BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 (Filed February 11, 2016)

ADVANCED ENERGY ECONOMY'S COMMENTS ON THE STAFF PROPOSAL ON PROCESS FOR INTEGRATED RESOURCE PLANNING

Amisha Rai
Senior Director, CA Policy
Advanced Energy Economy
135 Main Street, Suite 1320
San Francisco, CA 94105
Tel: 415.799.3718
E-mail arai@aee.net

On Behalf of Advanced Energy Economy

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I. INTRODUCTION

Advanced Energy Economy (AEE) respectfully submits these comments in response to the California Public Utilities Commission ("Commission") Staff's May 16 proposal on process for integrated resource planning. This is a timely effort as California grapples with the challenges of a changing electric system and meeting state greenhouse gas (GHG) emissions goals. As such, we greatly appreciate the opportunity to participate in and support this effort.

AEE is a national association of businesses dedicated to transforming public policy to enable a prosperous world that runs on clean, secure, affordable energy. We are comprised of over 100 companies both large and small across the technology spectrum, including energy efficiency, solar, wind, storage, fuel cells, biofuels, electric vehicles, demand response, advanced metering, and enabling software. Our members also include companies that have made a commitment to power their operations with clean energy and are working with us to break down the barriers that inhibit them from reaching their sustainability goals. In these comments, AEE will be referenced collectively as "AEE," "we," and "our."

AEE has substantial experience participating in regulatory proceedings across the country dealing with a variety of issues. AEE's participation in this proceeding is critical as the business voice for the advanced energy industry. The issues and questions raised in this proceeding will impact our membership and their future market in California. As an organization with stakeholders that provide a range of technologies and services, we balance a wide variety of interests and address issues with a technology-neutral perspective.

AEE believes that the increased participation of advanced energy technologies in integrated resource planning will improve grid reliability, help California meet its environmental objectives, and reduce overall costs for consumers. The Staff Proposal is well thought out and is a substantial step in the right direction to develop an IRP process that builds on the existing long-term procurement planning (LTPP) process to optimize the load serving entities' portfolios of resources to reach state policy goals – most notably the goal of reducing economy-wide GHG emissions 40 percent from 1990 levels by 2030. In these comments, we have based our responses on a targeted subset of the questions posed in the May 16 Staff proposal.

II. RESPONSES TO SPECIFIC QUESTIONS

1. Guiding principles. Are the guiding principles for IRP articulated in Chapter 1 of the Staff Proposal adequate and appropriate for Commission policy purposes? What changes would you recommend and why?

According to the Staff proposal, the main purpose of the integrated resource planning (IRP) planning process is to meet California's greenhouse gas (GHG) emissions reduction targets for the electric sector, consistent with the statewide goal of achieving a 40 percent reduction in GHG emissions below 1990 levels by 2030, while maintaining reliability, minimizing bill impacts, and prioritizing air quality benefits in disadvantaged communities. Staff has laid out six proposed revised principles and two new guiding principles that we believe align with this objective. In summary, these new principles state the IRP should: reduce GHG emissions, be conducted through a transparent process, provide clear market signals for new and existing resources, be flexible as the system evolves, be in coordination with other proceedings and state agencies, and fairly allocate costs across all load serving entities (LSEs). However, we also believe the guiding principles are silent on a few other important points.

Specifically, we believe the IRP should strive to meet California's GHG emissions reduction targets as cost-effectively as possible. We believe that advanced energy technologies are best suited to achieve this goal and that the guiding principles do not adequately address the current and growing need for better integration of distributed energy resources[1] (as addressed in the distribution resource plan proceeding) nor the growing need for control and automation of demand side management options, nor the potential for significantly higher penetration of renewables and storage on the network system if their pricing continues to decline sharply. At a minimum, we suggest the following additional principle, and offer additional recommendations in this draft:

"The IRP process should provide a method for coordinating and integrating the current and future distribution resource plans with the IRPs so that distributed energy resources can be considered as supply or demand-reduction options as appropriate."

In addition, there are many advanced energy technologies that may not be cost-effective today that may become commercially viable in the future. Therefore, we want to echo the point that "filing entities should have the flexibility to respond to changes in technology, electric system needs, and market conditions." To this end, it is important that as new technologies emerge or become more cost-effective, they should be included in the modeling process. By allowing this flexibility, the IRP process will adapt with changing conditions to reach GHG goals in the most cost-effective way and with a balanced and diverse portfolio of technologies.

3. Overall IRP process. Comment on the overall IRP process proposed in Chapter 2 of the Staff Proposal, beginning with the California Air Resources Board (CARB) establishing greenhouse gas planning targets for the electricity sector and ending with the Commission procurement and policy implementation. What changes would you recommend and why?

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[1] We define DER broadly to include distributed generation of all types (including solar, wind, combined heat and power, fuel cells, and other technologies), energy efficiency, demand response, energy storage, electric vehicles, and microgrids.

The overall IRP process of first creating a Reference System Plan, individual utility IRPs and then reconciling the two creates a lengthy and complex process. The Reference System Plan and the utility plans will remain in perpetual misalignment, since the utility plans will necessarily be in a continuous state of change to address evolving customer, system and market conditions. We suggest the staff consider providing just a standard set of input assumptions for the individual utility plans and then creating an aggregation of the individual plans that are received. This simplification of the process would reduce the time by eliminating the creation and reconciliation of the Reference System Plan.

We wish to also recognize the new staff proposal on Grid Modernization (as part of the Track 3 distribution resource planning [DRP] proceeding), which is proposing to add an additional planning cycle through the grid needs assessment (GNA) and grid modernization plan (GMP) with approval being sought in the three-year general rate case (GRC) cycles. There is a need for clarity on how these grid modernization plans will be incorporated into the IRP process.

Finally, the proposed IRP process is complex, with many moving parts and consideration of multiple interrelated proceedings. The process, to be successful, will require the Commission to clearly define how these proceedings will interact and ultimately work together (more on this in our response to Question 34).

4. 2017-2018 IRP process. Do you support the Staff Proposal's characterization of the purpose and outcomes of the first round of IRP in 2017-2018? Why or why not?

Staff has stated in the proposal that the goals for this first two-year IRP process are to demonstrate the feasibility of the IRP and establish the groundwork and infrastructure for the process moving forward. AEE generally agrees with these stated goals, however we do have some concerns (1) about how they will be put into practice going forward, and 2) if the process will move quickly enough to enable procurement to meet California's energy and climate objectives, as well as to take full advantage of expiring federal tax credits for solar and wind. To alleviate these concerns, we recommend that this iteration of the IRP include a future timeline or a roadmap to demonstrate the steps (i.e., the regulatory or policy actions) that must be taken to translate the lessons learned into practice moving forward. The roadmap should explicitly consider the benefits to California customers to advance procurement in order to benefit from federal tax credits. And, the roadmap may also include a timeline of when and how the IRP will take outputs from other proceedings (e.g., the DRP and integrated distributed energy resources [IDER] proceedings) and use them as inputs for the IRP process.

6. LSE-specific GHG emissions targets.

A. Do you support dividing electric sector responsibility between publicly-owned utilities (POUs) and LSEs regulated by the Commission, as suggested in the Staff Proposal? Why or why not?

Staff has stated that a bottom-up approach is appropriate for apportioning the electric sector GHG target among all LSEs and publicly owned utilities (POUs). Specifically, Staff suggests using the California Air Resource Board's (CARB's) allowance allocation formula, where Commission jurisdictional LSEs would comprise 77% of total electric sector emissions in 2030 and POUs would comprise the remaining 23%. AEE supports dividing up the electric sector responsibility between POUs and LSEs in concept but there still remains a question as to how the Commission intends to regulate the division of responsibilities across LSEs.

The Staff Proposal states on page 30 that individual LSEs will develop their IRPs using the GHG planning price, which is supposed to signal the most cost-effective investments across a broad range of LSEs. Therefore, the GHG planning price is supposed to signal that if GHG reductions are more expensive to achieve in one territory, then that jurisdictional LSE's plan may reflect lower GHG reductions in order to be the most cost effective. This makes sense in theory; however it is unclear how it will work in practice to achieve GHG reductions that are consistent with the electric sector target.

Additionally, the Proposal states on page 32 that the GHG planning price "avoids the need to make periodic adjustments in response to shifts in load between IOUs and CCAs." Again there should be more clarity on how this approach alleviates the issues with CCA expansion.

7. Modeling in 2017-2018.

A. Do you support use of the RESOLVE modeling approach for development of a Reference System Plan in 2017-2018? Why or why not?

See response to Question 3.

B. If you prefer an alternative approach, describe it in detail.

See response to Question 3.

8. GHG emissions scenarios to be modeled.

B. What alternative targets do you recommend and why?

We recommend that the guidelines allow the utilities to propose the least-cost options for achieving their GHG reduction targets, regardless of whether the GHG emissions reduction comes from electric generation (subject to the Renewables Portfolio Standard), transportation, industrial or other sources. This flexibility as to where to invest to reduce GHG emissions will potentially incentivize utility innovations that could provide lower-cost options to achieve the same GHG reductions. Utility investment in non-utility GHG reduction measures could be addressed in rates as either a pass-through (as with fuel), a rider or a rate based investment depending on the nature of the GHG measures proposed. If the final guidelines forgo this flexibility to substitute more cost-effective alternatives to achieve the target GHG reductions, California residents will be paying more than necessary for the GHG reductions.

9. Modeling Assumptions. Do you have any specific changes to recommend to the modeling assumptions detailed in Chapter 4 and Appendix B of the Staff Proposal and the associated spreadsheet Scenario Tool? What are they and why? Indicate a publicly-available source of your recommended assumptions.

As noted in our response to Question 1, we suggest that all controllable demand-side management options be considered as supply resources in the modeling, as opposed to reductions in demand.

12. Futures. Are the alternative futures proposed to be modeled in Chapter 4 of the Staff Proposal the appropriate ones? What changes would you suggest and why?

We believe that the alternative futures in the IRP should consider scenarios that achieve higher levels of renewable portfolio standards than currently shown, reflecting the potential for significant reductions in costs of renewable energy technologies (such as photovoltaics, as a semiconductor technology, and of storage, both of which have experienced significant cost reductions in recent years). In addition, the alternative futures are too conservative regarding transportation electrification. The scenarios are limited to 3.6 and 4.0 million light duty vehicles, a difference hardly worth measuring (0.4 million vehicles will be less than one percent of total California vehicles in 2030). Instead, we suggest using 4.0 million and 8.4 million as the two scenarios. The latter is in response to a comment by one of California's key stakeholders that "to meet the 2030 targets, we expect the State will need at least double the 4.2 million plug-in electric vehicles identified in the Scoping Plan Update."[2]

14. Risks

A. Are there any other risks or criteria that should be considered in the portfolio analysis described in the Staff Proposal?

The risks should include an assessment of all portfolios against a significant increase in the renewables portfolio standard or other clean energy procurement (as is being currently considered in the legislature) and/or reduction in GHG limits, as well as substantial increases in load due to more rapid electrification of transportation and/or other sectors of the economy. This might be addressed as a risk factor or an alternate future as noted in our response to question 12.

16. Demand-side resources.

A. Is the treatment of these resources in the staff's recommended approach reasonable? What changes would you suggest and why?

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[2] SCE CEO Pedro Pizarro, "Prepared Remarks Edison Insights Series California's Climate Policies and Transportation Electrification," April 12, 2017.

The electricity system is undergoing a fundamental transformation as we shift away from fossil fuel generating resources towards clean and renewable generation and as we shift away from the combustion-based highly centralized power system to a more decentralized system that embraces grid edge advanced energy technologies as well as, on the network grid, greater proportions of utility-scale renewables and storage. As such, AEE strongly believes that the IRP process should, at a minimum, include an evaluation of all existing and potential customer-sited and demand-side management resources in order to meet forecasted system demand. To this point, we are concerned that the modeling process is only looking at wholesale resources, and at that not considering sufficient levels of utility-scale renewables and storage, and that it is looking at demand side resources as fixed levels of resources in different scenarios, rather than optimizing distribution level resources' contribution to the energy supply and to reliability. AEE believes this does not accurately incorporate the values that different demand-side resources can provide.

Technologies such as energy efficiency, demand response, energy storage, rooftop PV, combined heat and power (CHP), microturbines (including small hydropower), fuel cells, electric vehicle-to-grid (EV2G) capabilities, advanced metering infrastructure, distribution automation, microgrids, and smart grid management technologies, are more than just "demand side modifiers;" they can also produce energy and provide protection against resource shortfalls at times and locations of peak demand. This includes benefits to the bulk power system, as well as a broader range of electricity system and non-energy benefits. With the continued retirement of inefficient older generating units, these widely available advanced energy technologies can be developed and deployed quickly to meet resource adequacy needs. Many of these technologies can also be sited strategically to alleviate specific local resource adequacy issues and provide additional reliability to critical loads such as hospitals, while also contributing to bulk power system resource adequacy along with utility-scale renewables and storage. For these reasons, in a recent study, the Smart Electric Power Alliance cites load shifting, energy efficiency, and renewable energy as viable strategies to address resource adequacy and thereby improve overall grid reliability.[3]

In order to optimize these technologies to support California's electric grid, the Commission should incorporate as soon as possible the outputs of California's DRP and IDER proceedings (more on this in our response to question 34), as well as recent trends in reliability services provided by utility-scale renewables and storage, such as the CAISO's recent study of ancillary services provided by utility-scale solar with advanced inverters.[4] In addition, the Commission should allow these technologies to leverage all of their resource potential and services. For example, the technologies should be able to monetize their contribution to shifting demand, providing load during times of peak demand and correcting local resource adequacy issues.

We would also like to reiterate the point we made in our response to Question 1 that there are many advanced energy technologies that may not be cost-effective today that may become commercially viable in the future. Therefore, it is important that as new technologies emerge or become more cost effective they should be included in the modeling process.

B. What additional information, other than modeling, might materially affect these resources? Provide specific sources of publicly available information, what question(s) the additional information would help address, and why you think the information should be used.

The benefit-cost analysis approaches in the California Standard Practices Manual (CaSPM) that have been used to evaluate cost effectiveness of resources (mainly energy efficiency programs and measures) are undergoing change and may need to be reevaluated.[5] The Commission should consider using newer cost-effectiveness frameworks to better consider

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[3] Smart Electric Power Alliance (SEPA), Beyond the Meter, Distributed Energy Resources Capabilities Guide (2016), https://sepapower.org/knowledge/sepa-releases-new-distributed-energy-resources-capabilities-guide/

[4] CAISO, "Using Renewables to Operate a Low-Carbon Grid," http://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf (2017)

[5]http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

integrating distributed energy resources. For example, on May 18, 2017, E4TheFuture, published the National Standard Practice Manual (NSPM)[6], which builds and expands on the CaSPM to provide a comprehensive framework to evaluate the cost-effectiveness of energy resources. The NSPM was developed via the National Efficiency Screening Project (NESP), which developed the Resource Value Framework (RVF) to provide guidance for states to develop and implement tests that are consistent with sound principles and best practices, while providing each state flexibility to ensure that the test they use meets their state's distinct needs and interests. The principles of the RVF include:

1) Efficiency as a Resource: EE is one of many resources that can be deployed to meet customers' needs, and therefore should be compared with other energy resources (both supply-side and demand-side) in a consistent and comprehensive manner.
2) Policy Goals: A jurisdiction's primary cost-effectiveness test should account for its energy and other applicable policy goals and objectives. These goals and objectives may be articulated in legislation, commission orders, regulations, advisory board decisions, guidelines, etc., and are often dynamic and evolving.
3) Hard-to-Quantify Impacts: Cost-effectiveness practices should account for all relevant, substantive impacts (as identified based on policy goals), even those that are difficult to quantify and monetize. Using best-available information, proxies, alternative thresholds, or qualitative considerations to approximate hard-to-monetize impacts is preferable to assuming those costs and benefits do not exist or have no value.
4) Symmetry: Cost-effectiveness practices should be symmetrical, where both costs and benefits are included for each relevant type of impact.
5) Forward-Looking Analysis: Analysis of the impacts of resource investments should be forward looking, capturing the difference between costs and benefits that would occur over the life of the subject resources as compared to the costs and benefits that would occur absent the resource investments.
6) Transparency: Cost-effectiveness practices should be completely transparent and should fully document all relevant inputs, assumptions, methodologies and results.

[6] https://nationalefficiencyscreening.org/national-standard-practice-manual/

In September 2014, Synapse Energy Economics prepared a report for AEE Institute[7] titled *Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits.* In this report,[8] AEE Institute proposed a benefit-cost framework for New York; however, much of the report is broadly applicable to other states. The key concerns with the existing practices are that 1) the standard cost-effectiveness tests are seen as too narrowly defined; 2) some of the hard-to-quantify costs and benefits are ignored in practice; and 3) the standard cost-effectiveness tests do not necessarily account for the benefits articulated in state energy policy goals.

AEE supports the Societal Cost Test as the principal test for deciding whether to proceed with any particular DER program or portfolio. The Societal Cost Test is the most comprehensive of the five common screening tests (the Participant Cost Test, the Utility Cost Test, the Total Resource Cost Test, the Societal Cost Test, and the Ratepayer Impact Measure Test) and provides the most information about the impacts of DER. Furthermore, we recommend use of the Utility Cost Test, and not the Rate Impact Measure Test, to inform the analyses of rate, bill and participant impacts. The Utility Cost Test provides a good indication of the extent to which utility system costs, and therefore average customer bills, are likely to be reduced as a result of DER investments. However, the Utility Cost Test results should not be used as the primary basis for deciding whether to proceed with any particular DER program or portfolio, because they do not include the impacts associated with key energy policy goals or benefits that accrue to the customer that are extended to the utility.

Below is an overview of all costs and benefits that should be taken into account:

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[7] The charitable organization whose mission is to raise awareness of the public benefits and opportunities of advanced energy that is affiliated with AEE.
[8] http://info.aee.net/hs-fs/hub/211732/file-1683401630-pdf/REV/Synapse-AEEI-NY-REV-DER-BCA-2014.pdf

	BENEFITS			COSTS		
		Category	Examples		Category	Examples
Impacts on All Customers	1	**Load Reduction & Avoided Energy Costs**	Avoided energy generation and line losses, price suppression	1	**Program Administration Costs**	Program marketing, administration, evaluation; incentives to customers
	2	**Demand Reduction & Avoided Capacity Costs**	Avoided transmission, distribution, and generation capacity costs, price suppression	2	**Utility System Costs**	Integration capital costs, increased ancillary services costs
	3	**Avoided Compliance Costs**	Avoided renewable energy compliance costs, avoided power plant retrofits	3	**DSP Costs**	Transactional platform costs
	4	**Ancillary Services**	Regulation, reserves, energy imbalance			
	5	**Utility Operations**	Reduced financial and accounting costs, lower customer service costs			
	6	**Market Efficiency**	Reduction in market power, market animation, customer empowerment			
	7	**Risk**	Project risk, portfolio risk, and resliency			
Participant Impacts	1	**Participant Non-Energy Benefits**	Health and safety, comfort, tax credits	1	**Participant Direct Costs**	Contribution to measure cost, transaction costs, O&M costs
	2	**Participant Resource Benefits**	Water, sewer, and other fuels savings	2	**Other Participant Impacts**	Increased heating or cooling costs, value of lost service, decreased comfort
Societal Impacts	1	**Public Benefits**	Economic development, reduced tax burden	1	**Public Costs**	Tax credits
	2	**Environmental Benefits**	Avoided air emissions and reduced impacts on other natural resources	2	**Environmental Costs**	Emissions and other environmental impacts

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It is also important to note the interactive benefits of certain renewable energy, energy storage and DERs. For some of these technologies, the net benefits may increase when certain technologies are used together. For example, co-location of utility-scale or distributed renewables and flexible storage could create combined benefits that exceed the benefits of either technology individually. Other technology combinations include wind with solar, anaerobic digester gas with fuel cells, and demand reduction/response technologies with energy storage.

[9] *Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits.* Prepared by Synapse Energy Economics for AEE Institute
[10] "DSP" or Distributed System Platform refers to both the institutional entity that creates and operates the DSP, as well as the platform itself. The DSP is responsible for planning, designing, constructing, operating, and maintaining needed upgrades to existing distribution facilities. The DSP also fosters broad market activity by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system.

Another example would be the effect of home energy report (HER) programs in increasing customer participation in other DER programs and technologies.

Integrated demand-side management (IDSM) programs offer another example of interactive benefits. IDSM programs integrate energy efficiency measures with demand response technologies by providing intelligent control systems that reduce energy consumption and demand. When effectively combined as part of a comprehensive energy saving retrofit project, these systems also provide a cost-effective demand response option to help with system peaks and customer engagement.

Many DER impacts, such as avoided energy costs, have already been quantified and monetized by regulators and utilities. Such impacts can be immediately incorporated into cost-benefit analyses and improved over time as new information or techniques become available. Other DER impacts have not yet been addressed or monetized. For some of these impacts, developing monetary values may currently be infeasible or impractical. Data may be unavailable, studies may require a considerable amount of time and resources to implement, and the results of such studies may still result in a high degree of uncertainty. Despite these challenges, DER impacts should not be excluded or ignored on the grounds that they are difficult to quantify or monetize. Approximating hard-to-quantify impacts is preferable to assuming that those costs and benefits do not exist or have no value.

Alternative approaches to estimating DER impacts include:

1. Proxies
2. Alternative benchmarks
3. Regulatory judgment
4. Multi-attribute decision analysis

C. What market, regulatory, or other barriers could prevent or impede an optimal level of procurement for each resource area and type of LSE, and what solutions would you recommend to address the identified barriers? Explain your answer clearly and provide quantitative support using publicly available information wherever feasible.

There are numerous market and regulatory barriers that have prevented California from fully taking advantage of demand side management resources.

Current procurement planning, particularly as it relates to fixed grid distribution assets, has long been based on traditional, or “wires” solutions. Wires solutions are familiar to distribution resource planners and are easy to buy because these resources are well-understood. Though implementation of traditional resources can often be logistically complex, expensive, and have long-lead times, the development process is linear with cost, schedule, and contingencies managed using traditional project management methods. DERs, despite the potential benefits and cost reduction they offer, are unfamiliar to the current planning/procurement/development process. To drive adoption and understanding of the potential benefits of DER and reduced costs to ratepayers, the planning/procurement process needs to be timely, granular, and transparent to all stakeholders through the disclosure of planning assumptions, real-time grid information, feedback/updates to assumptions, and other market/pricing signals. Transparency in the process will encourage and allow DER solutions to not only compete, but also inform planning/procurement earlier in the process and address grid needs, integrate solutions to meet those needs, and defer/minimize capital investment in fixed grid assets (traditional or otherwise).

In addition, the current processes for enrolling customers in programs, such as energy efficiency and demand response, are too cumbersome. Customers are asked to provide information that is not easily accessible to them (i.e., utility online login credentials) or that they may not be comfortable providing (i.e., social security numbers). This process entails too many screens and clicks, which limits customer participation. Agreeing to the terms of a program must be a simple and seamless click-through process, commensurate with how online business is typically conducted in other industries. To this point, customers should be able to use a digital signature for authorization.

In order to solve this issue, the click-through working group that formed after Commission Decision 16-06-008 must create a solution that appropriately addresses all the concerns raised by participating third parties. The current pathway still creates a complex customer enrollment process. Furthermore, we strongly recommend that all demand response programs implement a click-through type solution.[11]

Another barrier is evaluating the market potential for demand-side resources. For example, it is important to align energy efficiency and demand response's numerous capabilities with different market products and system needs. For example, weather-sensitive loads have certain attributes that make them capable of providing robust load shed during the hot afternoon hours, when many residential customers are home and the system is typically stressed. San Diego Gas and Electric (SDG&E), in Docket 14-10-010, has recommended the creation of a working group to discuss how to create a product that maximizes the potential for weather-sensitive loads.

Finally, a major barrier to entry is that customers who are participating in demand-side management programs, such as demand response, are not being paid appropriately for the services that they provide. All demand response programs in California should include baselines for evaluation measurement and verification (EM&V) that appropriately capture the load shed that the resource has provided. A baseline working group has come up with a few new alternatives that are more accurate and precise.[12] Once approved, these baselines should be used in all demand response programs.

17. Supply-side resources.

A. Is the treatment of these resources in the staff's recommended approach reasonable? What changes would you suggest and why?

AEE strongly believes that the IRP process should include an evaluation of all existing and potential supply-side and alternative resources in order to meet forecasted system demand. This includes traditional transmission-level generation that can be built or procured such as renewables (i.e., solar, wind, geothermal, biomass), hydroelectric, energy storage, and fossil fuels; regional resources available through the California Independent System Operator (CAISO); and community resources (i.e., shared solar and wind, and RPS-qualifying

[11] For more information on specific solutions to this problem please see EnergyHub's Whitepaper, "Optimizing the demand response program enrollment process." http://www.energyhub.com/optimizing-demand-response-enrollment
[12] http://www.cpuc.ca.gov/General.aspx?id=7032

hydropower). The IRP should establish a framework not only to include but also to optimize the use of community resources or net-zero communities.

To fully value all potential resources, we recommend incorporating the standing and any potential future environmental compliance costs into planning for existing and new resources. Resource planning should also incorporate cost trends for technologies (i.e., including technologies in planning that may not be cost-effective today but may be by the end of the five- to ten-year time horizon).

AEE strongly supports the flexibility of Staff's proposed process to have the Reference System Plan inform the Energy Division Staff or LSEs to undertake specific policy procurement when such activities are merited by analysis and the record for resources that are indicated to be beneficial (page 21). In this regard, AEE recommends that Staff consider utilizing this flexibility to initiate a specific procurement activity for the sake of securing rate-payer value from the expiring federal tax credits currently available for solar, energy storage and wind technologies. These important carbon-reducing technologies can still be procured with significant ratepayer savings in the near-term, but the timing of the IRP is such that by the time it is concluded in a cycle that is actionable from a procurement perspective, access to the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) will have sunset completely.

B. What additional information, other than modeling, might materially affect these resources? Provide specific sources of publicly available information, what question(s) the additional information would help address, and why you think the information should be used.

See response to Question 16B about new cost-effectiveness methodologies and incorporating non-energy benefits into modeling.

Additionally, AEE recommends taking into consideration the near-term opportunity that California ratepayers have with regard to expiring federal tax credits for solar, energy storage, and wind technologies. AEE would direct staff to the U.S. Energy Information Administration document *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the*

Annual Energy Outlook 2017.[13] The EIA describes the availability of federal tax credits for certain renewable generation facilities in the following way:

> **Investment Tax Credit (ITC):** New solar PV and thermal plants are eligible to receive a 30% investment tax credit on capital expenditures if the plants are under construction before the end of 2019, after which the ITC tapers off for new starts to 26% in 2020, and 22% in 2021. In 2022, the ITC expires for residential systems and declines to 10% for business and utility-scale systems in that year and each year thereafter. All utility-scale plants not placed in service prior to January 1, 2024 receive a 10% ITC regardless of the date construction was commenced. Results in this levelized cost report only include utility-scale solar facilities and do not include distributed solar facilities. In the National Energy Modeling System (NEMS), EIA assumes that new utility-scale solar PV plants will have a 2-year construction lead time and solar thermal plants a 3-year construction lead time. EIA assumes that all utility-scale solar plants entering service in 2019 receive the full 30% tax credit. PV plants entering service in 2022 receive 26%, whereas solar thermal plants entering service in 2022, having begun construction a year earlier receive 30%."
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> **"Production Tax Credit (PTC):** New wind, geothermal, and biomass plants receive a $23/MWh ($12/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service if the plants are under construction before the end of 2016. After 2016, wind continues to be eligible for the production tax credit, but at a dollar per kilowatthour rate that declines by 20% in 2017, 40% in 2018, 60% in 2019, and expires completely in 2020. Based on documentation released by the Internal Revenue Service (IRS) (see https://www.irs.gov/irb/2016-23_IRB/ar07.html), EIA assumes that wind plants will be able to claim the credit up to four years after beginning construction. As a result, wind plants entering service in 2019 will receive the full credit, and those entering service in 2022 will receive $14/MWh (inflation-adjusted).

In order to fully take advantage of the federal tax credits, AEE recommends that the Commission take the cost trajectory of the federal tax credits into their modeling.

C. What market, regulatory, or other barriers could prevent or impede an optimal level of procurement for each resource area and type of LSE, and what solutions would you recommend to address the identified barriers? Explain your answer clearly and provide quantitative support using publicly available information wherever feasible.

[13] U.S. Energy Information Administration: Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017. P. 2. https://www.eia.gov/outlooks/aeo/electricity_generation.cfm

The resource planning process should take into account the implications of existing and potential new community choice aggregators (CCAs) in an IOU's service territory. There is increasing uncertainty around IOUs' forecasting projections and RPS obligations caused by the increasing number, and consolidation, of CCAs. In order to ensure a robust market going forward, there needs to be legal clarification as soon as possible about the jurisdictional authority over, and compliance requirements for, CCAs.

The barrier of CCA uncertainty on procurement for IOUs also may have a negative effect on the ability for California ratepayers to access the significant PTC and ITC tax credits, which will expire in the near-term.

19. Transportation electrification.

A. Do you support the Staff Proposal's approach to characterizing transportation electrification and the uncertainties and impacts associated with it?

As noted in our response to Question 8, we believe the current plan does not adequately address the potential tradeoffs between investment in GHG reductions via transportation electrification and electricity generation. We recommend that the guidelines allow the utilities to propose the least-cost options for achieving their GHG reduction targets regardless of whether the GHG reduction comes from electric generation, transportation, industrial, or other sources.

29. Marginal GHG abatement cost/planning price: Is it appropriate and feasible for the Commission to use the results of the IRP analysis to inform the inputs for certain cost-effectiveness analysis, such as in the Integrated Distributed Energy Resource proceeding evaluation of the societal cost test for demand-side resources? Why or why not?

In the Staff Proposal, the GHG planning price is explained as representing the lowest possible price of carbon that would encourage investment in a given portfolio of resources (i.e., the Reference System Plan). AEE believes that there should be a price to inform the inputs for cost-effectiveness analysis in different proceedings. However, without seeing the results of the IRP analysis, we cannot comment whether it is appropriate to use the specific outcomes of the

IRP analysis. There is value in adopting one GHG planning price, however any price must be agreed to and reliable to ensure confidence in the market. If we can agree to an established and defined price, we believe that it would be valuable to use in cost-effectiveness tests to drive GHG abatement.

30. Relationship between IRPs and procurement. Describe your reaction to the Staff Proposal's characterization of how IRP development and approval will lead to actual resource procurement in the next few years.

We request clarification in the proposal that the procurement activities flowing from the IRP analysis will be open to a wide range of technologies and will not be limited to only the technologies that were explicitly modeled in the planning process. Just because a resource is not modeled in the IRP should not mean it can't (or shouldn't) be procured by a LSE if it provides, individually or collectively with other resources, attributes that contribute to meeting planning goals. Using this approach would ensure that all resources are considered to meet our goals as cost-effectively as possible and that innovative technologies and technology advancements can be incorporated into LSE portfolios. To this end, any resource solicitations should be competitive, technology-neutral, and attribute-based. In addition, alternative procurement mechanisms to the current RFO process should be used where applicable. This would allow for auction platforms to enable competing suppliers to offer the lowest-price solution to a defined need.

33. Cost allocation and cost recovery. How important is it for the Commission to allocate responsibility for deficiencies in the aggregate portfolio (of all LSE plans) to individual LSEs?

There needs to be a level playing field among all LSEs, and all LSEs should have equal responsibility for deficiencies in the aggregate portfolio. If there is a gap in resources needed to achieve reliability or to attain state policies such as GHG reduction, the Commission should allocate the procurement costs using data-driven analysis and based on readily observable facts across all LSEs, including community choice aggregators and not just among the three large IOUs and their bundled customers.

34. Alignment of IRP process with other Commission resource proceedings. Are there obvious opportunities for alignment across Commission proceedings that the staff should consider in developing a process alignment workplan? What would be the benefits to coordinating proceedings to align based on these opportunities?

In order for DER and other "grid edge" resources to optimize California's electric grid, the Commission should incorporate distribution system planning (as is currently being done in California's DRP and IDER proceedings) into the broader IRP process as soon as possible. There is currently a large gap between the top-down analysis of the IRP and the bottom-up analysis in the other distribution-level proceedings. The more we can align processes, the more they will complement and inform each other. In order to move towards alignment, the IRP process should incorporate lessons learned from the pilot projects in the DRP and IDER proceedings as soon as they are available.

Incorporating the outputs of these two proceedings, along with other distribution-level proceedings (i.e., transportation electrification, energy efficiency rolling portfolios, etc.) would help to identify where additional DER would most benefit the system and specify investments necessary to enable an integrated grid (e.g., smart inverters, advanced metering infrastructure, and storage). If properly integrated with enabling technology it will enable DER aggregation and allow DERs to be used as a dispatchable resource in the IRP process. In addition, local DER benefits described in locational net benefits analysis (part of the IDER proceeding) can be "stacked" on top of system and societal benefits to provide a more complete evaluation of total costs and benefits.

Finally, the Commission should more clearly define how California's existing long-term procurement planning (LTPP) process might change as the result of the new IRP process. The two processes are closely related, especially if the IRP directs individual resource procurement or infrastructure investments, and so there must be clarification on the future of the LTPP process.

36. Alignment with CEC's Integrated Energy Policy Report (IEPR) and California Independent System Operator's (CAISO's) Transmission Planning Process (TPP).

The IRP processes should be linked to the CAISO's Transmission Planning Process (TPP) in order to fully evaluate and deploy non-wires solutions such as distributed generation, storage, energy efficiency, demand response and software services; and smart wires solutions such as voltage and volt-ampere reactive optimization, that individually or in combination can delay or eliminate the need for traditional transmission investments.

III. CONCLUSION

Developing an integrated IRP process that considers all supply- and demand-side resources, and adequately considers the potential for substantial increases in renewable energy, storage and other clean energy technologies, is a timely effort as California grapples with the challenges of a changing electric system and meeting state GHG emissions goals. As the process evolves, other states will be watching closely to learn how they can take the lessons learned in California to integrate more advanced energy resources and reduce their environmental impact.

We appreciate the opportunity to provide the Commission these comments, and we look forward to our continued involvement in this process.

Respectfully Submitted,

/s/ Amisha Rai

Amisha Rai
Senior Director, California Policy
Advanced Energy Economy
135 Main Street, Suite 1320
San Francisco, CA 94105
Tel: 415.799.3718
E-mail arai@aee.net

On Behalf of Advanced Energy Economy

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