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.	R._____________

ORDER INSTITUTING RULEMAKING

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ORDER INSTITUTING RULEMAKING

Summary

This rulemaking is opened to establish policies, procedures, and rules to guide California investor-owned electric utilities (IOUs) in developing their Distribution Resources Plan Proposals, which they are required by Public Utilities Code Section 769[1] to file by July 1, 2015. This rulemaking also will evaluate the IOUs' existing and future electric distribution infrastructure and planning procedures with respect to incorporating Distributed Energy Resources into the planning and operation of their electric distribution systems.

1. Background: Assembly Bill (AB) 327 (Perea, 2013)

AB 327 is a multi-part bill that affects multiple aspects of the provision of regulated utility service and of the energy market, including Net Energy Metering, the Renewables Portfolio Standard, natural gas and electricity rates, and electricity resources. This rulemaking focuses on Public Utilities Code Section 769, which addresses the investor-owned electric utilities (IOUs') electric distribution planning and the Commission's obligation to review, modify, and approve the IOUs' Distribution Resources Plan Proposals (DRPs). Appendix A to this rulemaking provides the full text of Section 769.

2. A New Framework for Distribution Planning

Since 2001, the Public Utilities Code has provided that "[e]ach electrical corporation, as part of its distribution planning process, shall consider nonutility owned distributed energy resources as a possible alternative to investments in its distribution system in order to ensure reliable electric service at the lowest possible cost."[2] In addition, between 2001 and the present, the Commission has developed policies that engaged and promoted ever greater quantities of Distributed Energy Resources (DERs) located within the IOU distribution system. In recognition that traditional distribution system planning is limited in its ability to support State policies on DERs and emerging technologies, the Legislature passed AB 327. Section 769 requires IOUs to submit DRPs that recognize, among other things, the need for investment to integrate cost-effective DERs and for actively identifying barriers to the deployment of DERs such as safety standards related to technology or operation of the distribution circuit. Notably, the Commission is authorized to modify and approve an IOU's DRP "as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources."[3]

Giving full effect to Section 769 is not a straightforward undertaking. This rulemaking will consider an appropriate vision or set of principles to guide the IOUs' development of their DRP proposals.

In September 2013, drawing upon previous efforts of the Governor's Office and industry stakeholders, a small group of interested scholars, industry experts, and legislators gathered to develop a list of topics for potential use as a framework to provide recommendations in shaping the future of the State's energy infrastructure. Subsequently, one of the participants, Paul DeMartini,[4]

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1 Section 769 was added to the Public Utilities Code by Assembly Bill 327 (Stats. 2013, ch. 611).

2 Section 353.5.

3 Section 769(c).

4 Managing Director, Northpoint Energy Advisors LLC.

developed a draft framework paper titled "*More than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient*."

On June 9, 2014, a similar group of stakeholders met to further discuss the More than Smart paper. Based on these secondary conversations, Mr. DeMartini revised the *More than Smart* paper and put it forward for public consumption and comment. Mr. DeMartini's paper (Appendix B) provides both a basis for questions to be asked in this rulemaking and a useful framework from which this rulemaking will establish policies, procedures, and rules for the development of the IOUs' DRPs.

3. Preliminary Scope

The purpose of this rulemaking is to guide the IOUs in the development of their DRPs and to review, approve or modify and approve the plans as envisioned in AB 327. The rulemaking will consider providing guidance to the utilities for incorporating any additional spending necessary to integrate cost-effective distributed resources into its distributed energy plans for consideration in subsequent general rate case (GRC) requests, as specified by Section 769(d).

The goal of these plans is to begin the process of moving the IOUs towards a more full integration of DERs into their distribution system planning, operations and investment. Specifically, Section 769 requires that the DRPs must provide a roadmap for integrating cost-effective DERs into the planning and operations of IOUs' electric distribution systems with the goal of yielding net benefits to ratepayers.

In their DRPs, the IOUs are required to define the criteria for determining what constitutes an optimal location for the deployment of DERs, and then identifying specific locational values for DERs. To this end, the IOUs must include in their DRPs methodologies to define locational benefits and optimal locations for DERs, augmented or new tariffs and programs to support efficient DER deployment, and the removal of specific barriers to deployment of DERs. In this context, the preliminary scope of this proceeding is to:

1) Define principles and develop parameters to guide the development of the DRPs;
2) Consider the safety issues that arise from changes to the utility practices of distribution resource planning;
3) Develop a calculation methodology for assessing locational value of a particular DER;
4) Delineate how IOUs can more fully integrate DERs into distribution planning. Specifically, the IOUs should propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.
5) Identify methodologies for assessing whether DERs provide distribution reliability benefits;
6) Integrate DERs into distribution system planning and operations; Specifically, propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.
7) Define a set of scenarios and/or guidelines that will serve to test whether a specific DER integration strategy will work and clarify assumptions embedded in the DRPs;
8) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.
9) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

10) Review, approve, or modify and approve DRPs.
11) Consider further actions, if needed, to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs. Specifically the proceeding shall determine how any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation.

We note that the Commission may approve proposed spending in the GRC if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable. The Commission, in this proceeding, may also adopt criteria, benchmarks, and accountability mechanisms to evaluate the success of any investment authorized pursuant to a distribution resources plan.

3.1. Questions

To address the issues delineated above, we pose the following questions for all interested parties to comment on (please limit responses to questions 1-15 to no more than 1 page per question and no more than 3 pages for question 16):

1) What specific criteria should the Commission consider to guide the IOUs' development of 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?
2) What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?
3) What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?

4) What specific values should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERs for this value?
5) What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?
6) What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?
7) What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?
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?
9) What types of data and level of data access should be considered as part of the DRP?
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?
11) What considerations should the Commission take into account when defining how the DRPs should be monitored over time?
12) What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?
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?
14) What specific concerns around safety should be addressed in the DRPs?

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.

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

3.2. Safety and Distributed Resource Planning Proposals

The Commission is committed to ensuring full consideration of safety issues and practices related to its policies and proceedings, and promoting improvements in safety of all regulated utilities and entities. Prospective changes to distribution planning processes, as contemplated in this rulemaking, must take into account the safety of utility personnel, first responders, inspectors, installers and end-users. This is especially true given that there will be more opportunities in the future for customers to seek interconnection of new devices and technologies to the distribution system, and there may be increased involvement of non-utility personnel in the installation and operations of such equipment. Along with efforts to incorporate Safety and Reliability Risk Assessment in the context of GRCs (in Rulemaking (R.) 13-11-006), and in compliance with various general orders, this rulemaking provides another excellent opportunity to incorporate safety measures into the planning process for distribution utilities.

The distribution grid planning process reevaluation will look at how to identify risks, discuss how they may be addressed in the context of DER Plans, and ensure that DER Plans filed by the utilities specifically and comprehensively address safety.

This proceeding may also need to consider how utility reliability, as experienced by customer outages, may be affected by the introduction of higher penetrations of DERs.

Global climate change is one of the most significant long-term safety challenges facing California. In this context, the relative greenhouse gas (GHG) reduction impact of policies that the Commission considers fits into the rubric of safety considerations. As such, this proceeding may also explore the relationship between DER deployment, the DER Plans and California's GHG emissions reductions targets.

This proceeding will also be a forum at discussing how safety concerns can become an impediment to the adoption of new technologies that may pose any threat to utility safety. The proceeding may need to consider how best to ensure the need for safety while also providing an opportunity for the grid to adapt to large penetrations of new DERs.

4. Preliminary Schedule and Initial Comments

The schedule for this proceeding is stated below in Table 1:

Table 1

August 14, 2014	Issuance of Order Instituting Rulemaking
September 5, 2014	Interested parties file responses to the questions above, as well as any comments addressing scope, schedule, and other procedural issues
September 17, 2014	Energy Division Workshop
September 22, 2014	Replies to initial responses filed
To be Determined	Prehearing Conference
November 2014	Staff Proposal for Guidance on Distribution Resources Plan Proposal
November 2014	Workshop on Staff Proposal (if requested)
December 2014	Parties comments and replies on Staff Proposal
Late January 2015	Ruling with final Guidance on Distribution Resource Plan Proposals
July 1, 2015	Electric Utilities file DRPs
March 2016	Commission Final Approval of Distribution Resource Plan Proposals Anticipated

A Prehearing Conference (PHC) will be scheduled following receipt of responses and replies. The PHC will address scope and scheduling issues including whether this rulemaking should be divided into phases (for example, a first phase could deal with establishing guiding principles for DRPs, then a second phase involve consideration of the actual plans).

In addition to their responses to the questions above, parties may address any scope and scheduling concerns in their responses and replies. Following the PHC, the Assigned Commissioner will issue a scoping ruling refining the scope and procedural schedule.

Commission staff will host an initial workshop in this proceeding on September 17, 2014. Subsequent workshops may be scheduled, as noted in the schedule above. The initial workshop will be an opportunity for staff to receive input as they prepare a Staff Proposal on Guidance on the DRPs. This document is expected to serve as a template and outline for the DRPs. The Guidance document will provide instructions to the utilities as they prepare their DRPs for submittal in mid-2015. Questions about this workshop should be directed to Arthur O'Donnell at Arthur.O'Donnell@cpuc.ca.gov.

This proceeding will conform to the statutory case management deadline for quasi-legislative matters set forth in Section 1701.5. It is our intention to issue guidance by February 2015 to allow utilities to timely file their DRPs by July 1, 2015, and for the consideration of adopting those plans no later than 18 months from the date of the assigned Commissioner's scoping memo.

5. Proceeding Category and Need for Hearing

Rule 7.1(d) of the Commission's Rules of Practice and Procedure (Rules) specifies that an order instituting rulemaking will preliminarily determine the category of the proceeding and the need for hearing. As a preliminary matter, we determine that this proceeding is quasi-legislative as defined in Rule 1.3(d). It appears that the issues may be resolved through comments and workshops without the need for evidentiary hearings.

Any person who objects to the preliminary categorization of this rulemaking as quasi-legislative or to the preliminary hearing determination shall state any objections and material facts they believe require a hearing in their responses to the questions herein. After considering any comments on the preliminary categorization or preliminary hearing determination, the assigned Commissioner will issue a ruling making a final category and hearing determination; this final determination as to categorization is subject to appeal as specified in Rule 7.6(a).

6. Respondents

Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall be respondents in this proceeding. Respondents shall be placed on the service list automatically as parties, but each respondent shall alert the Commission's Process Office of the name and address and e-mail information for its representative(s) to receive service within 20 days of issuance of this rulemaking.

7. Service List

This rulemaking is served on all respondent utilities. In addition, to develop a temporary service list, this rulemaking also will be served on all Load Serving Entities listed on the Commission's official records (Appendix D), the California Energy Commission, the California Independent System Operator, and the service lists for the following:

- R.13-09-011 (Demand Response and Advanced Metering);
- R.13-11-005 (Energy Efficiency);
- R.13-12-010 (Long-Term Procurement Rulemaking);
- R.13-11-007 (Electric Vehicles);
- R.11-10-023 (Resource Adequacy Rulemaking);

- R.08-12-009 (Smart Grid Deployment Rulemaking);
- R.12-11-005 (California Solar Initiative and Distributed Generation Rulemaking);
- R.11-09-011 (Rule 21 Interconnection Rulemaking);
- R.12-06-013 (Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations); and
- Application 14-02-006, et al., (Energy Storage Procurement Applications pursuant to Decision 13-10-040).

The temporary service list is appended to this rulemaking as Appendix C and shall be used for service of all pleadings until a formal service list for this proceeding is established. Such service does not confer party status in this proceeding upon any person or entity, and does not result in that person or entity of being placed on the service list for this proceeding. All parties on the service list will be accorded service by others until final rules are proposed and/or a final decision issued. Filing and service of comments and other documents in the proceeding are governed by the rules contained in Article 1 of the Commission's Rules of Practice and Procedure. (*See* particularly Rules 1.5 through 1.10 and 1.13.)

8. Addition to Official Service List

Addition to the official service list is governed by Rule 1.9(f) of the Commission's Rules of Practice and Procedure.

Respondents are parties to the proceeding (*see* Rule 1.4(d)) and will be immediately placed on the official service list.

Any person will be added to the "Information Only" category of the official service list upon request, for electronic service of all documents in the proceeding, and should do so promptly in order to ensure timely service of comments and other documents and correspondence in the proceeding.

(*See* Rule 1.9(f).) The request must be sent to the Process Office by e-mail (process_office@cpuc.ca.gov) or letter (Process Office, California Public Utilities Commission, 505 Van Ness Avenue, San Francisco, California 94102). Please include the Docket Number of this rulemaking in the request.

Persons who file responsive comments thereby become parties to the proceeding (*see* Rule 1.4(a)(2)) and will be added to the "Parties" category of the official service list upon such filing. In order to assure service of comments and other documents and correspondence in advance of obtaining party status, persons should promptly request addition to the "Information Only" category as described above; they will be removed from that category upon obtaining party status.

9. Subscription Service

Persons may monitor the proceeding by subscribing to receive electronic copies of documents in this proceeding that are published on the Commission's website. There is no need to be on the official service list in order to use the subscription service. Instructions for enrolling in the subscription service are available on the Commission's website at http://subscribecpuc.cpuc.ca.gov/.

10. Public Advisor

Any person or entity interested in participating in this rulemaking who is unfamiliar with the Commission's procedures should contact the Commission's Public Advisor in San Francisco at (415) 703-2074 or (866) 849-8390 or e-mail public.advisor@cpuc.ca.gov, or in Los Angeles at (213) 576-7055 or (866) 849-8391, or e-mail public.advisor.la@cpuc.ca.gov. The TYY number is (866) 836-7825.

11. Intervenor Compensation

Pursuant to Rule 17.1, any party that expects to claim intervenor compensation for its participation in this rulemaking shall file its notice of intent to claim intervenor compensation no later than 30 days after the first PHC.

12. *Ex Parte* Communications

Pursuant to Rule 8.3(a) *ex parte* communications in this rulemaking are allowed without restriction or reporting requirement, unless and until the categorization of this proceeding, or of the applicable phase of this proceeding, is changed from quasi-legislative.

O R D E R

IT IS ORDERED that:

1. A rulemaking is instituted on the Commission's own motion to establish policies, procedures, and rules to guide California investor-owned electric utilities in filing Distribution Resources Plan Proposals pursuant to Public Utilities Code Section 769.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are named as respondents to this proceeding.

3. This proceeding is preliminarily classified as quasi-legislative, and it is preliminarily determined that evidentiary hearings will not be necessary. Any persons objecting to the preliminary categorization of this rulemaking as quasi-legislative, or to the preliminary determination that evidentiary hearings are not necessary, shall state their objections in response to this rulemaking along with their comments to the questions posed in this rulemaking.

4. Respondents shall file and interested persons or organizations are invited to file responses addressing the questions identified in this rulemaking, as well as any comments on the scope, schedule, categorization, or need for hearing by September 5, 2014. Parties shall file replies to the responses by September 22, 2014.

5. The assigned Commissioner or Administrative Law Judge may adjust the schedule identified herein and refine the scope of this proceeding as needed.

6. The Executive Director shall cause this Order Instituting Rulemaking (OIR) to be served on the Respondents, all load-serving entities listed in the Commission's official records, the California Energy Commission, the California Independent System Operator, and the service lists for Rulemaking (R.) 13-09-011 (Demand Response and Advanced Metering), R.13-11-005 (Energy Efficiency), R.13-12-010 (Long-Term Procurement Rulemaking), R.13-11-007 (Electric Vehicles), R.11-10-023 (Resource Adequacy Rulemaking), R.08-12-009 (Smart Grid Deployment Rulemaking), R.12-11-005 (California Solar Initiative and Distributed Generation Rulemaking); R.11-09-011 (Rule 21 Interconnection Rulemaking), R.12-06-013 (Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations) and Application 14-02-006, et al., (Energy Storage Procurement Applications pursuant to Decision 13-10-040). The temporary service list shall be used for service of all pleadings until a service list for this proceeding is established. A service list for this proceeding shall be created by the Commission's Process Office and posted on the Commission's Website (www.cpuc.ca.gov) as soon as it is practicable. Parties serving documents in this proceeding shall comply with Rule 1.10 regarding electronic service. Any documents served on the assigned

Commissioner and Administrative Law Judge shall be both by e-mail and by delivery or mailing a paper format copy of the document.

7. All respondents shall be parties to this proceeding. Entities other than respondents shall comply with Rules 1.4(a) and Rule 1.4(b) to become parties in this proceeding.

8. A party that expects to request intervenor compensation for its participation in this rulemaking shall file its notice of intent to claim intervenor compensation in accordance with Rule 17.1 of the Rules.

9. *Ex parte* communications in this Rulemaking are governed by Rule 8.3(a).

This order is effective today.

Dated ___________________________, at San Francisco, California.

Appendix A

(Distribution Resource Plan Code Section 769)

SEC. 8.

Section 769 is added to the Public Utilities Code, to read:

769.

a) For purposes of this section, "distributed resources" means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:

   1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.

   2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

   3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

   4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

(End of Appendix A)

Appendix B

(More than Smart Report Final)

GREENTECH
LEADERSHIP GROUP

MORE
THAN SMART

A Framework to Make the Distribution Grid More Open, Efficient and Resilient

RESNICKINSTITUTE
science • energy • sustainability

ACKNOWLEDGEMENTS

This paper is based on the discussions at the first two More Than Smart workshops as edited by Paul De Martini of the Resnick Sustainability Institute at the California Institute of Technology. The *More Than Smart* initiative is managed by Tony Brunello of the Greentech Leadership Group through the support of the Energy Foundation. The 2nd workshop was facilitated by John Danner of UC Berkeley. For information regarding the workshop participants, please visit the GTLG "More Than Smart" webpage at www.greentechleadership.org.

We wish to acknowledge the assistance provided by Dr. Neil Fromer, Prof. Steven Low, Dr. Lorenzo Kristov, Genesis Rivas, and Andrew De Martini in the development of this paper and Heidi Rusina for supporting the 2nd workshop at the Resnick Institute. The content of this report does not imply an endorsement by any individuals or organizations that participated in any More Than Smart workshop or reflect the views, policies, or otherwise of the State of California. It is intended to be a document that identifies and explores the future of California's electric distribution system so as to educate and stimulate discussion among stakeholders regarding requirements for a distributed future.

GTLG is a 501(c)(3) nonprofit organization committed to providing policy leadership by connecting innovators with policymakers. Participants in the organization are leading companies, clean technology business organizations and policy experts in the areas of distribution grid innovation, energy data, appliance energy efficiency, carbon management and renewable energy. GTLG has been instrumental in starting new initiatives including Mission Data (www.missiondata.org), Smart Electronics Initiative (www.howtokillavampire.org) and other efforts found on the GTLG website.

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I. Executive Summary

California environmental and energy policies[A] combined with customer choices enabled by innovation are forcing fundamental changes to California's power system. It is quickly evolving from the historically centralized structure toward a substantially more decentralized future. This transition creates an opportunity to significantly reduce greenhouse gases by harnessing the value of energy across the grid from customers at the edge through the bulk power system. Essential to achieving this outcome is enabling customer choice via an electric distribution system that becomes an open, integrated electric network platform that is ***more than smart***.

The current electric system serves the majority of California well today. However, it is necessary to consider the changes needed to scale to the levels of distributed energy resources[B] (DER) envisioned in California policy, including Assembly Bill 32[C] (Nunez) and Assembly Bill 327[D] (Perea). This is especially true given the capital intensive nature of grid investment and rapid distributed resource advancements. For example, changes are needed to integrate over 15 Gigawatts (GW)[E] of distributed resources into the grid. As distribution infrastructure is largely depreciated over several decades, investments this decade may need to be useful to 2040. The implication for California is that the current annual utility distribution investment of nearly $6 billion[1,2,3] is effectively *a 25+ year bet on a future* – which will likely be quite different than we can imagine today.

This paper is the result of a series of workshops with industry, government and nonprofit leaders focused on helping guide future utility investments and planning for a new distributed generation system. The distributed grid is the final stage in the delivery of electric power linking electricity sub-stations to customers. To date, no state has initiated a comprehensive effort that includes the planning, design-build and operational requirements for large scale integration of DER into state-wide distributed generation systems. This paper provides a framework and guiding principles for how to initiate such a system and can be used to implement California law AB 327 passed in 2013 requiring investor owned utilities to submit a DER plan to the CPUC by July 2015 that identifies their optimal deployment locations.

This paper outlines four key principles around distribution grid planning, design build, operations and integrating DER into operations to create a more open, efficient and resilient grid.

1. **Distribution planning should start with a comprehensive, scenario driven, multi stakeholder planning process that standardizes data and methodologies to address locational benefits and costs of distributed resources**. Distribution planning is becoming more complex. An integrated planning and analysis framework is needed to properly identify opportunities to maximize locational benefits and minimize incremental costs of distributed resources. This is enabled by a standardized

[A] See Appendix A
[B] Distributed energy resources means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies
[C] Global Warming Solutions Act of 2006, which set the 2020 greenhouse gas emissions reduction goal into law
[D] See Appendix B for AB 327 changes to Public Utilities Code related to Section 769
[E] 15 GWs: 12 GWs of distributed generation, over 2 GWs of demand response, about 1 GW of energy storage

set of analytical models and techniques based on a combination of utility grid operational data and DER market development information to achieve repeatable and comparable results.

2. **California's distribution system planning, design and investments should move towards an open, flexible, and *node-friendly network system* (rather than a centralized, linear, closed one) that enables seamless DER integration.** California's vision for significant DER contribution to resource adequacy and safe, reliable operation of the grid requires a move to a network system. The evolution to an open platform will involve foundational investments in information, communication and operational systems not seen in existing utility smart grid plans. These investments should be based on solid architectural grid principles while ensuring the timing and pace align with customer needs and policy objectives. In the future, the state should strive toward converging electric utility designs with other distribution systems for gas, water and other services.

3. **California's electric distribution service operators (DSO) should have an expanded role in utility distribution operations (with CAISO) and should act as a technology-neutral marketplace coordinator and situational awareness and operational information exchange facilitator while avoiding any operational conflicts of interest.** Today, bulk power systems and distribution systems are largely operated independently. DSO's can help play an integrating role with CAISO. California is already at the point at which integrated and coordinated operations based on better situational information is essential. This integration requires both an expansion of the minimal functions of utility distribution operations and clear delineation of roles and responsibilities between the CAISO and utility distribution system operators. Finally, as with transmission, distribution operations will need standards of conduct to ensure neutral operational coordination.

4. **Flexible DER can provide value today to optimize markets, grid operations and investments. California should expedite DER participation in wholesale markets and resource adequacy, unbundle distribution grid operations services, create a transparent process to monetize DER services and reduce unnecessary barriers for DER integration.** Flexible DER can provide a wide range of value across the bulk power and distribution systems. The issue is not *if* or *when*, but rather *how* do we enable integration of flexible DER into these systems. This will be enabled by the expansion of CAISO services and new distribution operational services. As such, new capabilities and performance criteria should be identified as part of the distribution planning process. These new services should be coordinated with existing programs knowing some existing demand response programs may be surpassed in their relevance and value in the context of AB 327 objectives. Finally, barriers to broad participation involving complex and expensive measurement and verification schemes and related settlement processes should be simplified for DER.

The distribution plans that each of the California IOUs will need to file to comply with AB 327 represent the first step towards starting to re-shape the distribution grid. The role of this paper is to provide a set of strategic frameworks and guiding principles that can inform stakeholders and policymakers in the development of AB 327 Distribution Plans that the CPUC will eventually ratify. Additionally, as other states and international locales consider a more distributed electric system this paper offers guidance on the critical questions and a framework for developing the path forward for their particular distribution systems.

II. Purpose

California environmental and energy policies[F] combined with customer choices enabled by innovation are forcing fundamental changes to California's power system. It is quickly evolving from the historically centralized structure toward a substantially more decentralized future. This transition creates an opportunity to significantly reduce greenhouse gases by harnessing the value of energy across the grid from customers at the edge through the bulk power system. Essential to achieving this outcome is enabling customer choice via an electric distribution system that becomes more transparent in terms of information and open in terms of access. This paper focuses on the optimal integration of distributed energy resources into the electric system and the related evolution of the existing distribution system to become an enabling network to realize the benefits for ratepayers and users of the system.

While the current electric system serves the majority of California well today, it is necessary to consider the changes needed to scale to the levels of DER envisioned in California policy, including AB 32[G] and AB 327[H]. This is especially true given the capital intensive nature of grid investment and rapid distributed resource advancements. For example, changes are needed to integrate over 15 GWs[I] of distributed resources into distribution and/or bulk power system operations. This amount of DER may be low as technological innovation is accelerating.[4] Bill Gates observed, "We always overestimate the change that will occur in the next two years and underestimate the change that will occur in the next ten." As distribution infrastructure is largely depreciated over several decades, investments this decade may need to be useful to 2040. The implication for California is that the current annual utility distribution investment of nearly $6 billion[5,6,7] is effectively *a 25+ year bet on a future* – which will likely be quite different than we can imagine today.

This paper continues a conversation among a diverse set of experts about the future of California's power system with a particular focus on its role and desired attributes. The objective is to define an integrated grid framework and related guiding principles that link California's policy goals and desired integrated power system qualities to utility implementation practices. Specifically, those practices related to distribution **planning, design-build, operations** and the **integration of DER** into markets and grid operations. This paper is derived from the discussions in a 1st More Than Smart Workshop in September 2013 and a 2nd workshop at Caltech's Resnick Sustainability Institute in June 2014. This paper will serve as a primer for a 3rd workshop planned for fall 2014 and a source of industry insights for relevant regulatory activity in California and elsewhere.

[F] See Appendix A

[G] Global Warming Solutions Act of 2006, which set the 2020 greenhouse gas emissions reduction goal into law

[H] See Appendix B for AB 327 changes to Public Utilities Code related to Section 769

[I] 15 GWs: 12 GWs of distributed generation, over 2 GWs of demand response, about 1 GW of energy storage

III. Integrated Grid Framework

The electricity system has been called the most complex machine developed by humans. This complex system has many interdependent components that must work harmoniously to ensure safe and reliable service. Any material changes to the system need to be considered holistically. This is why a systems view is essential to evaluate the transition underway for the electric grid in California, Hawaii[8], New York[9] and other places around the world.

The integrated grid framework in figure 1 below provides a systems view to conceptually illustrate the linkage between California's existing policy goals and regulatory defined electric system qualities we want to achieve, and the lifecycle development processes used to implement those goals and qualities in practice. This framework was developed from the comments and discussion in the first More Than Smart workshop utilizing a systems engineering approach. A systems engineering approach involves holistic design and management of complex engineering projects over their integrated life cycles. The process starts with identifying the policy objectives as well as customer needs to define system qualities and by extension the system design along with operational requirements.

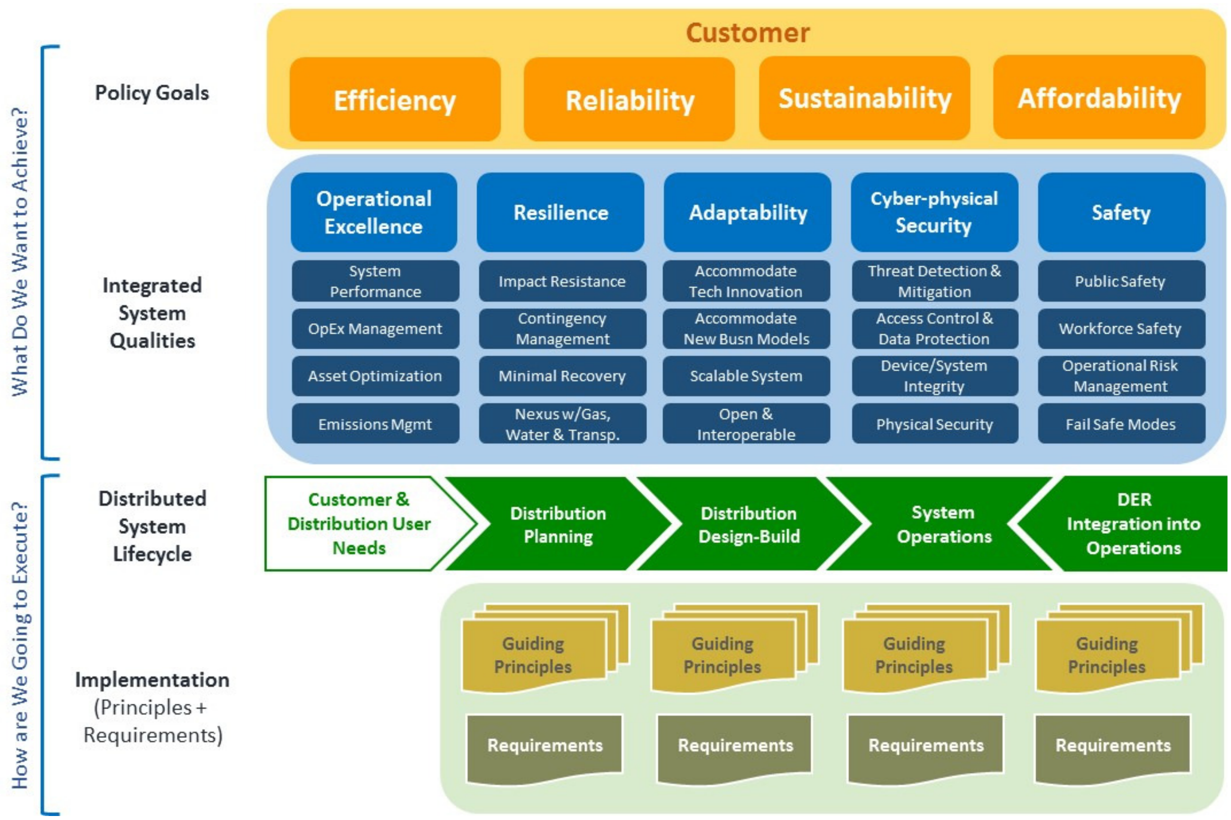

Figure 1: Integrated Grid Framework

This integrated lifecycle is identified above as the Distributed System Lifecycle shaded in dark green. The four key stages are: **(1) Distribution Planning, (2) Distribution Design-Build, (3) System Operations** and **(4) DER Integration into Operations**. Each interdependent stage represents a set of participants (people), complex processes and technologies. In this paper, a set of guiding principles is identified for each stage to enable customer needs and policy outcomes. Further definition of the attributes and requirements for each stage will lead to repeatable and scalable methods that address immediate and future system needs. This paper is purposely agnostic regarding technical solutions and technology.

The focus of this paper is not to define "what we want to achieve" as this has been clearly identified and codified in California law, regulation and standards. The focus is instead on the, "How are we going to execute on this vision?" considerations. This, in part, requires creating lines of sight between the policy goals and tactical implementation. It is also requires alignment of all aspects of the framework to accomplish the desired results. These various aspects should be viewed as synergistic, not additive if the objectives of AB 327 are to be achieved. This is why it is essential that a holistic, systematic approach is used.

Implementation will involve substantial changes to the processes and methods used in each of the lifecycle stages. AB 327 specifically calls for specific changes as noted in the discussion below. But, this law is only one of several existing California policies that should be considered for planning, design-build and operation of the distribution system going forward. As such, there are several proposed guiding principles for each stage to address the holistic changes needed. These are drawn from the More Than Smart workshops and best practice defined in several industry papers, such as EPRI's The Integrated Grid[10], Environmental Defense Funds Smart Grid Scorecard[11], DOE's Modern Grid Initiative[12], Carnegie Mellon's Smart Grid Maturity Model[13], and Gridwise Architecture Council's Decision Maker Checklist[14]. If done well the revised process for each stage will result in defining a set of integrated requirements for development of an electric system to meet California's needs for today and well into the 21st century.

A. Distribution Planning

Ensure ratepayers realize the net benefits from the optimal use of distributed resources at minimal cost to integrate these resources into the electric system.

California law AB 327[15] requires investor owned utilities to submit a distributed resource[J] plan proposal to the CPUC by July 1, 2015 that identifies optimal locations for the deployment of distributed resources. Also, that the "evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation." Subsequently, any additional distribution investment plans will need to consider maximizing the locational benefits and minimizing the incremental costs of distributed resources. This analysis must also consider "safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service." This last criteria is also part of the Operational Risk[16] requirements for California investor-owned utilities.

This level of planning now required in California involves a wider and more complex range of engineering and economic issues in an integrated and multi-disciplinary fashion with direct participation of relevant stakeholders. This includes:

- An integrated planning and analysis framework to properly identify the criteria, issues, interdependencies and methods of analysis
- Standardized set of related analytical models and techniques to achieve comparable results

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[J] Distributed Resources as defined by AB 327 means, renewable distributed generation, energy storage, plug-in electric vehicles

- Qualified access to utility operational and competitive market data to facilitate stakeholder analysis and independent research
- Use of future scenarios related to varying amounts and timing of DER and electric vehicle adoption to stress test distribution investment plans and DER benefit-costs
- Transparent processes incorporating relevant stakeholder participation

Integrated Distribution Planning
The first step toward an integrated systematic approach is development of a standardized planning framework. This is because of the diversity and scale of California's current DER objectives. This planning framework would involve identifying customer needs and uses of the distribution system, along with DER diffusion modeling, integrated resource planning, power system engineering and economic analyses needed along with the interdependencies among each. The opportunity exists to achieve California's objectives if we holistically understand the interrelationships and related benefits and costs of DER and the grid. Currently, such an integrated framework does not yet exist[K] and therefore many analyses performed today may be significantly deficient in answering the long-term questions raised in statues.

Framing the planning objectives in a practical and standard manner is essential to yield comparable results across the state. For example, the following three objectives should be clearly defined prior to the utility distribution planning required under AB 327:

- "Locational benefits"
- "Optimal location"
- "Value optimization"

Discussion in the 2nd workshop highlighted that "value optimization" could be construed as value maximization or cost minimization. Cost minimization in this case is the integrated lifecycle costs related to the environment, electric system value chain, society and customers. Also, it is important to define local optimization and benefits in the context of the whole system. The parameters for any planning objectives need to be identified. This should include identifying inputs such as flexibility, reliability, and resiliency as well as the scope of analysis. These parameters should also address how to consider customer value or externalities. The effective limits of an analysis should be defined.

California utilities continue to make significant investment in grid modernization. PG&E, for example, has incorporated fundamental changes to enable integration of DER at scale. These changes include larger distribution wire sizes and transformers that also improve safety and reliability. Given these grid modernization investments, distribution planning should start by establishing a common understanding of the capabilities of the existing system as a "baseline". This baseline evaluation should be stress tested for any capability gaps by a set of potential future scenarios described below.

Analysis Methodology & Tools
Existing distribution planning process, methods and modeling tools aren't equipped to fully assess the increasing random variability of supply and demand resources.[17,18] Historically, variability of net customer demand was rather predictable based on weather and macroeconomic factors. Plus, few distributed generators were directly interconnected to low voltage distribution systems so the impact to

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[K] EPRI is currently developing such a framework as part of the Integrated Grid program.

the system was negligible. This has changed based on the scale and pace of DER adoption and California's goals. Analysis today requires both the traditional power engineering analysis as well as an assessment of the random variability and power flows across a distribution system. Such an analysis would include real and reactive power flows under a variety of planned and unplanned situations across a distribution system, not just a single feeder. Evolution to a more network centric model for a distribution system to enable bi-directional power flow underscores the need for a fundamental shift in planning analyses.

As such, a more sophisticated and proactive[19] approach is needed to consider the "optimal locations" for DER. Value assessment as defined in AB 327 requires an evaluation of "locational benefits and costs of distributed resources located on the distribution system." As noted before, these analyses require a complex set of interrelated models to conduct. [20] Also, a more dynamic interface with the transmission system may occur and so analysis of the T-D interaction is necessary. A 2013 CEC commissioned study identified the "*need for studies and tools that capture the detail of distribution and distribution-connected generation with transmission for a unified regional view" (pg. 3).*[21]

Additionally, many of these analyses will involve trade-offs. One is the trade-off between economic optimization and system robustness (resilience & reliability). The challenge for distribution planning, unlike transmission, is that there is no current analytical framework to address the inherent trade-off between economic optimization and operational robustness. Failure to address this significant gap is a recipe for potentially disastrous results before 2030. Taking this a step further, there are optimization trade-offs between environmental, societal, grid-based and customer-based solutions. It is also important to recognize that the power system is becoming considerably more complex. This can create a more fragile system, not more resilient, if not done properly. There is a need to understand the inherent trade-off related to simplicity versus complexity in planning. This is best done through analysis of an expanded set of operational risks[22,23] not identified in the current CPUC Operational Risk proceeding. The planning framework must be able to address these types of trade-offs.

Based on the various new and converged analyses described above, there is a need to identify existing tools that can be used and any gaps that exist. A prioritization of the analyses is urgently needed as time is short to support AB 327 requirements, energy storage procurements, smart grid and operational risk plans.

Operational & DER Market Data

To enable research and transparency with the analyses, qualified access to grid asset and operational data is needed. Similarly, competitive DER/EE market data from services firms is required. This foundational data should be accessible, visible, and available (in terms of time granularity and type of data). Such access could be provided consistent with existing confidentiality rules for transmission planning and other utility operational data. Also, NERC's synchrophasor data repository may offer guidance on allowing limited access for research and transparency while respecting legitimate security and confidentiality concerns. Conversely, utility planning and analysis would benefit from confidential information provided by DER developers and services firms regarding system performance characteristics, market information and plans in their planning areas. There may also be an opportunity to consider expanding the role of the CPUC's new Energy Data Center[24] to also include this operational and market planning data.

DER/EE/EV Diffusion Scenarios

A key challenge for determining value as well as the timing and magnitude of grid investment is the uncertainty related to the diffusion patterns for DER, energy efficiency, electric vehicles, microgrids and zero net energy code compliance. A set of future scenarios looking toward 2030 and beyond are useful to guide discussion of the evolution of California's electric system to support customer's choices and public policy. There is a recognition that California is at a crossroads with respect to the future role of the electric system generally and the distribution system specifically. The discussion at the 2nd More Than Smart workshop identified the value of scenarios, as possible futures for distributed energy resource deployment, electric vehicle adoption and customer participation. These scenarios would be used to 'stress test' existing utility distribution systems, planned investments and research and development activity (in general rate cases, EPIC programs, and smart grid roadmaps).

Ideally, utilities would develop at least three future scenarios for the purpose of stress testing the baseline capabilities of the distribution system. Scenarios when used in conjunction with long term distribution infrastructure capital planning, should cover at least a 20 year time horizon. These scenarios should incorporate a range of relevant parameters including diffusion of various types of DER (plus EVs and energy efficiency), socioeconomic factors, and other key aspects. These scenarios should incorporate assumptions related to state policy goals (e.g., 12,000 MWs of local DG, 1.5 million ZEVs, 5% of peak met by DR). These assumptions could be augmented by insights from stakeholders and research analysis by Lawrence Berkeley National Lab (LBNL) along with other research organizations as well as scenarios developed in related California proceedings and planning. In these scenarios, DERs must be assumed to provide services identified in utility Distribution Resource Plans. In conjunction with the scenarios, the specified system qualities below can be used to test the robustness of distribution plans. The characteristics for each of the integrated system qualities below would be outlined based on each stakeholder (e.g., Customer, DER provider, DSO and TSO) specified needs.

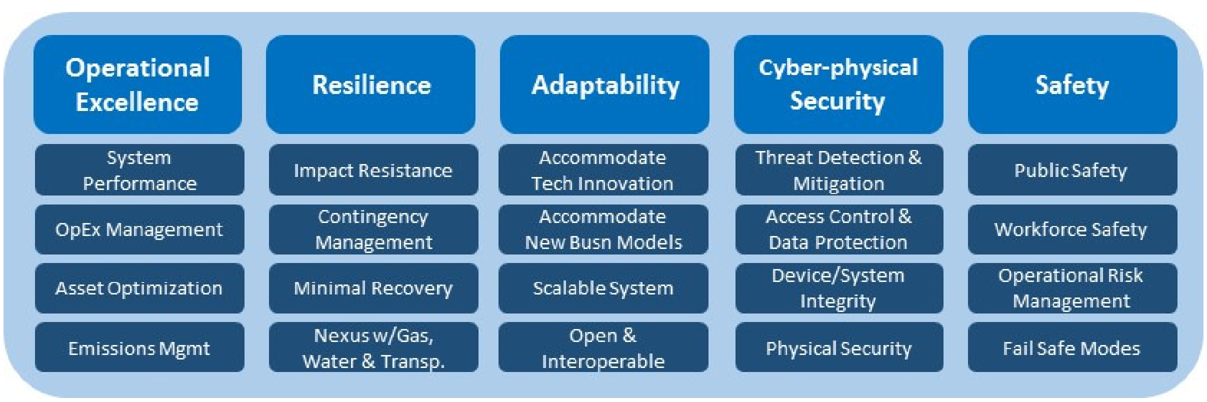

Figure 2: Integrated System Qualities

Multi-stakeholder engagement

The number of vested stakeholders in the distribution planning process has greatly expanded and incorporating stakeholder (including representatives of customers) engagement and input as well as greater transparency to the process is needed. There is also a concern that California's plethora of incentives, programs and policies for different clean technologies and resource types are not well coordinated, leading to inefficiencies in planning. It is also critical that the opportunity/problem to be solved needs to be defined from an integrated system view and not from a single stakeholder or technical solution perspective. These considerations suggest the need for revised processes to create a multi-stakeholder, scenario driven planning process similar in concept to that developed for transmission by CAISO in 2010.

However, engaging more stakeholders in such a planning process may increase the time for outcomes. Balancing the need for multi-stakeholder involvement with the need for accelerated changes to the distribution system will be a critical challenge that should be considered. Such as the need to identify and be in the position to execute short term reliability system upgrades versus longer term reliability investments required to support DER. One area that appears ripe for stakeholder engagement is the identification of optimal locations guided by planning and asset data in support of realized benefits.

Recommended Reading
Reference paper for analogous approach to scenario based planning: *CAISO Transmission Planning Process,* 2010 [25]

Guiding Principles for Distribution Planning
Based on the workshop discussions, the following guiding principles and potential requirements are offered for consideration. These are aligned with relevant federal and state policies, and leverage industry research and best practices referenced in this paper.

Guiding Principles	Potential Requirements
P1: Scenario-driven integrated planning analysis framework	P1a: Framework should identify all relevant analysis and modeling interdependencies and related engineering-economic trade-offs P1b: Planning should use scenario driven "futures" using a set of common parameters including customer DER adoption, and other critical factors P1c: Planning should establish baseline functionality of current infrastructure and designs
P2: Standardized methodology and tools for distribution planning	P2a: Planning should be performed using a consistent set of accepted engineering and economic methodologies, but remain vendor and modeling technology neutral P2b: Engineering models and tools should address all relevant power system characteristics and dynamics for a well defined distribution area and inter-related local transmission system consistent with best practice
P3: Greater access to grid operational and market planning data	P3a: Utility asset and operational data used for distribution planning should be accessible to 3rd parties and researchers under certain qualifications and subject to confidentiality and security conditions. P3b: Market planning data from DER developers and services firms will be available to utilities and research institutions for relevant distribution and bulk power system planning under specific conditions and subject to confidentiality
P4: Integrated multi-stakeholder distribution planning process	P4a: Planning scope should involve relevant stakeholders, including representatives of customers, in process P4b: Stakeholder engagement should not create a bottleneck to planning process

B. Distribution System Design-Build

Develop robust open, node-friendly electric network designs that address safety and reliability needs while incorporating architectural elements that enable innovation across the electric system and enhance customer value from connectivity.

Distribution system designs, investment decisions and related technology adoption processes for physical infrastructure, protection and control systems and operational systems need to quickly evolve toward achieving the objectives below in a cost effective manner and mindful of customer rate impacts:

- Grid as open network model to enable seamless DER/microgrid integration
- Employ flexible designs and layered architecture to create flexibility while managing complexity
- Align timing of infrastructure/systems deployment with needs
- Well defined and functioning utility advanced technology on-ramp

Distribution designs today generally reflect a traditional set of assumptions and uses for distribution circuit. Standard engineering design practices are often based on 50 year old operating paradigms. This may lead to significant stranded investment risk beginning in the next decade. It is essential that distribution designs align to the new requirements driven by customer choices and public policy.

This alignment also raises questions about the future role and value of the distribution system given potential growth of customer self-sufficiency[26] or independent micro-grids. In this context, the discussion at the 2nd MTS workshop identified a "node-friendly"[L] network model as the desired among four potential distribution end-states. The four end-states are; Grid as Back-up, Current Path, Grid as Network, and Convergence.[M] These end states should be viewed as on a continuum in terms of the value of the grid. In this context, Grid as Back-up envisions the grid providing less value than in the other end-states. The Current Path is analogous to the "baseline" discussed earlier. In the Convergence role the electric system provides the highest value. The discussion in the workshop recognized the value of an advanced grid and focused on Grid as Network with aspirations for evolving to a convergence end-state.

These end-states could be used to assess system qualities and validate whether utility investment plans derived from the scenario analysis and planning align with a particular desired end-state.

Grid as Open Network

An open network end-state builds on the current investments through an acceleration of more advanced technology adoption into the grid along with an evolution of distribution system designs to

[L] A node is a distribution grid interface with customer or merchant DER or microgrid
[M] See Appendix C for expanded definitions

create a node-friendly network. This network platform can incorporate seamless integration of DER and independent microgrids. This network platform model envisions a proactive approach to manage the alignment of investment to enable the adoption of DER. Such decisions would be made strategically through a collaborative assessment of optimal investment. This open electric network platform and related operations enables upwards of 20 GWs of distributed energy resources and over 1.5 million electric vehicles to integrate safely and reliably while also contributing to the reduction of greenhouse gases.

Fundamentally, these distribution designs need to consider how to evolve a closed single purpose system to a more open, flexible, operationally visible and resilient platform that can accommodate anticipated DER integration and future innovations. Such a platform would involve "node-friendly" standardized, low cost physical and information interconnections.[27] This would enable interconnection without lengthy studies. This approach would also allow for the continued evolution into a multi-cellular structure comprised of microgrids as discussed in the recent CPUC staff microgrid report[28]. This will not be easy or simple, yet engineering solutions enabled by technology innovations must be developed.

To accomplish this, distribution designs will likely evolve to a level beyond that contemplated in most smart grid plans. This "More than Smart" level is what EPRI describes as The Integrated Grid.[29] Evolution may require rethinking of circuit designs to other configurations, like the loop designs currently being tested in several utility demonstration programs, including SCE's Irvine Smart Grid Demonstration project[30] and utility microgrids such as SDG&E's Borrego Springs project[31].

The 2nd MTS workshop discussion centered on evolving distribution to achieve the network platform attributes and associated integrated value as reflected in this paper. However, the discussion identified the need to more fully explore, as in New York[32], the potential to enable innovation across the power system and other critical infrastructure such as water and transportation. Conceptually there is a real potential for "network effects"[33] through the synergistic value that could be created from such a convergence. This is a stretch goal, but worth consideration as part of any More Than Smart design.

Flexible Designs & Layered Architecture

The incorporation of advanced digital technologies and DER into the operation of the electric system requires consideration of the information, communication and physical interface considerations. For example, networked distribution systems will necessarily involve technologies with different lifecycles as more digital and software components are added. Also, interfaces with customers and 3rd party systems will likely be more dynamic as these systems will have different lifecycles. These cyber-physical interfaces become critical to achieving an open and flexible network desired. Therefore, it is essential that a systems engineering approach leveraging interoperability principles[34] is employed to integrate fast and slow cycle technologies. By understanding the functional requirements and interfaces it is possible to define boundaries to create a flexible system. Modularity would mitigate stranded cost risk and enable future optionality to benefit from unforeseen innovations such as was the case with modular smart meter designs developed before the iPhone was launched. The key to modularity is defining the boundaries correctly. This is fairly complex and involves identifying those engineering-design "constraints that de-constrain"[N]. If done well, constraining aspects of the design will allow flexibility around the constrained aspect. This modular and layered approach is what enables the internet to foster innovation in applications as well as hardware.

A number of architectural issues need to be addressed as distribution increasingly evolves from human-centric passive/reactive management to highly automated active management.[35] As such, operational systems will also evolve in complexity and scale over time as the "richness" of systems functionality increases and the reach extends to greater numbers of intelligent devices at the edge of the system. This also introduces operational risks from increases in system complexity and the cyber-attack surface.[36] This increased complexity requires new ultra large-scale layered architectural approaches[37] to manage data and interfaces across thousands and potentially millions of end points, federated controls to manage various latency requirements for certain grid operations, system security, reliability and extensibility. These systems will be based on architecture that embeds digital processing and analytics as well as control software at many locations in and along the power grid infrastructure to implement flexible grid automation.[38]

Deployment Timing Alignment

The current efforts of California's utilities[39,40] to modernize the grid has been widely recognized as among the world's leading efforts. But, the pace and scope of change incorporated into the multi-billion dollar distribution investment plans may not be sufficient to meet customer needs and policy objectives. This is due in part to the lag between accelerated customer DER adoption, and increasing policy mandates compared to the cycle time for engineering, design and construction. These alignment issues can be addressed by basing investment decisions on scenario based planning. Additionally, timing risk can be mitigated by identifying those investments that are required under any future scenario. These "no regrets" investments include advanced field telecommunications networks and increasing grid operational visibility – to allow more operational data, moving freely, in real time. This effort can be accelerated by focusing initial efforts within the development of optimal or preferred locations, revising in-flight programs such as fault indicator, switch automation, and capacitor control programs to offset otherwise expenditures that would become obsolete. Also, many of these developments will need to be concurrently consistent across roadmap work streams.

However, reducing the deployment time cycle for new designs and related technology solutions is critical. System-wide deployments take a long time from design to full deployment. At first glance, many believe far too long – wrongly comparing the adoption cycle of consumer electronics from the time they reach market to consumer purchase. Looking closer it becomes clearer why the overall duration for technologies deployed at scale in the grid or grid operating systems may take 10 years or more. Below is a conceptual timeline example for electric industry product development and adoption. There are limits to accelerating field deployments given safety considerations and availability of qualified people and equipment. But, there are opportunities to consider accelerating the front end of the lifecycle involving research, development and demonstration and business and regulatory decision making.

[N] Introduced by Caltech Prof. J. Doyle and discussed in Prof. S. Low's blog https://rigorandrelevance.wordpress.com/2013/11/26/power-network-and-internet-i-architecture/

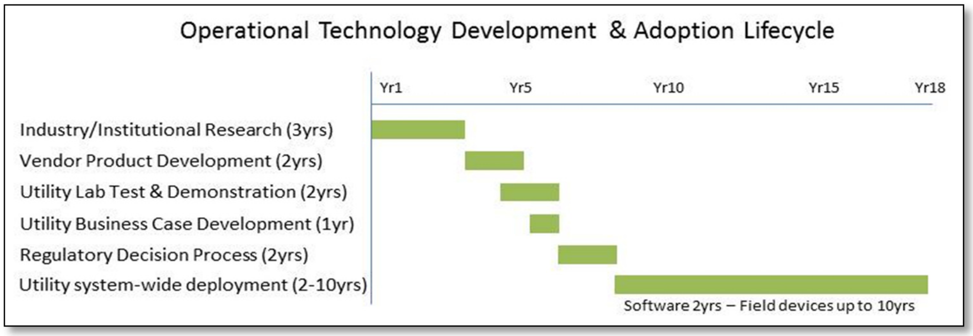

Figure 3: Operational Technology & Field Infrastructure Lifecycle

Utility Grid Technology On-Ramp

Technology advancements in the information and energy technologies that enable a modern grid are available or within reach. As recognized by the creation of the EPIC research and development funding and Smart Grid Roadmaps, utilities play a critical role both in new product development with technology suppliers and collaboration with research universities, institutes and national labs. Without utility involvement the technology development cycle significantly slows. But, the adoption process doesn't stop with lab testing or pilots. It is essential for California that well defined technology adoption on-ramps into operational deployment are established for grid infrastructure and operational systems technology. This would include lessons learned and shared information about technology testing and pilots. Likewise, it is important that scale pilots to demonstrate operational readiness of a wide range of flexible distributed resources (e.g., dispatchable generation, energy storage, electric vehicles and customer load) are conducted soon.

Such on-ramps for advanced grid technology and DER participation would align EPIC research and development funding with integrated resource and procurement plans, Smart Grid Roadmaps and general rate case funding requests for capital investment. Of course, technology development should align with public policy and customer benefits. Thereby, customer benefits and policy values pulling through new technology. This type of alignment is largely done in the energy efficiency and demand response area and was a critical part of the smart meter development and deployments. The time is now to address advanced grid technology adoption to enable the open network model. As such, the distribution plans envisioned in AB 327 should identify specific actions and incremental investment needed to develop an open, flexible electric distribution network as well as the related operational platform.

Recommended Reading

Reference papers for deeper discussion:

- *The Integrated Grid*, EPRI, 2014
- *Future of Distribution*, EEI, 2012

Guiding Principles for Distribution System Design Build

Based on the workshop discussions, the following guiding principles are offered for consideration. These are aligned with relevant federal and state policies, and leverage industry research and best practices referenced in this paper.

Guiding Principles	Potential Requirements
P5: Evolve grid to an open network platform	P5a: Create a node-friendly distribution network that is open, visible, flexible, reliable, resilient and safe P5b: Incorporate full operational risk mitigation considerations into physical designs and protection and control systems leveraging DER/microgrid
P6: Employ flexible designs & layered architecture	P6a: Leverage systems engineering methods to create more flexible designs to address differences in technology lifecycles to mitigate stranded costs P6b: Employ layered, distributed architecture for operational systems to address scale issues involving integration of edge devices
P7: Align deployment timing with customer and policy needs	P7a: Leverage scenario based planning to identify low risk capital investments to keep pace with needs P7b: Identify no regrets utility distribution investments needed in any scenario
P8: Align utility technology adoption	P8a: Establish well defined technology adoption on-ramps into operational deployment P8b: Align EPIC projects, Smart Grid Roadmaps with rate case requests for distribution capital investment

C. System Operations

To provide safe and reliable electric service across distribution system and operational boundaries while enabling seamless integration of DER and microgrids into markets and grid operations.

Providing safe and reliable electric service in a more distributed system requires an integrated and coordinated operational paradigm. This paradigm should clearly delineate roles and responsibilities between California Balancing Authorities (BA) like the CAISO, other transmission system operators and utility distribution system operators (DSO). These responsibilities include:

- Minimal DSO functions to ensure safe and reliable operations
- Reliability coordination at Transmission to Distribution (T-D) interface
- Potentially expanded DSO roles as energy transactions across distribution grow

The fundamental role and responsibility of the BA remains to provide reliable open-access transmission service. This entails maintaining supply-demand balance and transmission reliability through the scheduling and dispatch of resources and interchange transactions with other regional balancing authorities. The new challenge for the BA arises from the need to consider the increasingly dynamic net load and high penetration of flexible DER across the T-D interface at a substation or locational marginal pricing node (P-node). This drives the need to reconsider the various roles needed for physical operation and those for market operation need in the context of scaling DER to over 25% of California's peak demand. This brings about the question as to how appropriately balance existing California policy with economic impacts to customers when considering RPS goals that apply to both transmission and distribution.

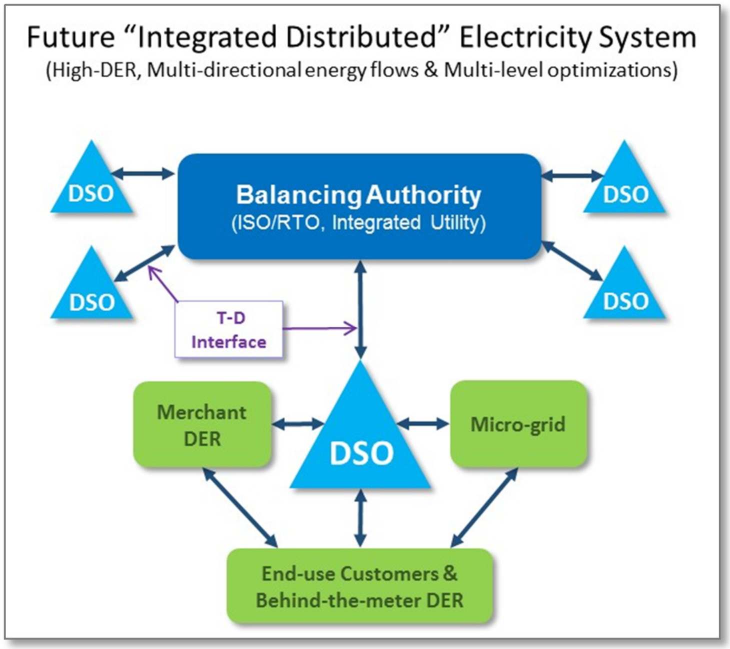

Figure 4: Integrated Electric System Operations

Minimal DSO Functions

The discussion of the potential role of distribution utilities often confuses the two distinct functions; physical operation of the electric system and that of market operation. These functions are closely related, but different. The following discussion is focused on the physical coordination of real and reactive power flows across the distribution system in an integrated manner with the CAISO. In this context, there is a new set of minimal functional responsibilities that define the new DSO. These new functions are in addition to the traditional DSO operational functions, like outage restoration and switching for maintenance. One function is managing distributed reliability services involving many types of DER and independent micro-grids providing distributed reliability services to support distribution system operations**.** The ability of the DSO to utilize locally-provided reliability services will also enable the DSO to maintain more stable and predictable interchange with the BA at the T-D interface. The minimal DSO functions also include responsibility to BA for providing situational awareness involving forecasting, real-time measurement and reconciliation of net load, dispatchable DER resource, and real and reactive power flows from the distribution side of a P-node.

It is important to clarify that the DSO functions described here do not require the DSO to be inserted into wholesale market operations and related economic transactions between parties involving DER. Rather, the core operational safety and reliability based DSO activities confine the DSO to managing real and reactive power flows across the distribution system. These activities require tight integration of the people, processes and technology used to operate the distribution system. Any concerns about conflicts of interest regarding the coordination of energy and capacity delivery schedules, can be addressed through the use of standards of conduct (SOC) modeled after the successful Federal Energy Regulatory Commission's transmission operation SOC[41] adhered to by utilities for over 15 years.

Reliability Coordination at T-D Interface
Another function required of the DSO is T-D interface reliability coordination**.** This function is to ensure that services provided by DER are properly coordinated, scheduled and managed in real-time so that the BA has predictability and assurance that DER committed to provide transmission services will actually deliver those services across the distribution system to the T-D interface.[42] This coordination also involves ensuring that DER dispatch (via direct control or economic signal) doesn't create detrimental effects on the local distribution system, and will require coordination of physical power flows at the T-D interface between the BA and DSO.

The need for real and reactive power flow coordination across distribution and the T-D interface is likely to increase with the growth of DER and related excess energy available for resale. This involves more than forecasting and managing net load as identified in the CAISO Duck Curve analysis.[43] It is also very likely that energy transactions may occur within any given local distribution area between distributed generators and municipal utilities, power marketers and energy retailers. At a minimum the physical aspects (not the financial aspects) of these transactions will need to be coordinated as part of the DSO's function of reliable distribution system operation. This does not mean that DSOs will operate balancing markets or an optimal resource dispatch function as done by the BA at the wholesale level. Supply-demand balancing will remain the sole responsibility of the BA. The DSO will, however, need to coordinate energy delivery schedules to ensure operational integrity of the distribution system.

Expanded DSO Roles
There is a set of potential market facilitation services beyond the minimum that may be provided by a utility DSO and/or third parties. An example is an evolution of the schedule coordinator role as described in CPUC Rule 24. If desired, the rule may need to be changed to allow investor owned utilities to offer this service. Also, incorporation of energy storage into the distribution system may enable DSOs to offer new non-core market enabling services similar to those provided by natural gas distribution utilities. Such services may include "park and loan," where parties may park or store energy that cannot be delivered immediately to be scheduled for delivery at another time. Likewise, DSOs may sell or loan short-term real or reactive power as needed to make-up for deficiencies in scheduled deliveries. The gas operational concept of "line pack" to increase the amount of energy that may be delivered in a short period may also be adapted to electric distribution systems with certain energy storage and demand management technology.

Recommended Reading
Reference paper for deeper discussion: *21st Century Integrated System Operations*, Caltech-CAISO, 2014

Guiding Principles for System Operations
Based on the workshop discussions, the following guiding principles are offered for consideration. These are aligned with relevant federal and state policies, and leverage industry research and best practices referenced in this paper.

Guiding Principles	Potential Requirements
P9: Provide safe and reliable distribution service	P9a: Define minimal utility DSO functional related responsibility and accountability for physical operations of a local distribution area P9b: DSO should provide T-D Interface reliability coordination with CAISO for a local distribution area. P9c. DSO should provide physical coordination with the TSO for energy transaction across the T-D interface.
P10: Provide neutral marketplace coordination	P10a: The DSO paradigm should support public policy energy and environmental objectives P10c. The DSO paradigm should enable the best new technologies to emerge and succeed, rather than picking winners through an administrative process.
P11: Situational awareness and operational information exchange	P11a: Operational information and communication standards are needed for "plug and play" DER integration P11b: DSO operational system architecture and related requirements should be developed to guide implementation P11c: T-D operational information interface requirements should be assessed current CAISO protocols and standards
P12: Avoid conflicts of interest through functional separation	P12a: DSO operations should follow similar standards of conduct as those imposed by FERC on transmission operations . This requires CPUC distribution SOC development. P12b: Define those optional market facilitation services that may be provided by DSO and/or 3rd party under specific conditions

D. DER Integration into Operations

Create opportunities for qualified DER to contribute to the optimization and operation of markets and the grid, and reduce the barriers and costs to participate.

Flexible DER can provide value to optimizing markets and grid operations, and infrastructure investment. This was identified and defined in research by Sandia National Labs[44] and SCE[45] and now required by AB 327. So the issue isn't *if* or *when*, but rather *how* do we enable integration of flexible DER into bulk power and distribution systems. There are several steps needed to needed to consider how to a) allow DER to fully participate in CAISO markets, b) allow DER to mitigate incremental interconnection costs, c) allow DER to meet distribution reliability and power quality services, and d) enable DER to provide an alternative for certain distribution investment. Additionally, there are several market barriers to DER participation as summarized by LBNL.[46] Therefore, to achieve California's policy objectives there are four key aspects that need to be addressed:

- Fully address DER potential to participate in bulk power system (e.g. wholesale energy and ancillary service markets) and to meet near, mid and long term resource adequacy requirements
- Unbundle and define distribution operational grid services
- Create transparency related to the value of services and related monetization methods (e.g., market, bi-lateral, tariff, etc.)
- Development of more open access rules and processes (incl. participant qualifications connectivity and measurement requirements, and settlement)

Operational Grid Services

Flexible DER is expected to provide a wide range of value across the bulk power and distribution systems. This will be enabled by the expansion of CAISO services and new distribution operational services. Bulk power system services may include: load following (ramp up/down), resource adequacy, reactive power support, and system inertia response.[47] Distribution level services may include: voltage/reactive power[48], power quality, power flow control and reliability services[49]. This needs to be done on a technology neutral basis. The starting point for such an effort has been developed by Sandia and SCE in their respective storage analysis reports, but it is important to note that their analysis applies to any flexible DER technology that can meet one or more of the over 20 services identified below in figure 6. There is an immediate need to prioritize those new bulk power and/or distribution services needed over the next 1-3 years in California to begin the development process.

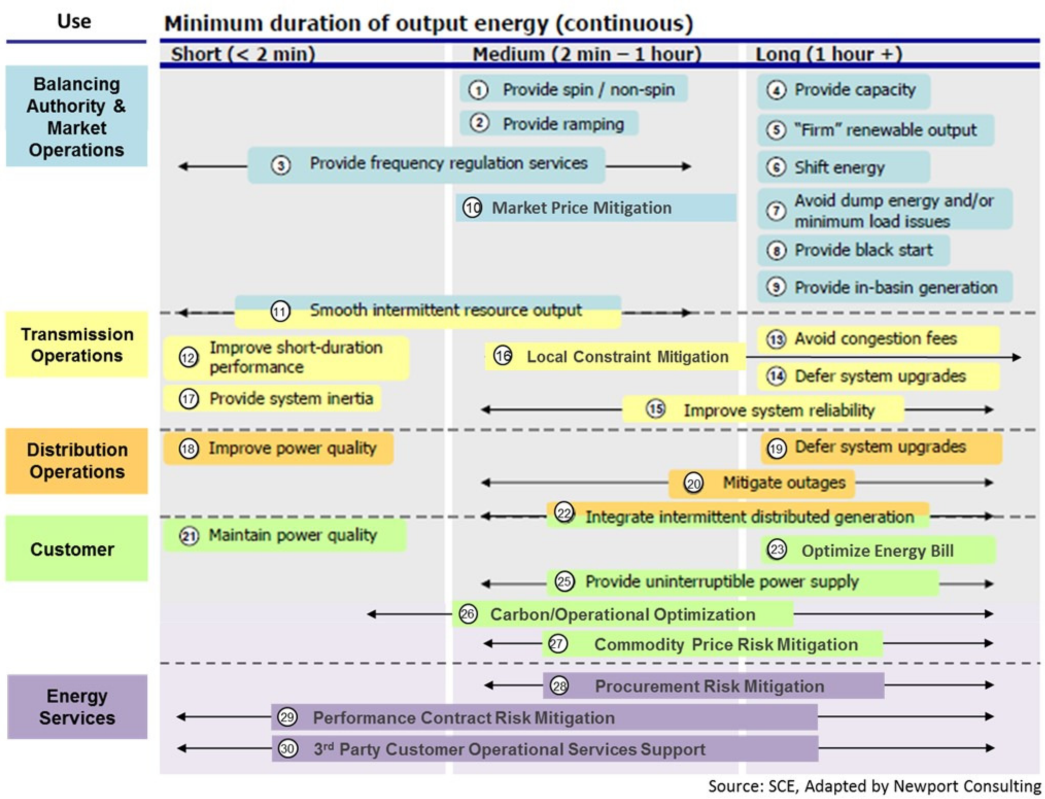

Figure 5: Potential Operational and Economic Services

Fully realizing the value of DER for the bulk power and distribution systems requires assurance of performance to avoid the need for new dispatchable generation and/or physical infrastructure to manage the operations of the electric system. As such, it is essential that clear performance requirements are specified for each service. This is because the evolving system operations discussed in this paper requires firm, dependable resources that can respond in kind to dynamic operational conditions or variable economic signals.

A first step is to recognize that the operational challenges facing CAISO, municipal utilities and distribution grid operators are driving the need for a new set of responsive DER capabilities with distinctly different characteristics.[50] Traditional demand response works very well to address predicable, discrete peak demand events and as an emergency resource for operators. However, much of this value erodes as the power system becomes more unpredictable and variable that requires much shorter response times to ensure reliable system operation. Therefore, ***the relatively analog, slow, inflexible and imprecise qualities that largely define existing demand response programs may be surpassed in their relevance and value.***

As such, new capabilities should be identified as part of the distribution planning process. It is important that the analytical framework identify new criteria for performance of individual DER technologies. Performance would include the expected outputs, duration, and operational times. Criteria could address preferred resources for each individual technology, or a combination to satisfy specific grid reliability needs in place of traditional investments.

In addition to DER services definition, new multi-layer distributed control schemes will be required to integrate a large number of distributed resources into integrated grid operations. This type of approach would allow the bulk power, distribution and customer/merchant the opportunity to autonomously optimize for their needs while also maintaining coordination between and across each tier.[51] This means, for example, some of this coordination may involve ensuring that autonomous control settings of DER devices are appropriately set for certain grid conditions occurring and responding appropriately. This distributed architecture with autonomous controls on customer devices can both mitigate problems created by high penetrations of DER at distribution, while also allowing for reliable dispatch across the T-D interface. A critical first step to enabling this coordination will be for DSO's and DER operators to launch pilot projects that seek to integrate advanced DER functionalities into DSO operations.

Transparent Value Identification & Monetization

As a foundation, customers should transparently see the benefits and costs related to a more distributed system including their choices in the context of related system upgrades and operational expense. This allows customers to weigh those benefits and costs in terms of affordability, reliability, the environment and safety. Customers and services firms should also know what types of services and benefits they can provide to the grid through access to relevant information. All system participants should also abide by the same operational rules to ensure reliability and safety.

A significant challenge with integration of DER is developing and implementing appropriate value monetization methods.[52] Valuation will necessarily need to consider the local value as well as the net system value given the integrated nature of the electric grid. This means benefits associated with the 30 uses identified in figure 5 above may be offset by system issues such as:

- Surplus generation in day-time hours requiring increasing amounts of renewable generation curtailment to avoid over-generation, and reliability problems.
- Increasing amounts of flexible ramping capacity to accommodate incremental amounts of solar generation, both ramping down in the morning when solar generation starts, and ramping up in the afternoon as solar generation decreases while the evening peak increases.
- Diminishing value of incremental solar additions due to decreasing contributions to reliability and decreasing energy value of solar additions as the hours of residual need shift to later hours in the afternoon with increasing amounts of solar additions.

This is not to diminish the value that DER can provide, but to recognize that any value determination requires holistic analyses, including the contribution other DER technologies could combine with solar generation to maximize value. As discussed earlier, an analysis framework and appropriate models are needed immediately to identify these values. In several cases, potential value is not easily monetized as it may not clearly involve tangible monetary benefits. Value may exist in mitigating externalities[O] such as those involved with customer outages. In other instances, value may be derived by displacing utility investment. Each of these values will need to be monetized through a defined method that transparently produces value for customers.

For example, the nature and value of reactive power services is distinctly different than an energy or peak load response service. Today, capacitor banks, line regulators and load tap changers manage reactive power. For new investment, the default cost is the lifecycle cost of this equipment. So, lifecycle cost may be one method for pricing DER provided service be based on this lifecycle cost, subject to a procurement similar in concept to the valuation method used for demand response. Or, the sub-minute time response characteristics and the unique, dynamic engineering value for each local distribution area that may suggest using stochastic[P] engineering models and option valuation methods for the valuation. This may also suggest a tariff based pricing (reflecting the “option premium”) as opposed to a dynamically calculated price signal. This example illustrates the considerations needed to define the appropriate value determination and monetization method for each of the required operational services. There is not a one size fits all model and pricing methods based solely on energy price ($/kWh) do not appear to be sufficient for grid operational services.

Open Access Participation

Reducing the barriers to participate in these new services is a fundamental factor to successfully integrate flexible DER at the scale envisioned in California. It is vital that the current barriers involving participation, complex and expensive measurement and verification schemes and related settlement processes be simplified. Since new DER services require firm, dependable and real-time measurable response, the complex estimation processes of existing demand response programs will be less of an issue. However, the measurement is a major issue as today’s rules were designed for integrating larger generation. Current thinking is also still largely centered on the form factor and functions of a utility type meter. There is a need to adapt the rules for smaller distributed resources and reflect the modern metrology, communication and information management options available. The current demand response proceeding on this issue may provide a good starting point. But, given the nature of the operational services required, it is likely these topics will need to be revisited within the next 2 years.

Recommended Reading

Reference papers for deeper discussion:

- *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide*, Sandia, 2010
- *DR 2.0: The Future of Customer Response*, ADS-LBNL, 2013

[O] New York REV initiative is exploring the value of externalities related to DER service provision

[P] Stochastic methods are used to evaluate random variability which is increasingly an issue on power systems

Guiding Principles for DER Integration into Operations

Based on the workshop discussions, the following guiding principles are offered for consideration. These are aligned with relevant federal and state policies, and leverage industry research and best practices referenced in this paper.

Guiding Principles	Potential Requirements
P13: Fully address DER participation in wholesale markets and resource adequacy	P13a. Wholesale opportunities for flexible DER should be fully expanded to support bulk power operations. P13b. Performance requirements should align with identified value to provide reasonable results for all stakeholders including net benefits for ratepayers.
P14: Unbundle distribution grid operational services	P14a. Identification and prioritization of differentiated distribution grid operational services should fully support grid operations, asset utilization, capital investment and meet policy requirements P14b: Definition of service performance characteristics and related performance requirements should use technology neutral methods
P15: Enable transparent DER value identification and monetization	P15a. Distribution services value identification and monetization methods should provide reasonable results for all stakeholders including net benefits for ratepayers. P15b. Distribution tariffs and/or procurements for flexible DER should be fully expanded to enable DER to support grid operations.
P16: Open access and low barriers to DER participation	P16a. Participation rules and processes should enable participation levels consistent with California policy objectives. P16b. The cost of integrating flexible DER should not be a barrier to participation. Alternative solutions should be considered. P16c. Transaction processes including scheduling, verification and settlement should not be a barrier to participation.

IV. Integrated Grid Roadmap

Customer adoption of DER holds the promise of enhancing the operational, environmental, and affordability of California's electric system. This requires "an integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity."[53] As discussed in the 1st and 2nd More Than Smart workshops, California needs to consider a more advanced and highly integrated electric system than originally conceived in many smart grid plans. This integrated grid will evolve in complexity and scale over time as the richness of systems functionality will increase and the distributed reach will extend to millions of intelligent utility, customer and merchant devices.

The conceptual roadmap below outlines a path that bridges the divide from today's realities to the opportunities envisioned in a more distributed future. This path is focused on the regulatory and industry actions needed over the next 1 to 3 years on the cross-cutting issues identified in the preceding sections to enable a graceful transformation of California's power system. But, it is important to recognize the interdependent nature of the distribution life cycle to successfully transition to a high value integrated electric distribution network. As noted in figure 6, many roadmap activities will need to be executed concurrently. This requires alignment of the intricate interdependencies of the various activities within each stage.

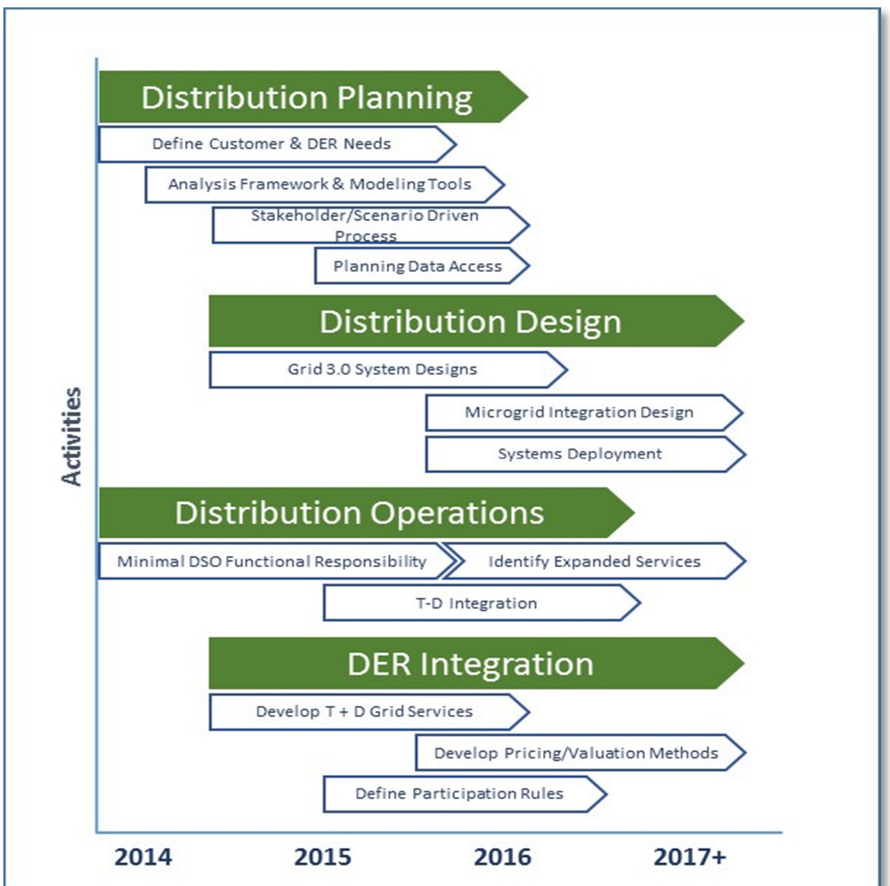

Figure 6: Conceptual More Than Smart Roadmap

This conceptual roadmap is provided only as a starting point for a more complete discussion at CPUC and the 3rd More Than Smart workshop. In these forums, consideration of the steps needed to scale up implementation of the comprehensive planning discussed. This is non-trivial as there are about 10,000 investor owned utility distribution circuits and several hundred distribution planning areas across California. Also, pilot implementations of new DER provided distribution services is needed to demonstrate the benefits identified in AB327 as well as T-D coordination with CAISO. This specifically includes operational technology testing and an integrated demonstration at sufficient scale to validate operational effectiveness. This is needed because California has yet to test fast response DER performance in distribution or in a coordinated operation between distribution utilities and CAISO. Several pilots, such as SCE's Preferred Resources Pilot have been discussed or planned that could serve this purpose.

The distribution plans that each of the California IOUs will need to file to comply with AB 327 represent the first step towards starting to re-shape the distribution grid. One of the key activities that the CPUC needs to take ahead of these filings is to provide guidance to the IOUs to ensure that their plans integrate many of the principles articulated in this paper. The role of this paper is to provide a set of strategic frameworks and guiding principles that can inform stakeholders and policymakers in the development of the guidelines for AB 327 Distribution Plans that the CPUC will eventually ratify. Additionally, as other states and international locales consider a more distributed electric system this paper offers guidance on the critical questions and a framework for developing the path forward for their particular distribution systems.

Appendix A: Relevant California Policies

The following list highlights relevant California policy and CPUC proceedings related to distribution planning, design-build, operations and integration of DER. This is only a representative list to show the range and diversity of policy and activity that directly or indirectly impacts the distribution system.

<u>California Policies (sample)</u>

AB 32; California Global Warming Solutions Act

SB1X 2; 33% RPS standard by 2020

State Water Board Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling; (Once Through Cooling)

Title 24; Residential & Commercial ZNE building codes

Executive Order B-16-2012; Electric Vehicle and Zero Emissions Vehicle targets

AB 758; Energy Efficiency Law

AB 2514; Energy Storage goals

SB 17; Smart Grid Systems

AB 327; Changes to Public Utilities Code Section 769

AB 340; Electric Program Investment Charge (EPIC)

<u>CPUC Regulatory Proceedings (sample)</u>

IOU General Rate Cases

08-12-009 Smart Grid (annual plan submissions)

10-12-007 Energy Storage

11-09-011 Interconnection OIR

11-10-023 Resource Adequacy & Local Procurement

12-06-013 Residential Rate Design

13-12-010, 12-03-014, 10-05-006 Procurement Policies & Long-term Procurement

13-09-011 Demand response

13-11-007, 09-08-009 Alternative Fueled Vehicles

13-11-006 Operational Risk-based Decision Framework

1405003/4/5 Investor-Owned Utility EPIC Triennial Investment Plans

Appendix B: AB 327 Sec. 8

California AB 327 Section 8 language regarding distributed resource consideration in planning and integration into operations.

"Section 769 is added to the Public Utilities Code, to read:

769. (a) For purposes of this section, "distributed resources" means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

(b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:

(1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.

(2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

(3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

(4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

(5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

(c) The commission shall review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission may modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.

(d) Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable. The commission may also adopt criteria, benchmarks, and accountability mechanisms to evaluate the success of any investment authorized pursuant to a distribution resources plan."

Appendix C: Value of the Grid

The value of the electric grid given potential growth of customer self-sufficiency or independent micro-grids is an open question. In this context, the discussion at the 2nd MTS workshop identified a "node-friendly" network[Q] model as the desired among four potential distribution end-states and related value of the grid. The four end-states below should be viewed as on a continuum in terms of the value of the grid.

Grid as Back-up

This end-state involves a majority of customers becoming largely self-sufficient through the adoption of distributed resources including energy storage and advanced building and home energy management systems. This end-state envisions a smaller number of customers remaining wholly dependent on the integrated electric system and a growing number of former customers that have become totally self-sufficient and have disconnected. Independently owned community microgrids arise displacing need for utility distribution investment. Utility investment in electric distribution diminishes, focused primarily on break-fix to maintain minimal service standards and quality.

Current Path

This end-state is based on the current utility investment plans for electric distribution refresh and smart grid technology adoption as identified in current rate cases and smart grid roadmaps. This end-state assumes an incremental and reactive approach to infrastructure investment. Lack of coordination or collaboration among stakeholders can create gaps in system planning and investment. This creates a risk of misalignment of the timing and location of advanced technology investment or substantive changes in distribution design with the pace of customer and merchant DER penetration.

Grid as Network

This end-state builds on the current investments through an acceleration of more advanced technology adoption into the grid along with an evolution of distribution system designs to create a node-friendly grid to enable seamless integration of DER and independent microgrids. This envisions a proactive approach to manage the alignment of investment to enable the adoption of DER. This open electric network platform and related operations enables upwards of 20 GWs of distributed energy resources and over 1.5 million electric vehicles to integrate safely and reliably while also contributing to the improved overall efficiency of CA's electric system.

[Q] Network in this context refers to an open, multi-directional electric distribution system that creates additional value for connected customers and distributed energy resources. It does not refer to, but doesn't preclude, the type of electrical distribution configuration that links the secondaries of multiple distribution circuits into a mesh configuration for enhanced reliability.

Convergence

This end-state envisions the convergence of an integrated electric network with California's water, natural gas and transportation systems to create more efficient and resilient infrastructure to enable the state's long-term economy and environmental policy objectives. Convergent opportunities to minimize capital investment in infrastructure for synergistic societal benefits are fully evaluated in local joint planning efforts. Advanced operational data and control technologies are increasingly integrated in highly coordinated operations across the water, natural gas, and transportation networks.

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Appendix C

(Temporary Service List)

Appendix D

(Load-Serving Entities)

LSE	Contact	Address	email
3 Phases Renewables	Margo Burrows	2100 Sepulveda Boulevard Suite 37 Manhattan Beach CA 90266	mburrows@3phasesrenewables.com
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Direct Energy Business, LLC	Jennifer Gray	12 Greenway Plaza Suite 250 Houston TX 77046	Jennifer.Gray@directenergy.com
EDF Industrial Power services (CA), LLC	Angela Gregory	4700 W. Sam Houston Parkway N, Suite 250 Houston TX 77041	angela.gregory@edftrading.com
Glacial Energy of California	Andrew Luscz	5326 Yacht Haven Grande Box 36 St. Thomas 00802	andrew.luscz@glacialenergy.com
Gexa Energy California, LLC	John Ritch	20455 State Highway 249 Houston TX 77070	john.ritch@gexaenergy.com
Liberty Power Holdings, LLC	Samantha Greves	1901 W. Cypress Creek Road Suite 600 Ft. Lauderdale FL 33309	sgreves@libertypowercorp.com
Marin Energy Authority	John Dalessi	3941 Park Drive, Suite 20-201 El Dorado Hills CA 95762	john@dmcadvisors.com

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Pilot Power Group, Inc.	John S. Friderichs	8910 University Center Lane Suite 520 San Diego CA 92122	JFriderichs@pilotpowergroup.com
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Shell Energy North America	Marcie Milner	4445 Eastgate Mall #100 San Diego CA 92121	marcie.milner@shell.com
Tiger Natural Gas, Inc.	Gregory Klatt	21700 Oxnard Street, Suite 1030 Woodland Hills CA 91367	klatt@energyattorney.com
Sonoma Clean Power	John Dalessi	3941 Park Drive, Suite 20-201 El Dorado Hills CA 95762	john@dmcadvisors.com
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(END OF APPENDIX D)