through 2017, looking back before 2002 on a few specific issues. The 2002–2017 time range captures several important developments:

- Centrally-organized wholesale electricity markets (Regional Transmission Operators [RTOs] and Independent System Operators [ISOs]) were in the early stages of implementation in 2002. Competition within centrally-organized markets among a large segment of merchant generation did not take effect until the mid-2000s. Three RTO/ISOs initiated mandatory capacity markets in 2006–2007: New York ISO (NYISO), PJM Interconnection (PJM), and ISO-New England (ISO-NE).
- The emergence of a large amount of unconventional natural gas production—the shale revolution—started in 2006–2007. The consequent drop in natural gas prices began in 2009 under the combined impacts of low demand during the economic recession and a significant increase in supply.
- The recession contributed to a significant drop in electricity demand in 2008, and it took several years for demand to return to 2008 levels. Although economic activity has picked up in recent years, electricity consumption and gross domestic product (GDP)—which grew together for decades—now appear less correlated as industries have become less energy-intensive and energy efficiency measures have taken full effect.
- Several environmental regulations implemented under statutes enacted in the 1970s and 1990s, which raise capital and operating costs for affected power plants, had compliance deadlines in the period 2010–2017.
- Driven in part by Federal and state policies, tax incentives, and mandates, significant quantities of variable renewable energy (VRE) resources—specifically wind and solar, and at levels high enough to alter traditional patterns of grid operation—began to impact certain areas around 2010.
- Also around 2010, demand response emerged as a way for customers to compete in most centrally-organized wholesale markets.

Because all of the above factors have emerged over the past 15 years—each affecting power supply and demand in different ways—looking at data since 2002 helps to reveal the impact and interactions of these changes. Additionally, EIA believes that the highly detailed EIA data used in this study (down to the level of individual generators) is most reliable for 2002 forward.

Further, the data used for this study include power plant fuel conversions as retirements for the original fuel source. This study reports power (e.g. generation capacity) and energy (e.g. production or consumption over time) in megawatts (MW) and megawatt-hours (MWh), respectively (unless otherwise noted). Finally, all generation capacity figures reported in this study are net summer capacity as opposed to nameplate (unless otherwise noted).

Defining Regions

The U.S. bulk power system (BPS) is a patchwork of different markets for electricity, shaped over time by technological changes, as well as state, regional, and Federal policies. This patchwork presents organizational and operational challenges, but its diversity also contributes to the system's robustness.

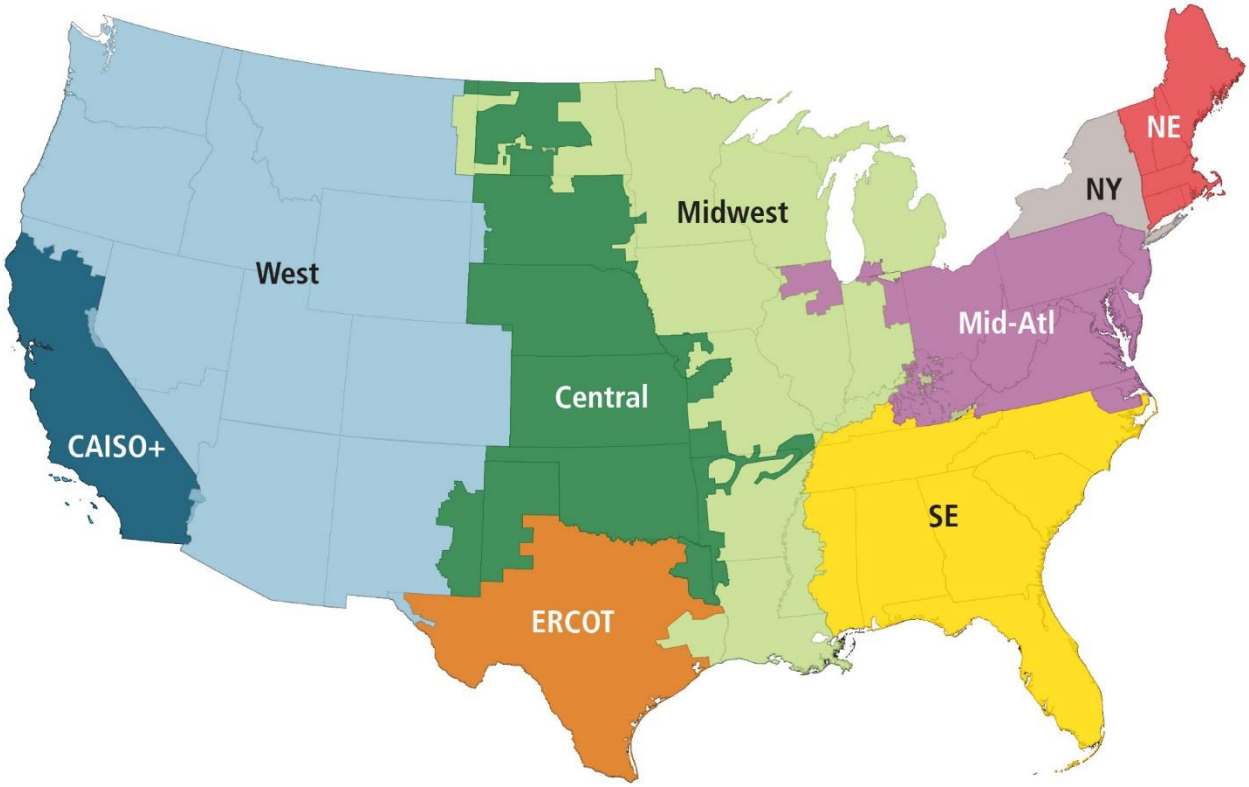
The U.S. power system in the lower 48 states[a] is divided into three synchronized grids: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT).[b, 9] There are limited connections between the Eastern and Western Interconnections, and even fewer connections from ERCOT to the other grids.

Issues confronting the BPS vary widely across regions. This study divides the lower 48 states into nine regions that represent either individual or groups of electric systems, known as balancing authority areas (see Figure 1.1). Within these regions, there are 66 balancing authorities (which can be as small as individual utilities or as large as a multi-state region). Using nine balancing authority-based regions for this analysis is a useful way of aggregating electricity data and revealing regional trends.

[a] Both Alaska and Hawaii have unique islanded electric power systems that are not comparable to the rest of the Nation and thus are not included in this study. This is discussed in detail in a later section.

[b] For most purposes, ERCOT can be considered electrically isolated from the other grids. ERCOT is also not subject to most elements of the Federal Power Act and therefore economic regulation by the Federal Energy Regulatory Commission. A significant exception is Federal Energy Regulatory Commission oversight and regulation of power system reliability, which does apply to ERCOT.

Figure 1.1. Regions Used in This Study[10]



Seven of the nine regions analyzed in this study correlate primarily or directly to the seven ISOs and RTOs in the United States that supply about two-thirds of electricity delivered to end-use customers:[c]

- NE = ISO-NE
- NY = NYISO
- ERCOT = Electric Reliability Council of Texas
- Mid-Atl = PJM
- Midwest = Mid-Continent ISO (MISO)
- Central = Southwest Power Pool (SPP)
- CAISO+ = California ISO (plus smaller balancing areas in the state)

The two remaining regions include numerous balancing authorities, all of which lie outside RTO/ISO service areas:

- SE = Southeast
- West = non-CAISO+ Western Interconnection.

[c] The last four regions in this list include a few additional (mostly small) balancing authorities outside the formal ISO or RTO footprint.

Defining Baseload Generation

This study defines baseload generation as power plants that are operated in baseload patterns—that is, plants that run at high, sustained output levels and high capacity factors, with limited cycling or ramping. While this definition includes most nuclear, coal, and natural gas steam generators, it is not a given that every nuclear, coal, or natural gas steam generator is operated as a baseload plant, or that other technologies cannot function as baseload plants (such as hydroelectric generators). In addition, this study uses the term conventional generation to mean coal, nuclear, and natural gas power plants, regardless of how they are operated.[d]

Other organizations and publications use similar definitions. For example, PJM defines baseload generation as "those units which operate the great majority of hours of the year to meet load requirements."[11]

The North American Electric Reliability Corporation (NERC) offers an explanation as well:

> There is a distinction between baseload generation and the characteristics of generation providing reliable "baseload" power. Baseload is a term used to describe generation that falls at the bottom of the economic dispatch stack, meaning [those power plants] are the most economical to run. Coal and nuclear resources, by design, are designed for low cost O&M [operation and maintenance] and continuous operation […]
>
> However, it is not the economics nor the fuel type that make these resources attractive from a reliability perspective. Rather, these conventional steam-driven generation resources have **low forced and maintenance outage** hours traditionally and have **low exposure to fuel supply chain issues**. Therefore, "baseload" generation is not a requirement; however, having a portion of a resource fleet with high reliability characteristics, such as low forced and maintenance outage rates and low exposure to fuel supply chain issues, is one of the most fundamental necessities of a reliable BPS. These characteristics ensure that "baseload" generation is more resilient to disruptions.[12]

The electricity industry has traditionally referred to baseload generation as the power plants that are used to meet "base" load—the minimum level of electricity that customers demand around the clock, as illustrated in Figure 1.2. Large nuclear, coal, natural gas steam, and hydroelectric plants have historically been used for baseload generation.[e] Baseload plants generally have high capital costs but low fuel costs, and they tend to be fairly fuel efficient. Although the output level of these plants can be changed, they are most economic—in terms of cost per unit of electricity produced—when operated at near-full capacity at all times (although hydroelectric plants are more flexible). Traditional baseload units tend to have longer start-up and shut-down times and generally move (ramp) slowly between production levels to avoid damaging plant components with thermal stress or metal fatigue (see Appendix C on cycling).

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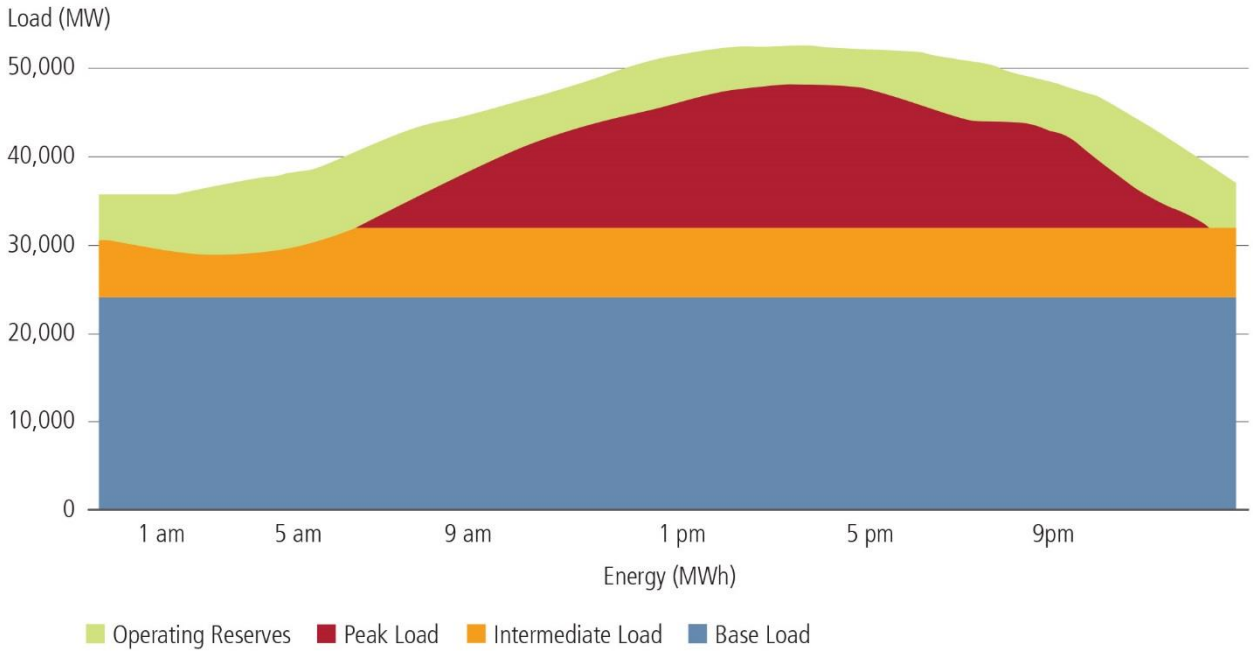
[d] QER 1.2 does not define the term baseload in its glossary. However, the report states in a caption on page 1-21 that "baseload is considered coal, nuclear, and natural gas combined-cycle plants."

[e] Other technologies that have traditionally operated as baseload include geothermal and biomass power plants. However, those technologies represent a relatively small portion of total U.S. electricity generation; while valuable for the grid reliability services they provide, they are not covered in this report.

Figure 1.2. Schematic of Typical Daily Load Curve Showing Base Load[13]



Intermediate or mid-merit plants are used to follow load, meeting daily variations in demand. Depending on the mix of generation resources available in different regions of the country and relative fuel prices, natural gas and/or coal units are typically used for load following. Short-duration demand peaks, which occur infrequently throughout the year, are generally met by natural gas units with high heat rates.[f] More recently, customer-provided demand response is helping to meet peak demand.

Analysis in Section 3 shows that many of the power plants that retired between 2002 and 2016 were used for baseload generation in the past, but were no longer operating in that role at the time of retirement due to changes in electricity market dynamics. With the sustained drop in natural gas prices, for example, natural gas-fired combined-cycle (NGCC) plants are currently a less costly source of baseload generation than coal or nuclear power in many regions of the country.

VRE resources such as wind and solar are beginning to serve more of minimum load, albeit at variable or intermittent output levels.[g] The proliferation of these sources has also led grid operators in some regions to place an increasing premium on flexible generation resources (e.g., NGCC units) that can help balance VRE variability by meeting base load and intermediate load, both of which are affected by a

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[f] According to EIA, "Heat rate is one measure of the efficiency of a generator or power plant that converts a fuel into heat and into electricity. The heat rate is the amount of energy used by an electrical generator or power plant to generate one kilowatt-hour (kWh) of electricity." https://www.eia.gov/tools/faqs/faq.php?id=107&t=3.

[g] For the purposes of this study, wind and solar are referred to as VRE. Terms such as "non-dispatchable" and "intermittent" may also apply to these technologies, but for consistency, this study uses the term variable. In contrast, some renewables are dispatchable—that is, sources that can provide power to the grid within sub-hourly time scales to match demand during any 24-hour period. Dispatchable renewables include sources such as biofuels, geothermal, and hydropower (with the caveat on hydropower that it may only be seasonally dispatchable in some cases).

changing net load profile.[h] These factors, among others, have collectively lessened the immediate need for traditional baseload resources in certain regions, but still speak to the need for baseload generation.

Defining Premature Retirement

The dictionary definition of premature is "happening … or performed before the proper, usual or intended time."[14] The Department does not have an official definition for the term "premature retirement"[i] with respect to power plants, as the term is highly subjective. Below are some of the prevailing viewpoints and associated meanings:

- ✓ Power plant engineers may think a power plant retired prematurely if it has not yet run to the end of its nominal design life (for instance, approximately 40 years for post-1970 coal plants) or through the term of reasonable plant life extension modifications.
- ✓ An RTO/ISO or reliability organization may think a power plant retirement is premature if its continued operation is still required to deliver Essential Reliability Services (ERS)[j] in that location (in which case the operator may delay retirement by designating it a "reliability-must-run" resource).
- ✓ A policymaker or legislator may think a power plant has been forced to retire prematurely if the plant delivers benefits that the state or society values, such as emissions-free energy, local jobs, or maintaining local generation.
- ✓ A mayor or employee may think a power plant is retiring prematurely if the retirement causes harms to the community and the individuals who work there.
- ✓ A merchant competitor that built or acquired a power plant may think its plant has been forced to retire prematurely if the merchant has not been able to recover its investment in the plant through sales of energy and capacity or through other revenue streams.
- ✓ A vertically integrated utility executive may think a power plant has been forced to retire prematurely if the utility has not yet fully recovered its rate-based capital investment in the plant and its return on that rate base.
- ✓ Nuclear or hydroelectric plant owners and regulators may think a power plant has retired prematurely if it has not yet run through the full term of its operating license and/or license extension. Federal Energy Regulatory Commission (FERC) hydro licenses run for up to 50 years with potential reauthorizations of 30–50 years, and Nuclear Regulatory Commission (NRC) nuclear operating licenses run for 40 years with potential 20-year extensions.
- ✓ Electricity economists may think a power plant retired has prematurely if the plant was still able to sell electricity competitively against other energy sources but was required to close due to policy directives. On the other hand, economists may also think a power plant retired

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[h] "Net load" is the instantaneous difference between total customer electricity demand (load) and VRE generation.

[i] QER 1.2—*Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review*—discussed "premature nuclear retirements" but did not explicitly define the term. For example, in Chapter 3, page 24, the report notes: "When analyzing the impacts of **premature nuclear retirements** on power generation in the state, a state of Illinois report considered a scenario in which 80 percent of the replacement generation was coal. Other analysis concludes that roughly 75 percent of the at-risk nuclear generation nationwide would be replaced with fossil generation, largely powered with natural gas." [notes omitted, emphasis added]

[j] See Section 4.1.1 for a discussion of ERS.

prematurely if the plant provided un-priced benefits to society that, if priced, would have made the plant profitable.

- ✓ A long-term planner and risk manager may think a power plant has retired prematurely if it offered valuable diversity, reliability, resilience, and optionality benefits that are not yet fully recognized, valued, and/or compensated.

Each of these viewpoints represents a valid perspective, particularly those of grid operators and other institutions responsible for reliability. While stakeholders may maintain that a power plant has been forced to retire prematurely based on one or more of the considerations above, the results of this study show that some observed power plant retirements were appropriate and consistent with markets as they are currently functioning. In other words, not every power plant retirement is cause for alarm.

However, NERC is concerned with the trend of retirements as it relates to reliability and resilience. NERC wrote in response to the April 14 memo:

> As conventional resources **prematurely** retire, sufficient amounts of essential reliability services, such as frequency and voltage support, ramping capability, etc., must be replaced based on the configuration and needs of the system.[15] [emphasis added]

Given the difficulty in assigning a single definition to premature retirement, as well as the subjective nature of such a definition, this study does not attempt to determine whether any *specific* power plant retirements have been premature. Instead, this study assesses the various factors that contribute to power plant retirement *trends*.

Topics Beyond the Scope of This Study

This study does not directly address several topics for the following reasons:

- **Cybersecurity** is a critical component to ensuring the reliable and resilient operation of the Nation's energy infrastructure. Existing and emerging cybersecurity threats can affect any aspect of the electric sector, ranging from power plants, to transmission and distribution systems, to customers and end-use devices. The December 2015 attack on the Ukrainian electricity system and the 2012 Shamoon virus targeting the energy sector in Saudi Arabia, for example, were wake-up calls.[16]

  DOE takes these threats seriously and is designated as the Federal Government's lead Sector-Specific Agency for cybersecurity for the energy sector, which entails supporting the cyber protection of the Nation's critical energy infrastructure.[k] However, while cybersecurity is a significant concern and top priority, it is not addressed in this report because it is the subject of an upcoming joint report between DOE and the Department of Homeland Security being prepared in response to Executive Order No. 13800, *Strengthening the Cybersecurity of Federal Networks and Critical Infrastructure*.

- **Alaska and Hawaii**: While the broad trends discussed in this report apply in Alaska and Hawaii as well as the lower 48 states, many of this study's economic observations do not directly apply to the power plants in the Hawaii and Alaska power systems, as they are not large, interconnected energy markets, and utility system operators in the states face unique operational and fuel supply chain considerations.

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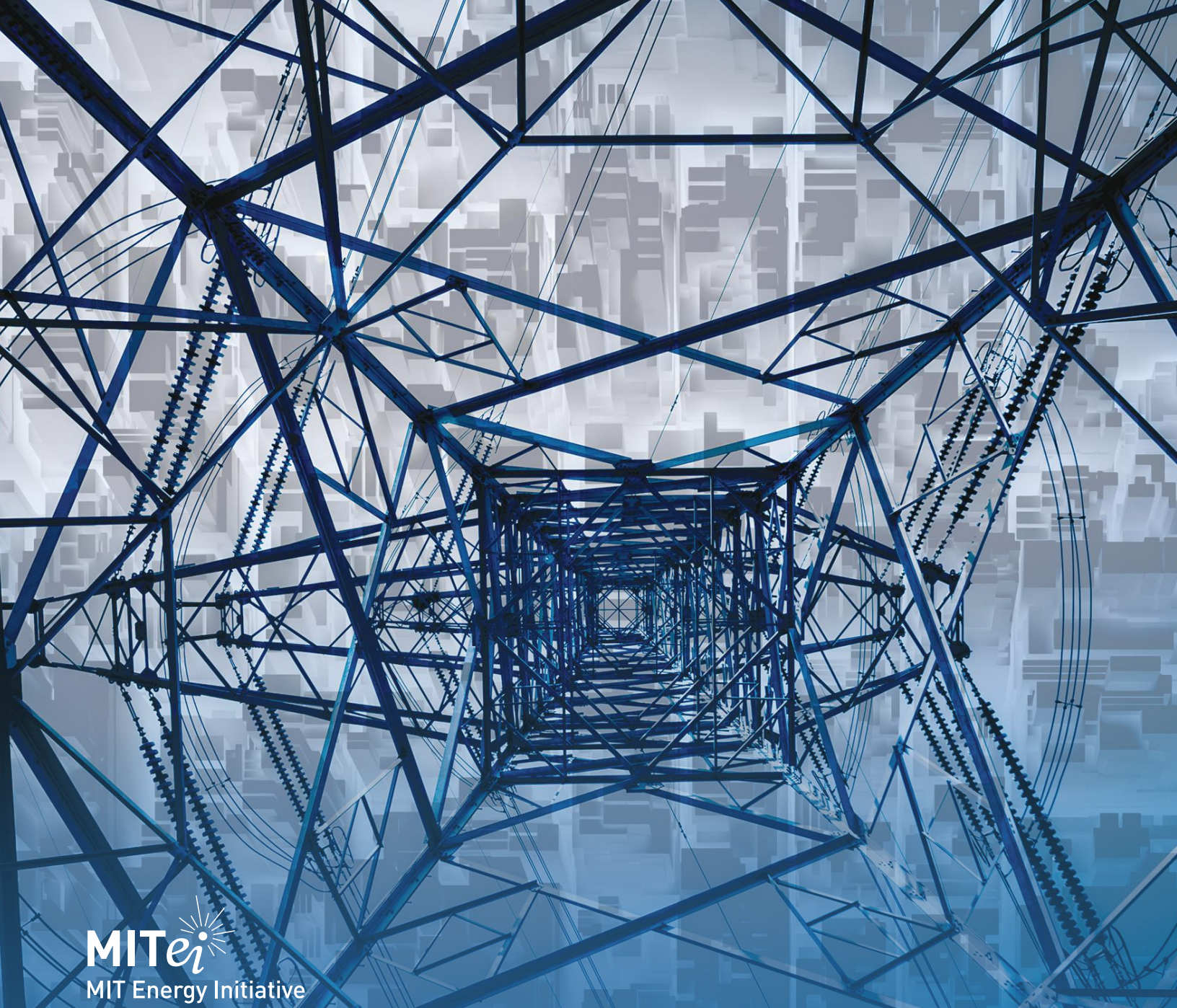
[k] For more information, visit DOE's website on the Department's cyber activities: https://www.energy.gov/national-security-safety/cybersecurity.

The Hawaii and Alaska power systems are remote, vertically integrated systems with plant sizes that tend to fall below the size screens used in this study. The average generating unit sizes in Hawaii and Alaska are 18 MW and 5 MW, respectively, compared to an average unit size of 70 MW in the lower 48 states.[17] Because neither state is interconnected with any of the major U.S. interconnections, or to any transmission or distribution network in Canada, utilities in both states must self-supply all ERS.[l] As a result, utilities in these isolated systems might consider different parameters for reliability in their system planning compared to utilities in the contiguous United States, who can obtain reliability services and products in real time through markets and bilateral transactions.[18] Their experiences, however, may inform the efforts of utilities in the contiguous U.S. seeking to better manage rural systems and effectively integrate VRE and microgrids.

- **Geothermal, biomass, and combined heat and power** plants are often operated as baseload plants, operating at a relatively stable level over a long period of time. However, because these types of plants are not as prevalent or widespread as gas, coal, and nuclear plants, this study did not perform detailed analyses of trends and closures for these technologies.

[l] In 2014, an intertie to the Western Interconnection of British Columbia was proposed to the Alaska Energy Authority in order to bring power to Alaska. However, as of 2016, no further work on the project had been completed due to economic reasons. http://energy-alaska.wikidot.com/railbelt.



MIT Energy Initiative

UTILITY OF THE FUTURE
EXECUTIVE SUMMARY

An MIT Energy Initiative response
to an industry in transition

In collaboration with IIT-Comillas

Universidad Pontificia ICAI ICADE Comillas Madrid
Instituto de Investigación Tecnológica

Full report can be found at: energy.mit.edu/uof

ISBN (978-0-692-80824-5)

UTILITY OF THE FUTURE: EXECUTIVE SUMMARY

An MIT Energy Initiative response
to an industry in transition

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Contents

Full report and related working papers are available at: ***energy.mit.edu/uof***

Foreword and Acknowledgments

An important evolution in the provision and consumption of electricity services is now under way, driven to a significant degree by a confluence of factors affecting the distribution side of the power system. A range of more distributed technologies — including flexible demand, distributed generation, energy storage, and advanced power electronics and control devices — is creating new options for the provision and consumption of electricity services. In many cases, these novel resources are enabled by increasingly affordable and ubiquitous information and communication technologies and by the growing digitalization of power systems. In light of these developments, the MIT Energy Initiative's *Utility of the Future* study examines how the provision and consumption of electricity services is likely to evolve over the next 10 to 15 years in different parts of the world and under diverse regulatory regimes, with a focus on the United States and Europe.

The Utility of the Future study is the first of a new series of reports that is being produced by the MIT Energy Initiative (MITEI) to serve as balanced, fact-based, and analysis-driven guides to key topic areas in energy for a wide range of decision makers in government and industry. This study specifically aims to serve as a guide for policy makers, regulators, utilities, existing and startup energy companies, and other power-sector stakeholders to better understand the factors that are currently driving change in power systems worldwide. The report distills results and findings from more than two years of primary research, a review of the state of the art, and quantitative modeling and analysis.

This study does not attempt to predict the future. We follow the dictum of poet and author Antoine de Saint Éxupéry: "As for the future, your task is not to foresee, but to enable it." We identify key barriers and skewed incentives that presently impede the efficient evolution of the power sector and offer a framework for regulatory and market reform, based on a comprehensive system of efficient economic signals, that will enable an efficient outcome, regardless of how technologies or policy objectives develop in the future.

MITEI's Utility of the Future study was supported by a consortium of 23 diverse organizations from across the energy sector, and it is complemented by [a] distinguished Advisory Committee and Faculty Committee. We gratefully acknowledge the support of the following consortium members at the Sponsor level: Booz Allen Hamilton, EDF, Enel, Engie, Gas Natural Fenosa, General Electric Corporation, Iberdrola, National Renewable Energy Laboratory, PJM, Saudi Aramco, Shell, US Department of Energy, and World Business Council for Sustainable Development. At the Participant level we wish to thank: The Charles Stark Draper Laboratory, Duke Energy, Enzen, Eversource, Lockheed Martin, NEC Corporation, PSE&G, Siemens, and Statoil. At the Observer level we wish to thank Paul and Matthew Mashikian. In addition to providing financial support, a number of our sponsors provided data that were helpful for our modeling activities. We are very grateful for this assistance.

Our Advisory Committee members dedicated a significant amount of their time to participate in meetings and to comment on our preliminary analysis, findings, and recommendations. We would especially like to acknowledge the efficient conduct of Advisory Committee meetings under the able and experienced direction of Chairman Philip R. Sharp and Vice Chairman Richard O'Neill.

This study was initiated and performed within MITEI. Professor Robert Armstrong has supported this study in his role as director of MITEI and as an active participant in the faculty committee. Louis Carranza, associate director of MITEI, structured the commercial model and worked closely with study executive director Raanan Miller in assembling the consortium members. MITEI staff provided administrative and financial management assistance to this project; we would particularly like to thank Emily Dahl, Debra Kedian, Francesca McCaffrey, Chelsey Meyer, Jennifer Schlick, Jessica Smith, and Kelley Travers for communications and event support. Finally, we would like to thank Kathryn O'Neill and Marika Tatsutani for editing this document with great skill and patience, and Opus Design for layout and figure design.

This report represents the opinions and views of the researchers who are solely responsible for its content, including any errors. The Advisory Committee and the Study Consortium Members are not responsible for, and do not necessarily endorse, the findings and recommendations it contains.

This report is dedicated to the memory of our friend and colleague Stephen Connors.

Executive Summary

Important changes in the provision and consumption of electricity services are now underway, driven to a significant degree by a confluence of factors affecting the distribution side of power systems. A variety of emerging distributed technologies — including flexible demand, distributed generation, energy storage, and advanced power electronics and control devices — are creating new options for the provision and consumption of electricity services. At the same time, information and communications technologies are rapidly decreasing in cost and becoming ubiquitous, enabling more flexible and efficient consumption of electricity, improved visibility of network use, and enhanced control of power systems.

These technologies are being deployed amidst several broad drivers of change in power systems, including growth in the use of variable renewable energy sources such as wind and solar energy; efforts to decarbonize the energy system as part of global climate change mitigation efforts; and the increasing interconnectedness of electricity grids and other critical infrastructure, such as communications, transportation, and natural gas networks.

The MIT Energy Initiative's *Utility of the Future* study presents a framework for proactive regulatory, policy, and market reforms designed to enable the efficient evolution of power systems over the next decade and beyond. The goal is to facilitate the integration of all resources, be they distributed or centralized, that contribute to the efficient provision of electricity services and other public objectives. This framework includes a comprehensive and efficient system of market-determined prices and regulated charges for electricity services that reflect, as accurately as possible, the marginal or incremental cost of providing these services; improved incentives for distribution utilities that reward cost savings, performance improvements, and long-term innovation; reevaluation of the power sector's structure to minimize conflicts of interest; and recommendations for the improvement of wholesale electricity markets. This study also offers a set of insights about the roles of distributed energy resources, the value of the services these resources deliver, and the factors most likely to determine the portfolio of cost-effective resources, both centralized and distributed, in different power systems. We consider a diverse set of contexts and regulatory regimes, but focus mainly on North America and Europe.

This study does not try to forecast the future or predict which technologies will prevail. Instead, it identifies unnecessary barriers and distortionary incentives that presently impede the efficient evolution of the power sector and provides a framework that will enable an efficient outcome regardless of how technologies or policy objectives develop in the future. In addition, we recognize that regulatory and policy reform often proceeds incrementally and that each jurisdiction faces

unique challenges and contexts. As such, we offer this framework along with guidance on the key trade-offs regulators and policy makers confront as they pursue opportunities for progressive improvements.

The measures identified in this study could produce significant cost savings. Low-cost information and communications technologies and advanced metering enable more cost-reflective prices and charges for electricity services that can finally animate the "demand side" of the power system and align myriad decisions with the optimization of net social welfare. Efficient prices and charges will unlock flexibility in electricity consumption and appropriately value the services that distributed energy resources provide. To date, power systems have been designed to meet infrequent peaks in demand and to comply with engineering safety margins established in an era when electricity customers were largely inflexible and blind to the true costs and potential benefits of their electricity consumption or production decisions. In many cases, this has resulted in costly and significantly underutilized infrastructure. Smarter consumption of electricity and, where cost-effective, the deployment of distributed energy resources, could deliver billions of dollars in savings by improving the utilization of electricity infrastructure.

At the same time, the need for proactive reform is clear. Customers now face unprecedented choice regarding how they get their power and how they manage their electricity consumption — regardless of whether they are aware of those choices or are acting on them today. New opportunities include the ability to invest in distributed generation, smart appliances, and energy efficiency improvements. At present, the vast majority of power systems lack a comprehensive system of efficient prices and regulated charges for electricity services. As a result, some customers are making inefficient investments and are overcompensated for the services that they provide to the power system. At the same time, many more opportunities that could deliver greater value are being left untapped because of inadequate compensation. For example, the combination of simple volumetric tariffs and net metering policies has contributed to the rapid adoption of rooftop solar photovoltaics (PV) in several jurisdictions, while exposing several flaws in current ratemaking. The rapid uptake of solar PV also demonstrates how quickly customers can react to economic signals — whether well or poorly designed — and the importance of proactive, rather than reactive, policy-making and regulation. In multiple jurisdictions, challenges that once seemed insignificant have quickly become overwhelming, and failure to act can catch policy makers and regulators flat-footed.

The framework proposed in this study is designed to establish a level playing field for the provision and consumption of electricity services, whether via centralized or distributed resources. The goal is to remove inefficient barriers to the integration of cost-effective new sources of electricity services, rethink ill-designed incentives for certain resources, and present a system of prices and charges that can animate efficient decisions. With this framework in place, all customers and producers of electricity services can make efficient choices based on accurate incentives that reflect the economic value of these services and their own diverse personal preferences.

This study highlights several core findings:

The only way to put all resources on a level playing field and achieve efficient operation and planning in the power system is to dramatically improve prices and regulated charges (i.e., tariffs or rates) for electricity services.

- To establish a level playing field for all resources, cost-reflective electricity prices and regulated charges should be based only on what is metered at the point of connection to the power system — that is, the profile of injections and withdrawals of electric power at a given time and place, rather than the specific devices behind the meter. In addition, cost-reflective prices and regulated charges should be symmetrical, with injection at a given time and place compensated at the same rate that is charged for withdrawal at the same time and place.
- Increasingly affordable information and communications technologies (e.g., advanced meters or interval meters) enable detailed monitoring of electricity withdrawals and injections and therefore facilitate more efficient prices and charges. Without more accurate consumption and injection data from all customers, it is impossible to capture the full value of electricity services.

- Flat, volumetric tariffs are no longer adequate for today's power systems and are already responsible for inefficient investment, consumption, and operational decisions.
- Peak-coincident capacity charges that reflect users' contributions to incremental network costs incurred to meet peak demand and injection, as well as scarcity-coincident generating capacity charges, can unlock flexible demand and distributed resources and enable significant cost savings.
- Granularity matters. The value or cost of electricity services can vary significantly at different times and at different locations in electricity networks. Progressively improving the temporal and locational granularity of prices and charges for these services can deliver increased social welfare. However, these benefits must be balanced against the costs, complexity, and potential equity concerns of implementation.
- Care must be taken to minimize distortions from charges that are designed to collect taxes, recover the costs of public policies (such as efficiency programs, heating assistance, subsidies for renewable energy, cross-subsidies between different categories of customers, etc.), and recover residual network costs (i.e., those network costs that are not recovered via cost-reflective charges).
- Policy makers and regulators must be wary of the possibility of societally inefficient "grid defection" if residual network costs and policy charges become too high. This may suggest an upper limit on the portion of these costs that can be collected in electricity tariffs rather than through broader taxes or other means.

The regulation of distribution utilities must be improved to enable the development of more efficient distribution utility business models.

- Forward-looking, multi-year revenue trajectories with profit-sharing mechanisms can reward distribution utilities for cost-saving investments and operations, aligning utilities' business incentives with the continual pursuit of novel solutions.
- Several "state of the art" regulatory tools, including an incentive-compatible menu of contracts, an engineering-based reference network model, and automatic adjustment factors to account for forecast errors, can better equip regulators for an evolving and uncertain electricity landscape.
- Equalizing financial incentives related to capital and operational expenditures can free utilities to pursue cost-effective combinations of conventional investments and novel operational expenditures (including payments to distributed resources).
- Outcome-based performance incentives can reward utilities for improvements in quality of service, such as enhanced resiliency, reduced distribution losses, and improved interconnection times.
- Incentives for longer-term innovation are needed to accelerate investment in applied R&D and demonstration projects and learning about the capabilities of novel technologies and practices that may have higher risk or longer-term payback periods.

The structure of the electricity industry should be carefully reevaluated to minimize potential conflicts of interest.

- Network providers, system operators, and market platforms constitute the critical functions that sit at the center of all transactions in electricity markets. Properly assigning responsibilities for these core functions is thus critical to an efficient, well-functioning electricity sector. It is also critical to establish a level playing field for the competitive provision of electricity services by traditional generators, network providers, and distributed energy resources.
- As experience with restructuring in the bulk power system has demonstrated, structural reform that establishes financial independence between distribution system operation and planning functions and competitive market activities would be preferable from the perspective of economic efficiency and would facilitate more light-handed regulation.
- If financial independence is not established, several additional measures are critical to prevent conflicts of interest and abuses of market power. These include: stricter regulatory oversight of distribution network planning and operation; legal unbundling and functional restrictions on information exchange and coordination between distribution system operators and competitive subsidiaries; and transparent mechanisms for the provision of distribution system services (such as public tenders or auctions).

- Maintaining a data hub or data exchange may constitute a fourth critical function. Such a hub or exchange would serve several purposes: securely storing metered data on customer usage, telemetry data on network operation and constraints, and other relevant information; allowing non-discriminatory access to this data to registered market participants; and providing end customers with timely and useful access to data on their own usage of electricity services. Responsibility for this function should also be carefully assigned, with priority given to data security and customer privacy considerations.

Wholesale market design should be improved to better integrate distributed resources, reward greater flexibility, and create a level playing field for all technologies.

- Wholesale markets should enable transactions to be made closer to real time to reward flexible resources and to enable better forecasting and control of variable renewable resources and electricity demand.
- Wholesale market rules such as bidding formats should be updated to reflect the operational constraints of novel resources such as demand response and energy storage, as well as new patterns of operation of conventional power plants.
- More efficient pricing of reserves can help wholesale markets function better, improve price signals for energy and operating reserves, and strengthen the link between these two services.

Widespread connection of distributed energy resources and smart appliances and development of more complex electricity markets increase the importance of cybersecurity and heighten privacy concerns.

- Robust regulatory standards for cybersecurity and privacy are needed for all components of an interconnected electricity network.
- To keep pace with rapidly evolving cybersecurity threats against large and complex electric power systems, electric utilities, vendors, law enforcement authorities, and governments should share current cyber threat information and solutions quickly and effectively.

Better utilization of existing assets and smarter energy consumption hold great potential for cost savings. At the same time, economies of scale still matter, and the distributed deployment of solar PV or energy storage is not cost-effective in all contexts and locations.

- The value of some electricity services can differ substantially depending on where within the power system that service is provided or consumed. This variation in "locational value" underscores the importance of locationally granular prices and charges and makes it impractical to define a single value for any distributed resource.
- Distributed energy resources can be sited and operated to provide services in those areas of the power system where their services are most valuable. Understanding the specific services that have locational value is thus critical to understanding how distributed resources can create value in power systems.
- Unlocking the contribution of resources that already exist — such as flexible demand, electric vehicles, power electronics, or distributed generation that is already deployed — can be an efficient alternative to investing in electricity generation and network capacity.
- Economies of scale still matter, even for distributed energy resources. For resources that can be deployed at multiple scales, such as solar PV and battery energy storage, incremental costs associated with failing to exhaust economies of unit scale can outweigh locational value. This can result in a "distributed opportunity cost," making distributed deployment of these resources inefficient. Trade-offs between the incremental costs and additional locational value associated with deploying distributed resources on a smaller scale must be considered in each context.
- For resources that exhibit significantly higher unit costs at smaller scales, such as solar PV and battery energy storage, distributed deployment is likely to be inefficient in many locations. Exceptions may include areas that have heavily congested networks or that are experiencing rapid growth in electricity demand. In these areas, locational value may be significant.
- New innovations may transform economies of unit scale for solar energy or storage technologies, enabling more ubiquitous distributed deployment of these resources.

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