**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)

COMMENTS AND RESPONSES OF ENVIRONMENTAL DEFENSE FUND TO QUESTIONS POSED IN THE AUGUST 14, 2014 ORDER INSTITUTING RULEMAKING

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I. INTRODUCTION

Pursuant to the Order Instituting Rulemaking ("OIR") to establish the policies, procedures and rules to guide the investor-owned utilities ("IOUs") of California in developing their Distribution Resources Plan ("DRP") Proposals, which will be filed by July 1, 2015, pursuant to Public Utilities Code Section 769, filed August 14, 2014, the Environmental Defense Fund, Inc. ("EDF")[1] respectfully submits its Comments regarding the scope, schedule and procedural issues addressed in the OIR and provides responses to the sixteen questions posed by the OIR to parties.

Specifically, Section 769 requires that the distributed resources plans provide a roadmap

[1] EDF is a leading non-profit organization representing nearly 315,000 members across the country, including nearly 55,000 in California. Since 1967, EDF has linked science, economics, law, and innovative private-sector partnerships to create breakthrough solutions to the most serious environmental problems. EDF has been active in California on environmental issues since the 1970s, and has participated in proceedings on energy-related topics at the California Public Utilities Commission since 1976. EDF has an interest and expertise in the role that market-based approaches can play in achieving positive environmental outcomes, an approach that is particularly salient in the field of energy regulation.

for integrating cost-effective distributed energy resources into the planning and operations of IOUs' electric distribution systems, with the goal of yielding net benefits to ratepayers. EDF strongly advocates for the robust integration of distributed energy resources into the California electric distribution systems. The opening of this proceeding and its scope reflect a critical step to the successful integration of clean energy resources into the traditional electric grid, and is vital to achieving California's stated greenhouse gas emission goals and securing a cleaner environmental future.

II. COMMENTS REGARDING SCOPE, SCHEDULE AND PROCEDURAL ISSUES

As more fully discussed in EDF's responses to questions 1 and 15, EDF is concerned about the timeframe for the IOUs to present comprehensive, robust DRP Proposals that comport with the parameters established in Section 769(b). EDF strongly advocates for and supports a DRP review and updating process that enables the utilities and the California Public Utilities Commission ("the Commission") to build on these plans to continue to create value to ratepayers and the environment.

III. RESPONSES TO THE SIXTEEN QUESTIONS POSED IN THE OIR

1) **What specific criteria should the Commission consider to guide the IOUs' development of Distribution Resources Plan (DRPs), including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources, and enables the achievement of California's energy and climate goals?**

   Under the current schedule, in which initial plans must be submitted by July 2015, the IOUs are unlikely to have sufficient time to develop fully formed plans for all optimal locations that should be subject to comprehensive DRPs. Likewise, implementing these plans will require actions in other proceedings, including predominately general rate cases. As a result, the DRP development process should proceed over time, with initial plans focusing on creating screening methods and mechanisms to identify optimal locations, as discussed in Question 3, and on comprehensive analyses focused on key locations within each IOU service territory.

In this respect, EDF recommends that the Commission require periodic future iterations to allow it and the IOUs to continue to comprehensively identify and develop plans for all optimal locations throughout the IOUs' service territories. As distributed energy resources (DER) continue to emerge, and existing infrastructure needs to be replaced or upgraded, an ongoing planning process would also allow for additional optimal locations to be identified and planned for appropriately.

A number of guidance criteria should be considered by the Commission to create a distribution grid that is at once reliable, safe, clean, resilient, cost-efficient, and accessible to DER, in furtherance of California's energy and climate goals, including:

- *Geographic scope*. DRPs should recognize geographic differences within an IOU service territory. For example, the California Energy Commission ("CEC") is creating load forecasts on a climate zone basis – and Pacific Gas and Electric Company files distribution level marginal cost estimates – both of which should be further refined and built-upon as part of DRP development. All IOUs should be required to publish distribution level marginal cost estimates for use in their DRPs. The Commission should utilize these and other finer grain information to examine what characteristics best delineate a DRP area. These characteristics could include attributes related to the physical (e.g., feeder and substation networks), economic (e.g., customer class or type), suitability to particular DER (e.g., load-modifying and distributed generation), and political/cultural (e.g., zip codes identified as meriting environmental justice consideration). See also Question 3 response.

  In addition, DRPs should specify the means to be used to communicate geographic (and other value-relevant) informatics to DER providers, through rates or maps delineating opportunities (or constraints) to develop particularly high value DERs.

- *Roll-out*. Plans to develop DRPs in the optimal locations may be best activated in a phased-in fashion over time to meet emerging grid needs, but these plans should also recognize and prepare to utilize DER that naturally and independently concentrates in specific areas. The criteria by which this roll-out should be staged should be identified, which could include the time-sensitive need for new investments, as triggered by growth, outage levels, or aging/obsolete equipment; particularly rapid emergence of related distributed resources; or to meet statewide DER penetration goals (e.g., storage).

- *Linkage to tariffs*. The costs illuminated by DRPs should be directly linked together with tariffs, including as applied to retail customers, net energy metering ("NEM"), and electric vehicle ("EV") charging. This will help ensure cost-efficiency, provide the proper financial incentives to DER, and inculcate a customer feedback mechanism (e.g., price response) into planning processes.

- *Incentive mechanisms*. The Commission should identify what revenues will be available to utilities, DER service providers and DER customer/owners. To the extent possible, these should reflect the full benefits provided by DER to the distribution system, be incentive-based, and encourage the utility to create a more neutral energy platform that houses both traditional utility infrastructure and different types of DER. The Commission should use performance-based rates to compensate the utilities for successfully implementing the DRPs, rather than traditional cost-of-service ratemaking, which ties the utility's revenues to the amount of distribution investment it makes.

- *Ownership*. Rules associated with asset ownership should be developed, including ensuring access by third parties and, potentially, utility holding companies and subsidiaries. If utilities or utility affiliates are permitted to own DER, the Commission should develop rules to prevent utilities from exerting market power. As well, attention must be given to monitoring and verifying the deployment of DERs since careful accounting will be necessary to incorporate DERs into Resource Adequacy ("RA") assessments and long-term procurement planning.

- *Linkage to reliability criteria*. There should be a transparent linkage between the DRPs and reliability metrics, at the distribution and system level. This may require a modification of existing reliability assessment methods to better incorporate an asset portfolio approach, as well as to address resiliency issues.

- *Scenario planning.* The grid should be modeled to simulate various levels, locations, and combinations of DER penetration, representing a variety of policy constructs. Scenarios should be compared using standard reliability criteria, revised contingency planning criteria to reflect the unique characteristics of DERs as different from central stations, and resource cost tests.

- *Metrics.* The Commission should develop detailed performance metrics to measure the outcomes which the utilities achieve as they implement their DRPs, including success in movement towards a more neutral energy platform and environmental impacts. The environmental metrics should measure the demand management and renewable energy enabled by the DRPs, which may be available for compliance with the Clean Power Plan.

- *Oversight.* The DRPs should include a section on how the plan will be administered and what type of review will occur. The Commission should consider whether independent third parties should be used to audit and/or assist with plan implementation.

2) **What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?**

EDF recommends the following to demonstrate compliance *Public Utilities Code* Section 769:

- A definition for "optimal location," with supporting information demonstrating that the plan focuses on these locations for distributed resources deployment. Target "optimal" locations based on DER's abilities to address reliability, cost, local and system needs, as well as to implement the state's energy-related environmental goals, including greenhouse gas reduction targets and environmental justice concerns.

- A comprehensive benefit-cost analysis (B-C), which includes the reliability and resiliency benefits and cost savings from the distribution, transmission, and generation systems, as well as associated integration costs, and how these can be accurately and transparently reflected in rates and tariffs.

- A set of tariffs, procurement processes or other mechanisms supporting the deployment of distributed resources, including those reflected in retail, NEM, and EV tariffs and associated vehicle integration investments.

- A means for communicating geographic and other value-relevant informatics to DER providers, through rates or maps delineating opportunities or constraints, as a means to develop particularly high value DERs.

- A clear roadmap to specific proceedings and/or protocols by which locational benefits will be reflected in retail tariffs, energy efficiency, demand response and other programs.

- An identification of any institutional, financial, or economic barriers to distributed resources deployment, including those the utility itself may be facing, and ways the utility and Commission can overcome these challenges.

3) **What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?**

Two somewhat distinct calculation methodologies may be required, one that identifies optimal, or target, DER locations that should be subject to comprehensive DRPs; and another that forms the basis for determining DRP-specific DER incentive mechanisms, including tariffs and procurement.

Determination of optimal DER locations should be based on the potential for these resources to cost-effectively make progress towards achieving Commission and state goals for reliability and grid management, pollution reduction, and clean energy penetration. The level of detail of DRP for a particular location should potentially be determined by an initial needs / opportunities screening. That is, highest priority should be given to locations for which there is:

- A strong need for DER, as suggested by near-term investment requirements, distribution outage levels, or other factors;
- Significant DER potential, as exhibited by the attributes required for deployment, such as steady wind, sunshine, or load-modifying opportunities;
- Opportunities for substantial environmental benefits, such as to reduce reliance on an otherwise polluting resource, with particular attention to areas that are sensitive due to their human populations of ecology; and
- Potential to provide system benefits (e.g., to both contribute to local distribution needs and grid requirements).

Locations that do not meet these initial screens should still have default access to a base level of more generic, system-wide, energy efficiency ("EE"), demand response ("DR"), and distributed generation ("DG") programs.[2]

Once a location has been identified as being optimal, a more detailed calculation methodology should be applied, based on an avoided cost model, which compares outcomes associated with deployment of different DER mixes with traditional distribution investments. This model should allow for an iterative approach, in which an optimal DER portfolio is identified for the location based on the particular value streams to be harvested. Ultimately, a best value (i.e., least-cost and best fit) portfolio should be identified at a locational level to achieve cost, reliability, and environmental performance goals.

The detailed calculation methodology can be used to develop expectations for the overall potential benefits of locationally-targeted DER, on the basis of which tariffs, procurement, and other DER incentive mechanisms can be developed. For a more comprehensive discussion, see also Question 4.

[2] Maximizing benefits through locational targeting will increase the overall cost-effectiveness of utility DER programs, and may result in reduced expenditures in less optimal locations, which should be considered an acceptable outcome. Likewise, methods developed to identify and enliven optimal locations may be usefully applied to broader DER deployment.

4) What specific values should be considered in the development of a locational value of DER calculus? What is the optimal means of compensating DERs for this value?

Locational value should be calculated based on a set of building blocks which come together to form the full value DERs provide, as follows:

- *DER's primary value should be associated with deferring or reducing capital and operating costs that would otherwise be incurred by ratepayers.* This should include consideration of opportunity cost savings created by delaying the need to make large capital investments as well as reduced financial and environmental risks to ratepayers. Valuable services at the distribution level may include meeting or reducing local peak capacity needs, voltage/reactive power,[3] power quality, power flow control and reliability services.[4] DER benefits should be assessed in a manner that reflects how outcomes change over time; over the course of a day or year, and over the longer-term based on evolving penetration levels.

- *Value should be calculated based on DER's contribution to local and system reliability needs.* These could be related to providing bulk power services, such as beneficially modifying or supplying peak or ramping needs, contributing to RA, reactive power support and system inertia response,[5] reductions in load loss, and other valuable outcomes.

- *Opportunities to combine DER to leverage their unique characteristics in a portfolio fashion should be identified and activated.* DER mixes could vary by location, depending on local needs and optimal combinations – for example, planning for distributed solar with associated appropriately located DR and storage. Additionally, areas with particularly dense EV and/or backup generator ("BUG") populations, existing steam or combined heat systems that could potentially be expanded, and efficiency or DR opportunities (e.g., large populations of air conditioners or older refrigeration units), should either be explicitly valued or included as a screening mechanism, as discussed in Question 3.

- *Contributions to meeting reliability criteria should be considered.* These could include reducing distribution-related outages, as well as helping to meet RA requirements, either through load modifications or contributing to supply. In this

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[3] Christopher Tufon, *et al.*, *A Tariff for Local Reactive Power Supply* , IEEE PES T&D Conference (Apr. 24, 2008), http://ewh.ieee.org/conf/tdc/A_Tariff_for_Reactive_Power.pdf.

[4] Yan Xu, *et al.*, *Nonactive-Power-Related Ancillary Services Provided by Distributed Energy Resources*, Power Engineering Society General Meeting (June 2007), http://ieeexplore.ieee.org/xpl/login.jsp?tp=&arnumber=4275745&url=http%3A%2F%2Fieeexplore.ieee.org%2Fiel5%2F4275198%2F4275199%2F04275745.pdf%3Farnumber%3D4275745.

[5] Electric Reliability Council of Texas, *Future Ancillary Services in ERCOT*, Draft Version.1.1, (2013), http://www.ercot.com/content/news/presentations/2014/ERCOT_AS_Concept_Paper_Version_1.1_as_of_11-01-13_1445_black.pdf.

vein, alternative methods of determining reliability that supplement, or even ultimately replace, existing requirements may be needed, including deeper consideration of local resiliency benefits.[6]

- *Environmental attributes should be fully valued as compared with traditional investments.* This should include consideration of polluting air and greenhouse gas emissions (including the six Environmental Protection Agency criteria pollutants), water quality and supply impacts, toxins, solid waste disposal, and land use disruptions (e.g., large or disruptive use of space; pollution concentrations). Greenhouse gas impacts should be expressly quantified and monetized.

- *DER's ability to help remedy currently high, inequitable concentrations of local pollution.* An analysis of location-specific DER deployment should be undertaken in order to ensure that the benefits of DER extend to where they are needed most, including areas that are currently over-burdened by pollution.

Dollar costs should provide the baseline comparison metric, with the above values factored in.

Optimally, DER should be compensated through tariffs that create cost-based incentives for adoption, modified as needed to take advantage of any gaps between cost and value. For example, EE, DR, DG, and storage can be incented into the market through properly structured tariffs. Capital-intense projects may require a competitive mechanism that encourages a transparent bidding process to identify the resources with the best value (i.e., least cost and best fit). This, in turn, may necessitate consideration of new business models that enable utility subsidiaries or holding companies to create a more neutral service platform and directly offer DER. Transparent incentive mechanisms should be provided for all providers that reflect all costs and benefits provided by DER, including the value of ancillary services.

5) What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?

Fundamental institutional reform of regulatory oversight mechanisms and IOUs may be required to effectively support DER integration. In particular, existing "siloes" related to distribution planning and investments in EE, DR, (including tariff development) and DG need to be removed, with the related regulatory proceedings better synced. For example, under current processes there is little interaction between IOU or Commission teams involved in developing or reviewing distribution investment plans, as well as load-modifying and DG tariffs and programs. Ratemaking is largely a residual of the revenue requirements necessitated by the distribution system, rather than crafted to consider potential ways to modify these requirements through lower-cost DER enabled by better-

[6] DER may provide resiliency benefits that are not captured by existing reliability criteria. For example, these resources may be better suited to recovering from catastrophic disruptions, such as earthquakes and fires.

structured tariffs. A much more integrated approach should be baked into IOU and regulatory planning and decision-making structures and processes.

Relatedly, potential DER providers, including ratepayers, need to be offered meaningful market signals to encourage cost-effective deployment. Under the status quo, ratepayers who could benefit from DER do not receive price signals that accurately capture the cost of energy, the potential to avoid new grid infrastructure in specific locations, or other system benefits. As a result, the value of strategically located DER goes largely unrealized. The only market signal facing ratepayers is what amounts to a tier-based opportunity to save energy over time, a signal that has provided a price signal to energy users with limited information – even if a ratepayer is motivated by energy savings, market signals fail to direct them to invest in the type of DER that would be best for the location.

If ratepayers could directly benefit when they install DER by receiving a tariff-based payment for the value of the services they are providing to the grid, operational and capital improvements would yield system wide savings. Absent an appropriate market signal, however, DER opportunities are left on the table - even where the alternative infrastructure investment costs more and is less practical.

In addition, incentives for IOUs to encourage DER should be aligned properly. IOUs should be incented to seek to avoid significant expenditures to expand distribution capacity to service time-limited peak demand. Their interest in improving the grid should instead be directed toward creating a safe, reliable, and secure distribution grid that is open to DER that meet the state's environmental requirements. If an IOU's interest in system efficiency is aligned with customers' interests, utilities will be more likely to procure and enable socially optimal DER levels.

6) What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?

EDF does not have a particular response to this question, but notes that the *More than Smart* paper, early reviews of which we participated in, contains a number of ideas in this realm that are worth considering.

7) What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?

Potential integration benefits are discussed in Question 4. The State of New York Department of Public Service developed the following list of benefits that can result from DER in its *Proceeding on the Motion of the Commission in Regard to Reforming the Energy Vision*, which are largely also applicable in California:

- Increased customer choice and opportunity;
- Increased system efficiency and associated cost reduction, calculated both in terms of the load duration curve and overall heat rate;

- Fuel diversity, reduced fossil fuel dependence, and reduced price volatility;
- Deferral or avoidance of transmission and distribution ("T&D") infrastructure investment;
- Reduced line losses;
- Increased penetration of clean DG;
- Reduction in carbon and other pollutant emissions, beyond what can be achieved under other existing public policies;
- Increased value of EE investments resulting from targeting programs to system needs;
- Reduced average customer bills versus a "business as usual" alternative;
- Increased grid resilience and security, including avoided restoration and outage costs;
- Increased reliance on markets, with resulting innovation in DER products and benefits and the ability to effectively integrate innovations into the system;
- Added levels of responsive demand and system flexibility that enable long-term development and integration of variable renewables;
- Increased non-energy benefits to customers and society including, for example, reduced health impacts or increased employee productivity; and
- Securing the long-term viability of universal affordable service.

In developing incentives to induce DER into a location, including tariffs, avoided costs may best be used as an informal litmus test, rather than a hard cap, at least during the early periods of the DER innovation cycle. As discussed in Question 3, estimates of avoided costs associated with DER may vary significantly from calculations of the potential value DER can secure. This is in part because avoided cost analyses can be biased in favor of IOU procurement of traditional resources, due to these institutions' incumbent status, lower need for marketing customers, access to low cost capital, and ability to spread costs over a wider base, among other factors. Likewise, DER costs may decline over time –learning by doing, economies of scale, and improvements in financing access as a particular resource is adopted (e.g., solar), represent a combination of factors that an avoided cost approach cannot capture.

8) What criteria and inputs should be considered in the development of scenarios and/or guidelines to test the specific DER integration strategies proposed in the DRPs?

Scenario development should be informed by an open and transparent process, designed to form useful economic and policy information, such as tracking greenhouse gas reduction goal progress. DER integration strategies should be tailored to the location-specific DRP, and reflect the characteristics, needs and assets of that area. In this respect, it will be important for each DRP to include specific, measurable goals related to reliability/resiliency; environmental outcomes, including greenhouse gas reductions; DER penetration levels; other identified benefits; costs; and "next best" plans if DER penetration does not reach desired levels.

Proposed DER integration strategies should be "tested" through a stepwise process, which includes the following elements:

- An assessment of basic plausibility should be conducted (e.g. do the scenarios and strategies match with the area's underlying characteristics?).

- Financial pro formas, either provided by the utility or developed by regulatory staff, should be examined to determine whether the incentive mechanisms – preferably in the form of tariffs, or procurement structures – are likely to result in DER adoption.[7]

- Sensitivity tests should be conducted to examine how outcomes might change based on different DER mixes and penetration levels and policy choices for how these resources are valued (e.g., tariffs). For example, grid physics could be simulated with DER penetration levels that could arise under a variety of policy constructs. Scenarios should be compared using standard reliability criteria, revised contingency planning criteria to reflect the unique characteristics of DERs as different from central stations, and resource cost tests.

  To fully understand and appreciate the impact of DERs on the power system, utilities, the Commission and, ultimately, the California Independent System Operator ("CAISO"), should use tools capable of examining a system with more DER and co-optimizing these resources with transmission-level power flows. The field of power sector analysis was developed in an era of centralized grids made up of large generators and uncontrollable load. Current grid models are often designed to analyze cost and reliability in a new regime with substantially more distributed resources and technology-enabled customers (aka, "smart loads"). The use of appropriate tools will provide the ability to explore engineering and economics questions at a variety of temporal and spatial scales needed for a DRP.

- DRP forecasts and analyses should be reconciled with CEC and RA-related analyses.

9) What types of data and level of data access should be considered as part of the DRP?

Each DRP should include a comprehensive, publishable description of the following, all of which should be available to customers and third party providers:

- Existing distribution characteristics, including substation and feeder-level coincident and non-coincident peaks, capacity levels, outage data, and projected investment needs.

[7] *See, e.g.,* Environmental Defense Fund, *SolaROI: Estimating Returns to Residential Solar Panels from Underlying Tariff Structures and Compensation Mechanisms*, forthcoming.

- Customer class-level load patterns and expenditures, based on smart meter and billing data, and associated forecasts.
- Populations of electricity-using equipment, taken from CEC and other data sources.
- EV and communal charging station populations.
- DG populations and characteristics.
- BUG populations and characteristics.
- Central generating facilities and associated characteristics.
- Relevant generation production characteristics, including those associated with wind and photovoltaic generation.
- Basic demographics, including household income levels and number of California Alternate Rates for Energy ("CARE") customers.
- Planning forecasts, as well as forecast scenarios. . Of particular importance for EDF is the ability to identify and isolate distribution (or bulk system) infrastructure investments that can be avoided with enhanced reliance on DER. This information is fundamental to being able to compare DER alternatives via resource cost tests. Identification of potential avoided costs should be as precise and time-specific as feasible; simply assuming avoided marginal costs will not reflect the "lumpiness" and time- and location-specific needs of grid investments. Some of the DERs to be planned for in DRPs can avoid new capacity additions that will have costs at least one order of magnitude higher (i.e., hundreds of dollars per kW) than current marginal capacity costs (i.e., tens of dollars per kW).

In addition, all key assumptions underlying the forecasts, benefit-cost and cost-effectiveness analyses should be explained.

10) Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

Identification of specific DER measures or projects may be worthwhile. However, under a resource neutral approach the DRPs would include transparent identification of the incentives available or that could be available to potential providers of these measures and projects, including third parties and ratepayers, to enable them to determine for themselves whether adoption is worthwhile.

As part of any examples and information, care should be taken to balance approaches to avoid the potential diminishing returns from measure adoption, for example with DG. DRP-specific payment schedules could be published, reflecting how value evolves based on the degree of penetration, location or other attributes.

11) What considerations should the Commission take into account when defining how the DRPs should be monitored over time?

Monitoring should be conducted in a manner that enables the Commission to assess how well the DRP is performing (e.g., making measurably progress to achieving the identified goals), to identify whether modifications need to be made to the plan, to link plan outcomes to changes in related proceedings, tariffs and programs, and to ensure that lessons learned can be incorporated into future DRPs.

For example, changes in a DRP's key elements, as outlined in responses to Questions 2, 8, and 9, should be tracked and reported to the Commission at least every three years. Tracking reports should include a comparison of the different DER portfolios identified in the DRP and actual resource-specific penetration rates, associated costs, and outcomes. Specific elements to be monitored include:

- Changes in customer class-specific load shapes and bills;
- Changes in generation mix emissions intensity; and
- Changes in the quality and level of services and technologies that aid in conservation and shifting.

In addition, transparent information sources should be available to ratepayers and third-parties that provide updates on available DER tariffs, contracts opportunities, programs, and penetration levels.

12) What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?

See Question 8. The review process should include opportunities for stakeholders to critique DRPs, with necessary modifications enforced by the Commission. This would usefully include review by local air quality management districts and municipal planning agencies.

13) Should the DRPs include discussion of how ownership of the distribution may evolve as DERs start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable?

Ownership issues should be considered as part of the planning process. IOUs' ability to direct and rate-base their investment in distribution encourages them to prefer these investments, as compared with localized DER solutions that they cannot control. That bias is exacerbated by the fact that under cost-based regulation, the utilities' pathway for earning a profit is clear for distribution system investments, but less obvious for all other solutions.

Similarly, under the current regulatory paradigm, IOUs' ability to rate-base investments approved by the Commission, and thus earn a predictable return on such assets, gives them an advantage over third parties, lower capital costs, and the ability to charge lower prices over a long period. Unless the Commission acts to create a more even playing field between utilities and third parties, these advantages will continue to exist as part of DRP development.

For this reason, EDF recommends that the Commission consider the example set by the United Kingdom in its adoption of the RIIO[8] model, transition from a regime in which IOUs are entitled to earn a return on asset value, and migrate to a different regulatory model, one where companies are entitled to be paid for performance irrespective of the value of their assets. Wherever possible, DER adoption should be induced by properly crafted tariffs or through competitive bidding processes, with the utility and its unregulated affiliates permitted to participate. Although a risk of self-dealing would exist under this approach, this risk can be tempered by compensating only for proper performance.

A change in regulatory model alone may not go far enough to level the playing field for DER ownership between utilities and third parties. Even in a radically altered ratemaking environment, IOUs – including new utility companies that may exist in the future – may enjoy unique advantages, stemming from their scale, existing customer relationships, and potentially continued low capital costs. For these reasons, the Commission should carefully consider ownership issues. To that end, the Commission should adopt an ownership approach that balances the following guiding principles for the near term, and reassess over time:

- It is reasonable for a utility to own DER where the primary function is to advance that entity's ability to meet its statutory obligations, including DER that primarily serves resiliency, reliability or demand-side management.

- Utility ownership of DER must not be permitted to interfere with the emergence and functioning of robust third party markets for generation and other DER services.

14) What specific concerns around safety should be addressed in the DRPs?

Safety that is directly related to equipment performance should be a binary, threshold consideration. Further consideration of safety, as associated with potential outages or performances, should be subsumed into the necessary reliability and resiliency assessments.

15) What, if any, further actions, should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs? Attachment 1 to this order is a complete copy of AB 327 as enacted.

Subsection (c) of 769 should be treated as the basis for a long-term DRP development and review process. This should include integrating the results of this proceeding into

[8] RIIO is Ofgem's new framework for establishing price controls on Britain's gas and electricity networks. It stands for Revenue = Incentives + Innovation + Outputs.

other proceedings as part of plan implementation; and revisiting and (re)developing the DRPs over time.

16) **Appendix B to this rulemaking is a white paper that articulates one potential set of criteria that could govern the IOUs DRPs. Please review the attached paper and answer the following questions:**

Integrated Grid Framework: the paper opens by presenting an 'Integrated Grid Framework', what additions or modifications would you suggest be made to this framework?

The primary missing element in the Framework is any type of customer or market-oriented feedback loop, although these are mentioned elsewhere in the paper. While the grid should be developed to meet customers' needs, demand levels and characteristics will change based on prices (e.g., tariffs) and information (e.g., related to environmental outcomes). Similarly, in a more open, diverse, and competitive market DER owners and vendors should be able to signal, through innovation and adoption rates enabled by price signals, their willingness to offer needed services.

These essential elements have been omitted from the framework. It is critical that a dynamic linkage be made between the reform opportunity created by DRPs, retail tariffs, and procurement. Otherwise, there is significant risk that this planning process will result in an even more expensive, over-capitalized system that what it replaces.

The language "Ideally utilities would develop at least three scenarios that are representative of varying levels and mixes of DER…"[9] does not capture the entire modelling effort that will be needed to develop DRPs. The IOUs must examine the various characteristics levels of these resources, as well as different approaches to integrating them, and how these options would meet the "Integrated System Qualities" described in Figure 2, as well as associated overall system costs.

Integrated Distribution Planning: what, if any, additions or modifications would you suggest to the Integrated Distribution Planning section of this paper?

This section states that "These parameters should also address how to consider customer value or externalities."[10] As indicated above, customer value is best determined by the customers themselves, as exhibited by their responses to value-based tariffs at the locational level. In the alternative, a value of service studies should be conducted, again within the context of the specific location.

[9] Resnick Institute, *More than Smart: A Framework to Make the Distribution Grid More Open, Efficient, and Resilient* at 10, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, R. 14-08-013, Appendix B (filed Aug. 14, 2014).
[10] *Id.* at 6.

The no-regrets discussion reflects a good approach to creating interesting opportunities to secure minimum investments towards environmental sustainability, and should be further explored in this proceeding. For example, no regrets could entail more fossil fuel plants assumed for planning purposes, price-based tariffs, or customer-side energy management systems. Environmental externalities should be internalized (e.g., monetized) within the analysis, so they can be compared on the same basis as other parameters.

Distribution System Design Build: what, if any, additions or modifications would you suggest to the Distribution System Design Build section of this paper?

EDF strongly supports the concepts outlined in this section.

Integrated Distribution System Operations: what, if any, additions or modifications would you suggest to the Integrated Distribution System Operations section of this paper?

Integration of DER into Operations: what, if any, additions or modifications would you suggest to the Integration of DER into Operations section of this paper?

EDF strongly agrees with the need to "create transparency related to the value of services and related monetization methods (e.g., market, bi-lateral, tariff, etc.)."[11]

However, it may not be desirable or cost-effective for all "DER to fully participate in CAISO markets."[12] This goal merits further examination before being adopted by the Commission. It is possible that only a portion of DER should engage in CAISO markets, with the majority creating benefits outside these markets through tariff redesign. That said, CAISO markets should be open to and supportive of DER.

Integrated Grid Roadmap: what, if any, additions or modifications would you suggest to the Integrated Grid Roadmap section of this paper?

This section essentially ends where this proceeding begins. EDF appreciates that the need to develop pricing and valuation methods is specifically identified as important for integration, and encourages the Commission to make progress on these elements in this docket.

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[11] *Id.* at 17.
[12] *Id.*

IV. CONCLUSION

EDF welcomes the opening of this rulemaking, as the proceeding will significantly influence the future role and value of third-party distributed energy resources on the traditional-utility owned distribution grid.

Respectfully signed and submitted on September 5, 2014

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