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To: Matthew McDonnell and Dave Parsons at Hawaii Public Utility Commission

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Subject: **Market Track Considerations for Hawaii PUC¹**

Introduction

This memo recommends approaches and processes, and provides examples, to guide the Hawaii Public Utilities Commission (HPUC) as they move beyond customer grid supply and customer self-supply tariff options into the market track of the distributed energy resources (DER) proceeding 2014-0192. This memo includes sections addressing each of the following:

- Context
- Tying markets to operations
- Bigger question of what types of problems are best addressed by markets
- Stakeholder input and market principles
- Procurement guidelines
- Planning for market evolution
- Non-wires alternatives
- Options for unbundled value and rate designs
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 - Appendix B – California Competitive Solicitation Working Group
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Context

As the most oil-dependent state in the United States, Hawaii spends approximately \$3 billion a year on imported oil to support its energy needs. Hawaii's reliance on oil for power generation is a major reason its electricity prices are the highest in the nation (29.87 cents/kWh compared to the national average of 12.93 cents/kWh).²

A fundamental principle of Hawaii's state energy policy is energy self-sufficiency and security, and the state has a formal goal of achieving 100% renewable generation by 2045. To that end, Hawaii now has the highest penetration levels of solar photovoltaics (PV) in the country. The Hawaiian Electric Companies³ (HECO or the Companies) predict the penetration of distributed PV to reach 17% by 2020. This, in combination with non-distributed renewables including an additional 9% from utility PV, will help Hawaii achieve a portfolio that is 48% renewable by 2020 (HECO 2016.).

In performing research for this document, the author spoke to national experts in distribution systems, markets, grid architecture, and integrated planning. What follows is a compilation of suggestions and examples from the author augmented by input from the experts. The author thanks Jeffrey Taft and Jason Fuller from Pacific Northwest National Laboratory (PNNL), Lorenzo Kristov from California Independent System Operator (CAISO), and Paul De Martini from Caltech for their insights.

Tying markets to operations

Markets should not be ends unto themselves

In his paper, *Evolving Distribution Operational Markets*, Paul De Martini and co-authors make the point that markets should not be an end unto themselves. Markets should be designed to solve real problems. De Martini suggests "Market animation should align to the utility's identified grid needs and the commercial needs of the DER providers" (De Martini et al. 2017).

Start with the Challenge

Hawaii should start with identifying specific challenges that need to be addressed. Once specific and pressing challenges are identified, desired outcomes can be summarized along with specific answers to the question, "what would solutions look like?" From there, market and non-market options for addressing the challenges and providing the desired outcomes can be explored. At that point, HPUC can study examples from around the country and the world to see who has experience with different types of solutions, including market-based solutions, and what can be learned from them. Figure 1 shows the process steps for assessing potential distribution system solutions.

² From EIA http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a

³ The "Hawaiian Electric Companies" are Hawaiian Electric Company, Inc; Hawai'i Electric Light Company, Inc; and Maui Electric Company, Ltd.

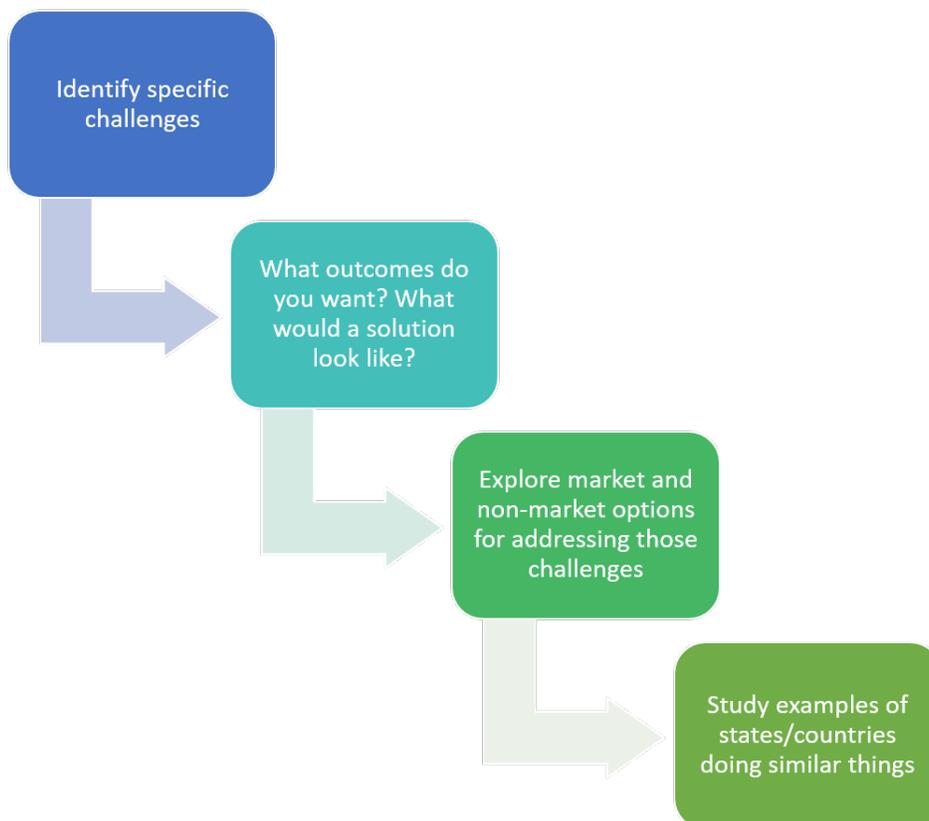


Figure 1. Process steps in assessing potential distribution system markets.

Generally, key issues for Hawaii are safely and securely providing grid services with 100% renewables in a way that reduces costs for everyone and provides customer choice. HECO’s 2017 Grid Modernization Plan describes some of the specific challenges Hawaii is facing. Namely, that Hawaii is closer than any other jurisdiction to experiencing the effects of high levels of DER penetration on system operations and reliability. Near-term identified challenges include (HECO 2017) the following:

- Reaching system level hosting capacity level, at which uncontrolled customer energy production exceeds the system’s capability to absorb the energy they produce.
- Reaching circuit hosting capacity levels, at which expenditures in new infrastructure are necessary to accommodate more export DER.

In a phone conversation, Lorenzo Kristov emphasized that a key challenge and “grid service” that is needed for Hawaii is flattening load profiles, at both the system level and the distribution circuit level, by shifting supply from the middle of the day to the peak hours of the afternoon or the net peak hours after solar production declines. This is a service not captured by traditional ancillary services (Kristov 2017). This will likely be a service Hawaii will address first through market or non-market means.

Markets should address head on operational challenges resulting from DER

Lorenzo Kristov from CAISO emphasized the need to make sure Hawaii addresses head on the operational challenges that renewables pose to the grid. There are operational effects when the

exogenous generation profile of solar power is substantially different from the system load profile. Additionally, short-term output and voltage variability is difficult to manage and, based on his experience, ramp rates of solar PV can be extremely fast, leading to frequency excursions. Once challenges are identified, solutions—potentially market solutions—can be designed in ways to mitigate the challenges. If too much emphasis is placed on markets as a goal while operational problems go unsolved, the problems can be exacerbated (Kristov 2017).

Do not divorce financial transactions from the physical system

In conversation, Jeffrey Taft emphasized that the physical system and financial transactions need to remain connected (Taft 2017). They should be considered, designed, implemented, monitored, and adjusted together. During the California energy crisis, from which it took years to recover, the energy spot market was operated independently of the physical transmission grid operation (De Martini et al. 2017). Hawaii needs to carefully consider and understand the intimate link between economic markets and electric system operations. Ultimately, grid signals should be the basis for market operations. Financial transactions/market transactions should not be independent of operational signals.

For any group considering creating new market structures, it is important to understand just how closely integrated the market and grid control mechanisms are in the various ISO/RTO wholesale markets. While there is no cookie cutter template for DER markets, understanding how this is done is very informative of the range of issues to be handled. It is also important to understand that if DER markets are to be implemented at the distribution level, there are complicating issues that do not arise at the bulk system level (lack of grid observability, unbalanced three phase operation). These might not seem like market issues initially, but end up impacting market implementations (Taft 2017).

Bigger question of what types of problems are best addressed by markets

Answer the bigger question of what problems are best addressed by market or by other approaches

Some schools of thought suggest it is good to identify all services provided by DER, parse them, and provide compensation for each one separately through a market framework. This can quickly become complicated and requires extensive sensors, communication and control systems, measurement rules and compensation mechanisms. There may be better and simpler ways acquire necessary grid services.

Certain distribution services may be better provided through non-market solutions. Some distribution system services may be better addressed as contractual interconnection or tariff requirements (e.g., visibility and certain minimum inverter functions such as voltage ride-through). In conversation, PNNL's Jeffrey Taft suggested another alternative to markets that should be considered—characterizing key distribution system services provided by the utility as core infrastructure. It may make sense to consider storage and the services storage provides as core infrastructure, rather than ancillary services (Taft 2017).

Through storage you're expanding operational capabilities, providing more resilience, and managing volatility so that volatility is not exported to the bulk system. Storage has huge potential value in addressing 1) short-term volatility (from clouds passing, for example) and 2) mitigating the extreme load profile (the "duck curve" phenomenon in California). Storage and dynamic demand management acquired through markets or as core infrastructure have real possibilities for Hawaii (Kristov 2017).

When something is treated as core infrastructure, we apply a different model for cost effectiveness. Rather than cost-benefit analysis, a best fit, and least cost approach applies. In a core infrastructure approach, comprehensive, detailed, and transparent planning is necessary to ensure core infrastructure investments are needed and made in the best interests of customers and the system.

Core infrastructure options and requirements or mandates should be considered along with market solutions. Transaction costs, visibility, controllability, latency, communication system infrastructure needs and cost, privacy, security, relative firmness/availability, and customer willingness are all factors that should influence the choice. Extensive stakeholder involvement should be engaged in developing appropriate characterizations.

Stakeholder input and market principles

Include all stakeholders in market development, particularly market participants

Stakeholders should be involved in all the steps described in Figure 1. In particular, market participants must participate in market design. The Commission or utility should not decide where to apply markets and what the market design will be without meaningful stakeholder engagement. Market participants must be heard. Hawaii can learn from New York in this regard; there, a market system was designed, but none of the battery or energy service providers wanted what was developed. Markets must be workable and beneficial to buyer and seller. The conversation is critical. For example, when it comes to financial contracts, the minimum contract term that is useful and viable must be determined. Developers should have a say in what contract terms are reasonable for them.⁴ A market is no good if no one shows up and wants to participate in it.

In New York, as part of the Distributed System Implementation Plan proceeding, the Commission required the formation of nine different implementation teams to “inform stakeholders of implementation progress, solicit feedback on implementation progress, achieve alignment for moving forward, and incorporate stakeholder input into implementation plans as applicable.” The implementation team topics were (JU NY 2017) as follows:

1. Customer Data
2. DER Sourcing + Non-wires Alternatives Suitability
3. Electric Vehicle Supply Equipment
4. System Data
5. Monitoring & Control
6. New York Independent System Operator (NYISO)/Distributed System Platform
7. Hosting Capacity
8. Load/DER Forecasting
9. Interconnection – Interconnection Technical Working Group and Interconnection Policy Working Group.

Additionally, as part of Phase 2 of the Value of DER proceeding in New York, the Public Service Commission required the formation of three working groups to address issues associated with 1) the Value Stack, 2) rate design, and 3) low and moderate income customers (NY PSC 2017a). Similarly, in California, as part of the Distribution Resource Planning Proceeding (R.14-08-013), both an Integration

⁴ Another option here would be to hire a consultant to do market interviews.

Capacity Analysis and Locational Net Benefits Analysis working group were formed to monitor and support demonstration projects and continue to improve and refine methodologies (CPUC 2016). The working groups are open to the public and are informal in nature. The Energy Division staff of the California Public Utility Commission (CPUC) have oversight responsibility for the working groups, but the groups are managed by the utilities and interested stakeholders.

Stakeholder input and participation must be timely

In the stakeholder process, it is important that participants, other than the utility, have the opportunity to make meaningful contributions early in the development of potential solutions. Stakeholder engagement in the process should occur early enough that their input is gathered before final determinations are made. The most effective time for acquiring stakeholder input is not after a utility has fully developed a proposal and is presenting it to the Commission. The time for meaningful stakeholder participation is during the creative development of solutions, ideally through a structured, Commission-initiated and facilitated process. This is especially true in Hawaii because of the complexity and pressing nature of the issues at hand.

Develop a set of market principles

Lorenzo Kristov suggested that an overarching set of principles be developed to guide the evaluation and implementation of markets in Hawaii. The following overarching goals or principles developed for the Utility Business Models RFP by the Hawaii Energy Office may be a good place to start (NCEC 2017):

- Achieve state energy goals.
- Maximize consumer cost savings.
- Enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer needs.
- Eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation.

The importance of setting the objectives well early on cannot be overstated. Objectives can significantly change how DER are treated not just in markets but throughout the entire architecture (Taft 2017). Hawaii may want to consider as a key strategy for achieving these goals, to implement incentives and mechanisms to manage locally-generated variability locally. Conversations with Lorenzo Kristov emphasized the importance and value of managing local variability locally. He pointed out that in California, a significant portion of the notorious “duck curve” is made up of a lot of little distribution circuit-level “ducklings.” Extreme local generation profiles contribute to the extreme system-level net load profile (Kristov 2017).

Guiding principles should be developed with formalized stakeholder input, particularly by the potential future market participants.

Procurement guidelines

Consider collaboratively developed clear procurement guidelines

Clear guidance for how procurements will be performed is needed, including what information should be provided in the terms and conditions of the contracts, participant rules, specific products and services to be offered, how contracts will interact with wholesale and other markets, and generally how procurements will be accomplished (for example with third-party aggregators for demand response).

Hawaii can consider how other states have developed these guidelines. In California, a detailed Competitive Solicitation Working Group developed a Competitive Solicitation Framework. In New York, a Market Design and Platform Technology Working Group developed a final report with detailed recommendations.

Appendix A contains details about California’s Competitive Solicitation Working Group.

Appendix B contains details and recommendations from New York’s Market Design and Platform Technology Working Group.

Planning for market evolution

It is natural that there will be a market evolution in Hawaii. It is recommended that Hawaii start with greatest need and simplest application and move from there. That is, start with the largest and most tangible value potential first (De Martini et al. 2017). Detailed markets for unbundled distribution services are likely not the best place to start due to complexity, transaction costs and supporting infrastructure requirements (communications, controls, etc.).

However, near-term, low-hanging fruit solutions should not preclude more complex and higher level market solutions over time. Near-term solutions should be thoughtfully designed to support a sequential and iterative process that allows for next evolution solutions as the need arises. For example, situational awareness systems (sensors and measurement devices), data collection and sharing, and communication systems should be designed with potential future market phases in mind.

Paul De Martini suggests three phases of market evolution (De Martini et al. 2017):

- non-wires alternatives
- real-time operations markets
- operational controls.

Many consider non-wires alternatives (NWAs) to traditional investments the low-hanging fruit when it comes to distribution system markets. However, whether any given utility can actually realize benefits involves a number of complicating factors and one should not have the impression that there is automatically a large amount of value to be easily had through NWAs (Taft 2017). NWAs can be secured through the three Ps - open competitive procurements, pricing, and programs (De Martini et al. 2017).

Real-time operations markets that provide reliability and resilience and manage losses and constraints may be viable options in the future, such as beyond 2025 (De Martini et al. 2017).

Operational controls—where DER (particularly inverters tied to PV systems and batteries) provide a means for controlling operations to manage voltage and reactive power—may be provided over the next 10 years through a tariff or subscription structure (De Martini et al. 2017).

Non-wires alternatives

New York and California are actively moving forward with NWAs for deferring or substituting for distribution infrastructure upgrades. In New York, significant substation and conductor upgrades are needed to accommodate load growth in certain areas. Non-wires solutions are being explored to

obviate the need for these upgrades. In California, NWAs, through the Integrated DER proceeding, are being used to eliminate the need for traditional investments.

In Hawaii, however, load growth is relatively flat and there's not a big need for NWAs to meet load growth with DER. The ongoing infrastructure replacements in Hawaii are not typical candidates for NWAs.

NWAs do apply in Hawaii for accomplishing the items listed below while systematically decreasing reliance on fossil fuels:

- increasing circuit hosting capacity for solar PV
- managing short-term volatility, and
- mitigating extreme load and supply profiles throughout the day with higher percentages of renewable generation.

Procuring services to address these issues can happen through a set of location-specific RFPs and/or through utility-owned assets characterized as core infrastructure, and/or through mandates or requirements associated with the interconnection of DER. Figure 2 suggests an NWA framework for Hawaii and the steps are detailed below.

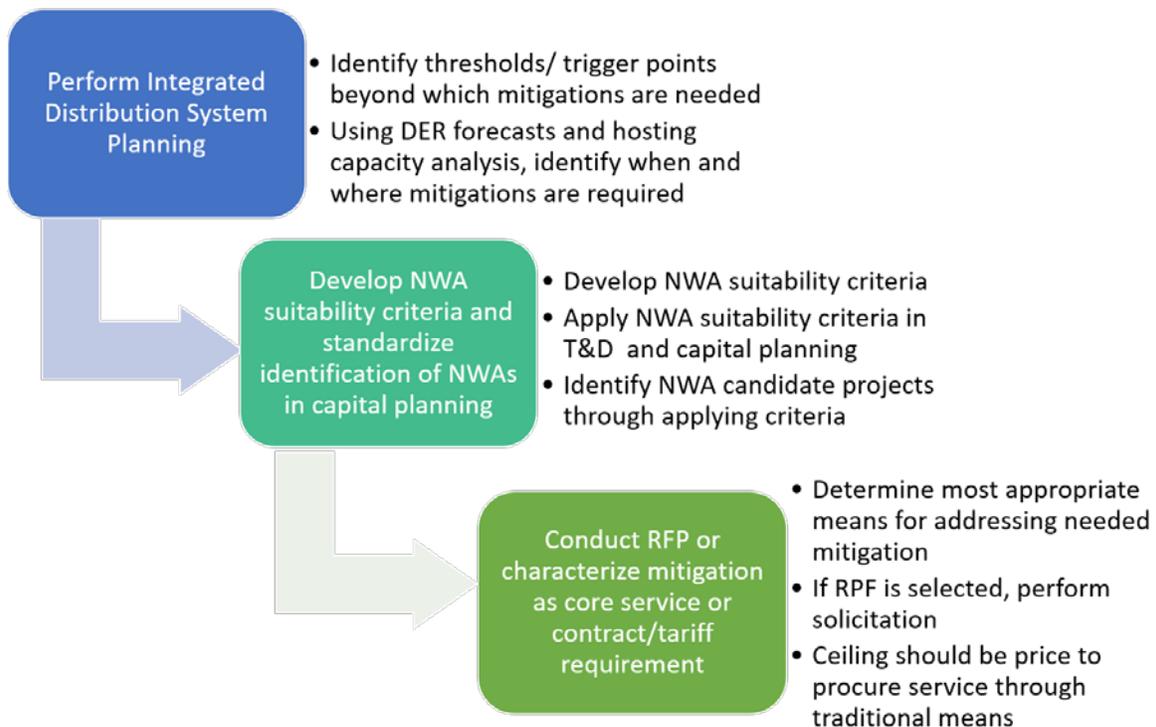


Figure 2 – Proposed Non-wires Alternatives Process for Hawaii.

Perform Integrated Distribution Planning

Through integrated distribution system planning, threshold levels (in general terms) and clear and specific triggers should be identified, beyond which operational problems arise on the grid that require mitigation. Then, through location-specific distribution planning, including projecting DER adoption and

net load profiles and performing hosting capacity analysis, it should be determined when specific identified (and agreed upon) thresholds are projected to be exceeded and where.

Develop NWA Suitability criteria

NWA Suitability, similar to what was developed in New York but tailored to Hawaii, should be developed to identify the characteristics of projects that are suitable for consideration as NWAs. As part of annual T&D needs assessments and capital planning, the NWA suitability criteria should be applied and NWA candidate projects identified.

Conduct RFP or secure NWA by other means

After candidate NWA projects are identified, an open and transparent process should be employed to determine whether the mitigation should be provided through an RFP, as a utility core service, or through interconnection or tariff requirements. In any case, the process should be standardized and systematically tied to HECO's annual T&D needs assessment and capital planning process.

In New York, development of NWA Suitability Criteria was a first step toward institutionalizing the process of identifying and securing alternative solutions to traditional grid investments. **Appendix C** describes New York's NWA process in detail, including how it is tied into the standard course of business in terms of capital planning.

Options for unbundled value and rate designs

Both New York and California have examples of unbundled value determinations. New York's Value Stack Tariff that was put forth as part of the Value of Distributed Energy Resources proceeding, is an example of an unbundled tariff design. California developed valuation components for distribution grid services competitive solicitations as part of the Integrated DER proceeding R.14-10-003. Each are briefly described below with more details provided in an appendix.

New York Value Stack Tariff

The Public Service Commission of New York issued a Value of DER order (VDER Order) in March 2017 that required utilities to put forward implementation proposals that addressed calculation of various benefits, compensation methodologies and cost allocation and recovery methodologies. Appendix D contains details on what was required by the NY PSC and what was provided by the New York utilities in implementation proposals (NY PSC 2017b).

California's valuation components for distribution grid services competitive solicitations

As part of the California Competitive Solicitation Working Group recommendations, a list of valuation components were identified. These components were then adopted by the Commission as a starting point for evaluating solicitation responses. The value components summarized below are to be used by the utilities in the incentive pilot established through the Integrated DER proceeding (R.14-10-003).

- **Quantitative Factors** – net market value, resource adequacy value, energy value benefit, ancillary services value benefit, renewables portfolio standard benefit, reduced greenhouse gas emissions benefit, renewable integration cost/reduced cost benefit, distribution deferral value, transmission deferral value, and contract payments cost

- **Qualitative Factors** – project viability, voltage and other power quality services, equipment life extensions, societal net benefits, and other factors such as supplier diversity, counterparty concentration, site diversity, and technology/end-use directory to help market transformation

Each of these is described in more detail in **Appendix E**.

Summary

The key points from this memo area summarized below:

- Markets should not be ends unto themselves. Markets should be used where they are determined to be the best approach to address specific challenges or objectives.
- Hawaii should address head-on operational challenges resulting from DER and renewable generation, in many areas using DER for that purpose.
- Financial and market transactions should not be divorced from physical systems, as was learned in the California energy crisis.
- Consider where markets are the best options and where mandates via interconnection or tariff requirements are the way to go. In some cases, distribution services may best be delivered by the utility as core services. In these cases, cost effectiveness is determined by least-cost, best-fit criteria rather than through traditional cost-benefit analysis. Transaction costs, visibility, controllability, latency, communication system infrastructure needs and cost, privacy, security, relative firmness/availability, and customer appetite are all factors that should influence the choice.
- Identifying and quantifying multiple value streams is not low hanging fruit when it comes to markets for DER. Instead, DER as non-wires alternatives to distribution infrastructure investment and for providing support to mitigate variability and shift demand and supply, are a good place to start, as evidenced by proceedings in New York and California.
- Market participants need to be included in the market design process. It is recommended that Hawaii formalize the stakeholder process early and not wait for utility proposals to engage stakeholders. It is especially important that future market participants be involved in any market design.
- Clear guidance for how procurements will be performed could be beneficial, including what information should be provided in terms and conditions of contracts, participant rules, specific products and services to be offered, how contracts will interact with wholesale and other markets, and generally how procurements will be accomplished.
- Hawaii should start with the largest and most tangible value potential. Initial indications are that the priority for Hawaii should be to employ DER as alternatives to new distribution infrastructure and for managing short-term volatility and mitigating extreme load and supply profiles throughout the day with higher percentages of renewable generation in a way that steadily decreases reliance on fossil fuels.

- Detailed markets for unbundled distribution services are not recommended as a place to start. Pricing, procurement and program methods are more straight forward and may be quite effective at satisfying grid and distribution system needs.
- Managing local variability locally, potentially through storage, can provide great value to system operation.
- New York's Value Stack Tariff that was put forth as part of the Value of Distributed Energy Resources proceeding, and the valuation components for distribution grid services competitive solicitations that were developed in California as part of the Integrated DER proceeding R.14-10-003 may provide models for Hawaii as they move into characterizing and securing important distribution system services.

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Appendix A – New York Non-Wires Alternatives Summary

In New York, the Commission directed a group of Joint Utilities to develop and apply non-wires alternatives (NWAs) suitability criteria that will be applied as a standard procedure in the development of T&D project justifications. Each utility was also required to identify in its five-year capital plan all projects that meet the criteria and when NWA solicitations will be issued for those projects. The Joint Utilities made a filing on May 8, 2017, to address a common NWA Suitability Criteria framework that utilities throughout New York will use. Included in the May 8 filing were appendices in which each individual utility summarized their own individual planning process, their capital work plan, and utility-specific NWA Suitability Criteria.

The proposed Suitability Criteria framework proposed by the Joint Utilities consists of three components to determine whether a project should be considered for an NWA. These are 1) project type, 2) timeline, and 3) cost. These three factors would serve as guidelines to help show where NWAs could be more cost-effective than traditional solutions (NY PSC 2017b, p. 19). Each is described in more detail below :

- **Project type** points to certain types of projects that better lend themselves to non-traditional solutions. For instance, load relief is a project type. Load relief would traditionally rely on solutions such as reconductoring, new substations or expansions, or transformer upgrades, but could also be addressed by EE, DR, or other DER.
- **Timeline** is the time needed to complete the procurement process, including developing and issuing an RFP, vendor response, technical review of proposals, contracting, and implementation.
- **Cost** is the floor amount, for which traditional projects with costs exceeding the floor would be considered for potential NWA solicitation. It is presumed that projects above the floor amount would be able to overcome transaction and opportunity costs (NY PSC 2017b).

The result of applying the NWA Suitability Criteria to the capital plan is a list of traditional infrastructure projects that are candidates for NWA solutions. RFPs will be filed for applicable NWA candidate projects. Starting in mid-May 2017 each of the Joint Utilities began posting on their respective websites the list of potential NWA opportunities along with preliminary descriptions and expected timing for solicitations (JU 2017b, page 8).

Each of the Joint Utilities identified their own NWA Suitability Criteria and proposed them to the Commission. In each utility filing, the project types identified were either or both of those that would provide load relief and/or reliability.

Appendix B – California Competitive Solicitation Working Group

This Appendix describes the California Competitive Solicitation Working Group (CSWG) approved recommendations and the approved valuation components for distribution grid services competitive solicitations.

To facilitate the development of a Competitive Solicitation Framework, a CSWG was developed as part of the Integrated DER proceeding (R.14-10-003). The CSWG also supports the Distribution Resource Planning proceeding in California.⁵ The framework to be developed by the CSWG was required to address the following seven items:

1. Define the services to be bought and sold within the identified area. Definitions must include details on expected reliability and other performance requirements, as well as any constraints on how DER can meet identified needs.
2. Develop methodologies to count services provided and ensure no duplication with procurement in other proceedings; i.e., ensure resources are incremental to existing efforts to avoid double-counting of resources.
3. Develop solicitation rules or principles such as constraints on procurement; e.g., floors and ceilings on volume procured, price paid, etc.
4. Develop solicitation oversight needs; e.g., procurement plans, procurement review groups, etc.
5. Develop a solicitation evaluation methodology that includes the valuation of any deferred distribution system upgrade.
6. Develop solicitation pro forma contract(s).
7. Develop outreach plans to ensure robust participation in the competitive solicitation.

The final Commission order addressing the working group recommendations also required that the utilities hire an industry consultant with expertise in DER and contracting to observe the pilot process and assist in developing a technology-neutral pro forma contract for future use in the Competitive Solicitation Framework.⁶ The utilities are also required to enter into a contract with an independent professional engineer to advise in developing bid evaluation methods, prepare reports on distribution planning process proposals and the DER deferral process, and provide presentations to different groups (Distribution Planning Advisory Group and Procurement Review Group).

The final report of the CSWG was issued on August 1, 2016, and can be found [here](#). On December 15, 2016, the California Commission adopted D16.-12-036, which adopted a Competitive Solicitation Framework. The decision re-established the Competitive Solicitation Framework Working Group which, along with the CPUC Energy division and an industry consultant, is tasked with developing a technology-neutral pro forma contract for future use.⁷

⁵ Initial report of working group is located here:

<http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=12211>

⁶ <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF>

⁷ <http://www.cpuc.ca.gov/General.aspx?id=10710>

The final order ([here](#)) identified the distribution services that DER can provide to address a distribution grid need are Energy (up/down); Capacity (up/down); and Voltage/Volt Ampere Reactive services (up/down). Also, it was determined that data being gathered from distributed energy sources that are incremental to data required for safe and reliable operation of the distribution grid have value and in some yet to be determined cases could be provided as a service.

The working group agreed on the following three principles for valuation:

1. Consider the potential services, benefits, and costs beyond what is asked for in the solicitation and other conceivable benefits/costs provided by distributed energy resources as qualitative factors.
2. Continue to refine the evaluation method and integrate lessons learned.
3. Avoid double-counting the benefits and costs.

To ensure that there is no duplication of procurements in other proceedings (i.e., ensure services are incremental to existing efforts and avoid double-counting services), it was determined that in the pilot, the method used to count services shall:

- ensure that ratepayers are not paying twice for the same service;
- ensure the reliability of a service; i.e., ensure it is not counting on a service to be there when the service might be deployed at another time or place;
- not be unduly burdensome to participants;
- be technology neutral;
- be fair and consistent;
- recognize that a DER is eligible to provide multiple incremental services and be compensated for each service; and
- be flexible and transparent to bidders.

12 principles that should apply to the Competitive Solicitation Framework:

- Framework meets the identified need on a least-cost, best-fit basis.
- Framework uses a competitive process with broad markets.
- Framework is technology neutral.
- Framework is transparent as allowed within confidentiality boundaries.
- Framework identifies a need without prejudging the technology.
- Framework does not limit the amount of any one type of technology.
- Framework is a streamlined process.
- Framework is a fair and consistent process.
- Framework focuses on the identified need.
- Framework provides sufficient assurance of performance.
- Framework allows for flexibility in the number and type of bids.
- Framework includes a lessons-learned feedback loop.

Appendix C – New York Market Design and Platform Technology Working Group

New York also had a Market Design and Platform Technology Working Group that issued a final report in August 2015 (accessible [here](#)). A key principle here was that the mission for the first 5 years of the market development stage 1 is to effectively procure DER, using market means to the maximum extent appropriate, to directly address distribution system operational needs and to avoid or defer the need for future distribution system capacity additions. In New York, a lot of emphasis is put on the need for and roles of a distributed system platform (DSP). The report notes that one of the core functions of the DSP is to develop and implement vibrant markets for distribution system products and services.

Recommended DSP functions related to markets include the following:

- identifying the standardized products to be transacted and the associated market rules with stakeholder and Commission involvement;
- maintaining an awareness of DER system-wide;
- designing and conducting RFPs or auctions to acquire DER;
- facilitating and processing market transactions; and
- measuring and verifying participant performance.

A first step is to identify specific locations within the distribution system that are of priority for distribution capacity and operational relief.

The New York group also pointed out the importance of data in DER-related markets. The report recommends making customer and distribution system data available to market participants at a degree of granularity and in a manner that will best facilitate market participation. The report articulates the areas of need for specific types of data, the current availability of such data, data interface issues, and the specific data necessary for DSP planning and operations functions. It was recommended that the expansion of data collection and availability could be prioritized for those areas that are in the greatest need of system capacity and operational relief.

The final report included the following specific recommendations for items relative to distributed market operations that should be included in utility distributed system improvement plans that New York utilities are required to file:

1. Define the organizational structure and role of the market operations organization within the distributed system platform (DSP).
2. Outline the outreach and coordination efforts that will facilitate the sourcing of assets for distribution grid services and development of distribution markets.
3. Outline a structure for coordinating resources, including an approach for coordinating among wholesale Independent System Operator markets, retail providers, and distribution operations.
4. Identify plans for integrating systems into utility operations using a common approach—developed across DSPs—for the following functions:

- a. Measuring and verifying the performance of participating DER.
 - b. Operating a communications portal, as well as the interface for managing market participant registration and activity.
 - c. Tracking schedules from DER that have the ability to schedule their generation or consumption.
 - d. Managing settlements, including billing, receiving, and cash management and the interfaces needed with the utility CIS to perform cash management.
 - e. Managing disputes that will be developed to support the DSP market operations capability.
5. Outline the capabilities necessary to ensure market security, legitimacy, and optimization, and specify which entity(ies) should perform which functions.
 6. Describe plans for providing longer-term signals to potential market participants and provide sufficient lead time to energy service providers and customers for successful market development.

Appendix D – Proposed Application of New York’s Value Stack Tariff

The Public Service Commission of New York issued a Value of DER order (VDER Order) in March 2017 that required utilities to put forward implementation proposals that addressed, at a minimum, the following items: (NY PSC 2017b)

- calculation and compensation methodologies for a Demand Reduction Value (DRV);
- identification of, compensation for, and MW caps for Location-Specific Relief Value (LSRV) zones;
- proposed methods and values for providing Capacity Values for the Value Stack using different methods;
- identification of average generation profiles for capacity and DRV compensation in a project’s first year of operation;
- cost allocation and recovery methodologies for each component of the Value Stack with emphasis on issues associated with capacity compensation;
- the practicality of allocating and collecting costs associated with DER compensated under Phase One net energy metering (NEM);
- proposed accounting transactions and ratemaking treatment;
- utility processes for managing billing and tracking bill credits;
- reporting procedures for tracking progress in tranches and any other necessary reporting; and
- draft tariffs stating the Market Transition Credit (MTC) for the residential and small commercial classes, for each tranche (including rules for how the MTC, DRV, and LSRV will be applied to community distributed generation).

The Joint Utilities of New York made a filing in April 2017 that laid out a work plan to consider additional potential sources of value created by DER through a Value Stack methodology and tariff. The basics of the Value Stack tariff, as proposed, are summarized below (PMT 2017):

- Eligible projects will get paid for a term of 25 years from their in-service date.
- To get paid through a value tariff, projects must have metering that can record net hourly consumption and injection.
- Payments under the tariff are based on the following:
 - ENERGY – Day-ahead hourly zonal locational marginal price inclusive of losses (eventually moving to subzonal prices).
 - CAPACITY – Capacity value is based on retail capacity rates for intermittent technologies, and will be different for dispatchable DER including intermittent resources paired with storage. Capacity payments for intermittent resources remains similar to the old system,

based on supply charge for service class and the load profile is most similar to solar generation profile.

- ENVIRONMENTAL – Environmental value is the higher of the latest Tier 1 REC procurement price established by NYSERDA or the social cost of carbon.
- DEMAND REDUCTION and SYSTEM RELIEF – DRV and LSRV are based on de-averaging the utility marginal cost of service studies, performance during the 10 peak hours, and other factors described in Appendix C.
- Costs associated with new Value of Distributed Energy Resources (VDER) payments will be collected proportionally from the same group of customers that benefit from the savings associated with the DER projects. Where compensation does not reflect a value that has been identified and quantified, recovery will come from customers within the same service class as the beneficiaries.

The table below contains details about the proposed quantification, valuation, compensation, and cost recovery of Value Stack components by two New York utilities: Con Edison and National Grid. Details in Appendix D include how LSRV areas are identified, how rates are calculated, compensation methodologies, different ways to calculate capacity values, and cost allocation and recovery methodologies. Included later in this appendix is a table showing Con Edison's specific recommendations for cost allocation and recovery of Value Stack payments.

Specific Value of DER elements from implementation plans of two New York utilities: Con Edison and National Grid

	Con Edison⁸	National Grid⁹
Identification of Locational System Relief Value (LSRV) areas	<p>LSRV areas are those where projected energy use in 2021 reaches or exceeds</p> <ul style="list-style-type: none"> • 98% of the current capability for high voltage sub-transmission lines that supply area stations; or • 98% of the current capability for area stations that supply distribution network or non-network load areas; or • 90% of the current capability in distribution network areas. <p>Applying these thresholds, just over 19% of Con Edison service territory is eligible to qualify for an LSRV.</p>	<p>To identify LSRV areas, the company scaled loads on all distribution substations to 2020 and then screened against planning ratings to identify potential loadings above those ratings.</p> <p>53 specific substations were identified as LSRV areas, representing 16.4% of the company’s total system load.</p>
	Actual qualification of a project for LSRV compensation will be determined on a project-by-project basis at the time an interconnection agreement is executed with the company.	
Cap limiting the amount of DER capacity that may receive LSRV compensation	Amount of coincident relief that would reduce projected energy use to the point that usage falls below the threshold criteria.	Lesser of the load reduction necessary to reduce peak loading to 100% of planning rating or DER penetration equal to substation minimum load levels (assumed to be 25% of peak load)
Calculation of LSRV and DRV rates	Combined LSRV and DRV value in the constrained areas shall be 150% of the current system-wide marginal cost of service level. This technique yields a “de-averaged” DRV value of \$199/kW-year and an incremental LSRV of \$141/kW-year .	<p>LSRV set to 50% of its DRV, thereby establishing the combined compensation (i.e., LSRV and DRV) received by LSRV-eligible projects as being equal to 150% of the DRV. Calculations yield an initial proposed DRV of \$61.44/kW-year and an LSRV rate of \$30.72/kW-year.</p> <p>Rates to be updated every three years.</p>

⁸ Con Edison Implementation Proposal for Value of Distributed Energy Resources Framework, May 1, 2017. Case 15-E-0751 and Case 15-E-0082

⁹ National Grid (Niagara Mohawk Power Corporation) National Grid Value Stack Implementation Proposal, May 1, 2017. (Date filed shown as May 3, 2017) Case 15-E-0751 and Case 15-E-0082.

	Con Edison ⁸	National Grid ⁹
Compensation methodology for DRV and LSRV	Credits will be based on a project's ability to offset peak electricity use in the zone in which the project is located. Exports to the distribution grid during the 10 highest peak load hours in the zone will be measured at the Con Edison meter and multiplied by the applicable LSRV rate to determine the annual credit, which is then divided by 12 and applied on a monthly basis beginning in January of the following year.	National Grid will distribute the calculated DRV and LSRV compensation in dollars per kW-year across 10 highest use hours in the company's service territory. Paid as a monthly lump sum based on a DER project's kW performance during those top 10 load hours in the previous calendar year. Monthly compensation will be calculated as the DRV and/or the LSRV in dollars per kW-year divided by 10 performance hours per year, multiplied by the sum of the project's kW output in the ten performance hours, divided by 12 months.
Calculation of capacity values – <u>Alternative 1</u>	<u>Alternative 1</u> : Capacity value will be the capacity portion of the supply charge for the service class with a load profile most similar to a solar generation profile. Capacity value will be multiplied by the project's total net hourly kWh injections in the billing month.	
Calculation of capacity values – <u>Alternative 2</u>	<u>Alternative 2</u> – Commission-mandated option for intermittent technologies . Capacity value for each summer season, defined as the period June 1 through August 30, based on the prior 12 months of capacity prices for the service class with the load profile most similar to the solar generation profile. Company proposes to sum its historical monthly capacity charges for the prior 12 month period to determine an annualized value. Annualized value will be divided by 460 peak summer hours to determine a \$/kWh value. The \$/kWh compensation value will be credited based on the project's kWh generation in the 460 peak summer hours only.	
Calculation of capacity values – <u>Alternative 3</u>	Will determine Installed Capacity (ICAP) market credits based on a project's actual exports of power, as measured at the Con Edison meter, coincident with the New York Control Area peak load during summer. Value Stack customers who select Alternative 3 will be compensated via a monthly lump sum payment based on the ICAP spot market in effect that is applicable in each respective billing cycle.	Capacity Tag Approach – Capacity Tag Approach credits will be calculated by multiplying the project's net injections for the peak hour of the previous calendar year by the applicable capacity rate (\$/kW-mo) in effect for each billing period of the current calendar year.
Identifying average generation profiles for capacity and DRV compensation in a project's first year of operation	Profiles provided by E3 using the National Renewable Energy Laboratory's System Advisory Model with typical meteorological year weather data for each utility service territory.	
Cost allocation and recovery methodologies, general	Generally, the market-based costs for Value Stack credits, which only full-service customers benefit from, will be recovered from full-service customers. Value Stack components that provide benefits to all customers, or any portion of the Value Stack	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 compensated DER. For compensation that does not reflect a

	Con Edison⁸	National Grid⁹
	<p>payment that is “out of market” will be recovered from all delivery customers with additional differentiation if the benefits accrue only to lower voltage customers. Where no specific benefit has been identified and valued, the company will allocate costs for those components in proportion to the service classes that receive the portion of the credits.</p>	<p>value that has been identified and calculated at this time, recovery will come from customers within the same service class as the beneficiaries.</p>
<p>Cost allocation and recovery for <u>ENERGY</u> part of Value Stack</p>	<p>Payments provided to Value Stack customers for energy produced will be allocated for recovery to all full-service utility customers. Energy exports reduce the amount of energy that Con Edison purchases from the NYISO on behalf of its full-service customers.</p> <p>The crediting rate for hourly energy injections by Value Stack customer-generators will be based on hourly locationally based marginal price (LBMP) prices including a factor that adjusts the LBMP price to account for losses in the distribution system.</p>	<p>Energy value credits based on NYISO Day-Ahead zonal LBMP hourly prices, as adjusted for losses applicable to the project, are applied to a project’s net hourly injections.</p> <p>Energy Value credits will be collected from the company’s supply customers, because these customers benefit from the avoided purchased power cost.</p> <p>Compensation will be calculated by multiplying the project’s net hourly injections (kWh) by the day-ahead zonal LBMP hourly price, including losses, for the applicable hours.</p>
<p>Cost allocation and recovery for <u>CAPACITY</u> part of Value Stack</p>	<p>All customers will receive the offsetting benefits of the load reduction from the capacity injections by Value Stack customers, because all customers will benefit from a general reduction in capacity purchase obligations.</p> <p>Capacity credits will be calculated using the same capacity prices used to determine capacity charges for full-service customers.</p>	<p>Cost recovery will be separated into two parts to reflect costs to be recovered. Recovery will vary based on the best estimate of avoided capacity costs (“Market Capacity Value”) and the portion of the capacity compensation that is above avoided capacity costs.</p>
<p>Cost allocation and recovery for <u>MARKET CAPACITY VALUE</u> (note, this is a subset of the CAPACITY above)</p>	<p>Market value will be determined by multiplying the exports from all Value Stack customer-generators on the peak hour from the previous year by the average price for generating capacity.</p> <p>Costs will be recovered through a new VDER Delivery Surcharge on a per-kW basis for service classes with demand charges, and on a per-kWh basis for energy-only service classes.</p>	<p>Value determined by multiplying 1) net injections from all Value Stack generators that occurred on the peak hour of the company’s system during the previous calendar year, by 2) by the average price for capacity for the previous calendar year using NYISO Spot Auction capacity prices.</p> <p>Costs will be recovered from all delivery customers through a per-kW surcharge for demand customers and a per-kWh surcharge for all non-demand customers.</p>

	Con Edison⁸	National Grid⁹
Cost allocation and recovery for <u>ABOVE MARKET CAPACITY VALUE</u> (Note, this is a subset of CAPACITY above)	<p>This value is calculated as the difference between the market value and the total Generating Capacity payments made to the Value Stack customers.</p> <p>The out-of-market value will be allocated to all delivery customers in the service classes of the customers receiving the credits through the VDER Delivery Surcharge.</p>	<p>This value will be calculated as the difference between the Market Capacity Value costs calculated above and the total capacity credits paid to projects receiving Value Stack compensation.</p> <p>Above Market Capacity Value costs will be collected from all delivery customers within the same service class as the customer receiving the capacity credit.</p>
Cost allocation and recovery for <u>ENVIRONMENTAL VALUE</u>	<p>To receive compensation for environmental value, projects must qualify to generate Tier 1 RECs under the Clean Energy Standard Proceeding, and elect to sell those RECs to the utility at the time of the customer-generator's interconnection.</p> <p>Con Edison will use the higher of the REC price published by NYSERDA for its most recent Tier 1 REC procurement or the net Social Cost of Carbon as calculated by staff.</p> <p>The market value of payments provided to Value Stack customers for RECs will be allocated to all full-service utility supply customers.</p> <p>Because the VDER Order requires utilities to purchase RECs from VDER customer-generators at fixed prices for a 20- to 25-year term, it is likely that the market value of RECs will vary from the weighted average cost of RECs purchased from Value Stack customers. Con Edison will establish a tracking account that calculates the difference between the two procurement methods, which will be collected from or refunded to all delivery customers via the VDER Delivery Surcharge.</p>	<p>Environmental credits will be based on the higher of the latest Tier 1 REC price published by NYSERDA or the net social cost of carbon per kWh applied to the volumetric net hourly injections.</p> <p>Since all default supply customers receive the benefit of a reduction to the utility's REC obligation, the avoided REC costs, based on the market value of RECs, will be collected from all default supply customers through the Clean Energy Supply Surcharge.</p>
Cost allocation and recovery for DRV and LSRV	<p>Payments for DRV and LSRV will be collected from all delivery stack customers. The company will establish which portions of the DRV and LSRV are associated with the lower voltage portion of the system and the higher voltage portion of the system, and the respective customers will pay accordingly. Secondary system customers will pay the low- and high-voltage portions of the</p>	<p>DRV will be calculated by multiplying 1) the average of the project's net injections (in kW) for each of the 10 highest peak hours in the company's service territory during the preceding year, by 2) the DRV (\$/kW-mo) in effect during the billing period of the current calendar year.</p>

	Con Edison⁸	National Grid⁹
	<p>DRV and LSRV, while the primary system customers will only pay for the high voltage portions.</p> <p>The DRV applicable to a specific customer-generator's performance will be the then-in-effect DRV as determined by the company, and will change as that DRV rate is updated. The LSRV rate will be the rate in effect at the time of the customer-generator's execution of an interconnection contract, and will be fixed for that customer-generator at that value for 10 years from the commencement of generation.</p>	<p>LSRV compensation will be calculated by multiplying 1) the sum of the project's net injections (in kW) for each of the (10 highest peak hours in the company's service territory during the proceeding calendar year, by 2) the LSRV compensation in effect, only if the project is eligible for the LSRV compensation.</p> <p>Costs for DRV and LSRV paid to projects will be collected from customers on a voltage-delivery-level basis and allocated to service classes based on the proportion of customers in each service class receiving DRV and LSRV, respectively. Costs will be recovered on a per-kW basis for demand customers and a per-kWh basis for non-demand customers.</p>
Cost allocation and recovery for Market Transition Credit (MTC)	<p>Payment provided to Value Stack customers of the MTC will be allocated to all mass-market delivery customers. Costs will be allocated among the mass-market service classes in proportion to the amount of MTC provided to each service class in the previous calendar year.</p>	<p>MTC is applicable to the portion of a community distributed generation project allocated to mass-market customers. MTC will be recovered from all mass-market delivery customers on a per-kWh basis. Costs will be allocated to each mass-market class based on the amount of MTC provided to the respective service class in the previous year.</p> <p>The MTC rate (\$/kWh) applicable to the project will be applied to the project's total net injections in a billing period. Only community distributed generation projects are eligible for the MTC.</p>
Metering	<p>A customer request for service under the VDER tariff will trigger the installation of the appropriate meter, which for the Value Stack customers with onsite generation will be an interval billing meter capable of tracking imports and exports from the customer's premises separately on an hourly basis.</p>	

Con Edison Value Stack

Cost Allocation and Recovery of Value Stack Payments from Con Edison May 1 VDER Implementation Filing

Value Stack Components	Customer Segment Bearing Costs	Cost Recovery Method	Allocation Method	Rate Recovery Units
Energy	Full-Service Supply Customers	Market Supply Charge	Included in supply rate	\$/kWh
Generating Capacity - Market Value	Delivery Customers	VDER Delivery Surcharge	Load-ratio share by SC	\$/kWh or \$/kW
Generating Capacity - Out of Market	Delivery Customers	VDER Delivery Surcharge	Pro rata per SC credit share*	\$/kWh or \$/kW
Environmental - Market Value	Full-Service Supply Customers	Clean Energy Standard Supply Surcharge	Included in supply rate	\$/kWh
Environmental - Out of Market	Delivery Customers	VDER Delivery Surcharge	Pro rata per SC credit share*	\$/kWh
Demand Reduction Value	Delivery Customers	VDER Delivery Surcharge	Load-ratio share by SC, separating high and low voltage benefits	\$/kWh or \$/kW
Locational System Relief Value	Delivery Customers	VDER Delivery Surcharge	Load-ratio share by SC, separating high and low voltage benefits	\$/kWh or \$/kW
Market Transition Credit	Delivery Customers	VDER Delivery Surcharge	Pro rata per SC credit share*	\$/kWh

* SC credit share recovers the Value Stack component credits from the specific service classes that received the credits.

Appendix E – California Competitive Solicitation Working Group – Approved Valuation Components for Distribution Grid Services Competitive Solicitations

The valuation components listed below were adopted by the Commission as a starting point for the Competitive Solicitation Framework’s solicitation evaluation method. The value components listed are to be used by the utilities in the incentive pilot established through the Integrated DER proceeding (R.14-10-003).

The Competitive Solicitation Framework Working Group discussed the following set of quantitative and qualitative factors.

- **Quantitative Factors**, including net market value, resource adequacy value, energy value benefit, ancillary services value benefit, renewables portfolio standard benefit, reduced greenhouse gas emissions benefit, renewable integration cost/reduced cost benefit, distribution deferral value, transmission deferral value, and contract payments cost; and
- **Qualitative Factors**, including project viability, voltage and other power quality services, equipment life extensions, societal net benefits, and other factors such as supplier diversity, counterparty concentration, site diversity, and technology/end-use directory to help market transformation.

Quantitative Factors

Net Market Value (NMV) – represents the value of an offer from the market perspective. It captures the market value provided by an Offer of Energy, Ancillary Services, and Capacity and compares it to the Offer’s cost. NMV is calculated for each Offer as follows:

NMV(levelized \$/kW-year) = Benefits – Costs

Benefits = RA(Capacity) Value + Energy Value + Ancillary Services Value + RPS Benefit + Reduced GHG Emissions Benefit + Renewable Integration Cost/Reduced Cost Benefit + Distribution Deferral Value + Transmission Deferral Value

Costs = Contract Payment Costs (including Fixed and Variable Costs).

Resource Adequacy (RA) Value Benefit – The RA value can apply to system, local, and flexible resources. The RA price forecast is developed from multiple sources and assumptions such as market-transacted data from utilities’ own previous solicitations, local requirements, long-term capacity value, cost of generation studies, and planning reserve margin assessment.

Energy Value Benefit – Energy price forecast is generally established using forward market data and fundamental model prices. Location-specific adjustments are made to reflect associated congestion value forecasts.

Ancillary Services Value Benefit – If a resource can provide ancillary services, the price forecast is based on historical market data, a statistical model, or a fundamental model.

RPS Benefit – Applies to renewable DER that count toward utilities’ RPS compliance requirements. Utilities forecast REC values from their own RPS solicitations data, third-party vendors’ subscribed data, and public market reports.

Reduced Greenhouse Gas (GHG) Emissions Benefit – This benefit is still being debated in California. As proposed, there was no separate quantification of this benefit because DER receive the value of avoiding GHG emissions via the value of reduced generation need energy costs. Emission costs are embedded in LMP prices.

Renewable Integration Costs/Reduced Cost Benefit – Where applicable, the Renewable Integration Cost Adder methodology from the RPS proceeding is generally used. Where flexibility reduces the cost of integrating renewables, this benefit is captured in the flexible resource adequacy or ancillary services value.

Distribution Deferral Value – The Real Economic Carrying Charge method being developed in California’s Distributed Resource Planning proceeding. The benefit of distribution deferral will be evaluated for DER that are located in identified substations and/or feeders using the deferred cost of the least expensive traditional solution that meets the identified operational need at that location. Main factors include installed cost, operation and maintenance cost, project lift, return on investment, and discount rate.

Transmission Deferral Value – Deferred or avoided costs are calculated using the cost of traditional grid investment and by identifying specific system characteristics or needs driving the need for the projects.

Contract Payment Costs – Could be composed of capacity payments and/or energy payments; i.e., fixed costs and variable costs. Energy payments could be associated with generation as all-in cost for DG type of resources, or variable costs for DR/ES type of resources.

Qualitative Factors

The following qualitative factors should also be considered when selecting bids.

Project Viability – Includes assessment factors such as developer experience, operation and management experience (proven track record), commercial technology, reasonableness of delivery data, and interconnection progress.

Voltage and Other Power Quality Services – The voltage and power quality services streams that are not identified as DER portfolio needs during solicitation, but deemed to be providing value to the system should also be considered when selecting bids.

Equipment Life Extension – If certain DER bids are deemed to have impact on extending/reducing the distribution equipment life, the attribute would be considered part of qualitative consideration, as secondary benefit or cost.

Societal Net Benefit – These include societal benefits and/or costs, such as public benefits and/or costs that do not have any nexus to utility rates. Societal benefits, and how they will be applied, continue to be debated as part of the IDER proceeding (R.14-10-003).