BEFORE THE STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER & LIGHT COMPANY CONCERNING A PROPOSAL FOR FOUR SMALL SCALE/PILOT DEMAND RESPONSE PROGRAMS FOR THE PERIOD BEGINNING JUNE 1, 2009	)))))))	**BPU DKT. NO. EO08050326 EO08080542**

SURREBUTTAL TESTIMONY OF J. RICHARD HORNBY

ON BEHALF OF THE

NEW JERSEY DEPARTMENT OF THE PUBLIC ADVOCATE
DIVISION OF RATE COUNSEL

RONALD K. CHEN
PUBLIC ADVOCATE OF NEW JERSEY

STEFANIE A. BRAND, ESQ.
DIRECTOR, DIVISION OF RATE COUNSEL

31 Clinton Street, Eleventh Floor
P. O. Box 46005
Newark, New Jersey 07101
Phone: 973-648-2690

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TABLE OF CONTENTS

Page No.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, EMPLOYER, AND PRESENT POSITION.

A. My name is James Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, MA 02139.

Q. ARE YOU THE SAME JAMES RICHARD HORNBY WHO SUBMITTED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. My surrebuttal testimony responds to certain of the statements made by Company witnesses Siebens and Gardow in their respective pre-filed rebuttal testimonies.

II. PROPOSED TARIFF-BASED CURTAILMENT PROGRAM

Q. PLEASE SUMMARIZE MR. SIEBENS' RESPONSE TO THE RECOMMENDATIONS PRESENTED IN YOUR DIRECT TESTIMONY REGARDING JCP&L'S PROPOSED CURTAILMENT PROGRAM.

A. In my Direct Testimony I recommended that the Board approve the Curtailment Program subject to three modifications. The three modifications were an explicit exclusion of customers who participated in the Demand Response Working Group ("DRWG") Modified Program in 2009, a cap on ratepayer funding equal to the amount approved for the DRWG Modified Program and a requirement that JCP&L submit an analysis of the changes needed to continue the Curtailment Program beyond May 2012. In his rebuttal testimony Mr. Siebens generally agreed with the first and third recommendations, but disagreed with my recommended cap on ratepayer funding of the JCP&L curtailment program.

Q. DID MR. SIEBENS DENY THAT THE PROPOSED TARIFF-BASED CURTAILMENT PROGRAM WOULD BE COMPETING WITH SIMILAR CURTAILMENT PROGRAMS OFFERED BY OTHER CSPs?

A. No. Mr. Siebens did not deny that JCP&L's proposed Tariff-based Curtailment Program would be competing with similar programs that Curtailment Service Providers ("CSPs") have been offering under the DRWG Modified Program.

Q. DID MR. SIEBENS DENY THAT THE CAP YOU RECOMMENDED WOULD PROVIDE JCP&L WITH THE SAME LEVEL OF RATEPAYER FUNDING AS WAS PROVIDED TO CSPs UNDER THE DRWG MODIFIED PROGRAM?

A. No. Under the DRWG Modified Program CSPs have two sources of funds to cover their program costs, revenues from PJM and a one-time annual payment from ratepayers equivalent to $22.50 per MW-day for each MW of demand response ("DR") enrolled. The CSPs bear the risk that the revenues from these two sources may not be sufficient to cover their actual program costs.

Under my recommendation JCP&L would have the exact same two sources of funding and would bear the exact same financial risk. The basis for Mr. Siebens' opposition to my recommended cap is the apparent unwillingness of JCP&L to bear any financial risk.

JCP&L expects the cumulative cost of its program to be $10.874 million. Schedule ___(CWS-3). JCP&L expects to fund those program costs with $10.825 million in revenues from PJM and $0.048 million in revenues from ratepayers.

However, unlike a CSP under the DRWG Modified Program, JCP&L has not agreed to operate its program subject to any limit on the amount of ratepayer funding. Under my recommendation JCP&L would be limited to no more than $0.493 million in ratepayer funding if it achieved 60 MW and proportionately less for a lower quantity of demand reduction. (The $0.493 million is equivalent to 60 MW of demand reduction times $22.50 per MW-day times 365 days).

As noted in my Direct Testimony, this cap will place JCP&L on a more equal footing with CSPs who are offering the DRWG Modified Program. If JCP&L is unwilling to offer its program subject to this cap on ratepayer funding, I recommend the Board consider initiating another solicitation for additional market-based demand response from CSPs.

III. PROPOSED PPLS AND ES PROGRAMS

Q. PLEASE SUMMARIZE MS. GARDOW'S RESPONSE TO YOUR RECOMMENDATION THAT THE PROPOSED PERMANENT PEAK LOAD SHIFT (PPLS) AND ELECTRICITY STORAGE (ES) PROGRAMS NOT BE APPROVED AT THIS TIME.

A. In my Direct Testimony I recommended that the Board find that JCP&L has failed to demonstrate that either the PPLS Program or the ES Program is cost-effective and therefore not approve either program at this time.

In her rebuttal Ms. Gardow disagreed with my position on the grounds that my recommendation relies too heavily upon the projected cost-effectiveness of each program. Ms. Gardow states that my analysis ignores additional benefits from the programs that cannot be quantified. Her rebuttal implies that, if quantified, these additional benefits would be significant enough to increase the benefit to cost ratio of each program to above 1 under the Total Resource Costs test and thereby render each program cost-effective.

Q. DID MS. GARDOW DISPUTE YOUR CALCULATIONS OF THE BENEFIT TO COST RATIOS OF EACH PROGRAM UNDER THE TOTAL RESOURCE COST TEST?

A. No. Ms. Gardow did not dispute the fact that, according to the Company's own projections of costs and benefits, that the ES program had a benefit to cost ratio of 0.28 and the PPLS program had a benefit to cost ratio of 0.33. (It is also important to note that JCP&L's projection of benefits for the PPLS program is more uncertain than the projections for its other DR programs. JCP&L will not register the demand reduction from the PPLS program in any PJM programs. As a result, its projected benefits from the PPLS program are not expected revenues from PJM but instead are expected reductions in capacity obligations and/or BGS prices.[1])

Q. DID MS. GARDOW DENY THAT JCP&L HAS THE BURDEN OF PROVING THAT THE PPLS AND ES PROGRAMS ARE REASONABLE?

A. No.

Q. DID MS. GARDOW ACKNOWLEDGE THAT THE BOARD'S JULY 2008 ORDER EMPHASIZED THE IMPORTANCE OF COST EFFECTIVENESS?

A. Yes. Ms. Gardow acknowledged that the Board's July 2008 Order explicitly states that "cost effectiveness will be a primary criterion in the Board's evaluation of the proposals." However Ms. Gardow also stated that cost-effectiveness should not be

[1] Responses RC-JCPL-82, RC-JCPL-83 and RC-JCPL-93 in Exhibit___(JRH-5).

"…the exclusive criterion" because cost/benefit calculations do not consider "…all of the unquantifiable benefits and advantages of a proposed program".

Q. DO YOU AGREE THAT THE ADDITIONAL BENEFITS FROM THE PPLS AND ES PROGRAMS CAN NOT BE QUANTIFIED?

A. No. As noted in my Direct Testimony, the PPLS and ES programs are two of several DR programs that JCP&L has proposed. The primary goal of each of these proposed DR programs is to reduce electricity use during the hours of highest system-wide electricity use, or peak demand, each year. (Typically peak demand occurs in less than 100 hours each year.)

The ***potential*** benefits of reductions in peak demand from DR programs such as the PPLS and ES programs can be grouped into seven major categories:

1. Avoided generation capacity costs;
2. Avoided electric energy costs;
3. Avoided local transmission and/or distribution (T&D) capacity costs;
4. Reduction in market prices of generation capacity (capacity price mitigation);
5. Reduction in market prices of electric energy (energy price mitigation);
6. Avoided generation market ancillary service costs; and
7. Avoided environmental externalities. (These are the costs of environmental impacts of electricity use that are not reflected in the rates or prices for electricity).

Of these seven categories of potential benefits, the two most commonly quantified are avoided generation capacity costs and avoided electric energy costs. For example, Public Service Electric and Gas and Atlantic City Electric each quantified these two categories of benefits in order to demonstrate the cost-effectiveness of the residential demand response programs that the Board approved in its July 29 Orders in BPU Dockets EO08080544 and EO08050326 et al respectively. Ms. Gardow and Mr.

Siebens have quantified those two categories of benefits for each of the JCP&L proposed DR programs in Schedules ELG-2 and CWS-2 respectively.

Contrary to Ms. Gardow's references to additional "unquantifiable benefits" throughout her rebuttal testimony, each of the other five categories of potential benefits can be, and have been, quantified.

- avoided local transmission and/or distribution (T&D) capacity costs can be estimated based on a specific study of the Company's distribution system or by using a proxy, such as the cost of avoiding transformer capacity;
- capacity price mitigation, energy price mitigation and avoided ancillary service costs can be estimated using a simulation model of wholesale markets to estimate those costs without demand reductions, i.e. a reference or under a business-as-usual case, and with demand reductions, i.e. a demand reduction case. The value of the demand reduction is measured by the differences between the costs under each case; and
- avoided environmental externalities can be estimated by projecting the physical quantity of a major emission, such as tons of carbon dioxide, that will be reduced due to a demand reduction and multiplying that quantity by the unit cost of that emission to society, such as $ per ton of carbon dioxide, that is not reflected in electricity market prices.

Following are three examples of quantitative estimates of additional benefits from demand reductions:

- Atlantic City Electric included estimates of the value of avoided ancillary service costs, energy price mitigation and capacity price mitigation in Exhibit B attached to Company filing dated November 19, 2007. Figure 8 from that

Exhibit is presented in Exhibit___(JRH-6), with the values of those three categories highlighted.

- Baltimore Gas and Electric (BG&E) estimated the value of avoided local transmission and distribution costs (labeled as avoided capital costs), capacity price mitigation, energy price mitigation and avoided bulk transmission costs (labeled as avoided capital costs) in the Direct Testimony of David Vahos in Maryland Case No. 9208. Figure 1 from Exhibit DMV-1 of that testimony is presented in Exhibit___(JRH-7) with the values of those categories highlighted.

- The Lawrence Berkeley National Laboratory estimated the value of avoided transmission and distribution costs, avoided environmental benefits and reliability benefits resulting from demand reductions. That analysis is presented in Exhibit___(JRH-8) with the values of those categories highlighted on pages 15 for central air conditioning DR and on page 17 for water heater DR.

My presentation of these three examples is not an endorsement of any of them. In fact the first two estimates are from filings that are likely to be, or are being, litigated. Instead, my point simply is that each category of benefits can be quantified. While parties to a particular proceeding may disagree with the specific values presented in a given filing, the fact remains that these quantitative estimates provide the essential starting point for a rigorous assessment of the benefits of a particular program relative to costs. JCP&L has failed to provide that essential starting point for its proposed PPLS and ES programs.

Q. PLEASE COMMENT ON JCP&L'S FAILURE TO QUANTIFY THE BENEFITS OF DEMAND REDUCTION TO ITS LOCAL TRANSMISSION AND DISTRIBUTION SYSTEM.

A. On page two of her rebuttal Ms. Gardow states that demand response has the potential to be "….an alternate solution to system upgrades and enable the deferral or avoidance of capital investments". However, she does not quantify the value of that potential benefit, i.e. the value of deferring or avoiding capital investments in the Company's distribution system.

JCP&L's failure to provide a projection of the avoided distribution cost benefits of demand response on its system is particularly surprising. There need be nothing "theoretical" about JCP&L's projection of these benefits since it is certainly aware of specific sections of its system which require capital investments. In January 2009, in BPU Docket No. EO09010055, JCP&L requested $40 million to fund accelerated capital investments to improve the reliability of its distribution and sub-transmission system. Analyzing the relative economics of alternative approaches to solving a distribution system problem is surely a routine exercise for planners at JCP&L[2].

Q. HAS MS. GARDOW PROVIDED ANY EVIDENCE TO SUPPORT THE IMPLICATION THAT, IF QUANTIFIED, THESE ADDITIONAL BENEFITS WOULD SIGNIFICANTLY INCREASE THE BENEFT TO COST RATIO OF THESE PROGRAMS?

A. No. In her rebuttal testimony Ms. Gardow states that cost-effectiveness should not be the exclusive criterion for approval of the PPLS and ES programs because those

[2] See, for example, Willis, H. Lee, *Power Distribution Planning Reference Book,* Marcel Dekker, New York, 1997. Chapter 6

calculations do not consider all of the unquantifiable benefits and advantages of those proposed programs. The implication of her rebuttal is that, if quantified, those benefits would increase the benefit to cost ratio enough to warrant approval. However, Ms. Gardow has presented no analyses or evidence to support that implication.

Contrary to Ms. Gardow's implication, the examples of comprehensive quantitative estimates of the benefits of residential DR presented in Exhibit___(JRH-6) and in Exhibit___(JRH-8) demonstrate that the first two categories of benefits, avoided generation capacity costs and avoided electric energy costs, far exceed the value of other categories such as capacity price mitigation, energy price mitigation and avoided T&D costs. Moreover those estimates have yet to be accepted in a regulatory order.

In the third example, presented in Exhibit___(JRH-7), BG&E projects significant savings from avoided transmission and distribution, capacity price mitigation and energy price mitigation. However, BG&E has prepared analyses to develop those projections, and the validity of those projections is currently being litigated in Maryland Case No. 9208. JCP&L cannot simply assume that the benefits of DR that BG&E or any other utility elsewhere has quantified for its distribution system and wholesale market zone will automatically apply to the JCP&L distribution system and wholesale market zone.

Q. DID MS. GARDOW DISPUTE YOUR POSITION THAT REDUCING ELECTRICITY DEMAND IN PEAK HOURS WILL NOT RESULT IN MATERIAL REDUCTIONS IN ANNUAL CARBON DIOXIDE EMISSIONS?

A. No. Carbon dioxide is emitted from the generation of electricity in all 8,760 hours of the year. In contrast, reducing electricity use during hours of system-wide peak demand only reduces generation in a limited number of hours of the year, typically less than 100. Thus, reducing electricity demand in peak hours will only reduce annual carbon dioxide emissions by approximately 1 per cent, i.e. in 100 hours out of 8760 hours.

Q. PLEASE SUMMARIZE MS. GARDOW'S RESPONSE TO YOUR RECOMMENDATION THAT JCP&L BE GIVEN THE OPTION TO RE-SUBMIT ITS PROPOSED PPLS AND ES PROGRAMS AT A LATER DATE.

A. In my Direct Testimony I recommended that the Board provide JCP&L the option to re-submit its proposed PPLS and ES programs for consideration at a later date with new estimates of their projected costs and benefits. Ms. Gardow did not address that recommendation in her rebuttal testimony. She did not indicate that JCP&L would suffer any disadvantage from re-submitting its proposed programs for consideration at a later date.

Q. **DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

A. Yes.

SCHEDULES

Jersey customers due to the fact that PHI's load reductions would have a market-wide impact on energy and capacity prices.

Figure 8. Benefits to New Jersey Customers from AMI-Enabled Dynamic Pricing and Direct Load Control Programs in ACE New Jersey for both Voluntary and Default Cases.

Rate Structure Scenario	CPP is a Voluntary Rate			CPP is the Default Rate		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS						
Avoided Capacity Costs	$38	$38	$43	$79	$79	$88
Avoided Energy Costs	$9	$9	$10	$19	$19	$21
Ancillary Services Benefit	$2	$2	$2	$2	$2	$2
SHORT-TERM PRICE IMPACTS						
Energy Price Benefit	$0.2	$0.8	$1.2	$0.4	$1.5	$2.0
Potential Additional Real-Time Benefit	$0.1	$0.2	$0.2	$0.2	$0.3	$0.3
Capacity Price Benefit	$0	$0	$10	$0	$0	$13
AVERAGE QUANTIFIED BENEFIT **	$49	$50	$67	$100	$101	$126
UNQUANTIFIED BENEFITS						
Improved Reliability			Very Large***			Very Large***
Enhanced Market Competitiveness						
Reduced Rate Volatility						
Reduced Transmission and Distribution Losses						
Reduced Need for Investments in T&D Infrastructure						

* Immediate response: short-term benefits last for 1 year; Slower response: short-term benefits last for 3 years; Delayed response: no generic entry and short-term benefits last until 2015

** Excluding additional potential real-time benefits

*** A PHI-wide implementation of AMI and energy efficiency would increase reserve margins in Eastern MAAC from 18.1% to 18.9% in 2010, and from 11.5% to 12.9% in 2013 with CPP as the default rate structure, and from 18.1% to 18.6% in 2010, and from 11.5% to 12.3% in 2013 with CPP as a voluntary rate structure

- The savings to New Jersey customers would be as much as two and a half times larger if all utilities in PJM-East followed PHI's lead in deploying DSM programs and achieved similar load reductions, with the aggregate load reductions creating a much greater impact on energy and capacity prices.

- The savings to New Jersey customers would be less than half as large if critical peak pricing were not the default rate structure, requiring customers to take initiative in order to sign up for the program. This finding is based on the assumption that a voluntary program would achieve only 20% participation by residential and small commercial and industrial customers, whereas making CPP the default rate structure with an option to switch to a fixed rate would achieve 80% participation. (This assumption is consistent with participation rates in California's Statewide Pricing Pilot.) However, even at a conservative 20% participation rate, the total benefits of AMI/DSM could exceed the total costs.

Source → Exhibit DMV-1

Figure 1: Summary of Net Present Value's (NPV) and Nominal $'s for BGE's proposed AMI and SEP solution

($'s in Millions)

	NPV	Total
O&M Savings	$ 170	$ 408
Avoided Capital Costs	97	204
Total AMI Benefits	**$ 267**	**$ 611**
Capacity Revenues	$ 264	$ 661
Energy Revenues	26	61
Energy Conservation	190	452
Capacity Price Mitigation	335	580
Energy Price Mitigation	69	104
Avoided Capital Costs	116	166
Total SEP Benefits	**$ 1,000**	**$ 2,024**
Total Benefits	**$ 1,267**	**$ 2,635**
Proposed Capital Expenditures	**$ 434**	**$ 641**
Total O&M Expense	**$ 95**	**$ 194**
Total Costs	**$ 529**	**$ 835**

Smart Grid Proposed Solution - TRC	
NPV Total Benefits	$ 1,267
NPV Total Costs	$ 529
Total Resource Cost	**2.4**

Cost-Effectiveness Valuation Guidelines for DR Resources in the Pacific Northwest

Chuck Goldman

Lawrence Berkeley National Laboratory

cagoldman@lbl.gov

NARUC-FERC Demand Response Collaborative

Washington, D.C.

February 15, 2009

Overview of Talk

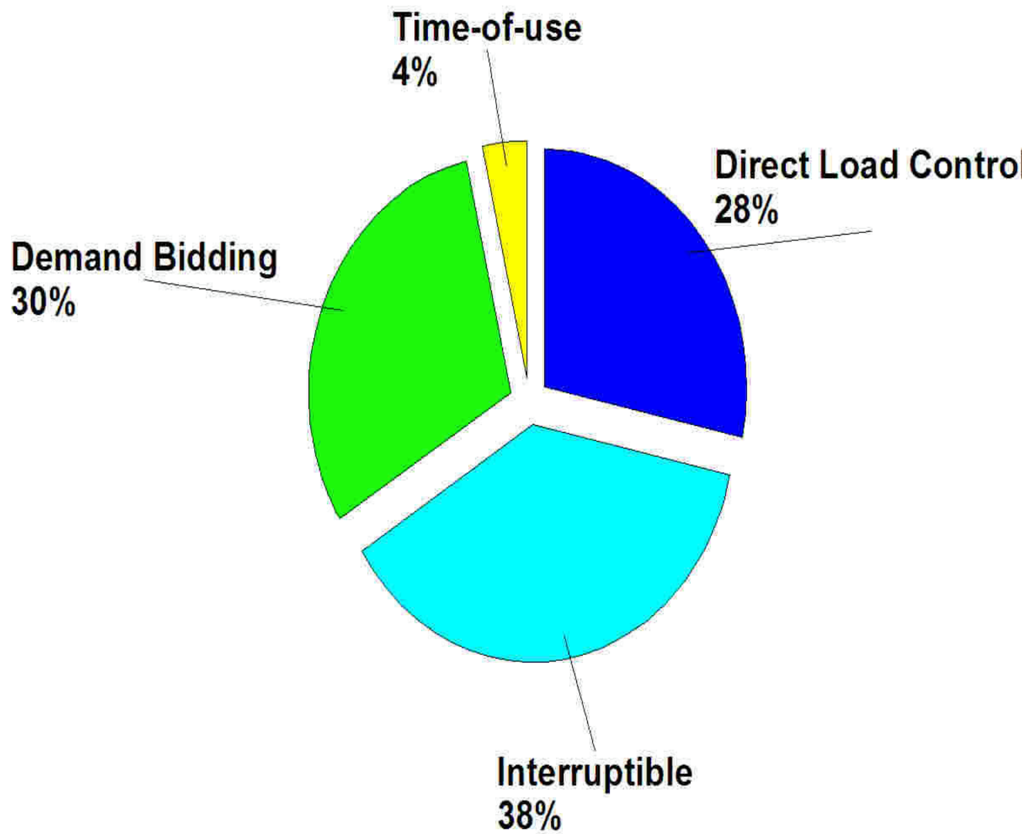
- **Existing DR Resources in the Pacific Northwest**
- **Regional DR Collaborative -- Pacific Northwest Demand Response Project (PNDRP)**
- **Cost-effectiveness Valuation Guidelines**
  - **Rationale/Need & Development Process**
  - **DR Benefits and Costs**
  - **Applying the C/E Screening Methodology to DR Programs: Spreadsheet Tool**

Pacific Northwest: Overview

- **Peak Demand = ~32700 MW in 2005**
  - **40% Res., 32% Comm., 23% Ind., 4% Irrigation**
- **Total DR resource ~720 MW**
  - **2% of 2005 Peak Demand**
  - **Largest Utility DR Programs: Idaho Power, Pacificorp, BPA, Portland General Electric, & Puget Sound Energy**
- **Why the interest in DR in the Pac NW?**
  - **Pac NW power system is running out of hydro, constrained, continuing load growth, environmental constraints, & need to integrate with other resources (e.g. wind)**
  - **Current/future situation changes the value for DR**
  - **Several recent pilot programs (e.g., BPA, Olympic Peninsula)**

Existing DR Resources in Pac NW

- Direct Load Control ~200 MW
- Interruptible ~265 MW
  - Irrigation Load Control ~208 MW
- Demand Bidding ~214 MW
- Time-of-use ~25 MW
- Resource potential data are not available on several DR programs



Pacific Northwest Demand Response Project (PNDRP): Regional Collaborative

- **PNDRP includes:**
  - **State PUCs (WA, OR, ID, MT)**
  - **Utilities and BPA**
  - **Northwest Power and Conservation Council (NPCC)**
  - **Other Stakeholders (DR providers, customer groups, consumer advocate, energy offices)**
- **Technical support and facilitation**
  - **Facilitated by RAP and NPCC; LBNL/RAP provides TA**
- **Working Groups:**
  - **(1) Cost Effectiveness, (2) Pricing and (3) Integrating DR into Distribution System Planning & Investment**

DR Cost Effectiveness Valuation Framework: Purpose & Development Process

- **Context**
  - **Lack of standardized methods to value DR resources, particularly "non-firm" resources (e.g. dynamic pricing, demand bidding)**
- **Purposes**
  - **Propose workable methods for state PUC and utilities to value benefits & costs of different types of DR resources**
  - **Use for ex ante screening of DR programs for C/E**
  - **Document value of DR for rate-setting purposes**
- **Development Process**
  - **Informational workshop (7/07); Workshops on draft guidelines (1/08 and 9/08) with comments/suggestions from members**
  - **Sources**
    - Review of Pac NW utility resource plans and current practices and guidance from state PUCs
    - CA Rulemaking on DR Cost-effectiveness; review, adapt, and simplify
    - DOE Report to Congress on Benefits of DR

Pac NW Guidelines and Principles

- Treat DR Resources on par with supply-side resources
- Distinguish among DR programs based on purpose, response time, dispatchability, & certainty of load response
- Account explicitly for all potential benefits
- Incorporate temporal and locational benefits of DR programs
- Include all DR program & participant costs
- Screen DR programs using multiple B/C tests; adapt B/C tests for distinctive features of DR programs
- Conduct DR pilots to assess market readiness, customer barriers and performance
  - Focus on “non-firm” DR resources (pricing) to identify resource value

DR Resources: Benefits & Costs

BENEFITS

- Avoided Generation Capacity Costs
- Avoided Energy Costs
- Avoid or Defer Investments in T&D System Capacity
- Environmental Benefits
- Reliability Benefits

COSTS

- Program Administration Costs
- Customer Costs
- Incentive Payments to participating customers

Benefits: Avoided Generation Capacity Costs

- "Firm" DR resources which are directly integrated into IRP process can avoid need for some peaking capacity
- Use cost of new CT as benchmark proxy for market value of capacity avoided by "firm" DR resources
  - Costs have typically ranged between $50-85/kW-yr; recent increases have resulted in estimates over $100/kW-yr
- Allocate avoided capacity costs to specific time periods appropriate for Pac NW
  - Linked to relative need for generation capacity in each hour (e.g. LOLE)
- Adjusted "upward" for avoided T&D losses and reserve margin
- Adjusted "downward" to include DR program operational constraints compared to use of CT

Benefits: Avoided Energy Costs

- Load shifting or curtailments enable utilities to avoid energy costs
- Expected wholesale market elect. price in each future time period is relevant opportunity cost for estimating value of elect. avoided by DR resource
- Adjust “upwards” to capture line losses avoided during events
- Likely necessary to further adjust “upwards” for “event-based” DR programs as likely to be called in hours when prices are higher than average peak period prices
- Two options to estimate avoided energy costs:
  - Wholesale energy prices averaged over highest prices hours of price forecast
  - Stochastic methods that analyze correlation between DR events and elect prices & which can explicitly address uncertainty in future loads, prices, hydro conditions

Benefits: Avoid or Defer T&D System Capacity

- Key Elements of T&D System: Interties, Local Network Transmission, Local Distribution System
- DR resources that provide highly predictable load reductions on short notice in congested locations may allow utilities to defer T&D capacity investments
- Two options for setting value:
  - Estimate on a case-specific basis using geographically specific T&D studies
  - Develop a default value for DR programs (e.g., avoided cost of transformer capacity) that meet pre-established “right place” and “right certainty” criteria

Benefits: Environmental & Reliability

- **Environmental**
  - **DR resources may avoid emissions from peaking generation units and some potential conservation effects**
  - **Depends on emissions profile of utility generation mix and customer’s DR strategy (e.g. shifting, curtailment, onsite generation)**
  - **For DR resources that yield load curtailments, emission rate characteristics of a new CT are reasonable proxy for estimating avoided GHG emissions**
- **Reliability**
  - **Joint consideration of economic and reliability benefits is challenging**
  - **Once “firm” DR incorporated into IRP process, resources become part of planned capacity**
  - **“Non-firm” DR (e.g., voluntary “emergency” programs) are not counted on as system resource and thus can provide reliability assurance**
  - **Reasonable proxy for monetizing value of “non-firm” load curtailments is VOLL ($3-5/kWh) * Expected Unserved Energy**

DR Resource Costs

- Program Administration costs
  - Pgm mgmt, marketing, onsite hardware, event notification system upgrades, payments to CSPs
- Customer costs
  - Investments in enabling technology, developing load response strategy, comfort/inconvenience costs, rescheduling costs, reduced product production
- Incentive payments to participating customers
  - Paid to encourage initial enrollment and/or ongoing participation
  - Compensate for reduction in value of service

C/E Screening Methodology Example: Smart Thermostat A/C program

- Smart Thermostat A/C Program
  - Manage cycling and set-point of A/C system
  - Limited to 120 Summer peak hours
  - Assume 65% of households participate during events & 7% annual attrition rate
- Participation Goal: 30,000 units within 7 years
- Peak Demand Savings: 1.1 kW/unit
- Annual Peak Energy Savings: 132 kWh/unit (with 66 kWh/unit increase in off-peak energy usage)
- A/C Energy: Peak=$75/MWh, Off-Peak=$45/MWh
- A/C Capacity: Gen=$80/kW-Yr., T&D=$3/kW-Yr.
- Environmental Benefits: $8/MWh
- Reliability Benefits: None (treated as firm)

Smart Thermostat A/C Program C/E Screening Analysis

Year	2008	2009	2010	2011	2012	2013	2014
Utility System Characteristics							
Forecasted Retail Sales (GWh)	23,000	23,460	23,929	24,408	24,896	25,394	25,902
Forecasted Peak Demand (MW)	4,000	4,088	4,178	4,270	4,364	4,460	4,558
Residential Retail Sales (GWh)	8,740	8,915	9,093	9,275	9,460	9,650	9,843
Residential Peak Demand (MW)	1,520	1,553	1,588	1,623	1,658	1,695	1,732
DR Program Characteristics							
Number of New Participants (Units)	4,286	4,586	4,886	5,186	5,486	5,786	6,086
Number of Returning Participants (Units)	0	3,986	7,971	11,957	15,943	19,929	23,914
Number of Total Participants (Units)	4,286	8,571	12,857	17,143	21,429	25,714	30,000
Peak Period Energy Reduction (MWh)	368	735	1103	1471	1839	2206	2574
Off-Peak Period Energy Increase (MWh)	184	368	552	735	919	1103	1287
Proportion of Class Retail Sales (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity Reduction (MW)	3.06	6.13	9.19	12.26	15.32	18.39	21.45
Proportion of Class Peak Demand (%)	0.2%	0.4%	0.6%	0.8%	0.9%	1.1%	1.2%
Benefits							
Avoided Energy Cost Savings ($MM)	$0.02	$0.04	$0.06	$0.09	$0.11	$0.14	$0.16
Avoided Capacity Cost Savings ($MM)	$0.26	$0.54	$0.83	$1.14	$1.46	$1.81	$2.17
Avoided T&D System Cost Savings ($MM)	$0.01	$0.02	$0.03	$0.04	$0.05	$0.06	$0.08
Environmental Benefits ($MM)	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01
Reliability Benefits ($MM)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total ($MM)	***$0.29***	***$0.60***	***$0.92***	***$1.27***	***$1.63***	***$2.02***	***$2.42***
Benefits - Present Value ($MM)	**$19.91**						
Costs							
Program Development Costs ($MM)	$0.15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Customer Acquisition Costs ($MM)	$0.90	$0.95	$1.00	$1.04	$1.08	$1.13	$1.17
Annual Program Administration Costs ($MM)	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
Annual Program Variable costs ($MM)	$0.18	$0.36	$0.55	$0.75	$0.95	$1.16	$1.39
Total ($MM)	***$1.29***	***$1.37***	***$1.61***	***$1.86***	***$2.11***	***$2.36***	***$2.63***
Costs - Present Value ($MM)	**$19.28**						
Net Benefits ($MM)	***0.63***						
Benefit Cost Ratio	***1.03***						

- **7 years shown but full 20-years included in screening analysis**
- **Benefits exceed program costs (on PV basis) by $630,000**
- **Program is only marginally cost effective**

C/E Screening Methodology Example: DLC Water Heater program

- <u>DLC Water Heater Program</u>
  - Cycle Water Heater
  - Targeted to winter weekdays; 60 hrs/year
  - Assume 95% performance rate for households & 7% annual attrition rate
- Participation Goal: 30,000 units within 7 years
- Peak Demand Savings: 1.0 kW/unit
- Annual Peak Energy Savings: 60 kWh/unit (with 60 kWh/unit increase in off-peak energy usage)
- A/C Energy: Peak=$75/MWh, Off-Peak=$45/MWh
- A/C Capacity: Gen=$80/kW-Yr., T&D=$3/kW-Yr.
- Reliability Benefits: None (treated as firm)

DLC Water Heater Program
C/E Screening Analysis

Year	2008	2009	2010	2011	2012	2013	2014
Utility System Characteristics							
Forecasted Retail Sales (GWh)	23,000	23,460	23,929	24,408	24,896	25,394	25,902
Forecasted Peak Demand (MW)	4,000	4,088	4,178	4,270	4,364	4,460	4,558
Residential Retail Sales (GWh)	8,740	8,915	9,093	9,275	9,460	9,650	9,843
Residential Peak Demand (MW)	1,520	1,553	1,588	1,623	1,658	1,695	1,732
DR Program Characteristics							
Number of New Participants (Units)	4,286	4,586	4,886	5,186	5,486	5,786	6,086
Number of Returning Participants (Units)	0	3,986	7,971	11,957	15,943	19,929	23,914
Number of Total Participants (Units)	4,286	8,571	12,857	17,143	21,429	25,714	30,000
Peak Period Energy Reduction (MWh)	244	489	733	977	1221	1466	1710
Off-Peak Period Energy Increase (MWh)	244	489	733	977	1221	1466	1710
Proportion of Class Retail Sales (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity Reduction (MW)	4.07	8.14	12.21	16.29	20.36	24.43	28.50
Proportion of Class Peak Demand (%)	0.3%	0.5%	0.8%	1.0%	1.2%	1.4%	1.6%
Benefits							
Avoided Energy Cost Savings ($MM)	$0.01	$0.02	$0.02	$0.03	$0.04	$0.05	$0.06
Avoided Capacity Cost Savings ($MM)	$0.35	$0.71	$1.10	$1.51	$1.94	$2.40	$2.89
Avoided T&D System Cost Savings ($MM)	$0.01	$0.03	$0.04	$0.05	$0.07	$0.08	$0.10
Environmental Benefits ($MM)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Reliability Benefits ($MM)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total ($MM)	***$0.37***	***$0.75***	***$1.16***	***$1.60***	***$2.05***	***$2.54***	***$3.05***
Benefits - Present Value ($MM)	**$25.12**						
Costs							
Program Development Costs ($MM)	$0.10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Customer Acquisition Costs ($MM)	$0.88	$0.96	$1.04	$1.13	$1.22	$1.31	$1.40
Annual Program Administration Costs ($MM)	$0.06	$0.06	$0.06	$0.06	$0.06	$0.07	$0.07
Annual Program Variable costs ($MM)	$0.16	$0.32	$0.49	$0.67	$0.86	$1.05	$1.25
Total ($MM)	***$1.20***	***$1.34***	***$1.60***	***$1.86***	***$2.14***	***$2.43***	***$2.72***
Costs - Present Value ($MM)	**$19.63**						
Net Benefits ($MM)	***5.49***						
Benefit Cost Ratio	***1.28***						
Levelized Cost ($/kW-Year)	**$77.54**	**$92.73**					

- **7 years shown but full 20-years included in screening analysis**
- **Benefits exceed program costs (on PV basis) by $5.4M**
- **B/C Ratio = 1.28**

BERKELEY LAB

Summary and Next Steps

- DR Cost-effectiveness guidelines supported by all participating PNDRP stakeholders (Sept 2008); recommendation that NPCC include in next Regional Plan
- NPCC will include DR C/E Guidelines in its 6th Northwest Electric Power and Conservation Plan (May 2009) as an Appendix
- Pac NW DR Cost-effectiveness guidelines are useful as a B/C SCREENING tool for DR Programs

Questions?

LBNL: Chuck Goldman

CAGoldman@lbl.gov (510) 486-4637

NPPC: Ken Corum

kcorum@nwcouncil.org (503) 222-5161

RAP: Rich Sedano

rsedano@raponline.org (802) 223-8199

Pacific Northwest Demand Response Project documents can be downloaded at:

http://www.nwcouncil.org/energy/dr/Default.asp