CALIFORNIA
ENERGY
COMMISSION

DISTRIBUTED ENERGY RESOURCES STAKEHOLDER COLLABORATION AT WORK: SHAPING A CALIFORNIA DISTRIBUTED ENERGY RESOURCES PROCUREMENT

PIER COLLABORATIVE REPORT

Arnold Schwarzenegger, *Governor*

November 2006
CEC-500-2005-062-F

Prepared By:
Electric Power Research Institute
E. Petrill
Palo Alto, California

John Nimmons & Associates, Inc.
J. Nimmons
Mill Valley, CA

Energy and Environmental Economics, Inc.
S. Price
San Francisco, CA

Madison Energy Consultants
J. Torpey
Madison, NJ

and

Southern California Edison
S. Hamilton
Monterey Park, CA

Contract No. 500-02-014

California Energy Commission

Public Interest Energy Research (PIER) Program

Nancy Libonati
Contract Manager

Mark Rawson
Energy Systems Integration Program
Area Team Lead

Laurie ten Hope
Energy Systems Integration &
Environmental Research Office Manager

Martha Krebs, Ph.D.
Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

B. B. Blevins
Executive Director

DISCLAIMER

This report was prepared as the result of work sponsored by the California Energy Commission. It does not necessarily represent the views of the Energy Commission, its employees or the State of California. The Energy Commission, the State of California, its employees, contractors and subcontractors make no warrant, express or implied, and assume no legal liability for the information in this report; nor does any party represent that the uses of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by the California Energy Commission nor has the California Energy Commission passed upon the accuracy or adequacy of the information in this report.

DEDICATION

This report is dedicated to Joseph Iannucci, who delighted in this project, brought wisdom and infectious enthusiasm to the collaboration, and called it a leading effort in the nation being watched by other states and the U.S. Department of Energy, whom Joe represented. The project was privileged to have Joe be part of the collaborative and sorely misses his quips and insights, which we will carry forward through all of our days.

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THIS DOCUMENT WAS PREPARED BY THE ORGANIZATION(S) NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION(S) BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS DOCUMENT IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS DOCUMENT OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT.

ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

John Nimmons & Associates, Inc.

Madison Energy Consultants

Energy and Environmental Economics, Inc.

Electric Power Research Institute (EPRI)

Southern California Edison

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

Electric Power Research Institute and EPRI are registered service marks of the Electric Power Research Institute, Inc.

Copyright © 2006 Electric Power Research Institute, Inc. All rights reserved.

CITATIONS

This report was prepared by

John Nimmons & Associates, Inc.
175 Elinor Avenue, Suite G
Mill Valley, CA 94941

Principal Investigator
J. Nimmons

Madison Energy Consultants
21 Ferndale Road
Madison, NJ 07940

Principal Investigator
J. Torpey

Energy and Environmental Economics, Inc.
53 Sacramento Street, Suite 1700
San Francisco, CA 94111

Principal Investigator
S. Price

Electric Power Research Institute (EPRI)
3420 Hillview Avenue
Palo Alto, CA 94304

Project Managers
E. Petrill
D. Rastler

Southern California Edison
1000 Potero Grande
Monterey Park, CA 91754

Project Manager
S. Hamilton

This report describes research sponsored by EPRI and the California Energy Commission, New York State Energy Research and Development Authority, City Public Service of San Antonio, and the Massachusetts Technology Collaborative.

This publication is a corporate document that should be cited in the literature in the following manner:

DER Stakeholder Collaboration at Work: Shaping a California DER Procurement: A Report of the EPRI Distributed Energy Resources Public/Private Partnership. EPRI, Palo Alto, CA; California Energy Commission, Sacramento, CA; New York State Energy Research and Development Authority, Albany, NY; City Public Service of San Antonio, San Antonio, TX; and Massachusetts Technology Collaborative, Westborough, MA: 2006. 1013628.

Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit electricity and natural gas customers.

The PIER program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

DER Stakeholder Collaboration at Work: Shaping a California DER Procurement is a technical update report for the DER Public/Private Partnership Phase 2: Creating and Demonstrating Incentives for Electricity Providers to Integrate DER project (contract number 500-02-014) conducted by EPRI, the Energy Commission, New York State Energy Research and Development Authority, City Public Service of San Antonio, and the Massachusetts Technology Collaborative. The information from this project contributes to PIER's Energy Systems Integration program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier/ or contact the Energy Commission at 916-654-5164.

TABLE OF CONTENTS

PREFACE ..... **IV**

ABSTRACT AND KEYWORDS ..... **X**

EXECUTIVE SUMMARY **1**

CHAPTER 1 INTRODUCTION **17**

EPRI DER Public/Private Partnership 17

Previous DER Market Integration Reports 17

DER Scoping Study, Spring 2003 17

Framework for Developing Collaborative DER Programs, Fall 2003 18

Report Structure 20

CHAPTER 2 CALIFORNIA DISTRIBUTED ENERGY RESOURCES PILOT PROJECT **21**

Background and Regulatory Context 21

SCE's Proposed DG Solicitation 23

Approach and Scope of Support for SCE Pilot Procurement 25

CHAPTER 3 COLLABORATIVE ORGANIZATION AND PROJECT SCHEDULE **27**

Selecting Participants for the Collaborative 27

Ensuring Fairness and Openness 28

Overview of the Work 29

CHAPTER 4 BRINGING STAKEHOLDERS TOGETHER AND DEFINING THE ISSUES – WORKSHOP NO. 1 ..... **31**

Workshop Preparation 31

Specificity of System Information 31

Screening for Potential DER Projects 32

Analyzing Costs and Benefits from Multiple Stakeholder Perspectives 32

Workshop Objectives, Topics and Presentations 33

Workshop Participation 34
Issue Group Process 34
Workshop Results 35

CHAPTER 5 COLLABORATING TO RECOMMEND SOLUTIONS 39
Issue 1: Eligibility for Incentives. 39
Issue 2: Physical Assurance Requirement. 40
Issue 3: Eligible Resources. 40
Issue 4: Alternatives to the RFP Process. 40
Issue 5: Additional DG Values. 41
Issue 6: Business Model. 41
Issue 7: DG Deferral Value. 41
Issue 8: Simplification of the Process. 42
Issue 9: Availability of Distribution System Data. 42
Issue 10: Tailoring SCE Deferral Agreement to DG Project Realities. 43
Issue 11: Facilitating Interaction between SCE Customers and DG Developers. 43

CHAPTER 6 RECONVENING STAKEHOLDERS TO INTEGRATE THE WORK – WORKSHOP NO. 2 45
Evaluating the Process – What Worked Well and What Can Be Improved 46
What Worked Well 46
What Could Be Improved 47
Identifying Next Steps 47

CHAPTER 7 SOUTHERN CALIFORNIA EDISON REPORT ON SOLICITATION DEVELOPMENT AND RESULTS 49
Introduction 49
Overview of SCE's Planning Process 49
CPUC Criteria for Considering DG as an Alternative to Distribution System Upgrades, and SCE's Methodology 50
Located in the Right Place 50
Installed and Operational 51
Provide Sufficient Capacity 51
Provide Physical Assurance 52
Summary of Findings for Deferring 2007 Projects 52
Evaluating DG as a Distribution Alternative 53

CHAPTER 8 ACHIEVEMENTS, LESSONS AND RECOMMENDATIONS FROM THE CALIFORNIA PILOT PROJECT 55

Framework-Recommended Initiatives Addressed in This Pilot 55

Collaborative Achievements 55

Lessons for Moving Forward with DER Market Integration 57

Lessons for DER Integration 59

1. Comprehensive consideration of DER benefits 60

2. Integrated resource planning 61

3. Inclusion of third party experience 62

4. Streamlining Procurement 63

5. Value-based economic incentives 63

Lessons for DER Stakeholder Collaboration 64

6. Usefulness of the facilitated stakeholder collaboration 64

7. Availability of detailed utility planning data 65

8. Regulatory review 67

9. Regulatory Incentives 67

Recommendations 68

1. Develop a nationally based stakeholder collaborative to encourage win-win business and regulatory models that encourage utilities to use all forms of distributed energy resources and reward DER customers fairly. 68

2. Develop regionally based stakeholder collaboratives (linked to the national collaborative) to develop and implement regional approaches to innovative DER solutions. 69

3. Apply the stakeholder collaborative process to demonstration programs to test concepts in the field, quantify DER costs and benefits, and measure success of specific projects or programs. 71

APPENDIX A 73

CALIFORNIA DER PILOT PROGRAM – COLLABORATIVE PARTICIPANTS 73

Developers 73

Suppliers 73

Customers/Customer Representatives 73

Utility 73

Advisers: 73

DER Partnership Pilot Project Team: 73

DER Partnership Pilot Project Team: 74

APPENDIX B **75**

CALIFORNIA PROGRAM – JULY 14-15 WORKSHOP ATTENDEES **75**

APPENDIX C **77**

CALIFORNIA DER PILOT PROGRAM – JULY 14-15 WORKSHOP SUMMARY REPORT **77**

Introduction 77

Purpose 77

Attendees 77

Major Outcomes 77

Workshop Approach 78

Issue Groups 79

APPENDIX D **81**

CALIFORNIA DER PILOT PROGRAM – OCTOBER 15 WORKSHOP ATTENDEES **81**

APPENDIX E **82**

CALIFORNIA DER PILOT PROGRAM – OCTOBER 15 WORKSHOP SUMMARY REPORT **82**

Stakeholder Working Group Report 83

SCE's Plan for Integrating Customer-Operated DG into Distribution Planning 85

The Unresolved Issue: Self-Generation Incentive Program (SGIP) Eligibility 87

What Worked, What Didn't, What's Missing 87

LIST OF FIGURES

Figure 3-1 Project Timeline 29

LIST OF TABLES

Table ES-1 Working Group Issues & Recommendations 8
Table 2-1 SCE Pilot Compared with New York PSC Pilot 24
Table 4-1 Working Group Issues 36
Table 8-1 Framework Initiatives Addressed by California Pilot Project 56
Table 8-2 Collaborative Achievements 58
Table 8-3 2003 Example Data – DG Value 66

Abstract

This report describes a 2004 pilot project in which stakeholders collaborated to help Southern California Edison (SCE) comply with a 2003 California Public Utilities Commission (CPUC) Order to *evaluate distributed generation (DG) as an alternative to distribution system upgrades, and develop a procurement approach and model contract* that could serve that purpose. Its overall intent was to support SCE's objectives to design a DG procurement process consistent with CPUC directives that would meet the needs of specific distribution areas and encourage third parties to help integrate DG into the distribution system in ways that would benefit SCE ratepayers.

The project was built around a stakeholder collaborative process facilitated by the EPRI Distributed Energy Resources (DER) Public/Private Partnership's project team. This project was conducted under EPRI's DER Public/Private Partnership Market Integration Platform, sponsored by the California Energy Commission, the New York State Energy Research and Development Authority, City Public Service of San Antonio, and the Massachusetts Technology Collaborative.

Keywords

Distributed energy resources, distributed generation, market integration, model agreement, model contract, procurement, RFP, stakeholder collaboration

REPORT SUMMARY

This report describes a 2004 pilot project in which stakeholders collaborated to help Southern California Edison (SCE) comply with a 2003 California Public Utilities Commission (CPUC) Order to evaluate distributed generation (DG) as an alternative to distribution system upgrades, and develop a procurement approach and model contract that could serve that purpose. Its overall intent was to support SCE's objectives to design a DG procurement process consistent with CPUC directives that would meet the needs of specific distribution areas and encourage third parties to help integrate DG into the distribution system in ways that would benefit SCE ratepayers.

The project was built around a stakeholder collaborative process facilitated by the EPRI Distributed Energy Resources (DER) Public/Private Partnership's project team. This project was conducted under EPRI's DER Public/Private Partnership Market Integration Platform, sponsored by the California Energy Commission, the New York State Energy Research and Development Authority, City Public Service of San Antonio, and the Massachusetts Technology Collaborative.

Results & Findings

Within boundaries established by the CPUC's 2003 decision, this pilot project demonstrated the ability of the stakeholder collaborative process to create innovative solutions that recognized the interests of all stakeholders and yielded distinct advantages over traditional adversarial proceedings. Significant achievements included much-improved communication about stakeholder business needs and constraints; better stakeholder understanding of utility service obligations, investment processes, planning horizons and uncertainties, DG valuation methodology, and range of values; better utility understanding of DG providers' project development and investment concerns; recommendations for a more robust DG procurement process; and a more flexible, fairer, and more realistic model contract to use for future utility DG procurements.

However, some barriers to DER market integration remain. This project found that to enhance DER market integration, additional stakeholder collaboration should be done with the following guidelines:

- Broaden the inquiry beyond "generation" resources and distribution capacity deferral to include the other DER value streams.
- Expand relevant planning horizons geographically and over time.
- Develop value-based incentives and business models to facilitate appropriate integration of DER into utility operations.
- Coordinate the policies and rules of various public entities with incentive programs.
- Continue stakeholder collaboration as an alternative to more adversarial approaches.

Challenges & Objectives

A great challenge for sensibly integrating distributed resources into large central utility systems is to bridge gaps of information and understanding among stakeholder groups that operate in very different business and regulatory environments and bring widely diverse perspectives to the table. These environments and perspectives converge in the DER procurement and contracting process, which must recognize the interests of utilities, their customers, DER providers, and regulators to benefit any of them. The objective here was to promote true collaboration among stakeholders more accustomed to confrontation in regulatory proceedings, to enhance understanding and appreciation of other parties' legitimate business and institutional needs, and to craft solutions that work for as many stakeholders as possible, with as little prejudice to others as possible.

Applications, Values and Use

This report is a reference document for stakeholders to use to structure and implement effective DER collaboratives. It documents real-world experience in collaborating to shape a workable DER procurement process and an innovative model contract for business arrangements that can work for the distribution utility, its customers, and prospective DER providers alike, while meeting a specific set of regulatory requirements. While regulatory requirements and approaches to DER integration will vary for other utilities in other settings, this report offers a useful template and concrete lessons to help stakeholders benefit from this first-of-its kind California pilot project.

EPRI Perspective

EPRI's public/private partnership approach draws on stakeholders representing all segments of the DER community, including utilities, government and regulatory entities, DER developers, suppliers and manufacturers, customers, and non-governmental organizations. EPRI's role is to assemble these players and provide and facilitate a collaborative environment to stimulate the best use of resources, knowledge, and skills of the stakeholders and project team to achieve results. In seeking to optimize benefits for multiple stakeholders, this approach provides constructive ways to communicate and cooperate, and opens the door for innovative departures from business as usual in DER markets.

While the results of the effort reported here were not as broadranging as originally anticipated, this effort is being exploited to plan follow-up efforts in both California and Massachusetts in the 2006-2007 time frame. The follow-up activities will draw in the experience reported here in an attempt to remedy the various difficulties that surfaced.

Approach

The EPRI project team designed the collaborative process used here based on results of the DER Partnership Phase I, worked closely with SCE to structure and plan both stakeholder workshops, facilitated the workshops as well as the focused efforts of stakeholder "issue groups" between workshops, documented the process, drew lessons from the experience, and prepared this report. The team also provided professional expertise in DER legal, regulatory, economic, and business analysis, including the CPUC's rulemaking proceeding, DER screening and cost/benefit tools, and utility business models.

DEDICATION

This report is dedicated to Joseph Iannucci, who delighted in this project, brought wisdom and infectious enthusiasm to the collaboration, and called it a leading effort in the nation being watched by other states and the U.S. Department of Energy, whom Joe represented. The project was privileged to have Joe be part of the collaborative and sorely misses his quips and insights, which we will carry forward through all of our days.

EXECUTIVE SUMMARY

Project Overview

This report describes a 2004 pilot project in which stakeholders collaborated to help Southern California Edison (SCE) comply with a California Public Utilities Commission (CPUC) directive to evaluate distributed generation (DG) as an alternative to distribution system upgrades, and develop a procurement approach and model contract that could serve that purpose.

This California pilot was the first to begin implementing some of the distributed energy resource initiatives and collaborative approaches developed in the Electric Power Research Institute's Distributed Energy Resources Public/Private Partnership Market Integration Platform. The results of the earlier work were documented in the report *A Framework for Developing Collaborative DER Programs: Working Tools for Stakeholders*, referred to here as the *Framework*[1].

The project's overall intent was to support SCE's objectives of designing a DG procurement process consistent with the CPUC directives that would meet the needs of specific distribution areas and would encourage successful third-party proposals to integrate DG into SCE's system. SCE aimed to develop a solicitation that many proposers could easily understand and respond to, that would encourage innovation, and that would result in sound proposals benefiting ratepayers.

Specific goals for the pilot included:

- Use a stakeholder collaborative process to develop a solicitation that customers, developers, vendors, and others will confidently bid on and can serve as a model for other procurements.
- Test and demonstrate the stakeholder collaborative process.
- Develop innovative win-win approaches for encouraging DER and advancing DER market integration and policy.
- Document lessons learned and win-win approaches developed from the stakeholder collaboration so they can be replicated and scaled in California and elsewhere.

These collaborative activities took place from May through early October, 2004, in preparation for a solicitation that SCE initially targeted for November 2004, to defer distribution upgrades projected for 2006 to 2007. By October 2004, changes in SCE's distribution planning cycle and its desire to seek CPUC approval for improvements to its Model DG Agreement resulting from the collaborative's work caused the utility to postpone the target date for its solicitation until March 2005. In the end, unfortunately, SCE could not identify any distribution upgrade projected

[1] *A Framework for Developing Collaborative DER Programs: Working Tools for Stakeholders.* EPRI, Palo Alto, CA, 2004. 1011026.

for 2007 where the utility believed that CPUC requirements and its own system needs could be met, and no solicitation had been issued by the end of 2005.

Regulatory Context

SCE is one of the nation's largest investor-owned electric utilities, serving about 13 million people over 50,000 square miles of service territory in Central and Southern California. The utility is regulated by the CPUC, which has taken an active interest in DER since the mid-1990s.

In 1998, the CPUC and the California Energy Commission began extensive rulemakings that focused on distributed generation or 'DG' (but not demand-side resources or energy storage), primarily as an alternative to distribution capacity expansion. These proceedings involved many stakeholders representing all sectors of the DG community, and eventually resulted in a CPUC decision and Order that addressed a wide range of issues identified and briefed by the parties.

Among other things, this 2003 Order required California's investor-owned utilities, including SCE, to (1) incorporate in their distribution planning activities a utility-proposed process to evaluate and procure alternatives to distribution system upgrades, and (2) develop model contracts for DG designed to defer such upgrades. The decision contemplated a DG procurement process based on utility-issued requests for proposals (RFPs), which were expected to incorporate model contracts similar to ones the utilities submitted to the Commission when the proceeding ended in 2003 (albeit without input from other DG stakeholders).

The 2003 decision imposed four essential criteria that DG must meet to allow the utility to defer distribution upgrades and avoid future cost. These were that the DG –

- Be appropriately located, where the utility's planning studies identify capacity needs that will not be met by existing facilities, given forecasted load growth;
- Provide sufficient capacity to accommodate the utility's planning needs; and
- Be installed and operational in time to defer or avoid utility expansion or modification;
- Provide "physical assurance"' through devices that would interrupt customer load equal to the DG unit's capacity, if the DG did not perform as contracted.

For DG meeting these criteria and selected through the utility procurement process to defer capacity upgrades, the 2003 decision directed utilities to pay providers a deferral value, capped at the utility's short-term cost of capital, multiplied by the cost of the planned distribution addition and the number of years of deferral.

SCE's Proposed DG Solicitation

SCE believed that the DER Partnership's collaborative approach could help it design a planning and procurement process that would meet CPUC requirements and defer distribution investment. So in early 2004 the utility agreed to work with EPRI's DER Partnership team and interested stakeholders toward those ends.

Work on the pilot project began in the spring of 2004. SCE planners had not yet settled on specific circuits or distribution upgrades that would be required in 2006-07, when DG projects solicited through this project would need to begin operating. However, the planners expected to be able to identify perhaps three to five local areas where DG might defer specific distribution investments. They initially expected that each area would average around 3 to 5 MW of needed capacity additions, so this pilot procurement would likely target a total 10 to 25 MW of DG-provided capacity deferral, once SCE determined its actual system needs later in the year.

To meet SCE's proposed schedule, the stakeholder collaboration needed to begin around June 2004 and be completed that fall. This time constraint, together with SCE's need to satisfy the CPUC criteria described above, dictated the scope of the pilot.

Organizing the Collaborative

Unlike formal regulatory proceedings, the collaborative approach described in EPRI's Framework document[2] is intended to help structure non-adversarial exchange of ideas, constructive cooperation, and relationship-building among stakeholders, to find solutions that benefit as many as possible, as much as possible, with as little prejudice to others as possible.

The DER Partnership team assumed primary responsibility for structuring the collaborative and took a much of care to identify and select the participants. The challenge was to bring together enough stakeholders to ensure wide-ranging knowledge, experience, and viewpoints, while limiting the group to a size and composition that could meet regularly, focus on complex issues, have a genuine interest in the outcome, and be managed and coordinated effectively.

To do this, the team created a dual structure consisting of a smaller "working group" responsible for the Collaborative's day-to-day work and a larger group that also included advisory members with strong DER experience and/or valuable institutional perspectives, but not in a position to offer actual DG resources or projects in response to an SCE solicitation.

The working group included five DER project developers; five DG equipment manufacturers or vendors; two customer groups or associations; and four SCE personnel responsible for distributed generation, transmission and distribution engineering, and customer service. The larger group included all working group members as well as representatives of the California Energy Commission and Public Utilities Commission, NYSERDA, the Massachusetts Technology

[2] *ibid.*

Collaborative, the U.S. Department of Energy, and other utilities including CPS San Antonio, Southern California Gas, San Diego Gas & Electric, NStar Electric & Gas, and First Energy.

Ensuring Fairness and Openness

SCE chose to target the solicitation to its customers who could act as site hosts, working with third-party DG providers if the customers elected to do so. The DER Partnership team therefore considered both customers and DG providers in selecting collaborative participants.

With respect to customers, the project team chose to invite representatives of customer groups that could present general customer perspectives but would not gain any advantage for individual customers who might later propose DG solutions. With respect to DG providers, the team looked for potential provider representatives that could convey not only their own companies' views, but the views of other similar companies in the industry.

Since not all potential providers could participate in the collaborative, the team was careful to structure a process that would not prejudice others who might later wish to respond to SCE's solicitation. The team proposed a set of guidelines designed to balance the need for an efficient and productive collaborative process with the need for fairness and integrity in SCE's solicitation process. These guidelines, accepted by SCE and followed in the Collaborative, provided for posting information on a publicly accessible website; using objective criteria to screen additional participants; working with general or historical system information rather than actual project characteristics; and leaving ultimate decisions about any DG solicitation in the control of the utility rather than the collaborative.

Overview of the Collaborative's Work

The SCE collaboration was structured around two stakeholder workshops facilitated by the DER Partnership and hosted by SCE in Southern California. The first, on July 14-15, was to educate all stakeholders about the planning constraints and business needs of other stakeholders and identify issues critical to a successful solicitation. The second, on October 6-7, was to integrate recommendations developed by the stakeholder working group over the summer. Between the July and October stakeholder workshops, the project team led and facilitated multiple meetings of two stakeholder groups working in parallel to address high priority issues identified at the first workshop.

Workshop Preparation

The first workshop was intended (1) to help non-utility stakeholders understand more about how SCE does its distribution planning, how it values potential DER offerings, and how regulators will assess their costs and benefits for other utility customers, shareholders, and the general public; and (2) to help SCE personnel understand how non-regulated DG vendors, developers, and customers would evaluate the costs, risks, and benefits of responding to an SCE solicitation, and what could smooth the procurement path for both SCE and prospective respondents. To prepare for the July workshop, the project team worked with SCE to support its analysis of

distribution planning area needs; identify screening criteria for deferrable distribution projects; and estimate costs and benefits of potential distributed solutions for various stakeholders.

Disclosure and Specificity of System Information

The DER Partnership team believed that the more concrete and specific the system information SCE provided, the more useful it would be to DG providers who needed to understand how their projects could support SCE's system, and what value they might offer to the utility. The challenges were to balance these considerations against utility concerns over disclosing sensitive business information and against concerns over fairness to other potential bidders not participating in the Collaborative and not privy to such information before the solicitation.

As it turned out, fairness concerns were largely mooted by the fact that SCE's normal planning process would not identify specific distribution circuits or construction projects needed until later in the year, after most of the collaborative's work was done. To address utility concerns over disclosure of sensitive business information, SCE proposed to present historical data from its 2003 planning cycle without identifying specific areas or projects represented by the data. This data was intended to be representative of typical SCE distribution expansion projects but was not the actual data for projected 2007 projects or circuits that SCE would compile later, and that would eventually drive any DG solicitation.

Screening for Potential DER Projects

Before the first stakeholder workshop, EPRI's project team worked with SCE's DER planners to understand the process SCE uses to estimate local DER values and described processes that other utilities had used to integrate DER into their distribution planning. The team also provided SCE with an Excel spreadsheet tool for high-level DER technical and economic screening to augment SCE's in-house capabilities.

Analyzing Costs and Benefits from Multiple Stakeholder Perspectives

The project team also used the modeling tool developed for its 2003 *Framework* report, updated with current information, to develop a preliminary cost and benefit analysis of DER projects from the perspective of multiple stakeholders invited to participate in the SCE Collaborative. This analysis would be presented at the first workshop to illuminate each stakeholder group's economic perspective and identify potential "win-win" opportunities, and Collaborative participants would comment on input assumptions based on their own expertise and experience.

These were the major activities completed as background for the first stakeholder workshop. Their results were presented at the workshop along with other topics listed in the next section.

First Stakeholder Workshop (July 14-15, 2004)

Objectives

The first workshop's objectives were to:

- Increase understanding and develop trust among stakeholders for productive collaboration.
- Introduce the DER Partnership cost-benefit tool and Framework.
- Identify "win-win" approaches with the highest potential for success in this pilot.
- Form smaller working groups to address priority issues and develop recommendations.

Attendees

Thirty-one people, including top officers and managers of their organizations, attended all or part of the July workshop. Participants included DER developers and equipment vendors, electric and/or gas utilities or affiliates, public customer representatives, energy regulatory and policy agencies, and the EPRI project team.

Topics and Presentations

The presentations made on the first day of the July workshop reflect the agenda topics. At the end of the first day, the stakeholders prioritized what they considered key issues, and the project team organized and grouped the highest priority ones for assignment to working subgroups.

Working Assignments

On the second day, the attendees fine-tuned the assignments and established two smaller "Issue Groups" each facilitated by a member of the project team, to systematically address the stakeholders' priority concerns over the summer. Specific issues assigned to each group are described (and their outcomes summarized) in Table ES-1.

Workshop Results

- SCE demonstrated its commitment to develop a viable and successful RFP.
- Other stakeholders (including some who were skeptical at first) demonstrated their own commitment to helping SCE succeed in that effort.
- Priority stakeholder issues were identified, including:
  - "physical assurance", requiring interruption of a customer's normal load when its DG does not perform as contracted;
  - distribution deferral value, the ceiling price the utility would pay DER providers;

  - eligibility for California's Self-Generation Incentive Program (SGIP), which prohibits utilities from paying otherwise-available incentives to customers who contract for and receive payments for distribution deferral activities.

- Other stakeholder issues to be explored by the Issue Groups were raised, including:
  - a more central role for utilities in integrating DG, including DG ownership.
  - utility help in matching qualified developers with eligible customers.
  - combining demand response with DG resources for distribution deferral.

- The highest priority issues were categorized and assigned to two Issue Groups, one focusing on business models and longer-term regulatory issues, and the second on structuring the RFP process and documentation.

Focused Collaboration through Issue Groups (Summer 2004)

Objectives

The two Issue Groups were formed to undertake more focused and thorough work on the Collaborative's highest priority issues (listed in Table ES-1) between the July and October workshops and to recommend mutually acceptable approaches that could benefit multiple stakeholders.

Priority Issues Addressed

Table ES-1 lists specific issues considered by each of the Groups (numbered for convenient reference, but not necessarily in order of priority), and the Group's resolution or recommendation of each issue.

Second Stakeholder Workshop (October 6-7, 2004)

Objectives

The second workshop's objectives were to:

- report recommendations from the July workshop and summer Issue Group activities.
- report on SCE's perspectives and current RFP plans.
- move toward consensus on outstanding issues identified by the working group.
- hear stakeholder perspectives on the value and results of the collaborative process.

Attendees

Most participants returned for this workshop, and some who could not join in July attended.

Topics and Presentations

SCE reiterated the importance of this project for its vision of the "utility of the future". It underscored that the most difficult questions concern the business model needed to achieve future grid objectives, and that if these questions are not addressed, utilities will simply replace today's grid with technology, design, and thinking dating back 50 to 100 years. SCE invited DG providers to work with the utility to test concepts and hardware for using customer-owned capacity to defer SCE investment in its planned "Circuit of the Future," near San Bernardino.

Other presentations reported that the two Issue Groups had resolved virtually all of the near-term issues identified as high priorities at the July workshop. Attendees worked through additional details on customer notification, developer/customer contacts, "market reference price" disclosure, and exempting planned maintenance from "physical assurance" requirements.

SCE also announced that it would submit to the CPUC a new Model Agreement reflecting the Collaborative's input, and that this together with recent changes in the utility's planning cycle would delay issuance of any DG RFP until at least the spring of 2005 for expansion projects planned for construction in 2006-2007.

Table ES-1
Working Group Issues & Recommendations

Issue Group 1	
1	Eligibility for Incentives: *Are participants forming deferral contracts under this solicitation also eligible for self-generation program incentives?* Resolution: Not under existing SGIP rules. Recommend SGIP re-target incentives to reward peak load reduction in distribution- and transmission-constrained areas (avoiding any double payment for the same benefit).
2	Physical Assurance Requirement: *Is 'physical assurance' required every hour of the year, or only during periods when SCE expects to call on the DG resource?* Resolution: No; the CPUC's 2003 decision gave utilities the flexibility to define 'physical assurance' in the customer contract that would limit demand when required by the utility.
3	Eligible Resources: *Where customer facilities have both DG and demand-side resources, can their proposed load reduction include demand response?* Resolution: Combining DG with other demand reduction may improve project economics and serve utility needs, so recognizing demand reduction combined with bona fide DG that meets critical loads advances CPUC intent to encourage sensible DG.
4	Alternatives to the RFP Process: *Can SCE develop feeder-specific tariffs, distribution credits, or other RFP substitutes to simplify the DG solicitation process?* Resolution: The CPUC chose not to embrace these approaches outside of a broader ratemaking, but it is important to streamline DER procurement, and future DER Partnership collaboratives should seriously consider these and similar options.
5	Additional DG Values:

	Will SCE consider DG values distinct from distribution deferral, such as generation savings from curtailment or demand response? Resolution: SCE's existing load curtailment and demand response programs reflect the value of demand reduction to the *generation* but not the *distribution* component of rates, so customers can also be paid for distribution deferral benefits they provide.

6	Business Model: *What longer-term business model(s) will advance DER as a significant contributor to the larger electricity enterprise?* Resolution: Stakeholders should seek to enhance distribution utilities' roles as DER facilitators and integrators, leveraging their positioning to identify customer opportunities, deploy and service equipment, and centralize DER purchasing and development.
	Issue Group 2
7	DG Deferral Value: *Will SCE disclose the value it assigns to distribution deferral using DG, or an area-specific ceiling or floor price it will pay for DG?* Resolution: SCE would disclose a "market reference price" (not necessarily its avoided cost) to indicate the relative value of projects, but not a ceiling on acceptable proposals, and would negotiate a deferral payment consistent with CPUC formula.
8	Simplification of the Process: *How can the solicitation process and/or SCE's Model DG Agreement be simplified to reduce all parties' transactions costs?* Resolution: Among other changes, SCE recast its model agreement from one that guaranteed DG equipment performance, to one that commits the customer to limit demand at critical times, increasing customer flexibility and prospects for viable proposals.
9	Availability of Distribution System Data: *What distribution system data will SCE provide to help customers and developers prepare DG proposals that meet its needs?* Resolution: Recommended a two-step process that would first identify qualified respondents and secure non-disclosure agreements, then provide detailed system information (location, capacity needs, hourly requirements) only to those respondents.
10	Tailoring SCE Deferral Agreement to DG Project Realities: *Can deferral periods be extended to provide greater value? Can SCE's Model Agreement be improved to encourage proposals?* Resolution: DG providers proposed and SCE agreed to offer a limited option to renew deferral contracts, including a preference for existing projects.
11	Facilitating Interaction between SCE Customers and DG Developers: *How will SCE customers be notified & developers made aware of the RFP? Will SCE facilitate contacts among interested customers and DG developers through workshops, mailings, website information, or otherwise?* Resolution: SCE will encourage customers in targeted areas to participate in its RFP process and, with their concurrence, will share their contact information with DG providers; it will also host customer-provider gatherings in or near targeted deferral areas.

Evaluating the Process

Attendees were asked to evaluate the DER Partnership collaborative process used in this project, including successes, limitations, and suggestions for improving the process or integrating substantially more DER into the electricity enterprise. Their responses are highlighted below.

What Worked Well

- Very high quality group that included the right mix of stakeholders.
- Effective organization of workshops and focused Issue Group conference calls.
- Developers gained new understanding of utility distribution planning and operations.
- Collaborative effort accomplished a lot, and developers hope it will lead to DG opportunities.
- SCE was open to input and very supportive of the process, and stakeholders were pleased with constructive, non-adversarial approach of this forum.
- SCE participants learned a lot about issues important to DG providers and customers and realized the need for more flexible utility approaches and methods to reach program potential.
- Collaborative quest for win-win solutions was productive and collegial and helped avoid failures that have plagued similar attempts elsewhere.
- SCE's Model Agreement resulting from the Collaborative's work is a much better document, with a much higher chance of success.

What Could Be Improved

- SCE's process for identifying target areas and deferrable upgrades could overlook high value projects and deserved more attention.
- Using sample data from historic projects rather than actual data for planned projects made the effort more abstract, more uncertain and less valuable for providers.
- This pilot would engage few SCE customers and short-term deferral payments would have little value – to succeed, stakeholders need at least a five-year commitment.
- More participation by customer representatives would be helpful.
- Participation by other California utilities would be helpful.
- Mainstreaming DER will require a simpler process, without legal entanglements and complicated customer requirements.
- Delaying RFP issuance for CPUC review and planning cycle changes was frustrating.

Identifying Next Steps

Participants suggested some next steps needed to increase DER integration, including:

- Educate other utilities on DER value and deployment benefits through DER Partnership workshops across the country.

- Adapt this pilot collaborative's experience to create a simpler, replicable model.
- Design regulatory approaches like those used for DSM that allow DER to compete equally with utility construction.
- Identify a "killer DG application" to drive widespread market adoption.
- Design a pilot model that makes utilities at least neutral to DER by ensuring that utility DER investments that benefit ratepayers can earn returns at least equivalent to utility T&D assets.
- Change regulatory rules so utilities can make money on sensible DG, no matter who owns it.
- Design a DER portfolio standard similar to the state's Renewables Portfolio Standards.
- Construct a business model that yields 10-12 percent returns, and Wall Street money will be there.
- Proactively pursue integrating DG supply, demand management, and demand response into California's IEPR planning process and preferred "loading order" including IEPR workshops.

SCE Perspective on the Solicitation Development and Results

The pilot project described here was undertaken to support SCE in developing a solicitation that was consistent with CPUC Decision 03-02-068, dated February 27, 2003. This Decision placed constraints on the solicitation. These constraints are indicated below with SCE's perspective on how the constraint affected the development and implementation of the solicitation.

Located in the Right Place

"The distributed generation must be located where the utility's planning studies identify substations and feeder circuits where capacity needs will not be met by existing facilities, given the forecasted load growth."[3]

For the areas where an upgrade or expansion project had been proposed for installation and initial operation during calendar year 2007, SCE developed and utilized a screening process to determine if:

- Enough <u>existing</u> <u>DG</u> was operated by customers, or
- Enough customer load was concentrated in a manageable number of customers who had a <u>viable potential to use DG</u> and participate in a demand limitation program.

SCE mapped its proposed distribution upgrade projects along with larger (>1,500 kW peak demand) customers connected to its distribution systems to visualize which customers had the potential to defer a project if the utility could control their loads. Smaller customers were not included in this screening process due to the relatively low capacity that any individual customer could contribute as compared to SCE's projected costs of program deployment and administration.

[3] California Public Utilities Commission, Decision 03-02-068, February 27, 2003, page 18.

Installed and Operational

"The unit must be installed and operational in time for the utility to avoid or delay expansion or modification."[4]

Following this obvious requirement, SCE focused its 2005 evaluation on 2007 projects so that if it identified potential deferments, there would be enough time for customers to form operating agreements and install DG facilities and any load controls necessary to allow project deferral.

Provide Sufficient Capacity

"Distributed generation must provide sufficient capacity to accommodate the utility's planning needs."[5]

SCE's Distribution System Planning (DSP) process forecasts the amount of capacity needed to serve its customers in each distribution area on a year-by-year basis. As with most forecasting, near term projections tend to be more accurate than long term predictions. In support of its 2005 screening process, SCE's distribution planners projected the minimum capacity needed to defer projects proposed for 2007.

SCE hoped to find individual customers located on the (projected to be) stressed portions of its distribution system who were operating DG facilities that could produce enough capacity coincident with the utility's peak loading periods and were willing to enter into a demand limitation agreement that would allow SCE to defer a planned upgrade for two or more years.

Not finding any individual customer meeting such criteria, SCE expanded its screening criteria to include situations where a few (<5) larger customers were located near the distribution upgrade project. Although SCE recognized that a deferment program based on this more liberal screening criterion would be more expensive and difficult to administer, SCE did not want to preclude any reasonable opportunities to produce ratepayer savings using DG. In spite of such liberalization, SCE's hopes were frustrated, as it found no set of customers who appeared capable of providing enough controllable capacity to defer a project.

Provide Physical Assurance

"[D]istributed generation must provide appropriate physical assurance to ensure a real load reduction on the facilities where expansion is deferred."[6]

SCE's plan to implement the Commission's "Physical Assurance" requirements will require the participating customer to place all or part its load under the utility's physical control for a specified number of hours each year, using automatic load control equipment to assure performance. SCE's screening process considered this requirement, as well as the likelihood that

---

[4] Ibid.
[5] Ibid.
[6] Ibid.

customers with critical loads (such as hospitals, government services, and retail operations) would participate in a deferment program.

Summary of Findings for Deferring 2007 Projects

Utilizing the methodology described in this document and following the parameters established by the CPUC, SCE could not identify any project where it appeared that satisfactory arrangements could be made with customers using (or possessing economically viable potential to use) DG facilities to defer a proposed distribution upgrade project and provide economic benefits to both the participating customer and SCE's ratepayers.

The primary reason for SCE's inability to find customers with the potential to use DG facilities and load controls as a viable option to defer a distribution upgrade project was its inability to identify enough controllable customer load concentrated in a manageable number of distribution customers with the potential to use DG and enter into demand limitation agreements with SCE.

While SCE can identify locations where utility control of large customer loads could provide a "comforting level of insurance" to the engineers responsible for planning and operating its distribution facilities, it could not identify arrangements to actually defer the installation of new facilities and provide reasonable economic benefits to SCE's ratepayers.

Project Achievements, Lessons and Recommendations

Collaborative Achievements

Within the CPUC-established boundaries, this pilot project demonstrated the ability of the stakeholder collaborative process to create innovative solutions that recognized the interests of all stakeholders, and stakeholders believed the process yielded distinct advantages compared with traditional adversarial proceedings. Some of the more significant include:

- Much-approved communication about stakeholder business needs and constraints
- Better understanding of utility service obligations, investment process, planning horizons and uncertainties, DG valuation methodology, and range of values, along with better utility understanding of DG providers' investment concerns;
- Inclusion in any solicitation of specific system information and a "market reference price" to guide qualified proposers, and utility willingness to negotiate final terms with those selected;
- More flexible interpretation of the CPUC's "physical assurance requirement that should enable more customers to support utility distribution needs; and;
- More equitable sharing of risks in the Model Agreement to be offered to successful proposers, expected to be more likely to elicit responsible and responsibility proposals.

Lessons for Moving Forward with DER Market Integration

Lessons for DER Integration

Successfully targeting DG for distribution cost savings requires tight integration with distribution planning. DG must be the right size, with the right operational characteristics, installed in the right place on the distribution system, at the right time. The project must be large enough to defer the distribution need, but not so large as to overwhelm a feeder or circuit. Even when it meets all these conditions, the deferral value that DG provides will likely be available only for as long as the utility can postpone a needed upgrade, typically several years at best. Additional institutional and regulatory factors further constrained this California pilot and taught the following lessons, each discussed more fully in the report.

1. Focusing only on "generation" and on "distribution capacity deferral" severely constrains DER opportunities because it ignores other value streams important to key stakeholders, especially local communities and the larger society. DER is unlikely to significantly impact the larger electricity enterprise until other distributed value streams are recognized and captured for some combination of the utility, the host customer, its other customers, and society at large.
2. Longer-term, better-integrated resource planning is essential to integrating DER as part of a balanced portfolio of demand, supply, and delivery options. DER needs a planning horizon of at least five to ten years to attract financing and should be targeted at larger distribution planning areas than circuits and substations. DER also needs a proactive "total resource" approach to integrating small distributed and local resources into regional energy supply networks.
3. Utilities should take advantage of third-party experience to identify DER opportunities once their expansion needs are known, at the stage of deciding whether a DER procurement is warranted. The earlier in the process that diverse perspectives are brought to bear, the more likely it is that win-win solutions will emerge.
4. More streamlined procurement processes will help integrate DER into electricity markets. The RFP process imposes sizeable transactions costs and inevitable delays and typically focuses on short-term projects addressing narrowly defined needs. A more promising approach is to create targeted, self-executing tariffs or distribution credits at a planning area level, structured to meet each area's particular growth issues and aligned with long-term resource values rather than short-term project deferrals.
5. Value-based economic incentives for utilities to use least-cost/highest-value resources (including customer-side resources) to benefit all customers will promote efficient DER integration. Financial incentives for more efficient asset use, rather than for capital investment or energy throughput, are needed to encourage utilities to support, integrate, and adopt distributed solutions where they make sense for utility customers and society at large.

Lessons for DER Stakeholder Collaboration

6. Facilitated stakeholder collaboration works well to bring together diverse interests, engage customers and regulators, and shape nuanced solutions. Collaborative efforts are much

more likely than adversarial forums to encourage open, unguarded dialogue; clarify misunderstandings; build consensus from conflict; nurture constructive business models; and lead to “win-win” solutions benefiting many stakeholders.

7. Stakeholder collaboration will yield better results if utilities provide actual data on planned expansion projects, instead of historical data that may not reflect future needs. The more real the data is, the more helpful it will be to providers in deciding whether and what to propose, and the more likely utilities are to benefit from DER market experience.
8. Advance agreements about any regulatory review required will strengthen collaboration. To maintain momentum, frame realistic expectations, and enhance timely results, participants might agree with regulators in advance what the collaborative can do, and how much flexibility it has to innovate without further regulatory reviews and associated delays.
9. Regulatory incentives for utilities to take collaborative DER projects to fruition could help utility innovators overcome institutional inertia and obtain corporate buy-in to experiment with new offerings, and gain concrete experience in deploying real DER projects.

Recommendations for Further Consideration

Based on the pilot project findings and *Framework* recommendations, the following concepts are offered for discussion.

- Develop a nationally based stakeholder collaborative to encourage win-win business and regulatory models that motivate utilities to use all forms of distributed energy resources and reward DER customers fairly.
- Linked to the national collaborative, develop regionally based stakeholder collaboratives to develop and implement regional approaches to innovative DER solutions.
- Apply the stakeholder collaborative process to demonstration programs to test concepts in the field, quantify DER costs and benefits, and measure success of specific projects or programs.

CHAPTER 1
INTRODUCTION

EPRI DER Public/Private Partnership

The Electricity Innovation Institute (E2I), a non-profit affiliate of EPRI, was chartered in 2001 to conduct strategic research and development through public/private partnerships. E2I initiated the Distributed Energy Resources (DER) Public/Private Partnership in 2002 to reduce barriers to DER deployment and to enable widespread DER integration where it brings value to the electricity enterprise. In 2005, EPRI assumed E2I's charter and programs to streamline the business and to reduce costs. Throughout this report, the DER Partnership will be referred as the EPRI DER Partnership. E2I will be referred to in historical context.

The Partnership comprises two platforms: 1) DER Market Integration, to address market barriers to DER, and, 2) DER Environmental Benefits/Impacts, to conduct objective analysis of the environmental impacts of widespread DER. As described below, this report is the third in a series developed under the DER Market Integration platform.

The EPRI DER Partnership defines DER as small (usually less than about 10,000 kW) electric generation, storage, or demand-side resources located near the load they serve and interconnected with utility wires at distribution system voltages. Generation technologies may include small gas turbines, microturbines, reciprocating engines, fuel cells, or photovoltaics, operated for stand-alone generation or combined heat and power (CHP) applications, and using either conventional fuels (for example., natural gas or oil) or renewable resources (for example, biogas, biomass, or solar radiation). DER storage may include flywheels, thermal storage, and other local storage technologies. DER may also include technologies and operations used for demand response or otherwise to reduce end-user load.

Previous DER Market Integration Reports

DER Scoping Study, Spring 2003

In January 2003, E2I assembled a group of DER stakeholders to identify gaps in research needed to encourage DER where it can add value to the electric system. The group assigned high research priority to DER market integration-–defined to mean the development of win-win business models, regulatory approaches and utility rate structures that encourage DER that adds value to the system[7]. The group also recommended further scoping to refine the research agenda.

[7] In EPRI's DER Market Integration work, a "win-win" approach is one that benefits multiple stakeholders without significantly harming others.

During April and May of 2003, the project team conducted a scoping study[8] to baseline the current market situation in key states, identify elements of win-win approaches, and recommend research actions to advance widespread DER integration. Team members interviewed 27 stakeholders (including utilities and their affiliates, regulators, and DER equipment suppliers and project developers) actively involved with DER issues, and analyzed DER regulatory developments in New York, California, and New Jersey. The team proposed win-win business elements for DER and identified related research actions.

On May 30, 2003, these were presented to the project working group of DER stakeholders, consisting of 30 top thought leaders representing all segments of the DER community, at a workshop at EPRI headquarters in Palo Alto, California. The group reviewed the scoping study results, proposed a set of objectives to enable value-driven DER market integration, and prioritized the following action recommendations for the DER Partnership:

- Develop a catalog of actions that utilities and regulators can take to incentivize DER that adds value to the electricity enterprise;
- Examine DER costs and benefits, and how utility rate structures and incentive approaches can allocate them across stakeholder groups to achieve win-win outcomes; and
- Develop a framework for flexible, collaborative programs to refine and improve existing incentive approaches and implement new ones in several states.

Framework for Developing Collaborative DER Programs, Fall 2003

During the fall of 2003, the DER Partnership's Market Integration platform implemented the three action recommendations above that came from the DER Scoping Study[9]. This work serves as the "*Framework*" for follow-up activities.

Addressing the first recommendation, the project team researched actions that some leading states and utilities have already taken to facilitate DER (often demand response) that adds value for electric systems and their customers. As part of a final *Framework* report, this work yielded a catalog of approaches reflecting the differing interests of distribution utilities, bulk power utilities, DER customers, and society at large. The catalog offers insights about what has been tried to date, as well as ideas and recommendations for designing the kind of win-win incentives favored by DER Partnership participants.

Accompanying the catalog in the *Framework* report is a discussion of utility revenue-setting and rate design methods available to allocate DER costs and benefits among stakeholders, and thus shape incentives that help or hinder DER integration. The discussion describes basic rate forms

---

[8] *Integrating Distributed Energy Resources into Emerging Electricity Markets: Scoping Study: Report of the E2I Distributed Energy Resources Public/Private Partnership*. E2I, Palo Alto, CA. 2004. 1011030.

[9] *A Framework for Developing Collaborative DER Programs: Working Tools for Stakeholders.* E2I, Palo Alto, CA, 2004. 1011026. This work was sponsored by the California Energy Commission, the New York State Energy Research and Development Authority, the Tennessee Valley Authority, City Public Service of San Antonio, and the Massachusetts Technology Collaborative.

that can make it easier or harder to align stakeholder interests (such as volumetric charges, fixed charges, demand charges, and two-part rates). It also reviews options such as customer-oriented demand subscription and non-firm standby rates, monetization of societal emissions costs, recognition of generation multipliers, and revenue-based Performance Based Ratemaking (PBR).

Addressing the second action recommendation of the DER Partnership, the project team identified and described costs and benefits that accrue to each stakeholder group (DER customer, utility shareholders and other ratepayers, and society at large). The team developed a spreadsheet model to quantify those costs and benefits from each stakeholder's perspective and to illustrate how they can be reallocated among stakeholders to achieve win-win outcomes. The model structure enables users to vary numerous parameters relevant to DER projects to see how they affect the costs and benefits flowing to each stakeholder group. Its results reveal which stakeholders profit and which ones pay for different combinations of DER technologies under differing assumptions concerning energy prices, T&D deferral, "generation multiplier" effects, emissions profiles, financing terms, operational characteristics, available incentives, and so forth.

The DER Partnership's third action recommendation was to initiate flexible, collaborative pilot programs in several states to refine and improve existing incentive approaches and implement new ones. To begin that process, the project team developed a framework to support such programs.

The framework builds on the catalog of approaches, rate design options, cost/benefit descriptions and modeling tools to outline a four-part process for collaboration among willing stakeholders to develop innovative DER pilot programs. The process proceeds as follows:

1. Structure the collaborative and define the program's scope and objectives.

2. Introduce basic strategies for participants to consider in developing programs and outline the stakeholder needs that each strategy can address.

3. Consider options available to tailor each basic strategy to local conditions.

4. Prepare a detailed example showing how the catalog, incentive mechanisms, and cost/benefit modeling tool can be combined to evaluate a potential CHP pilot project, or to shape other collaborative DER programs.

The *Framework* report identified a wide variety of collaborative initiatives that could help integrate DER into larger electricity markets – ranging from specific methods of leveraging DER values, introducing efficient incentives, and eliminating barriers, to rate design changes and high-level policy approaches. At the same time, however, it emphasized that any pilot program would need to tailor its objectives to meet particular state, regional, and local needs through the stakeholders' collaborative process. The Southern California Edison (SCE) DER pilot project described in this report provides a real-world example of that process.

Report Structure

Following this Introduction, Section 2 describes the SCE Project in general. Section 3 chronicles formation of the collaborative and the first Workshop. Section 4 describes collaboration between workshops. Section 5 chronicles the second Workshop. Section 7 presents Southern California Edison's perspective of the effort. Section 8 presents lessons learned and recommendations.

Appendix A lists the project Collaborators. Appendix B lists participants in the first workshop. Appendix C presents notes from the first workshop. Appendix D lists participants in the second workshop. Appendix E presents notes from the second workshop.

CHAPTER 2
CALIFORNIA DISTRIBUTED ENERGY RESOURCES PILOT PROJECT

Background and Regulatory Context

Southern California Edison (SCE) is one of the nation's largest investor-owned electric utilities, serving over 50,000 square miles of service territory in Central and Southern California. SCE provides power for about 13 million people, 430 cities and communities, 5,000 large businesses, and 280,000 small businesses. To do this, SCE relies on nearly 5,000 transmission and distribution circuits, more than 400 transmission and distribution crews, and more than 13,000 employees.

SCE is regulated by the California Public Utilities Commission (CPUC). Since the mid-1990s, the CPUC has taken an active regulatory interest in DER. Beginning in 1998, the CPUC and the California Energy Commission initiated extensive rulemakings focused specifically on distributed generation or 'DG' (as distinct from demand-side resources or demand response). These proceedings involved numerous stakeholders representing all sectors of the DG community, including utilities, state agencies, municipalities, environmental and consumer advocates, and DG equipment vendors and project developers.

The proceedings resulted in a February 2003 CPUC decision and Order[10] that addressed a wide range of issues that the parties had identified, supported through written and oral testimony, and briefed extensively over many months. Among other things, the 2003 Order required California's investor-owned utilities, including SCE, to (1) incorporate in their distribution planning activities a utility-proposed process to evaluate alternatives to distribution system upgrades based on San Diego Gas and Electric's (SDG&E's) distributed generation procurement approach[11], and (2) develop model contracts for DG designed to defer such upgrades[12].

The CPUC's 2003 decision imposed four important conditions for utility DG procurements used to defer upgrades to their distribution systems:

---

[10] CPUC Decision 03-02-068 in R.99-10-025, February 27, 2003. Conditions discussed are from mimeo, p. 18 and the Commission's Conclusions of Law.

[11] www.sdge.com/tm2/pdf/1492-E.pdf#page=1, www.sdge.com/business/distributionGeneration.doc

[12] Id., Ordering paragraphs 1-3, p. 72. On May 13, 2003, the utilities made compliance filings in the same proceeding, describing how they would incorporate DG in their planning and procurement, and proposing model contracts as a starting point for negotiations with DG providers selected through this process.

- **Appropriately Located**. "The distributed generation must be located where the utility's planning studies identify substations and feeder circuits where capacity needs will not be met by existing facilities, given the forecasted load growth."
- **Sufficient Capacity**. "Distributed generation must provide sufficient capacity to accommodate the utility's planning needs." This requirement appears intuitively obvious and incidental, but it turned out to be the primary barrier that SCE later cited as frustrating its efforts to use customer DG to defer a distribution upgrade.
- **Installed and operational**. "The [DG] unit must be installed and operational in time for the utility to avoid or delay expansion or modification." This requirement guides utilities and participants regarding the lead time required to defer distribution projects. Utilities need assurance that DG facilities contracted to defer distribution will be available when needed.
- **"Physical Assurance"**. The rulemaking had focused on DG that could avoid or defer utility distribution upgrades[13]. To be considered for that purpose, DG installations would need to include devices and equipment to physically assure that customer load equal to the DG unit's capacity would be interrupted if the DG did not perform as contracted, to prevent harm to the distribution system and other customers[14]. This means that a customer who contracts with a utility to provide DG capacity to defer a distribution capacity upgrade must risk load interruption if its DG is not operating when distribution capacity (without the upgrade) is exceeded. This requirement can help make deferment feasible, but it may preclude participation by customers who have installed DG to serve critical loads and who typically are more interested in assuring service reliability than reducing electric costs.

For DG meeting these criteria and selected through the utility procurement process to defer distribution capacity upgrades, the CPUC's 2003 Order directed that utility payments to DG providers cannot exceed a prescribed formula: *the utility's short-term cost of capital, multiplied by the cost of the planned distribution addition and the number of years of deferral*[15]. This requirement is to ensure that the utility does not pay more to participants providing DG facilities to defer upgrades, than it would pay to finance and construct the upgrade.

The 2003 decision contemplated a DG procurement process based on a utility-issued request for proposals (RFP). Utility RFPs were expected to incorporate model contracts similar to those the utilities had submitted to the CPUC in May 2003, but with little or no input from other DG stakeholders who the utilities and the Commission hoped would respond with DG projects meeting utility needs.

---

[13] California DG rulemakings began in 1998-99, when the state's utilities were required to divest most of their generation and expected to become wires-only utilities. That, and the structure of California's wholesale markets at the time, may explain the rulemaking's focus on DG primarily as an alternative to distribution capacity expansion. E2I's 2003 Scoping Study noted that states with different restructuring regimes and wholesale market structures have taken a broader view of DER's contribution to the larger electricity enterprise. California has also moved toward that view in a 2004 DER rulemaking (R.04-03-017).

[14] Id., Finding of Fact 7, p. 69; Conclusion of Law 3, p. 70; note 2, p.7; and discussion at pp. 12-13.

[15] Id., Conclusion of Law 6, p. 71, and Ordering paragraph 4, pp. 72-73.

SCE's Proposed DG Solicitation

SCE had been actively involved as a stakeholder in the earlier Scoping Study[16]. It had also participated in the DER Partnership 2003 work to develop the *Framework* for collaborative DER pilot projects[17]. As a result, SCE representatives believed that the DER Partnership's collaborative approach could help the utility design a planning and procurement process that would meet CPUC requirements and yield DG projects that could defer distribution investment.

SCE was also aware that New York's pilot program to integrate DG into utility planning and procurement through an RFP process had been under way for several years[18], but its early solicitations had not elicited strong interest from DG providers, or resulted in successful projects. Industry feedback suggested that utilities could benefit from a better understanding of the needs of prospective DG providers, and that providers could be more responsive if they learned more about utility system planning processes and constraints. Believing that a more collaborative approach might meet these needs, SCE agreed in the spring of 2004 to work with the DER Partnership project team and stakeholders toward those ends.

SCE's original objective was to issue its first DG solicitation implementing the CPUC directives by November 2004. The utility initially hoped to target projects that could be installed and operational in time to meet peak distribution system needs about 18 months later (in the summer of 2006). Early discussions among the DER Partnership concluded that 24 to 36 months would be a more realistic target, in part because completion of any DG project would need to be assured in time for SCE to revert to its traditional wires solution if that became necessary.

Based on its normal distribution planning process, SCE expected to be able to identify three to five distribution planning areas facing significant upgrade investments that might be deferrable using DG – provided it was the right size, in the right location, installed at the right time, and with physical assurance to guarantee the load reduction needed to defer capacity upgrades.

In the spring of each year, SCE's annual planning update identifies distribution upgrades needed within the next two years, based on information and projections that evolve during that planning year. Work on this DG pilot project began in the spring of 2004, so SCE had not yet settled on specific circuits or distribution upgrades that it would require in 2006-07, when DG projects solicited in the fall would need to be operational.

From past experience, the utility expected to identify three to five local areas on its system where DG had the potential to defer specific distribution investments. The amount of new capacity required in each area of course would vary with the condition of the distribution infrastructure,

---

[16] *Integrating Distributed Energy Resources into Emerging Electricity Markets: Scoping Study: Report of the E2I Distributed Energy Resources Public/Private Partnership.* E2I, Palo Alto, CA. 2004. 1011030.

[17] *A Framework for Developing Collaborative DER Programs: Working Tools for Stakeholders.* E2I, Palo Alto, CA, 2004. 1011026.

[18] *Identifying Areas where Distributed Generation can Defer Distribution System Investments.* Prepared for NYSERDA by Resource Dynamics Corporation. June 2006. In Publication.

its forecasted load growth, and other factors. In general, however, SCE expected that capacity additions needed in each area would be in the multi-megawatt range, perhaps averaging three to five MW per area. Multiplying the estimated number of areas by the average MW likely to be needed in each one, this initial pilot procurement was expected to target about 10 to 25 MW of DG-provided capacity deferral, once SCE determined its actual distribution system needs later in the year.

For this DER pilot to meet SCE's proposed schedule, the stakeholder collaboration needed to begin around June and be completed by year-end, 2004. This relatively short period, coupled with SCE's need to comply with the CPUC's boundary conditions for DG solicitations, dictated the scope of the pilot.

Table 2-1 compares the SCE scope with that of the New York pilot program.

Table 2-1
SCE Pilot Compared with New York PSC Pilot

Program Characteristic	New York	California (SCE)
Regulatory context	NY PSC established pilot program requirements, including procurement mechanism, number of solicitations, timelines, cost thresholds for RFPs, project evaluation criteria, etc.	CPUC required utilities to consider DG in planning, procure it if competitive, & develop model contract terms. CPUC set ceiling price formula and required physical assurance for distribution deferral. Utilities are otherwise free to structure their own solicitations.
Duration of pilot	3 years	6 months (collaborative RFP design only)
Number of utilities	6	1
Number of solicitations planned, in total	2 each year for each utility; 2 additional for Con Ed in third year; total of 38	Annual
Number of solicitations issued to date	at least 12	None. Solicitations to be made only if deferral opportunities are identified
Solicitation type	RFP	RFP or direct negotiations, depending on number of potential participants
Solicitation design	PSC and utilities	SCE, with collaborative input from other stakeholders
Model contract(s)	developed by NY utilities	developed by SCE
Model contract design	developed by NY utilities	initially by SCE, substantially modified through collaboration

Approach and Scope of Support for SCE Pilot Procurement

SCE's planning and procurement needs presented an early opportunity to test the DER Partnership's collaborative approach, apply the tools developed through the 2003 Market Integration work, and begin to implement some of its findings and recommendations.

The intent of the project was to support SCE's objectives of designing a DG procurement process consistent with CPUC directives that would meet specific distribution area needs and would encourage successful third-party proposals to integrate DG into SCE's system. The CPUC's 2003 decision did not restrict utility ownership or operation of DG. The Commission stated that utilities and their affiliates remain free to enter customer-side DG markets along with independent third parties, although they "do not appear to offer any sort of specialized expertise in the manufacture, sale, or operation of distributed generation on the customer side of the meter, so we do not encourage them to enter this new business line within the regulated utility"[19]. In any case, SCE indicated from the outset that this initial procurement would focus on customer-sited, customer-, or third-partyowned DG, and that the utility and its affiliates did not intend to submit proposals.

SCE's aims for the process were similar: to develop a solicitation that would be easy to understand and respond to; encourage many proposers to submit innovative options for the utility; and result in sound proposals that SCE ratepayers could enthusiastically support[20].

Specific goals of the SCE pilot program included:

- Using a stakeholder collaborative process to develop a DG or DER solicitation that developers, customers, vendors, and other third parties will confidently bid on and that will lead to a pilot that can serve as a model for other procurements.
- Testing and demonstrating the stakeholder collaborative process.
- Developing innovative win-win approaches for encouraging DER and advancing DER market integration and policy.
- Documenting lessons learned and win-win approaches developed from the stakeholder collaboration so they can be duplicated and scaled in California and other states.

To help achieve these goals, the DER Partnership project team agreed to help SCE in the following tasks:

1. Recruiting participants and organizing the collaboration.
2. Supporting SCE's analysis of distribution system needs and conducting preliminary analyses of costs and benefits to key stakeholder groups
3. Planning and preparing materials for an initial stakeholder workshop

---

[19] D.03-02-068 at p. 23.

[20] Remarks of SCE Vice President Jim Kelly welcoming participants to the E2I/SCE July 14, 2004, collaborative workshop.

4. Facilitating initial collaborative discussions at the opening workshop.
5. Leading stakeholder groups in developing win-win approaches for a successful pilot.
6. Reconvening stakeholders in a second workshop to integrate results into a successful solicitation.
7. Supporting SCE in developing its DG RFP.
8. Monitoring results, developing lessons learned, and reporting on what was done.

Activities 1-7 took place from May through early October, 2004. Changes in SCE's distribution planning cycle and its desire to seek CPUC approval for improvements to its Model DG Agreement resulting from the collaborative's work, caused SCE to postpone the targeted dates for its DG solicitation from November 2004 to March 2005 and for execution of DG contracts to October 2005.

CHAPTER 3
COLLABORATIVE ORGANIZATION AND PROJECT SCHEDULE

The *2003 DER Framework* report posited that DER stakeholders' underlying interests are often more compatible than the positions they advocate in formal regulatory proceedings that address DER issues. In those forums the parties' positions, advocated by legal counsel, often proceed from incomplete understanding of other parties' needs, desires and business constraints, without the more nuanced appreciation that comes from informal give-and-take among principals. Regulatory litigation generally is designed to yield a decision that parties can act on (or challenge, as the case may be) – not to produce consensus or compromise, or to build relationships among businesses that have much to gain from each other, but operate in very different environments.

The *Framework's* collaborative approach, by contrast, is intended to help structure non-adversarial exchange of ideas and constructive cooperation among stakeholders, to find solutions that benefit as many as possible, as much as possible, with as little prejudice to others as possible. The Framework suggested that this works best when care is taken to organize and structure the collaborative from the outset. It is this collaborative approach that was undertaken to assist Southern California Edison in its efforts to identify win-win opportunities to use DG under the California PUC's 2003 Order,[21] which is reported here.

Selecting Participants for the Collaborative

EPRI's DER Partnership assumed primary responsibility for structuring the collaborative, including identifying and selecting the participants. The challenge here was to balance potentially conflicting needs. On the one hand, it was important to accommodate as many interested stakeholders as possible, to ensure a wide range of knowledge, experience, and viewpoints that could contribute to innovative solutions. On the other hand, it was essential to limit the group to a size and composition that could meet regularly and with continuity over several months; could focus in depth on a variety of complex issues; was motivated by a genuine interest in the outcome; and could be organized, managed, and coordinated effectively.

The solution was to create a dual structure for the collaborative. This consisted of a relatively small core group (the "working group") responsible for the Collaborative's day-to-day work, and a larger group that also included advisory members with strong DER experience and/or valuable institutional perspectives, but without a direct stake in the SCE solicitation (in other words, not in a position to respond with actual DG resources or projects). The larger group brought a

[21] CPUC Decision 03-02-068 in R.99-10-025, February 27, 2003.

broader outlook, and acted as a sounding board for the working group's more concentrated work. The DER Partnership project team facilitated and directed the work of both groups.

Sixteen participants were initially invited to join the working group. They included representatives of five companies engaged in DER project development; five DG equipment manufacturers or vendors; two customer groups or associations; and four SCE personnel responsible for distributed generation, transmission and distribution engineering, and customer service.

The larger group, most of which sent representatives to one or both pilot workshops, included all working group members; representatives of the California Energy Commission and California Public Utilities Commission, NYSERDA, the Massachusetts Technology Collaborative, and the U.S. Department of Energy; and interested personnel from other utilities including CPS San Antonio, Southern California Gas, San Diego Gas & Electric, NStar Electric & Gas, and First Energy. The list of collaborative participants is included in Appendix A.

Ensuring Fairness and Openness

The collaborative's overall objective was to enlist the broader DG community to help SCE develop a competitive solicitation process that would yield viable proposals for projects that could defer SCE distribution investments. SCE chose to target the solicitation to its customers who could act as site hosts, working with third-party DG providers if they elected to do so.

In selecting collaborative participants, the DER Partnership considered both customers and DG providers. With respect to *customers*, SCE had not yet identified the distribution areas its solicitation would target, and could not provide customer names in those areas (even apart from questions of customer confidentiality). Rather than invite some individual SCE customers and exclude others, the project team chose to invite representatives of customer groups that could present general customer perspectives but would not gain any advantage for individual customers who might later propose DG solutions.

With respect to *DG providers*, the project team made every effort to identify potential provider representatives that could convey not only their own companies' views, but the views of other similar companies in the industry. The California DER pilot project needed to engage companies willing to commit time and resources to the collaboration, and it needed to limit the working group to a manageable and productive size. This meant that some but not all potential DG providers would participate in the collaborative, and that it was important to structure a process that would not prejudice others who might later wish to respond to SCE's solicitation.

The DER Partnership project team proposed a set of guidelines designed to balance the need for an efficient and productive collaborative process, with the need for fairness and integrity in SCE's solicitation process. The guidelines, accepted by SCE and followed in the Collaborative, provided for:

- Posting on E2I's public website[22] information about the collaborative process, workshop attendance and presentations, and a report on workshop activities, all available for download.
- Objective criteria for other interested parties to join the collaborative as it proceeded.
- A stipulation that information SCE shared with the collaborative would not identify specific locations or characteristics of actual projects, but would be historical and/or for general or undisclosed areas of SCE's distribution system.
- An understanding that industry participants would be encouraged to offer their perspectives during the collaborative process but would not make decisions that could affect potential competitors; rather, SCE would ultimately decide how to structure its RFP, who would receive it, what projects would be included, who would be eligible to propose, how proposals would be evaluated and awards made, and what terms and conditions would be required.

Overview of the Work

As described more fully in Section 3, the SCE collaboration was structured around two stakeholder workshops facilitated by the DER Partnership and hosted by SCE in Southern California. The first workshop took place on July 14-15 to educate all stakeholders about the planning constraints and business needs of other stakeholders and identify issues critical to a successful solicitation. The second workshop occurred on October 6-7, 2004, to integrate recommendations developed by the stakeholder working group over the summer.

The following timeline illustrates the schedule initially established for the project team's support tasks and stakeholder collaborative activities: [23]

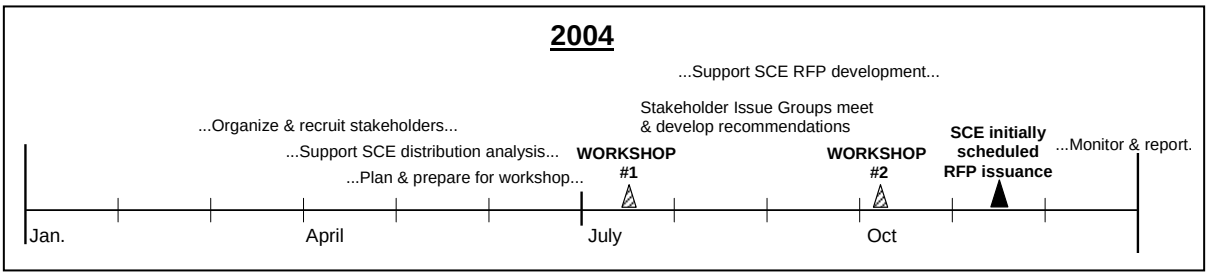

Figure 3-1
Project Timeline

To prepare for the July workshop, the project team worked with SCE during May and June to support the utility's analysis of distribution planning area needs; identify screening criteria for

[22] www.epri.com/der-ppp/California_DER_Pilot_Project.html

[23] The project followed this schedule, except that SCE proposed to postpone issuing its RFP from November 2004 to March 2005 due to changes in its planning cycle and its decision to seek Commission approval for changes to a Model DG Agreement it had proposed in 2003 without benefit of the Collaborative's input.

distribution projects that DER might be able to defer; and estimate costs and benefits of potential distributed solutions for various stakeholders. Between the July and October stakeholder workshops, the project team led and facilitated multiple meetings of two stakeholder groups working in parallel to address high priority issues identified at the first workshop.

SCE's team was led by Stephanie Hamilton and Tom Dossey, both in SCE's Transmission and Distribution group responsible for the utility's DER activities. These activities include forward-looking work on the conceptual design of an SCE "circuit of the future" that will showcase cutting-edge technologies for DG, energy efficiency, demand response, and advanced communications and controls. SCE's team also included representatives from Customer Service, Distribution Engineering, Regulatory Affairs, and the utility's Law Department.

CHAPTER 4
BRINGING STAKEHOLDERS TOGETHER AND DEFINING THE ISSUES – WORKSHOP NO. 1

Workshop Preparation

As collaborative participants were being identified and guidelines for a fair and open process developed, the project team worked with SCE to plan and prepare for the opening stakeholder workshop.

This first workshop was intended to help non-utility stakeholders (DG providers, customer representatives, and others) understand more about how SCE does its distribution planning; how it will value potential DER offerings; and how regulators will assess their costs and benefits for other utility customers, shareholders, and the general public. The workshop was equally intended to help SCE personnel, accustomed to operating in a regulated environment, understand how non-regulated DG vendors, project developers, and utility customers would evaluate the costs, risks, and benefits of responding to an SCE solicitation, and what could smooth the procurement path for both SCE and prospective respondents.

Specificity of System Information

The DER Partnership project team believed that the more concrete and specific the system information SCE provided, the more useful it would be to DG providers who needed to understand how their projects could support SCE's system, and what value they might offer to the utility. The challenges were to balance these considerations against utility concerns over disclosing sensitive business information, and against concerns over fairness to other potential bidders not participating in the Collaborative, and not privy to such information in advance of any solicitation.

SCE's internal analysis would identify areas where the utility anticipates a need for distribution upgrades or expansion (usually due to population and business growth). The utility expected to identify and rank perhaps three to five distribution planning areas where it would need relief over its two- to three-year planning horizon. However, during discussions in the spring, SCE explained that its normal planning process would not actually identify specific distribution circuits or construction projects needed until fall 2004, based partly on actual load growth and operating experience over the summer. The fact that data specific to projects that would be part of the solicitation was unavailable in any case, mooted concerns over revealing such information to potential bidders who were part of the Collaborative but not to others.

Reflecting its planning realities and business concerns, SCE proposed to present historical data from its 2003 planning cycle, but without identifying specific planning areas, distribution circuits

or construction projects represented by the data. This data was intended to be representative of typical SCE distribution expansion projects, but not necessarily identical to the forward-looking data for different parts of its distribution system that SCE would compile later in 2004, and that would drive its DG solicitation.

Screening for Potential DER Projects

Before the first stakeholder workshop, E2I's project team worked with SCE's DER planners and engineering professionals to understand the process and analysis SCE uses to estimate local DER values and described processes that other utilities had used to integrate DER into its distribution planning. The team also provided SCE with an Excel spreadsheet template for high-level DER technical and economic screening to help planners identify key issues that make DER either more or less attractive in different areas. SCE compared this tool with screening tools developed in-house and incorporated parts of it that augmented its own capabilities.

Analyzing Costs and Benefits from Multiple Stakeholder Perspectives

In parallel with this work, the project team used the modeling tool developed for its 2003 *Framework* report to develop a preliminary cost and benefit analysis of DER projects from the perspective of multiple stakeholders invited to participate in the SCE Collaborative. This analysis would be presented at the first workshop to illuminate each stakeholder group's economic perspective to identify DER projects that could succeed from all perspectives – or to identify potential 'win-win" opportunities.

To do that, the team updated the 2003 cost-benefit modeling tool with the most current set of parameters and defined the ranges of critical uncertainties. Core parameters that were confirmed or updated included SCE rates, system energy and capacity values, and DER cost and performance. Once updated, the tool would be used to help identify the highest value DER applications – those most likely to result in 'win-win-win' outcomes – for discussion at the first workshop, where participants later commented on input assumptions based on their own expertise and experience.

Taken together, the purpose of the activities described above was to improve workshop participants' understanding of –

- The nature and magnitude of DER's potential value for the local utility system;
- The requirements DER must meet to provide that value;
- The most promising types of applications from a cost-benefit perspective; and
- The methods described in the *Framework* to use this information to craft approaches that meet the needs of as many stakeholders as possible.

These were the major activities completed as background for the first stakeholder workshop. Their results were presented at the workshop along with other topics listed in the next section.

Workshop Objectives, Topics and Presentations

SCE and the DER Partnership hosted the first stakeholder workshop on July 14-15, 2004, at SCE's Customer Technology Application Center (CTAC) in Irwindale, California (east of Los Angeles). The workshop's objectives were:

- To increase understanding and develop trust among stakeholders for productive collaboration.
- To introduce the DER Partnership cost-benefit tool and *Framework.*
- To identify win-win-win approaches with the highest potential for success in this pilot.
- To form smaller working groups to address priority issues and develop recommendations.

The following agenda topics for the first day of the July workshop were established[24]:

- DER Partnership Collaborative Approach for Win-Win DER Opportunities.
- SCE's Distribution Planning Process for Valuing DG as a Distribution Alternative. (examples from SCE 2003 sample projects)
- Computing DG value.
- Analyzing costs & benefits for multiple stakeholders.
- Key Elements of SCE's Proposed RFP.
- Stakeholders' Interests, Needs, and Issues.
- DER Partnership Collaborative Strategies and Program Examples.
- Breakout sessions to prioritize top issues emerging from workshop sessions.
- Reconvene and assign group priorities for issues meriting in-depth attention.

Following the stakeholders' prioritization of issues at the end of the workshop's first day, the project team organized and grouped the highest priority issues. On the second day, July 15, the team offered a strawman for assigning sets of issues to smaller working groups. Attendees fine-tuned the assignments and established two smaller "Issue Groups", each facilitated by a member of the project team, to systematically address the stakeholders' priority concerns over the summer. The issues assigned to each group are described, and their outcomes reported, in Section 5.

[24] Workshop presentations are available at www.epri.com/der-ppp/California_DER_Pilot_Project.html.

Workshop Participation

Thirty-one people, including top officers and managers of their organizations, attended all or part of the July 14-15 stakeholder workshop[25]. These included representatives of:

- Five DER project development companies.
- Four DG equipment manufacturers and vendors.
- Four electric and/or gas utilities or affiliates, including SCE.
- One public customer with multiple facilities in SCE's service area.
- Two regulatory agencies, including the California Energy Commission and the Massachusetts Division of Energy Resources.
- The U.S. Department of Energy.
- E2I and EPRI program managers and members of the project team.

Workshop participants expressed considerable interest in all of the topics presented. They engaged actively and enthusiastically in the discussions on both days and contributed helpful and important insights into the perspectives their organizations brought to the table. During the first workshop, and continuing through the summer's Issue Group meetings and the second workshop in early October, participants did not hesitate to express their views candidly and respectfully. Throughout the process, many expressed increasing trust and confidence in other stakeholders' willingness to contribute and to consider different points of view.

Issue Group Process

The DER Partnership designed the workshop process to identify issues that were important to both the DG development community and SCE. On the second day of the July Workshop, representatives of each elected to join one of the two Issue Groups formed to work on high priority issues between the July and October workshops and to find mutually acceptable approaches that could benefit multiple stakeholders.

In looking at the list of priority issues identified during the workshop, it became clear that some pertained directly to the specifics of SCE's planned solicitation. Others pertained to longer-term barriers to widespread deployment of DG and DER. This second set of issues required a different approach than the first and the involvement of some stakeholders not present in this Collaborative. A third set of issues included ones that would directly impact the RFP but whose solution could not be negotiated within the Collaborative. Workshop participants decided to assign the issues that were longer-term or less amenable to collaborative influence to Issue Group One and the RFP-specific issues to Issue Group Two. Each participant then selected the set of issues and the group he or she would be willing to work with between workshops.

---

[25] Appendix B lists the attendees at the July 14-15 Workshop.

For Issue Group 1, an example of a longer-term issue would be how to provide appropriate incentives for utilities to embrace DER as part of the solution to grid reliability. An example of a barrier that the Collaborative could not resolve by itself would be the disincentive created by California's current Self-Generation Incentive Program rules, described below.

Issue Group 2 was set up to address "nuts and bolts" issues in structuring SCE's first DER procurement, including some that had hindered other efforts around the country to incorporate DER into utility distribution planning and procurement. This Group was tasked to evaluate the RFP process being developed by SCE and to suggest ways to simplify it and otherwise encourage maximum participation by the DG community. It was also tasked to review a Model Agreement that SCE had previously filed with the CPUC to use as a starting point for negotiations with successful proposers and to give SCE feedback regarding viable contract approaches and language from the perspective of customers and third-party DG providers.

Table 4-1 lists specific issues considered by each of the Groups, respectively. The issues are numbered for convenient reference, but not necessarily in order of priority.

Workshop Results

The summary report on the July workshop is included as Appendix D. The following highlights its description of the major outcomes of the workshop.

- SCE demonstrated its commitment to develop an RFP that could attract bidders and result in successful bids for solutions that make sense for all of its customers. Senior managers, engineers, and project personnel from several of the utility's business units echoed this.
- Other stakeholders were also committed to helping SCE develop a successful RFP process. Even participants who were skeptical at first committed to work on the group's priority issues and to make recommendations for SCE to consider in developing its solicitation.
- Major issues of concern to stakeholders included the following (explored further by the two Issue Groups over the summer):
  - "*Physical assurance*" – interpretation of the CPUC's requirement to interrupt a customer's normal load when its DG unit does not perform as contracted.
  - *Distribution deferral value* – Defined by the CPUC as the utility's short-term carrying cost of capital, multiplied by the cost of the planned distribution addition and the number of years of deferral. This is the ceiling price the utility can pay to DER providers, which by itself will rarely be enough to fully support customer-sited projects.

Table 4-1
Working Group Issues

Issue Group 1	
1	Eligibility for Incentives: Are participants forming deferral contracts under this solicitation also eligible for Self-Generation program incentives?
2	Physical Assurance Requirement: Is 'physical assurance' required every hour of the year, or only during periods when SCE expects to call on the DG resource?
3	Eligible Resources: Where customer facilities have both DG and demand-side resources, can their proposed load reduction include demand response?
4	Alternatives to the RFP Process: Can SCE develop feeder-specific tariffs, distribution credits, or other RFP substitutes to simplify the DG solicitation process?
5	Additional DG Values: Will SCE consider DG values distinct from distribution deferral, such as generation savings from curtailment or demand response?
6	Business Model: What longer-term business model(s) will advance DER as a significant contributor to the larger electricity enterprise?
Issue Group 2	
7	DG Deferral Value: Will SCE disclose the value it assigns to distribution deferral using DG, or an area-specific ceiling or floor price it will pay for DG?
8	Simplification of the Process: How can the solicitation process and/or SCE's Model DG Agreement be simplified to reduce all parties' transactions costs?
9	Availability of Distribution System Data: What distribution system data will SCE provide to help customers and developers prepare DG proposals that meet its needs?
10	Tailoring SCE Deferral Agreement to DG Project Realities: Can deferral periods be extended to provide greater value? Can SCE's Model Agreement be improved to encourage proposals?
11	Facilitating Interaction between SCE Customers and DG Developers: How will SCE customers be notified & developers made aware of the RFP? Will SCE facilitate contacts among interested customers and DG developers through workshops, mailings, website information, or otherwise?
Other Issues (not addressed)	
	Schedule more construction time for projects.
	RFP evaluation criteria for project selection.

- *Self-Generation Incentive Program (SGIP[26]) eligibility* – Utility customers who have installed DG as a distribution upgrade or replacement deferral and are receiving payments for that service are ineligible for SGIP incentives. Since those incentives typically will exceed any distribution deferral payment the utility can offer under the CPUC's 2003 formula, a customer who has received or may be eligible for SGIP incentives is unlikely to participate in a DG- based distribution deferral program[27].

- The stakeholders raised other possibilities to help integrate DG, to be explored further by the Issue Groups. These included:
  - a more central role for utilities in integrating DG, including DG ownership
  - utility help in matching qualified developers with eligible customers
  - combining demand response with DG resources for distribution deferral

- The highest priority issues identified by workshop participants were categorized and assigned to two Issue Groups. The first group would focus on business models and regulatory issues, and the second on structuring the RFP process and documentation.

[26] www.cpuc.ca.gov/static/energy/electric/051005_sgip.htm

[27] See SGIP Handbook, April 23, 2005-Rev.1, pp. 2-4, 3-25. As of 2005, customers with systems up to 5 MW per site may be eligible for SGIP incentives, although the incentive payment is capped at 1 MW. Customers with larger systems would not face the same disincentive to participate in distribution deferral programs.

CHAPTER 5
COLLABORATING TO RECOMMEND SOLUTIONS

Between the July 2004 and October 2004 workshops, each Issue Group held a series of conference call meetings facilitated by the project team. Collaborative participants researched the issues raised in the first workshop, discussed alternative approaches, and tested them with other colleagues not directly involved in this collaborative process. They then brought these issues, vetted within their organizations, back to the Groups and discussed potential solutions with other conference call participants. All workshop attendees were notified of these calls and invited to participate, but in practice most of the specific issue work was done by interested and committed members of the respective Issue Groups. The Groups' resolution of issues and/or recommendations to SCE or others in a position to act are highlighted below.

Issue 1: Eligibility for Incentives.

Question: Are proposers entitled to deferral incentives under this solicitation also eligible for SGIP incentives?

The answer was no, because existing SGIP rules have been interpreted to disqualify customers who have received SGIP incentives from also receiving contract payments for distribution upgrades or replacement deferrals. Most Issue Group 1 members felt that the SGIP rules were arbitrary and not based on a true value analysis. They articulated that view in a document forwarded to the staff of the California Energy Commission for their consideration.

Issue Group 1 suggested restructuring the SGIP program to target incentives toward areas of the State where the distribution and/or transmission systems are stressed. It argued that targeting DG projects to these areas would yield California ratepayers a better return on the public's investment. This approach would provide different incentive levels throughout particular regions of the State, based on the value that a peak load reduction would bring to each of the generation, transmission and distribution systems involved. To the extent that individual self-generation projects could provide value to an area of the distribution grid over and above the region-wide average, SGIP customers should be eligible to receive additional payments for those services (such as contracted load response via DG or other strategies) that provide actual value to distribution utilities, as long as the incentives do not result in 'double-dipping' for the same benefit. The proposal was offered for consideration to a group responsible for evaluating SGIP program changes. The Group recognized that other active proceedings at the CPUC and CEC (DER Rulemaking, Avoided Cost Rulemaking, etc.) could also materially impact utility RFPs soliciting DER.

Issue 2: Physical Assurance Requirement.

Question: Is 'physical assurance' required every hour of the year, or only during periods when SCE expects to call on the contracted DG resource?

Questions had been raised at the workshop concerning SCE's leeway to interpret the CPUC's Order requiring 'physical assurance' as a prerequisite for utility deferral payments. Issue Group members determined that the CPUC's decision gave SCE and other utilities the flexibility to define the meaning of physical assurance within the context of the customer contract that guaranteed demand reduction when required by the utility. Given this conclusion, the development of proposed contract language was transferred to Issue Group 2.

Issue 3: Eligible Resources.

Question: Where customer facilities have both DG and demand-side resources, can their proposed load reduction include demand response?

The history of the CPUC proceedings that directed utilities to incorporate DG in their planning and procurement, and some of the Commission's language, initially led SCE to conceptualize its distribution deferral efforts as a program limited strictly to the use of capacity provided by DG. Issue Group discussions revealed that the economics of these projects could often be improved by recognizing other sources of demand reduction at customer facilities along with the DG installation. The discussions also revealed that SCE's purposes could be better served if customers reduced their onsite demand at critical times, whether they did that with onsite generation alone, or by combining DG with other demand response measures. In compliance with the CPUC's Order, SCE did need assurance that customers, who agreed to reduce their demand on the distribution grid when called on by the utility, would in fact do so. In exchange, they would be paid for this firm reduction based on the value of deferring SCE's investment. That said, Issue Group participants recognized that the CPUC's intent was to encourage DG deployment. The Group therefore agreed that SCE's program could and should recognize some amount of demand reduction offered by customers, as long as they installed DG sufficient to cover their facility's critical loads (as defined by the customer).

Issue 4: Alternatives to the RFP Process.

Question: Can SCE develop feeder-specific tariffs, distribution credits, or other RFP substitutes to simplify the DG solicitation process?

Issue Group members investigated the possibility of proposing a standard tariff or distribution credit that would be available to any customer who would agree to SCE's terms and conditions for demand reduction, physical assurance, minimum generation, etc. The Group found that the CPUC's 2003 decision had considered arguments for DG tariffs or localized incentives, and chose not to embrace those approaches outside of a broader investigation into their implications for other areas of ratemaking. Since then, the CPUC has initiated comprehensive proceedings on DER costs, benefits and other issues that could reach this issue of targeted distribution

incentives. The Group concluded that any attempt to redirect CPUC efforts toward allowing a pilot approach here would likely delay SCE's effort to procure DER alternatives for its 2006-07 construction projects. However, the Group fully agreed on the importance of streamlining DER procurement using these or similar concepts, and urged that future DER Partnership collaborative activities take this on.

Issue 5: Additional DG Values.

Question: Will SCE consider DG values distinct from distribution deferral, such as generation savings from curtailment or demand response?

With SCE's help, the Group determined that incentives under the utility's existing load curtailment and demand response programs were based on the value that demand reduction brought to the generation portion of customer rates, but they did not account for values conferred on the distribution component of rates. For example, lower electric rates due to reduced peak purchases resulting from curtailment programs, did not reflect the benefits of those reductions to the distribution system. Because SCE's current incentives reflect generation but not distribution savings, recognizing the latter would not amount to 'double-dipping'. The Issue Group concluded that customers participating in SCE's existing curtailment and demand response programs should also be permitted to participate in its DG solicitation, and should be paid for any distribution deferral benefits they provide.

Issue 6: Business Model.

Question: What longer-term business model(s) will advance DER as a significant contributor to the larger electricity enterprise?

Issue Group 1 members discussed various business models that could advance the deployment of DER/DG in California and other states. They agreed with views expressed by DG providers during the July workshop that it was time to reexamine the role that distribution utilities could and should play in deploying least-cost DER resources to enhance local grid reliability. A number of DG providers pointed out that distribution utilities remain the hub of the electricity enterprise; are well situated to identify customer DER opportunities and help deploy and service DER installations; and can advance DER integration through centralized purchasing and development activities. Enhancing the role of utilities as facilitators and integrators was identified as an important topic for further work by DER Partnership collaboratives.

Issue 7: DG Deferral Value.

Question: Will SCE disclose the value it assigns to distribution deferral using DG, or an area-specific ceiling or floor price it will pay for DG?

This was one of the more difficult issues addressed by Issue Group 2. SCE was concerned that giving out information about its avoided construction costs could involve the company in contentious proceedings at the CPUC, and could result in higher bids from customers than they

might otherwise offer. DG providers, on the other hand, did not want to waste time or incur the considerable expense of responding to an RFP if there was little value to deferring utility expansion projects. After much discussion, SCE agreed to include a "market reference price" in its RFP. This price will provide some indication of relative value for the projects being presented, but it will not necessarily reflect the utility's avoided cost and will not prevent SCE from accepting customer proposals above or below the reference price. Final prices (or, deferral payments) will be negotiated between successful proposers and SCE based on the overall project value to the utility (not to exceed the deferral value formula established in the CPUC's 2003 Order).

Issue 8: Simplification of the Process.

Question: How can the solicitation process and/or SCE's Model DG Agreement be simplified to reduce all parties' transactions costs?

Issue Group 2 worked through the sequence and details of the solicitation process, as well as the terms of the Model DG Agreement SCE had submitted to the CPUC in 2003 but now believed could be improved and made more appealing to DG customers. Based largely on input from the Collaborative and its own DER staff, SCE recast the agreement from one that imposed strict requirements to guarantee DG equipment performance, to one that focused on the customer's commitment not to exceed agreed load levels at critical times. The result was a simpler, more flexible and considerably less onerous Model Agreement[28], more sensitive to the business realities facing DG customers and developers, and more likely to encourage viable responses to SCE's DG solicitation.

Issue 9: Availability of Distribution System Data.

Question: What system data will SCE provide to help customers and developers prepare DG proposals that meet its needs?

The challenge here was to strike a reasonable balance between SCE concerns over system security and disclosure of sensitive business information on the one hand and, on the other, the needs of customers and other potential proposers for information adequate to assess the feasibility and cost of projects they might propose, and the value they could expect to receive for them.

Issue Group 2 reconciled these interests by recommending a two-step process, which would first identify qualified respondents and require them to sign binding non-disclosure agreements, and then provide detailed system information only to those respondents. This information would include:

- Specific locations where projects could potentially defer SCE investment, by street map, ZIP code, or other concrete description.

---

[28] www.epri.com/der-ppp/docs/SCEDLAgt107.pdf

- The amount of load reduction or DG capacity needed for deferral in each area, including incremental amounts for different years when SCE's forecasts permit.
- The times when SCE expects to need load reduction/DG capacity for each area, including the number of hours per month, which hours of the day, and the maximum number of hours per year during which proposers must commit to reduce load

Issue 10: Tailoring SCE Deferral Agreement to DG Project Realities.

Question: Can deferral periods be extended to provide greater value?

DG developers were interested in maximizing the value of deferral payments by extending contract terms over multiple years. SCE's planning experience has been that distribution upgrades and expansion projects can be accurately projected at most two to three years in advance of the need. Contract terms for DG deferral projects in SCE's territory are unlikely to exceed three years, and most will be based on two-year planning cycles. During Issue Group discussions, DG providers proposed that SCE offer a limited option to renew these contracts, including a right of first refusal for existing projects. SCE accepted this proposal and proposed option language in the Model Agreement.

Issue 11: Facilitating Interaction between SCE Customers and DG Developers.

Question: How will SCE customers be notified & developers made aware of the RFP? Will SCE facilitate contacts among interested customers and DG developers through workshops, mailings, website information, or otherwise?

Developers and equipment vendors desire as much support as possible from SCE to connect them with SCE customers interested in hosting projects. SCE agreed to facilitate interactions by:

- Encouraging candidate customers in targeted deferral areas to participate in its RFP processes;
- Sharing with prospective proposers contact information for customers who respond to the first "informational" phase of an RFP process and agree to be contacted; and
- Holding customer-vendor 'fairs' in or near the targeted deferral areas.

CHAPTER 6
RECONVENING STAKEHOLDERS TO INTEGRATE THE WORK – WORKSHOP NO. 2

On October 7, 2004, the DER Partnership and SCE hosted a second workshop at SCE's CTAC facility in Irwindale, California. Its purposes were to:

- Report on the working group's recommendations for a successful RFP, based on its July workshop and the work of its two Issue Groups over the summer.
- Report on SCE's perspectives and current plans for an RFP.
- Move toward consensus on any outstanding issues identified by the working group.
- Hear stakeholder perspectives on the value and results of the collaborative process.

Most of the Collaborative participants returned for this workshop, and some who could not join the July workshop were able to attend Workshop No. 2[29].

SCE opened the workshop by reiterating the importance of this project to begin integrating new thinking and technology into its vision of the utility of the future. Russ Neal, SCE's Manager of Distribution Engineering, stressed that much remains to be learned about the technical design of tomorrow's grid, but the most difficult questions will concern the business model needed to achieve future grid objectives, including who will own the equipment and access the benefits and how costs will be recovered. Russ observed that if these issues are not addressed, utilities will simply replace today's grid with more of the same technology, design, and thinking that date back 50 to 100 years.

SCE announced that it has embarked on planning for a "Circuit of the Future" project in its service territory, near San Bernardino. The project will rebuild an existing circuit to incorporate new technologies that will allow SCE to understand and control the utility-owned equipment that delivers power along that circuit. It will also incorporate and use customer-owned DG. SCE invited DG developers present at the meeting to work with the utility to test concepts for using customer-owned capacity to defer SCE investment in expanding its own capacity in the area. The utility is also prepared to test hardware (such as control switches) that will be needed to 'physically assure' contracted load reduction as discussed in the Collaborative.

SCE also announced that it would be submitting the new Model Agreement worked out during the Collaborative for CPUC approval, since the Collaborative's input had resulted in major modifications to the model agreement the utility had filed in 2003. This submittal, as well as

[29] Appendix D contains the attendance list for the October Workshop. Appendix E reproduces the summary report of the Workshop.

recent changes in SCE's distribution planning cycle, would delay issuing the DG RFP until Spring 2005. The first expansion projects that might be deferred by the program will be those planned for construction in 2006-2007.

Presentations at the October workshop reported that over the summer and in the days preceding this meeting, the two Issue Groups had resolved virtually all of the important near-term issues identified as high priorities at the July workshop[30]. (A resume of the issues is given in Section 5 above.) Stakeholders at the October 7 meeting worked through a number of additional details regarding customer notification, facilitation of contacts between customers and developers, disclosure of SCE's market reference price, and the exemption of planned customer maintenance periods from "physical assurance" requirements.

Evaluating the Process – What Worked Well and What Can Be Improved

Participants in the October 7 workshop were asked to evaluate their experiences with the DER Partnership collaborative process during this DER pilot project. They were asked to comment on the successes of the stakeholder collaboration approach, the limitations or frustrations they experienced, and their suggestions for improving the process or achieving the goal of integrating significant amounts of DER into the electricity enterprise. Their responses are highlighted below.

What Worked Well

- The Collaborative was a very high quality group that included the right mix of DG manufacturers, project developers, public representatives, and utility representatives.
- The organization of the workshops and the follow-up approach of focused Issue Group conference calls with specific agendas worked well to accomplish the Collaborative's objectives.
- Developers came away from the process with a much better understanding of how utilities plan and operate their distribution systems. They gained perspectives on utility operations that they had not heard before.
- The collaborative effort accomplished a lot. Although its ultimate success cannot be judged until an RFP is issued and customers are enrolled in the program, developers were hopeful that the process will lead to DG opportunities for their companies.
- Stakeholders felt that SCE was open to input and very supportive of the process. Many had previously interacted with SCE only in adversarial CPUC or CEC proceedings and were pleased with the more constructive approach of this forum.
- SCE participants learned much that they had not known about what issues were important to DG providers and prospective DG customers. They realized that traditional utility approaches and methods of operations will need to be made more flexible if the program is to reach its potential.

[30] Workshop presentations are available at www.epri.com/der-ppp/California_DER_Pilot_Project.html.

- All participants felt that the collaborative quest for win-win solutions had led to a productive, collegial approach throughout the process. Getting stakeholders together to identify and work through issues helps everyone avoid some of the failures that have dogged similar attempts in other parts of the country.
- The SCE Model Agreement that resulted from the Collaborative's work is a much better document, with a much higher chance of success.

What Could Be Improved

- Some developers expressed disappointment that the pilot would engage only a small number of SCE customers (perhaps 20, with potential for 1 to 20 MW projects) and the value of short-term deferral payments (probably 5-20 percent of project cost) would be relatively low.
- Some stakeholders were frustrated by SCE's need to delay issuance of an RFP beyond the fall of 2004 to seek CPUC review of the new Model Agreement and to mesh it with the utility's new planning cycle.
- Developers and vendors would have preferred to see data from the actual projects that SCE might call on them to defer. Some felt that using sample data from 2003 projects made the effort more abstract than they would have liked.
- Stakeholders would like to see involvement from Pacific Gas & Electric as well as SCE.
- This process is useful as a short-term approach, but stakeholders need a sustained long-term commitment – at least five years – to build a successful business.
- Mainstreaming DER solutions will require a simpler process without legal entanglements and complicated customer requirements.
- More attention could have been given to SCE's process for identifying target areas and potentially deferrable upgrades, which some thought could overlook certain high value projects.
- Too few customer representatives participated in the Collaborative; more customer perspectives would be helpful.

Identifying Next Steps

Participants in the October 7 workshop suggested a number of next steps to increase DER deployment on the grid. Stakeholder suggestions included the following:

- Educate other utilities on the value of DER and how they can benefit from its deployment. The DER Partnership should conduct workshops with utilities across the country.
- Adapt the learning and experience from this collaborative pilot to a simpler model that other jurisdictions can easily replicate.

- Design regulatory approaches that allow DER to compete on an equal footing with utility construction. Look for analogies where utilities were compensated for lost revenues from DSM programs in the 1970s and 80s.
- DG needs to identify a “killer application” to drive widespread market adoption.
- In today’s environment, encouraging customer-side DER is not in the interest of utility shareholders because it results in revenue loss and erodes utility earnings. Utilities will not embrace DER unless it offers financial returns at least equivalent to their other investments. Come up with a pilot model that makes utilities at least neutral to DER by ensuring that utility DER investments that benefit ratepayers can earn returns at least equivalent to other utility assets.
- Change regulatory rules so utilities can make money on sensible DG, no matter who owns it.
- Design a DER portfolio standard similar to renewables portfolio standards adopted by many states.
- Construct a business model that yields 10-12 percent returns and Wall Street money will be there.
- Proactively pursue integrating DG supply, demand management, and demand response into California’s *Integrated Energy Policy* Report (IEPR) planning process, and develop ways to implement the California *Energy Action Plan’s* loading order (efficiency, renewables, demand response, distributed generation, and so forth) Conduct a workshop on this as part of the IEPR process.

CHAPTER 7
SOUTHERN CALIFORNIA EDISON REPORT ON SOLICITATION DEVELOPMENT AND RESULTS

Introduction

CPUC Decision 03-02-068, dated February 27, 2003 directed SCE to evaluate distributed generation ("DG") as an alternative to upgrading or expanding its distribution system[31]. This section presents SCE's distribution planning process, DG's role in that process, and to document SCE's efforts in 2005 to find a situation where DG could provide an economically and operationally viable alternative to allow the deferral of a distribution project scheduled for initial operation in 2007.

Overview of SCE's Planning Process

SCE's primary goal is to provide safe and reliable service to its customers. SCE uses its DSP process to determine the need for future distribution system upgrades or additions that include substation transformers and circuit breakers, bus capacity, short circuit duty capability, reactive capacity requirements, and circuit load carrying capability. As part of this process, SCE analyzes historical load, abnormal weather, forecasts of expected load growth based on economic indicators and local government land planning studies, and detailed technical studies that include short circuit duty studies, load flow studies, reactive planning studies, stability studies, and substation transformer capacity studies.

SCE maintains a 10-year plan for expansion of its distribution system to meet load growth demands. The 10-year load forecast identifies potential long-lead-time projects such as the construction of new substations and/or subtransmission lines that would require right-of-way/easement acquisition and/or individual approval by the CPUC. The plan is updated annually considering equipment loading and reliability design criteria, with specific focus on planning for the following year's load requirements.

The annual DSP update forecasts load growth and compares such forecasts to the capacity of distribution substation transformers and distribution circuits. SCE accommodates the projected load growth by a combination of adding distribution substation transformers, adding distribution circuits, transferring heavily loaded sections of distribution circuits through "tie-points" and switches to circuits with capacity available (load rolling), and upgrading existing circuits. The output of this annual process is a set of distribution projects, which involve distribution

[31] Decision 03-02-068, p. 19.

substation transformer additions, circuit additions, and circuit upgrades. SCE's planning analysis considers both system reliability requirements and overall project costs.

CPUC Criteria for Considering DG as an Alternative to Distribution System Upgrades, and SCE's Methodology

The CPUC required utilities to "incorporate SDG&E's distributed generation procurement approach to evaluate alternatives to distribution system upgrades, stating that "SDG&E's distributed generation procurement approach should be adopted for all utilities because it allows the utility to retain control of its distribution system planning process, maintain reliability at reasonable cost, while providing flexibility to evaluate distributed generation alternatives to a wires solution[32]." The CPUC adopted the following four conditions that "distributed generation must meet to allow the utility to defer capacity additions and avoid future cost[33]." Each condition is followed by a summary of SCE's methodology and approach to screening its distribution upgrade projects for the potential to use DG and/or customer load controls.

Located in the Right Place

"The distributed generation must be located where the utility's planning studies identify substations and feeder circuits where capacity needs will not be met by existing facilities, given the forecasted load growth[34]."

For the areas where an upgrade or expansion project had been proposed for installation and initial operation during calendar year 2007, SCE developed and used a screening process to determine if:

- Enough existing DG was operated by customers, or
- Enough customer load was concentrated in a manageable number of customers who had a viable potential to use DG and participate in a demand limitation program.

SCE mapped its proposed distribution upgrade projects along with larger (>1,500 kW peak demand) customers connected to its distribution systems to visualize which customers had the potential to defer a project if the utility could control their loads. Smaller customers were not included in this screening process due to the relatively low capacity that any individual customer could contribute as compared to SCE's projected costs of program deployment and administration.

---

[32] Decision 03-02-068, Conclusion of Law No. 4.

[33] Decision 03-02-068, *mimeo*, p. 18.

[34] Decision 03-02-068, *mimeo*, p. 18

Installed and Operational

"*The unit must be installed and operational in time for the utility to avoid or delay expansion or modification*[35]."

Following this obvious requirement, SCE focused its 2005 evaluation on 2007 projects so that if it identified potential deferments, there would be enough time for customers to form operating agreements and install DG facilities and any load controls necessary to allow project deferral. Projects for 2006 were considered for further evaluation only if it appeared that enough DG had already been installed and was operating at customer locations served by the facilities to be upgraded. Projects for 2008 were not addressed because of the uncertainty of SCE forecasts for projects three or more years distant in its plans.

Provide Sufficient Capacity

"*Distributed generation must provide sufficient capacity to accommodate the utility's planning needs*[36]."

SCE's DSP process forecasts the amount of capacity needed to serve its customers in each distribution area annually. As with most forecasting, near term projections tend to be more accurate than long term predictions. In support of its 2005 screening process, SCE's distribution planners projected the minimum capacity needed to defer projects proposed for 2007.

SCE hoped to find individual customers located on the (projected to be) stressed portions of its distribution system who were operating DG facilities that could produce enough capacity coincident with the utility's peak loading periods and were willing to enter into a demand limitation agreement that would allow SCE to defer a planned upgrade for two or more years.

Not finding any individual customer meeting such criteria, SCE expanded its screening criteria to include situations where a few (<5) larger customers were located near the distribution upgrade project. Although SCE recognized that a deferment program based on this more liberal screening criterion would be more expensive and difficult to administer, SCE did not want to preclude any reasonable opportunities to produce ratepayer savings using DG. In spite of such liberalization, SCE's hopes were frustrated, as it found no set of customers who appeared capable of providing enough controllable capacity to defer a project.

---

[35] Decision 03-02-068, mimeo, p. 18

[36] Decision 03-02-068, mimeo, p. 18

Provide Physical Assurance

"[D]istributed generation must provide appropriate physical assurance to ensure a real load reduction on the facilities where expansion is deferred."[37]

SCE's plan to implement the Commission's "Physical Assurance" requirements will require the participating customer to place all or part its load under the utility's physical control for a specified number of hours each year, using automatic load control equipment to assure performance. This physical control of the customer's electrical loads (which may or may not be served by a DG facility) allows the utility to assure that the customer will not be connected to its distribution system when insufficient capacity would result from having deferred the planned upgrade. SCE's screening process considered this requirement, as well as the likelihood that customers with critical loads (such as hospitals, government services, and retail operations) would participate in a deferment program.

Summary of Findings for Deferring 2007 Projects

Using the methodology described in this document and following the parameters established by the CPUC, SCE could not identify <u>any</u> project where it appeared that satisfactory arrangements could be made with customers using (or possessing economically viable potential to use) DG facilities to defer a proposed distribution upgrade project and provide economic benefits to both the participating customer and SCE's ratepayers.

The primary reason for SCE's inability to find customers with the potential to use DG facilities and load controls as a viable option to defer a distribution upgrade project was its inability to identify enough controllable customer load concentrated in a manageable number of distribution customers with the potential to use DG and enter into demand limitation agreements with SCE.

SCE's distribution systems are typically designed and installed in a manner that provides enough operating flexibility to transfer and balance relatively small (2-4 MW) load increases among its facilities at little or no cost. Accordingly, when upgrade or expansion projects are proposed under SCE's distribution system planning (DSP) process, it is typical to require the new facilities to assume a significant load (>6 MW) during the first two years of operation. It is this 6MW+ of customer load that must be placed under utility control to gain the "physical assurance" required to allow a deferral payment. SCE planners did identify proposed upgrade projects that would require control of less than 6 MW of load to allow a deferral, but these projects were in remote or rural locations where "large" customer loads were proportionately smaller and still not adequate to support a deferral.

While SCE can identify locations where utility control of large customer loads could provide a "comforting level of insurance" to the engineers responsible for planning and operating its distribution facilities, it could not identify arrangements to actually <u>defer</u> the installation of new facilities and provide reasonable economic benefits to SCE's ratepayers.

---

[37] Decision 03-02-068, mimeo, p. 18

Evaluating DG as a Distribution Alternative

SCE continues to hope that its screening process will identify customers using DG and willing to submit to utility load controls such that the utility can meet distribution load growth requirements more economically than through traditional transformer and circuit additions. To determine where this is the case, during each annual DSP update process, SCE will screen distribution upgrade and expansion projects proposed for the following two years to determine if they are candidates for deferral. This screening will include the following attributes:

- Forecasted additional capacity (load growth) needed year by year.
- Amount of additional capacity provided by the planned distribution upgrade project.
- SCE's projected cost of the upgrade.
- ancillary reasons for performing the upgrade project, including required maintenance and replacement of obsolete equipment, developing system ties and reconfiguring to improve operating flexibility, required circuit relocations, and so forth.

Where the use of DG supported by customer load controls appears capable of providing a technically satisfactory alternative to a traditional distribution upgrade, SCE will determine if any customer or reasonable combination of customers has the potential to reduce enough capacity to defer the project. If the use of existing or potential DG facilities, combined with load control systems to provide physical assurance, appears to be feasible and practical, SCE will solicit interest in participation by the candidate customers and provide related information to other interested parties.

CHAPTER 8
ACHIEVEMENTS, LESSONS AND RECOMMENDATIONS FROM THE CALIFORNIA PILOT PROJECT

Framework-Recommended Initiatives Addressed in This Pilot

EPRI's 2003 Framework report described a process for designing effective DER initiatives, and it presented a wide range of collaborative options. The California pilot project focused on a limited subset of these activities. It was created specifically to help SCE structure a response to a CPUC Order that required utilities to evaluate DG as a distribution alternative and take steps to procure it where it appears viable. The scope of that order shaped the Collaborative's activities.

The CPUC's 2003 Order addressed 'DG' rather than the more inclusive category of "DER". It focused on the use of DG as an alternative to distribution capacity expansion, but not on other value streams that DG might offer for society or the utility system (for example, local energy security and control, use of sustainable community resources, generation capacity deferral, transmission congestion relief, wholesale price mitigation, and so forth.) The Order directed an RFP solicitation process, rather than one that involved tariff changes, localized incentives, or distribution credits. And it adopted a requirement for "physical assurance" and a specific formula for calculating the value of DG to the utility. These boundary conditions defined SCE's procurement challenge, and the Collaborative was designed to help SCE successfully meet it.

Table 8-1 summarizes the range of activities that DER Framework document recommended for a comprehensive approach to DER market integration. It shows which of them the SCE project addressed and which remain to be addressed by future collaborative efforts.

Collaborative Achievements

Within the CPUC-established boundaries, this pilot project demonstrated the ability of the stakeholder collaborative process to create innovative and robust solutions that address multiple stakeholder interests. The approach of stakeholders partnering to find win-win solutions yielded distinct advantages compared with the typically adversarial mode seen in formal CPUC proceedings and hearing rooms. Collaborative participants found that working together toward common and complementary ends built trust and understanding of each others' perspectives and helped develop solutions that recognized the interests of all stakeholders.

Table 8-1
Framework Initiatives Addressed by California Pilot Project

***DER Framework* Initiatives** (from *Framework* report, Chapters 3 and 4)	**SCE Pilot Activities** ● – addressed ◒ – partially addressed ○ – not addressed
Structuring the Collaborative Process	
– Choosing the participants	●
– Defining ground rules & structure	●
– Setting objectives and priorities	●
– Evaluating success	●
Analyzing Costs and Benefits (using DER Partnership Cost-Benefit Tool)	
– Tailoring tool to local conditions	◒
– Using tool to adjust regulatory incentives, reallocate costs and benefits	○
Basic Program Strategies	
– Leveraging DER values	
o For DER customers *(bill savings, renewable energy credits, energy sales, demand response programs, etc.)*	◒
o For utility shareholders & other ratepayers *(reduced wholesale purchase costs, avoided generation, transmission or distribution costs, ancillary services, etc.)*	◒
o For society generally *(reduced emissions, increased network reliability, etc.)*	○
– Introducing efficient incentives	
o For customers & DER providers *(bilateral contracts, load reduction tariffs, standby waivers, environmental adders, hourly pricing arrangements, etc.)*	◒
o For utilities to actively facilitate DER *(cost recovery, revenue loss treatment, rate-of-return adders, decoupling, etc.)*	○
– Eliminating barriers	
o Permitting and interconnection	○
o Market barriers (*access to wholesale markets, area- and time-specific pricing, offsite energy sales, etc.)*	○
o Transactional barriers *(lack of flexibility, need for simplified processes and model contract provisions, etc.)*	●
Rate Design & Regulatory Incentives	
– Volumetric vs. fixed charges & demand charges	○
– Short-run vs. long-run pricing	○
– Standby rate methodologies *(demand subscription, non-firm standby, etc.)*	○
– Two-part rate designs *(historical billings + marginal pricing for usage changes*)	○
– Recognizing additional DER benefits	
• Distribution deferral	●
• Other locational benefits	○
• Energy value	○
• "Generation multiplier" effects	○
• Ancillary services	○
• p\Potential emissions reductions	○
– Efficient market rules to recognize customer-provided benefits	○
– Rate decoupling through PBR	○
– Experimental pilot incentives	◒

Several key achievements attributable to the collaborative approach used here include:

- The requirement for "physical assurance" that a customer's load will be interrupted if its DG does not operate has been recognized as a more flexible standard than some had initially supposed. Instead of requiring load reduction or "demand limitation" at all times when the distributed generator is not operating – which can seriously burden customers otherwise willing to help the utility – SCE will limit the requirement to only what it expects to need (typically 200 to 400 hours per year and not more than 8 to 12 hours on any day) and will make allowances for scheduled customer maintenance outages.
- DG customers and third-party providers will be given important information they need to decide whether it's worth the considerable time and expense to respond to a utility DG solicitation. SCE's starting point was that no price or value would be included in its RFP, and proposals would be considered sealed bids, to take or leave. Based on the Collaborative's input, SCE will now include a "market reference price" to guide prospective proposers and will negotiate the final agreement with those selected.
- The Model Agreement to be offered to successful proposers was originally designed such that the utility would take virtually none of the risk. Collaborative discussions persuaded SCE to rewrite the Agreement to share more of the risks to elicit responsible proposals, and collaborative participants are satisfied that it meets many of the needs of prospective proposers.

Table 8-2 documents these and other achievements of the Collaborative.

Lessons for Moving Forward with DER Market Integration

These achievements represent significant movement toward a workable DER solicitation process and toward one form of model agreement that recognizes business realities that both utilities and DG providers face in negotiating deferral arrangements. Participants were pleased with the collaborative's process and progress toward these goals, and SCE reports that it will be able to make a much better offering when it finds deferral opportunities that meet CPUC criteria and its own needs. These accomplishments notwithstanding, in the year since the Collaborative completed its work, SCE has been unable to identify what it considers economically viable deferral opportunities for distribution upgrades needed in 2006-2007, and it has not issued a DG solicitation under the CPUC's 2003 Order as anticipated by all collaborative participants. This section describes important lessons to be learned from these experiences. Some of these lessons are about integrating DER into the electricity enterprise, and some are about using DER stakeholder collaboration as a means toward that end.

Table 8-2
Collaborative Achievements

Topic	Initial Status	Final Results
Model for successful DG solicitation	Initial response from CA IOUs to CPUC Order did not address all stakeholder needs or capabilities.	DER Partnership stakeholder-driven process has engaged participants in defining their needs, recognizing co-parties' needs, and seeking common ground.
Communication among stakeholders	Participants wary. Based on previous experiences skeptical that progress could be made.	Participants openly communicate, are willing to listen, share, and address problems jointly.
Utility distribution planning process	Non-utility participants knew little about utility planning.	Non-utility participants better understand utility service obligations, planning horizons and uncertainties, and investment process.
Value of DG to utility & providers	Most participants unfamiliar with timing & valuation issues affecting utility deferral, or driving DG investment.	Factors influencing DG value to utility are better defined; valuation methodology now explicit, and tools accessible; range of grid values explained; DG provider investment concerns explored.
Information needs	Utility uncertain what info DG providers need to prepare responsive proposals.	Specific types of information identified as critical to DG providers to allow rational participation, including physical location and deferral value in the form of a "market reference price".
Confidentiality issues	Utility cautious about sharing information regarding system upgrade costs, needs, or customers.	Two-step process proposed to qualify respondents and require non-disclosure agreements, to limit recipients of sensitive information.
DG procurement process	Exclusive focus on traditional RFP approach.	Considering alternatives to RFP approach for next solicitation, using credits, tariffs, etc.
Recognizing multiple DER values	Initial utility proposal did not address importance of multi-program participation to DG providers; would have foreclosed opportunities.	Considering ways for customers / providers to receive value from other programs for generation-related benefits (e.g., curtailment), in addition to distribution deferral value from this program.
Recognizing non-DG demand response	RFP limited to capacity supplied by DG-only.	If DG is available for critical loads, demand response resources may also be offered to meet utility needs.
Reliability requirement	Initial 'physical assurance' concept required customer to drop its load whenever DG is down – 24 x7, 8760 hours/year.	Customer commits only for utility's peaking needs, perhaps 200-400 hours/year, estimated in advance by month, hours of day, etc. with adequate provisions for maintenance of DG facilities.

Table 8-2 (Concluded)
Collaborative Achievements

Topic	Initial Status	Final Results
Matching DG providers & utility customers with potential host sites	Utility had not identified the need to assist.	Utility willing to invite customers to request to be contacted by qualified respondents.
Matching utility deferral needs with proposers' investment needs	Payments for one or two-year deferral considered inadequate to assist project financing.	Two-year agreement with right of first refusal or renewal option if deferral remains utility's least-cost or best-fit option may encourage customer participation.
Response time for DG solicitation	Driven exclusively by utility planning cycle.	Driven by combination of utility planning needs and developer time requirements to put projects together.
Regulatory oversight of process	Strict literal interpretation of CPUC directives to minimize utility regulatory risk.	Recognition that CPUC intent is better served by more flexible win-win approach supported by participants and regulatory staff
Cost to assure responsive load reduction	Host customer to absorb 100 percent.	Utility to finance its portion of notification and control system costs, and deduct from deferral payments.
Model contract between utility and successful proposers	Model agreement prepared solely by utility; presented serious business issues for DG providers.	Model agreement rewritten and much improved from both utility and DG provider viewpoints.
Overall project risk	To be borne almost entirely by DG customer / developer.	To be allocated between utility and DG customer / developer as necessary to elicit win-win responses.

Lessons for DER Integration

Successfully targeting DG for distribution cost savings requires tight integration with distribution planning. DG must be the right size, with the right operational characteristics, installed in the right place on the distribution system, at the right time. The project must be large enough to defer the distribution need but not so large as to overwhelm a feeder or circuit. Even when it meets all these conditions, the deferral value that DG provides will likely be available only for as long as the utility can postpone a needed upgrade, typically several years at best.

These factors circumscribe almost any DG project considered for distribution cost savings. In the end, additional institutional and regulatory factors further constrained the California pilot project and any procurement that would follow it. Generally, these included the CPUC's early focus on generation distinct from demand-side initiatives, and on distribution capacity as DG's only value stream; the minimum controllable capacity required by SCE and "physical assurance" required by the CPUC for deferral; the low distribution value in sampled areas of SCE's system with multiple MW of load reduction; and the unavailability of California's SGIP incentives to customers considering participation in any SCE distribution deferral program. More specific observations follow.

1. Comprehensive consideration of DER benefits

Challenge: Focusing only on "generation" and on "distribution capacity deferral" severely constrains DER opportunities because it ignores other value streams important to key stakeholders, especially local communities and the larger society.

The California collaborative was tasked with helping SCE implement the CPUC's 2003 directive to evaluate DG as an alternative to distribution upgrades and to model its procurement process on an RFP approach proposed in the rulemaking. Reflecting California's electricity restructuring at the time,[38] the rulemaking had focused quite narrowly on the distribution function of the State's newly de-integrated utilities and had limited its scope to distributed generation technologies (excluding end-use efficiency, demand response, and energy storage).

SCE and its collaborative partners sought to proceed within this regulatory framework, which is considerably more constrained than more recent DER analytical and policy initiatives. These recognize that reducing customer load at critical times and places benefits utilities and non-participating customers whether reductions are achieved through onsite generation or storage, demand response, or end-use efficiency; that combining these often yields the highest value; and that any utility incentives should target the goal – demand management or reduction from the utility's perspective – rather than any particular set of technologies used to achieve it.

Recent efforts also recognize that although customer-side energy solutions can provide value for the host customer in the form of reduced energy costs, enhanced reliability, power quality and/or environmental stewardship, *significant impacts on the larger electricity enterprise will not occur until other distributed value streams are recognized and captured* – not only for host customers, but for some combination of the utility, its other customers, and society at large.

Examples of these value streams include deferred or avoided capital investment not only in distribution capacity, but in transmission and generation; reduced prices for grid-supplied energy at constrained times and places; enhanced local security and reliability when the larger grid is down or severely congested; and for some distributed resources and technologies, the use and re-use of renewable and waste resources, with associated economic and environmental benefits. Some of these values (like generation and transmission displacement, or price mitigation) are integral to utility and regulatory thinking and amenable to quantification. Other values (like capturing local renewables or reusing waste resources) may benefit local communities or society but are rarely recognized in central utility planning or regulation, less readily quantifiable (or at least less commonly quantified), and largely ignored today in valuing DER.

Given today's technologies, economics and regulatory conditions, the approaches that most readily yield or capture recognized values over the medium and long term include:

- Energy efficiency measures.

---

[38] California's DG rulemakings actually began in 1998, and final briefs were submitted in August of 2000. The State's energy market crisis began that summer and crested in late 2000 and early 2001, shifting the CPUC's priorities and delaying its decision in the rulemaking until early 2003.

- Demand response where there are spikes in peak power costs.
- Combined heating and power (CHP), or heating, cooling, and power (CHCP).

Approaches that yield value streams less embedded in the utility enterprise – such as the use of local resources that otherwise present waste disposal problems, or renewable resources that minimize extraction and fuel costs and substitute for diminishing fossil fuels, or ensuring local power in case of major system outages – are less readily recognized today but may be at least as important from a long-term societal perspective.

To improve the likelihood of successful procurements, regulators should encourage all of these approaches, and utilities should broaden their planning horizons and tools to include them as part of an expanded vision of tomorrow's utility.

2. Integrated resource planning

Challenge: Longer-term, better-integrated resource planning is essential to integrating DER as part of a balanced portfolio of demand, supply, and delivery options.

A major challenge in the California pilot project was that utility planners could not comfortably forecast local distribution needs more than two, or at most three years out. For SCE as for other utilities, load growth driven by economic cycles and large new developments can be unpredictable, and forecasted needs can change quickly. Given the CPUC's focus on short-term distribution capacity deferrals for this procurement, it was difficult to consider longer-term benefits in valuing distributed resources for the utility system.

DER needs a longer-term planning and implementation horizon to succeed. Planning horizons of at least five to ten years (instead of two) can support DER financing and allow new customer resources to be built up gradually as marketing programs pick up momentum.

DER also needs a proactive approach to integrating small distributed and local resources into regional energy supply networks. For nearly a century, regional electricity systems in the United States have been highly centralized. To enhance and supplement these systems with distributed resources requires sophisticated planning and integration, with respect to both central station approaches and alternative distributed solutions. A prime goal is to use each type of resource optimally, in applications where it contributes the highest value relative to other solutions.

Pursuing this goal requires a total resource planning approach that includes three elements—saving, buying, and building resources, guided by least-cost/highest-value principles. Grid operators need incentives that encourage them to promote energy efficiency (save) and to share customer-side resources that can be managed or dispatched (buy), as well as traditional approaches that default to adding new central generation, transmission, or distribution facilities (build). Ownership and control of some grid-connected DER by system operators and distribution utilities should be considered as one option in a total resource planning approach.

In short, useful steps to integrate DER into larger energy supply networks include:

- Designing a total resource planning approach that builds DER into some desired mix of "save some, buy some, build some;"
- Identifying an appropriate mix of centralized energy sources, energy efficiency, demand response, distributed generation and CHP/CHCP (including renewables);
- Designing programs to coordinate and optimize the interactions of the distributed sub-components; and
- Integrating DER into distribution planning processes and geography by targeting distribution planning areas rather than circuits or substations, and considering DER as an enduring component of regional electric reliability over a longer planning horizon, not simply a replacement for project X or Y in the coming year or two.

3. Inclusion of third party experience

Challenge: Utilities should take advantage of third-party experience to identify DER opportunities once their expansion needs are known, as part of deciding whether to initiate a procurement.

Although stakeholders recognized the efficacy of SCE determining where grid reinforcements were needed, some stakeholders commented that the process SCE described for identifying target areas and potentially deferrable upgrades could overlook some high value projects and deserved more attention from the collaborative than it received. Others noted that more customer perspectives would have been helpful throughout the process. The message in both cases was that, for utilities traditionally focused on large centralized projects, DER is a very different business – and the earlier that diverse perspectives are brought to bear, the more likely it is that win-win solutions will emerge.

Because of its planning cycle, SCE was not able to identify potentially deferrable 2007 projects until many months after the collaborative ended, and its process for identifying DG/DER opportunities at that stage did not include developer or targeted customer input. SCE reports in Section 7 that in evaluating planned 2007 upgrades for DG potential, its planners generally focused on projects that would require at least 6 MW of customer load reduction to defer. When it appeared that no individual customer in these areas could reduce its load by that much, utility planners broadened their criteria to include up to five customers located near the planned upgrade, but still found no set of customers they thought could offer enough controllable capacity to defer a project.

EPRI's 2003 Framework report points out that in situations that may be somewhat analogous, one utility is now buying about 25 MW of load reduction capacity from a third-party aggregator that dispatches 400-2000 kW backup generators owned by 15 utility customers; a different utility has contracted to buy up to 50 MW of demand reduction from another aggregator installing about 1,500 automated demand control systems at multiple customer sites.

Of course, similar approaches may not be suitable for the specific upgrade situations that SCE planners reviewed. But the stage of deciding whether DER can offer solutions promising enough

to warrant a procurement is a place where utilities can productively enlist the different perspectives and experience of DER developers, aggregators, and customers to suggest innovative arrangements like the ones just referenced to tap the rich marketplace of ideas emerging in this field. This does not mean that third parties would usurp utility planning decisions about what the system needs: only that they may be able to offer insights about ways to meet those needs more efficiently, more economically, at lower risk to ratepayers or, in some cases, with less impact on the environment. If no such options emerge from third-party input at this stage, utilities of course remain free to proceed with conventional wires solutions.

4. Streamlining Procurement

Challenge: Streamlined procurement processes will help utilities integrate DER.

The RFP approach endorsed by the CPUC and pursued in this pilot probably is not the simplest or most efficient process for procuring DER benefits. Each new RFP cycle imposes sizeable transactions costs and inevitable delays on all participants, and the focus on short-term projects addressing narrowly defined needs further limits the appeal of this process. To unleash the potential of these resources, regulators and utilities should consider:

- soliciting and accepting distributed solutions targeted at entire utility planning areas, rather than at individual circuits or substations
- creating targeted, self-executing tariffs or distribution credits for planning areas where utilities will otherwise need to construct capacity additions or upgrade circuits, to confer value for customers who limit their demand when and where the utility signals its need
- structuring these mechanisms to meet the specific growth issues confronting each planning area (e.g., peak growth, baseload capacity, etc.), and making incentive tariffs or credits available for defined periods that align more closely with the long-term resource value than with the short-term deferral value of any single project.

5. Value-based economic incentives

Challenge: Value-based economic incentives for utilities to use least-cost/highest-value resources (including customer-side resources) to benefit all customers will promote efficient DER integration.

Utilities (particularly distribution companies) often see reduced revenue when customers adopt distributed generation or load management technologies. Most current regulatory schemes tie utility earnings directly to energy throughput and capital investment. These regimes discourage utilities from responding to increasing consumer demand with better asset utilization (and thus increased efficiency).

Solutions based on more efficient asset use typically pay customers to control their facility's demand at times of high system demand, or modify pricing structures to encourage this behavior. Utilities that adopt these sensible strategies for their delivery business often are rewarded with lower earnings for their shareholders. This must change to enable DER solutions to compete

impartially within the traditional electricity enterprise: the regulated business model needs to encourage utilities to support, integrate and adopt distributed solutions where they make sense for utility customers and society at large.

State-regulated investor-owned utilities must serve the public interest. To remain viable business entities, they must also serve the interests of their investors. Where public interests diverge from investor interests, or long-term objectives appear incompatible with short-term ones, progress requires recognizing these tensions and re-aligning stakeholder interests. In a noticeable shift from California's earlier, more adversarial forums on distributed generation, diverse stakeholders in this pilot project joined in urging *a more central role for utilities* in facilitating and coordinating DER development and in integrating it with conventional utility operations. They stressed that in order to engage utilities as DER advocates, facilitators, integrators, and adopters, stakeholders must find ways to:

- Remove disincentives for utilities to incorporate customer demand reduction initiatives as a resource to manage their systems;[39]
- Reward utilities financially for creating and managing a least-cost / highest-value approach to the overall delivery of energy, including both electricity and other useful energy forms;
- Work with state regulators, utilities, and others to develop and adopt new approaches to utility ratemaking that will advance these objectives.

Lessons for DER Stakeholder Collaboration

6. Usefulness of the facilitated stakeholder collaboration

Result: Facilitated stakeholder collaboration works well to bring together diverse interests, engage customers and regulators, and shape nuanced solutions.

Stakeholders involved in the California pilot strongly endorsed the collaborative model that the DER Partnership has used successfully for several years. They urged its continuation to:

- Bring together interested stakeholders and more actively engage customers, regulators, and their staffs.
- Pursue other elements of the DER Framework methodology that were tabled to focus on SCE's 2005 solicitation process.
- Facilitate informal working groups of experienced professionals representing key stakeholder views, working closely to design pilot programs that benefit from lessons learned here and pursue the ideas described below.

The California pilot has again affirmed the advantages of the collaborative model. As SCE and other utilities have acknowledged, large regional utilities embody decades of bureaucratic

[39] One of the clearest disincentives is tying utility investment returns primarily to utility-built and -owned facilities (although Collaborative participants generally supported this as one possible alternative).

adaptation and enormous inertia. This is especially true of regulated utilities, whose activities are continuously subject to review, analysis, and oversight through formal – and usually adversarial – regulatory proceedings. These are usually judicial or quasi-legislative forums governed by strict procedural rules and intended to yield formal outcomes that the parties can act on or challenge. They serve important and useful purposes – but they rarely encourage open, unguarded dialogue; clarify misunderstandings; acknowledge that improvements are possible; build consensus from conflict; or seek "win-win" solutions that benefit multiple stakeholders.

Stakeholders in this collaborative pilot project concluded that it had done all of those things and done them well. Virtually all who commented strongly favored this approach over formal regulatory proceedings, believing that it is far more likely to nurture constructive business models and generate innovative DER solutions. Future collaborations could be strengthened further if regulatory staff could be brought into the process at the initiation of the Collaborative so they could provide informal feedback on regulatory issues that must be addressed during the project.

7. Availability of detailed utility planning data

Challenge: Stakeholder collaboration will yield better results if utilities can provide actual data on planned expansion projects, instead of historical data that may not reflect current or projected needs.

The question of what kind of data utilities supply to help DER providers understand their distribution expansion needs is critical – both for purposes of collaborating to help shape DER procurements, and for the procurement itself. The more real the data is, the more helpful it will be to providers in deciding whether and what to propose.[40]

In this pilot, actual data for parts of the system that a procurement would target was not available because SCE had not yet identified circuits or substations that would need upgrades in 2006-07. Instead, SCE supplied historical data on distribution expansion projects expected to be representative of future upgrade needs. In hindsight, that data appears to have been less representative than SCE or other participants had expected.

During the first collaborative workshop, this historical (2003) data was used to illustrate the likely range of deferral values to SCE, DG providers and other participants. SCE planners culled this data from distribution projects that had already been built, so there were no longer opportunities in these areas. However, these real examples were used to illustrate the value DG would have had at actual locations on SCE's distribution system, to help the group understand the magnitude of potential benefits. The examples included transformer upgrades and replacements to serve new load or increase reliability, as well as circuits added to transfer and balance load without adding capacity. As shown in Table 8-3, deferral values calculated for those projects

---

[40] ~~But the more sensitive it may be to utilities concerned about system security, municipalization or other competitive issues.~~ However, the utilities may be concerned about releasing the data about system security, municipalization or other competitive issues. Also, in a collaborative process expected to be followed by an actual procurement, questions of fairness to others not participating in the collaborative also arise.

varied widely depending on the specific location and rate of load growth – but not on distribution project size or cost. In fact, among the examples, both the least and most valuable projects turned out to be new circuits to transfer or balance load without adding capacity.

However, SCE indicates that the actual areas SCE planners later chose to evaluate for DG potential were significantly different than the examples provided to the Collaborative. Projects deferrable using DG might or might not have surfaced using the same selection criteria used for the collaborative examples, but SCE reports that its planners applied additional screening criteria that may well have excluded projects like those previously identified as representative, and in any case resulted in a decision not to issue an RFP. These additional criteria are discussed below.

Table 8-3
2003 Example Data – DG Value

ID	Reason for Project	Cost ($)	Capacity Addition (MVA)	DG Capacity Needed For 2-Year Deferral (MVA)	Deferral Value (2-Year Contract) ($/MVA)
A	Upgrade/replace transformer to serve new commercial & residential load & replace existing transformer due to maintenance requirements	$1,040,000	10	0.580	$ 129,000
B	Add transformer to serve new commercial & residential load	$1,747,000	34	2.060	$ 61,000
C	Add transformer to provide capability for (N-1) loss of existing transformer banks	$1,695,000	28	2.940	$ 42,000
D	Add circuit to serve new residential & customer load	$ 600,000	0	1.960	$ 22,000
F	Add circuit to balance circuit loading & facilitate load transfer to adjacent substation	$ 840,000	0	0.210	$ 288,000

First, SCE planners limited their consideration to areas that required greater than 6 MW of DG to defer. This created the need to locate very large customers with the ability to provide, singly or in limited combination, at least 6 MW of physically assured load reduction in case the DG did not operate. The sample projects presented to the Collaborative showed that the larger the DG project, the lower its distribution capacity value per kW, so even if planners had identified large customers willing to meet physical assurance requirements, the economic value of any distribution capacity deferral would likely have been quite low.

Second, SCE reports that its planners concentrated on areas where new capacity would be added to the system and excluded areas where feeder switching alone could balance load. While switching load between feeders is typically a low-cost solution, SCE's sample projects had included areas where load switching projects offered high capacity deferral value.

8. Regulatory review

Challenge: Advance agreements about any regulatory review required will streamline stakeholder collaboration and increase the likelihood of timely results.

The CPUC's 2003 Order directed California utilities to file a DG procurement methodology and a model agreement that would serve as a starting point for negotiations with successful respondents, and SCE had done so nearly a year before this project began. With the collaborative's input, SCE re-examined both the methodology and the model agreement it had filed a year earlier and proposed substantial modifications that collaborative participants believed would make the process and the agreement more realistic, more flexible and more likely to elicit interest from DG providers.

SCE believed that it was important to notify the CPUC of its proposed changes before going ahead with any procurement, but this did not occur until about six months after the collaborative ended. This hiatus interrupted the momentum gained during the collaborative and could have discouraged participants from responding to any RFP had SCE identified potential deferral projects. To benefit most from the time and effort dedicated to future collaborations, participants and regulators should consider agreeing in advance about what the collaborative can do and how much flexibility it has to innovate without further regulatory reviews and associated delays. Such advance agreement could help frame realistic expectations about what the effort can accomplish, and on what schedule.

9. Regulatory Incentives

Challenge: Regulatory incentives for utilities to take collaborative DER projects to fruition could help utility innovators overcome institutional inertia to experiment with new offerings and gain concrete DER experience.

This pilot project occurred as a voluntary effort undertaken largely outside of California's formal regulatory process. Although the CPUC had earlier directed utilities to incorporate DG in their distribution planning and to develop processes and agreements for procuring it, the utilities were not required or motivated to undertake the pilot itself. Nor were they to be rewarded for successfully implementing DG projects supporting the grid as a result of this or any other pilot.

While stakeholders are still experimenting with ways to effectively integrate DER into larger electricity markets, rewarding utilities for successful experiments with real projects could help overcome the institutional inertia that can undermine the efforts of utility innovators to implement novel projects that require buy-in by other utility departments. Rewarding utilities through incentive rates of return or in other ways for deploying actual DER projects that contribute knowledge and experience for tomorrow's grid can help ensure that collaborative efforts like this one fulfill their potential.

Recommendations

Based on the findings of the pilot project and the recommendations of the *Framework*, the following recommendations are offered:

1. Develop a nationally based stakeholder collaborative to encourage win-win business and regulatory models that encourage utilities to use all forms of distributed energy resources and reward DER customers fairly.

This stakeholder collaborative would focus on the concept of win-win DER integration and provide a forum for building momentum and moving it into mainstream thinking. It would consist of government agencies, state regulatory commissions, the National Association of Regulatory Utility Commissioners, utilities, DER suppliers and developers, and customers.

Primary activities would include:

"Win-win" model development. The collaborative would explore models that reward the players, including utilities, for integrating distributed energy resources, including distributed generation, storage, energy efficiency, and load management. These models would provide options for states to select or build upon to fit with their particular needs. Concepts for discussion include:

- Recommend a regulatory mechanism to encourage utilities to adopt DER where appropriate.
- Design pilot tariffs to enable utilities that now earn returns on self-invested capital to earn equivalent "phantom" returns on DER investments that displace poles, transformers, or wires.
- Consider allowing utility returns on customer DER investments or credits paid to customers.
- Consider rate-of-return adders for utility DER investment that meets defined criteria for efficiency, environmental benefits, congestion relief, system support, or other characteristics
- Develop standardized methodologies to design customer incentives for DER targeted to stressed distribution points.

Workshops. Workshops to build interest and participation and to conduct brainstorming sessions will feed the model development. Best practices will be shared and documented. Workshops provide opportunities for outreach.

DER Value Assessment. The collaborative provides a forum to vet approaches for determining value and measuring success. The collaborative will:

- Develop standardized approaches for determining the value of utility distribution deferrals and ways that utilities can prioritize their construction projects.
- Design appropriate measurement criteria (asset utilization, reduced budget, and so forth) to judge the success of pilot programs and other DER deployment initiatives.

- For the national collaborative, the DER Partnership will:
- Convene the collaborative, consisting of a working group of stakeholders.
- Provide background and analysis for concept development and facilitate working sessions to innovate new or improved concepts.
- Hold workshops for broader audiences to build momentum, share experiences, and brainstorm new ideas.
- Provide DER value and measurement approaches for assessment by the collaborative.

2. Develop regionally based stakeholder collaboratives (linked to the national collaborative) to develop and implement regional approaches to innovative DER solutions.

Collaboratives representing states, or regions comprising multiple states, would develop win-win models for encouraging DER integration to meet regional needs. States with high interest, such as California, Massachusetts, and New York, or regions such as the Northeast, are likely initial focus areas. The regional collaborative would link to the national one to benefit from its work, supply input, and consider options.

In California and New York, regulatory agencies have directed the approach to procuring DG as a distribution alternative. In New York, the RFP approach has so far had little success. In California, utilities have somewhat more flexibility, but stakeholders agree that simpler, broader approaches should be considered.

The collaborative approach will build directly on shared stakeholder experience and enable innovative thinking ‘outside the regulatory box’ by parties with different perspectives working cooperatively toward an outcome that benefits each stakeholder.

EPRI recommendation is to:

- Convene a working group of stakeholders.
- Provide background and basis for concept development.
- Facilitate working sessions to innovate new and refined concepts.
- Support the working groups with analysis by the DER Partnership Project Team.
- Document the process and findings.
- Develop presentation materials for stakeholders outreach.
- Conduct outreach to share results and encourage states to apply the findings in their jurisdictions.

The regionally based collaboratives would consider concepts such as the following:

a. *Develop a viable business model for utilities and other stakeholders to benefit from a proactive utility role in facilitating, coordinating, integrating, and developing grid- and customer-side DER.*

   Develop innovative mechanisms to reward utilities for successfully managing and coordinating economically and environmentally appropriate approaches to supply and demand portfolio management. The portfolio incorporates DER technologies and applications regardless of ownership. DER includes renewables and other distributed generation technologies, demand management, and energy efficiency. Work to remove utility disincentives to encourage demand reduction to help manage their systems. Develop and adopt new ratemaking or incentive approaches to advance these objectives.

b. *Develop a tariff-based credit for DER located in targeted areas.*

   Determine how such a credit would be implemented, and how to encourage utilities to support or be indifferent to the approach. For example, utilities that now receive returns on self-invested capital might receive a "phantom" return on DER investments that replace poles, transformers, or wires.

c. *Design and implement a process to include distributed generation, renewables, combined heating/cooling and power, demand response, and energy efficiency in target area programs.*

   Use all-resource planning techniques to suggest appropriate portfolio mixes for various types of DER along with conventional system resources to capture, for example, the value of distributed installations to the distribution grid. Once an optimal portfolio is determined, adapt market rules so that the value of the identified DER solutions can be monetized by market participants.

d. *Design and implement an approach for targeting system benefit charges and other public incentives to locations with the highest grid value.*

   Work with interested utilities to assign a value to DER investments in selected areas of the utility service territory. For example, work with California to redesign its Self-Generation Incentive Program to offer higher incentive payments to projects located in targeted utility planning areas or other designated regions of the state, or with the Massachusetts Technology Collaborative to design DER incentives to target high value areas of the Massachusetts grid. Design approaches to target renewables meeting RPS requirements to locate at highvalue locations within the distribution grid.

e. *Develop mechanisms to incorporate DER/DG solutions into regional generation and transmission adequacy planning.*

   Use all-resource planning techniques to suggest appropriate portfolio mixes for various types of DER in combination with conventional system resources. Once an optimal portfolio is determined, adapt market rules so market participants can monetize the value

of the DER solutions identified. [Note: The CA IOUs have already been asked to address this through the Resource Adequacy Proceeding.]

3. Apply the stakeholder collaborative process to demonstration programs to test concepts in the field, quantify DER costs and benefits, and measure success of specific projects or programs.

Develop stakeholder collaboratives to work closely with states, utilities, and others demonstrating DER in the field. The intent for this work is not to lead or fund demonstration projects but to work with them. The goal will be to extend the experience from specific projects to a larger group of stakeholders who can guide and review the process of understanding and quantifying value. In this way, the lessons learned from specific demonstration projects can become part of the broader conversation about adopting new business and regulatory statewide or regionwide.

Stakeholders will provide input to the quantification of costs and benefits, since a benefit to one stakeholder may be a cost to another. Stakeholders will provide credibility to the process. Through involvement in the process, stakeholders will gain understanding of other stakeholders' perspectives and thus open the door for creating new approaches for successful win-win strategies that can be applied in these and subsequent projects.

EPRI recommends to:

- Convene a working group of stakeholders to field test concepts.
- Arrange to collaborate with DER projects in the field or in progress.
- Provide analysis and facilitate assessment and collaboration to determine value and measure success.
- Document and provide outreach materials and opportunities to build industry agreement.

Opportunities include:

a. Demonstrating the cost and benefits of win-win DER projects.

Southern California Edison will take a soft-start approach, tapping into customer-owned DER systems to test their capability to provide distribution services to defer system upgrades. Work with SCE and DER stakeholders to guide development of win-win demonstration projects and provide input on operations, customer agreements, and other project elements. Quantify costs and benefits and document lessons learned and recommendations for successful win-win DER projects.

Work with other state organizations that have funded CHP, renewables, and similar projects (such as NYSERDA's CHP projects in New York). EPRI will convene stakeholders and provide working tools and expertise to guide cost and benefit quantification and will document lessons learned and recommendations for DER projects benefiting multiple parties.

b. Demonstrating the value of DER in the Circuit of the Future.

Southern California Edison is proceeding with a program to demonstrate and test a distribution "Circuit of the Future", which will include both distribution and generation technologies. Work with SCE and other stakeholders to facilitate and structure demonstrations of technologies that provide distribution services. Quantify the value that DER provides on this Circuit of the Future.

c. Demonstrating the value of optimizing a supply and demand resource portfolio.

In conjunction with SCE's "Circuit of the Future" work, collaborate with SCE and other stakeholders to demonstrate how distributed generation and customer-side demand management and energy efficiency programs can be used to optimize an integrated supply and demand portfolio. Contribute expertise and guide collaboration on ways to motivate customers to adopt solutions that strengthen the portfolio. Demonstrate approaches to optimize supply and demand on local electricity systems. Quantify the value of the optimized portfolio, and provide lessons learned and recommendations for other jurisdictions.

APPENDIX A

CALIFORNIA DER PILOT PROGRAM – COLLABORATIVE PARTICIPANTS

Developers

Kevin Best	RealEnergy (Substitute: Robin Luke)
Tom Drolet	DTE Tech
Chach Curtis	Northern Power Systems
Jeff Lyons	US Power
Gordon Savage	Simmax Energy

Suppliers

Tod O'Connor	STM Power
George Wiltsee	Ingersoll-Rand
Eric Wong	Cummins *
Kevin Duggan	Capstone
Bob Bjorge	Solar Turbines

Customers/Customer Representatives

Justin Bradley	SVMG (Substitute: Jeff Byron) *
Gary Sparks	California Society for Healthcare Engineers
Howard Choy	LA County ISD (Substitute: Steve Crouch)

Utility

Stephanie Hamilton	SCE
Tom Dossey	SCE
Ishtiaq A Chisti	SCE
Dan Tunnicliff	SCE
Lynn Ferry	SCE

Advisers:

Valerie Beck	CPUC*
Mark Rawson	California Energy Commission
Nag Patibandla	NYSERDA*
Valerie Harris	CPS San Antonio*
Fran Cummings	Mass Tech Collaborative (Substitute: Gerry Bingham)
Tony Prietto	SDG&E
Sephir Hamilton	CHG&E*
Eileen Buzzelli	First Energy*
Pat Hoffman	DOE. (Designee: Joe Ianucci)
Jim Armstrong	NStar Electric & Gas Corp

* Not available to attend July 13–15, 2004

DER Partnership Pilot Project Team:

John Nimmons	John Nimmons & Associates, Inc.
James Torpey	Madison Energy Consultants
Snuller Price	Energy & Environmental Economics, Inc.
Dan Rastler	EPRI
Ellen Petrill	E2I

APPENDIX B

CALIFORNIA PROGRAM – JULY 14-15 WORKSHOP ATTENDEES

Name	Title	Affiliation
Armstrong, Jim	Program Manager	NStar Electric and Gas
Bingham, Gerry	Policy & Markets Coordinator, Renewable Energy & Climate Change Group	DOER, Mass. Div. of Energy Resources
Bjorge, Bob	Market Development Manager	Solar Turbines
Chisti, Ishtiaq	Manager, Project/Product II	SCE
Counihan, Rick	Vice President	E2I
Crouch, Steve	Manager	LA Co. Internal Services Dept.
Curtis, Chach	Vice President	Northern Power Systems
Dossey, Tom	Project Manager, DER	SCE
Drolet, Tom	VP International Business	DTE Tech
Duggan, Kevin	Manager	Capstone
Ferry, Lynn	Distribution Engineering	SCE
Gatto, Joe	Sales Manager	US Power
Iannucci, Joseph	President	DUA
Keefer, Dave	Mgr. Distributed Generation Development	SCE
Kelly, Jim	Vice President	SCE
Lines, Jeff	Manager	US Power
Luke, Robin Ms.	Director	Real Energy
Neal, Russ	Manager, Distribution Engineering	SCE
Nimmons, John	President	John Nimmons & Associates
O'Connor, Tod	Representative	STM Power
Petrill, Ellen	Program Director	E2I
Price, Snuller	Partner	Energy & environmental Economics
Prietto, Tony	Self-Generation Program Manager	Southern California Gas Co.
Rastler, Dan	Technical Leader, DER Program	EPRI
Rawson, Mark	PIER Program: Strategic	California Energy Commission
Savage, Gordon	Manager	Simmax Energy
Stonerock, Brian	Manager	SCE
Takayesu, Erik	Distribution Engineering Manager	SCE
Torpey, James	President	Madison Energy Consultants
Tunnicliff, Dan	Proj. Manager, Major Customer Div.	SCE
Wiltsee, George	Manager, Market Devmt, Western US	Ingersoll-Rand Energy Systems

APPENDIX C

CALIFORNIA DER PILOT PROGRAM – JULY 14-15 WORKSHOP SUMMARY REPORT

Introduction

The Electricity Innovation Institute (E2I) held a well-attended and lively workshop for distributed energy resources (DER) stakeholders to solicit their ideas on how to structure a successful utility DER procurement in California. This workshop kicked off the California pilot project of E2I's DER Public/Private Partnership Market Integration program. Through this project, E2I and its partners are exploring ways to identify and implement win-win approaches for DER—with the goal of DER applications that benefit multiple stakeholders and no harm to other stakeholders.

Purpose

The goal of the pilot project is to support Southern California Edison's (SCE) objective of producing a request for proposal (RFP) for DER that results in successful proposals and meets specific needs of the SCE distribution system. The workshop established a collaborative working group of stakeholders to provide feedback on the solicitation process so that customers, customer groups, developers, manufacturers, and others can confidently propose DG solutions responsive to utility needs in a DER pilot that could serve as a model for utility DER procurements.

Attendees

Thirty-one stakeholders participated in the workshop, representing DER developers and equipment manufacturers, electricity customers, researchers, electricity utilities, and federal and State energy agencies.

Major Outcomes

- SCE demonstrated commitment to develop an RFP that attracts bidders and results in successful bids. Vice President Jim Kelly urged stakeholders representing "'both sides of the table'…often with some fairly strongly held opinions about the likely intent of the potential counter-parties…to suspend those opinions…and let the facts speak for themselves." Kelly told the group that "SCE is committed to solutions that make sense for our customers- all of them." Strong support and participation from other key SCE personnel

included Russ Neal, Manager, Distribution Engineering, and senior engineers and project managers from Distribution Engineering and the Customer Business Unit.

- Other stakeholders were also committed to providing input to SCE to achieve a successful RFP. While several participants began as somewhat skeptical, in the end, each stakeholder committed to work on the issues the group brought forward and prioritized.
- The highest priority issues identified by workshop participants were categorized and assigned to two issue groups:
  - Business models and regulatory issues.
  - RFP process issues.

Each stakeholder committed to join one of the two groups to analyze and discuss specific issues assigned to each group and make recommendations to SCE for its consideration in developing the RFP.

- The stakeholders were concerned about some major issues that could make this RFP not particularly attractive to end-use customers. These will each be explored further by the issue groups.
  - Physical assurance—interpretation of the requirement to automatically interrupt a customer's normal load when its distributed generation does not perform as contracted.
  - The value of distribution upgrade deferral, defined as the utility's carrying cost of deferred capital investment for the period of deferral —the service for which the utility would offer payment to the DER owner. In most cases, this service appears to have limited financial value and is not likely to provide the sole impetus to make a customer site project viable.
  - Self-Generation Incentive Program eligibility—currently, customers who have entered into contracts with the utility to provide distribution-related distributed generation service are not eligible for the self-generation incentive.
- The stakeholders raised several other possibilities that might help integrate distributed generation. These will also be explored further by the issue groups.
  - Utility ownership of distributed generation.
  - SCE matching qualified developers with eligible customers.
  - Combining demand response with distributed generation resources for distribution deferral.

Workshop Approach

The 1½day workshop was hosted by the E2I DER Public/Private Partnership and was held at SCE's Customer Technology Application Center. E2I invited a working group of stakeholders that represent the types of organizations that might respond to the RFP. It also invited an advisory group of other stakeholders, including regulators, E2I Partners and their representatives

and other interested utilities. Several advisers attended and contributed significantly in the workshop and will continue to work as members of the issue groups.

The workshop began with a roundtable of what each participant hoped to get out of the workshop. The responses included a successful RFP, a user-friendly RFP, increased business opportunities, creative new ideas, learning about the process, and advancing the integration of DER.

The first day of the workshop included an overview of the E2I Partnership highlighting the win-win goals of the program, plus example calculations of the value of deferring distribution upgrades and the costs and benefits of distributed generation projects. Strategies for collaboration and examples of win-win opportunities were described. SCE described its distribution planning process and key elements of the proposed RFP. Stakeholders each had a chance to express issues, needs, concerns, and desires. Throughout the day, issues that arose in discussion were recorded. At the end of the day, additional issues were captured and all issues were prioritized by voting. After the session, the E2I team categorized the issues into two groups.

On the second day, the working group and advisers concurred in the team's categorization, and each participant elected to join one of the two issue groups. Each issue group held its first meeting, further discussed the issues, and determined next steps. Each group will work via e-mail and conference call to develop recommendations to SCE for improving the chances of success of the RFP. A workshop will be held mid-September to finalize the recommendations. The workshop ended with a closing roundtable, asking for last comments. Responses included appreciation for SCE's commitment and interest in making this process work and affirmation that the collaborative process had so far been very valuable in helping participants understand each others' perspectives.

The discussions and results of this pilot program will be shared publicly. This report plus workshop materials and attachments are posted on the EPRI website[41].

Issue Groups

Stakeholders at the workshop on the second day joined one of the following issue groups. Stakeholders who were not in attendance on the second day are invited to join a group of their choosing and participate in the groups' conference call discussions. Please contact Ellen Petrill with your choice and to receive information on the planned conference calls.

The following gives the prioritized issues of each group. Further details are available in attachments "Issue Group 1" and "Issue Group 2."

[41] www.epri.com/der-ppp/index.html.

1. **Business Models and Regulatory Issues**

Near-Term Issues Requiring Resolution Before SCE RFP Is Issued

a. Eligibility for incentives
b. Physical assurance
c. Eligible resources (for example, DG or demand response)
d. Feeder specific tariffs or distribution credits (fixed payments to participating customers) as alternatives to RFP
e. Additional DG values

Longer Term Issues for Future RFPs

a. Business model
b. Physical assurance (for example, alternative approaches to dropping load)
c. Eligible resources

2 **RFP Process Issues**

a. Availability of cost data and value of distribution upgrade
b. Simplification of the RFP process and proposed contract terms
c. Availability of distribution system data
d. Length of contract
e. Utility role in matching customers and developers

APPENDIX D

CALIFORNIA DER PILOT PROGRAM – OCTOBER 15 WORKSHOP ATTENDEES

Name	Title	Org
Armstrong, Jim	Program Manager	NStar Electric and Gas
Beck, Valerie	Distributed Generation, Energy Division	California Public Utilities Commission
Best, Kevin	Principal	Real Energy LC
Asgeirsson, Haukur	Supervising Engineer	DTE Energy
Bjorge, Bob	Market Development Manager	Solar Turbines
Chisti, Ishtiaq	Manager, Project/Product II	SCE
Dean, Amber	Attorney	SCE
Dossey, Tom	Project Manager, DER	SCE
Drolet, Tom	VP International Business	DTE Tech
Duggan, Kevin	Manager	Capstone
Green, Gary	Dir., Technical Support, Major Customer Div.	SCE
Iannucci, Joseph	President	DUA
Luke, Robin Ms.	Director	Real Energy
Mascarenhas, Sheridan	Distribution Engineer	SCE
Montoya, Mike	Senior Attorney	SCE
Neal, Russ	Manager, Distribution Engineering	SCE
Nimmons, John	President	John Nimmons & Associates
O'Connor, Tod	Representative	Solar Turbines
Petrill, Ellen	Program Director	E2I
Price, Snuller	Partner	E3
Prietto, Tony	Self-Generation Program Manager	Southern California Gas Company
Rastler, Dan	Technical Leader, DER Program	EPRI
Rawson, Mark	PIER Program: Strategic	California Energy Commission
Seguin, Rich	Distribution Engineer	DTE Energy
Takayesu, Erik	Distribution Engineering Manager	SCE
Torpey, James	President	Madison Energy Consultants
Wiltsee, George	Manager, Market Devmt, Western US	Ingersoll-Rand Energy Systems
Wong, Eric	Manager, Bus. Devmt & Gov. Relations	Cummins Power Generation

APPENDIX E

CALIFORNIA DER PILOT PROGRAM – OCTOBER 15 WORKSHOP SUMMARY REPORT

The E2I DER Public/Private Partnership held its second stakeholder workshop at Southern California Edison's CTAC facility on Thursday, October 7, 2004. This report summarizes the workshop discussions, results, and actions.

Twenty-four stakeholders participated in person and three on the phone. The group made unprecedented progress before and at the workshop toward developing a successful utility request for proposals for customers to supply distribution services using distributed generation (DG) at their sites. Success is defined as proposals being submitted and accepted and DG projects being implemented to defer distribution upgrades.

The purpose of the workshop was to:

- Report the working group's recommendations for a successful RFP, based on its July workshop and the work of its two issue groups over the summer.
- Report SCE's perspectives and current plans for the RFP.
- Move toward consensus on how to approach key issues identified by the working group that remained outstanding.
- Record stakeholder perspectives of the value and success of this stakeholder process.

In opening remarks, Russ Neal, manager of SCE's distribution engineering, invited stakeholders to continue collaborating toward what is right, and to rise above the "us versus them" approach all too common in similar discussions. He acknowledged that because utilities bring enormous inertia and investment approaches that have worked in the past, it is difficult for new approaches to succeed – but that with work like this stakeholder collaboration, and the commitment to do the right thing, we can move toward a new future. Russ asked the group to imagine the future grid and how we would design it starting from a clean slate. Distributed generation (DG) has technology characteristics that could provide value to the grid and may be easier to site than central power stations and transmission and sub-transmission systems. DG could bring higher reliability and security to the grid. Because DG can be modulated, DG may supply VAR support better than capacitors and may enable intentional islanding that could be an advantage in major grid collapse scenarios. A portfolio including demand response and DG may offer the lowest cost and best safety options.

Russ stressed that while much remains to be learned about the technical design of the future grid, more difficult questions involve the business model necessary to encourage and achieve future grid objectives. Who will own the equipment and access the benefits? How will the costs be covered? These and other business questions are even harder to resolve than the technical problems.

Russ observed that "if we don't plan, we'll just replace today's circuit in kind," with technology and design that is 50 or 100 years old. To avoid that scenario, SCE is planning a new circuit to be built and operating in 2006 to utilize advanced technology available today and to serve as a platform to demonstrate new uses and new technologies. He invited stakeholders to offer ideas for the circuit, such as power quality islands, as well as ideas and technologies "as ornaments to hang on this Christmas tree."

Stakeholder Working Group Report

Stakeholders participated in two issue groups since the first workshop in July to work through the issues they identified as high priority. SCE staff worked closely as part of each issue group to help reach consensus. Utility solicitations have sometimes neglected to address stakeholders' perspectives because they have not been sought or articulated. The issue group discussions proved an effective way to do this and to move the issues forward.

The two groups focused on the following issues. At this workshop, presenters identified each issue; reported on its resolution, if any, by the responsible issue group; and identified questions remaining to be addressed in the workshop (presentation number 2).

	Issue Group 1
1	**Eligibility for Incentives:** Are proposers entitled to deferral incentives under this solicitation also eligible for Self-Generation program incentives?
2	**Physical Assurance Requirement:** Is 'physical assurance' required every hour of the year, or only during periods when SCE expects to call on the DG resource?
3	**Eligible Resources:** Where customer facilities have both DG and demand-side resources, can their proposed load reduction include demand response?
4	**Alternatives to the RFP Process:** Can SCE develop feeder-specific tariffs, distribution credits, or other RFP substitutes to simplify the DG solicitation process?
5	**Additional DG Values:** Will SCE consider DG values distinct from distribution deferral, such as generation savings from curtailment or demand response?
6	**Business Model:** What longer-term business model(s) will advance DER as a significant contributor to the larger electricity enterprise?
	Issue Group 2
7	**DG Deferral Value:** Will SCE disclose the value it assigns to distribution deferral using DG, or an area-specific ceiling or floor price it will pay for DG?
8	**Simplification of the Process:** How can the solicitation process and/or SCE's model DG agreement be simplified to reduce all parties' transactions costs?
9	**Availability of Distribution System Data:** What distribution system data will SCE provide to help customers and developers prepare DG proposals that meet its needs?
10	**Tailoring SCE Deferral Agreement to DG Project Realities:** Can deferral periods be extended to provide greater value? Can SCE's Model Agreement be improved to encourage proposals?
11	**Facilitating Interaction between SCE Customers and DG Developers:** How will SCE customers be notified and developers made aware of the RFP? Will SCE facilitate contacts among interested customers and DG developers through workshops, mailings, website information, or otherwise?

Issues not fully resolved by the issue groups over the summer are listed below. Most were resolved to the stakeholders' satisfaction just before or during the workshop. Results are discussed later in this report.

#1. Eligibility for incentives.

#2. Physical assurance – how often and how much of the customer's load.

#7. DG deferral value – supplying a price signal in the RFP so customers and developers could determine whether it was worth the effort to propose.

#8. Simplification of the RFP process and model agreement.

#11. Facilitating interaction between SCE customers and DG developers.

SCE's Plan for Integrating Customer-Operated DG into Distribution Planning

This section highlights key components of SCE's plan. Presentation number 3 provides the full information presented by SCE.

A. SCE's approach addresses high priority issues with remaining questions as follows:

2. "Physical assurance" will rely on demand limitation.

"Physical assurance" required by the CPUC's 2003 order will be achieved not by requiring a customer's DG to operate at critical hours, but by requiring those customers to drop load from the grid if their DG *doesn't* operate during those hours – in other words, by customers willing to limit demand under agreed conditions, or face automatic disconnection of designated load if they fail to do so. The agreement between customer and utility will be based on a firm service level (lower than full load) selected by the customer that will not be exceeded at those peak times when the utility cannot serve the customer's full load due to deferring an upgrade or expansion. If the customer's DG is operating, then it can continue to meet its full load above the firm service level supplied by the utility. The demand limitation periods, when the firm service level caps grid-supplied electricity, will be limited to about 200 to 400 hours per year and 8 to 12 hours on any single day, as agreed between the customer and the utility.

7. DG deferral value (supplying a price signal in the RFP so customers and developers can determine whether it's worth proposing).

SCE considered this working group request long and hard. SCE ultimately agreed to provide a "market reference price" to guide proposers. This reference price will likely be lower than the utility's carrying cost of capital for the deferment. The actual price (deferral payment) paid to customers willing to limit demand may be higher or lower than the market reference price, depending on the proposals submitted and selected.

8. Simplification of the RFP process and model agreement

To comply with the CPUC's 2003 Order, SCE and other California utilities had submitted "Model Agreements" as a starting point for negotiations to acquire DG following a solicitation process. Reconsideration of that process through the collaborative, and working group comments on SCE's original Model Agreement, caused SCE to substantially rewrite its proposed Agreement. Its new form of Agreement is essentially a different agreement than the original, embodying the "demand limitation" approach described above rather than focusing on physically assuring the performance of customer DG units. Risks are spread more reasonably between customer and utility than was the case with the original agreement.

SCE plans to seek CPUC approval for its new form of Model Agreement. Final terms governing individual transactions between customers and the utility will be based on negotiations, starting with the form of Agreement developed in this stakeholder process.

This is another key point of the process: this will not be a sealed bid process with a "take it or leave it" result. Since any final agreement will be between SCE and its customer, SCE wants its customer to be satisfied with the process and the end result, and recognizes that negotiations may lead to substantive changes in individual final Agreements compared with the Model Agreement developed here. For example, if SCE needs more capacity to defer the distribution upgrade, proposing customers may be asked if they are willing to increase the demand limitation offered in return for a higher price.

The collaborative discussed the RFP process in detail. It sketched out a simplified, two-step process in which customers and developers indicate interest in further information, sign a non-disclosure agreement, then after some screening for vendors, receive the full request for proposal package with detailed information including location, market reference price, and size of proposed deferment. SCE agreed to refine this process and share its conclusions with the working group for comment before finalizing.

9. Customer-vendor (developer, manufacturer, or consultant) interaction

Developers and equipment vendors desire as much support as possible from SCE to connect them with SCE customers interested in hosting projects. SCE agreed to facilitate interactions as follows:

- It will encourage customers located in areas targeted for deferral to participate in the RFP process.
- It will share with prospective proposers contact information for customers who respond to the first phase of the RFP process and agree to be contacted.
- It will hold customer-vendor "fairs" in or near the areas targeted for deferral.

B. RFP Timing

- SCE will delay issuing its first RFP from the expected fall 2004 release to spring 2005, due to changes in its distribution planning process and its desire to secure CPUC approval for changes in the Model Agreement that have resulted from this stakeholder process.
- Delaying the RFP will preclude its use for 2005-2006 projects, so SCE proposes "soft start" activities to occur in parallel with its formal solicitation during those years. SCE will contact customers with existing DG in regions where demand limitation has value and will pilot agreements and installations to test concepts, develop procedures, and gain experience. This may be an opportunity for continued stakeholder involvement to collaborate on innovative solutions.
- SCE's "Circuit of the Future" activities may also offer opportunities for stakeholder involvement.

The Unresolved Issue: Self-Generation Incentive Program (SGIP) Eligibility

The SGIP program rules state that SGIP recipients may not be recipients of incentive payments for distribution deferral. The E2I working group suggests a waiver of that exclusion for this pilot project. An issue paper was prepared about this issue and delivered to Mark Rawson, the California Energy Commission's point person for DER policy. Mark agreed to work the issue within the Energy Commission and possibly the California Public Utilities Commission, and to keep the working group apprised through Ellen Petrill.

What Worked, What Didn't, What's Missing

The roundtable to address these questions resulted in the following general comments.

What Worked:

- SCE – willingness to listen and cooperate, hard work and energy of the team, especially Tom Dossey and Stephanie Hamilton.
- SCE's vision—Russ Neal.
- E2I project team's expertise, organization, effort, energy, conference calls.
- Stakeholder team--talented, energetic, willing to work.
- Opportunity to collaborate to work through issues, better to talk than to shout as adversaries.

What Didn't Work:

- The size of the opportunity – small numbers of MW and customers to be part of the RFP.
- "Voting with dots" – may miss some key issues by narrowing the discussion.

What's Missing:

- Final result is missing – we can't call this a success until we get iron in the ground.
- Customers are largely missing from the discussions – more representation would help.
- Concrete information about projects (for example., which circuits, size of deferrals needed, etc.).
- Developing DG to serve distribution system needs, not just customer needs.

Actions:

1. Mark Rawson to work the SGIP eligibility issue within the California Energy Commission and possibly the California Public Utilities Commission, and keep the E2I working group apprised through Ellen Petrill.
2. Ellen Petrill to send working group the three issue papers prepared to address major issues identified by this group.
3. Tom Dossey to refine the RFP process and share with the working group for final input.
4. Working group to review Model Agreement and send comments to Ellen Petrill and Tom Dossey by October 15 (two have done this).

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute (EPRI)

The Electric Power Research Institute (EPRI), with major locations in Palo Alto, California, and Charlotte, North Carolina, was established in 1973 as an independent, nonprofit center for public interest energy and environmental research. EPRI brings together members, participants, the Institute's scientists and engineers, and other leading experts to work collaboratively on solutions to the challenges of electric power. These solutions span nearly every area of electricity generation, delivery, and use, including health, safety, and environment. EPRI's members represent over 90% of the electricity generated in the United States. International participation represents nearly 15% of EPRI's total research, development, and demonstration program.

Together…Shaping the Future of Electricity

About PIER

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable and reliable energy services and products to the marketplace.

The PIER Program annually awards up to $62 million to conduct the most promising public interest energy research by partnering with RD&D organizations including individuals, businesses, utilities and public or private research institutions.

PIER brings new energy services and products to the marketplace and creates state-wide environmental and economic benefits.

© 2006 Electric Power Research Institute (EPRI), Inc. All rights reserved. Electric Power Research Institute and EPRI are registered service marks of the Electric Power Research Institute, Inc.

Printed on recycled paper in the United States of America 1013628