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DER Benefits Analysis Studies: Final Report

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DER BENEFITS ANALYSIS STUDIES: FINAL REPORT

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INTRODUCTION

Background

The electric power industry in the United States is undergoing dramatic change. Once totally controlled by utilities that had monopolistic holds on the supply, transmission and distribution of electricity in their service areas, the electric power system is being deregulated, introducing competition among electricity providers who can distinguish themselves by price, services and other factors. The new electric power system will feature advanced technologies and services that can be used on-site or located in close proximity to the load, instead of depending solely upon large, central station generation and transmission. Using a variety of advanced modular generating technologies (including small-scale renewables), distributed energy resource (DER) plants supply baseload power, peaking power, backup power, remote power and/or heating and cooling, and in some cases supply higher and more reliable quality power. Currently, DER represent a minor part of the electric supply system. If the potential of DER is to be realized in the new electric power market, a full understanding of the value and benefits these technologies provide to the electric system is necessary.

The DOE Distributed Energy Resource Program has requested analytical assistance from the National Renewable Energy Laboratory's (NREL) Analysis Energy Office to benchmark DER valuation studies that have been completed and are publicly available. Benchmarking will serve to provide both a starting point for future analysis efforts and a comparison of the findings of studies that are publicly available.

Objective

The objectives of this project are to:

1. Catalogue at least 30 key <u>quantitative</u> studies reporting on the values and benefits of distributed energy generation technologies (including renewables) in various applications; and
2. Develop a summary of the studies in matrix format that permits comparisons of key study factors: analysis approach, methodology, treatment, applications, benefits, results and knowledge gaps by technology.

Process

One hundred and twenty-four published DER analysis reports were screened to determine the "Top 30" recent studies dealing with the valuation and benefits of DER. This report includes 31 in-depth reviews of studies that were considered to be among the best in quantifying the benefits of distributed resources (see Appendix). The criteria used to evaluate the studies are explained in detail in the methodology section below.

These short reviews are intended to synopsize the relevant research aspects of each study, and specifically to highlight the benefits and value methodologies employed and which DER benefits were quantified and how they were used.

The information from the reviews was then summarized in two matrices. The first, a Summary Matrix, provides the basic information for each study: title, authors, sponsor, objectives, models employed, and so forth. The second, a Benefits Matrix, shows which specific benefits are addressed by each study, and the sources of data used in the study.

Value to Readers

The "casual" reader of this report will be able to note the strengths and weaknesses in the coverage of the various benefit categories. For example, by scanning the Benefits Matrix, the reader will notice that many of the "Top 30" studies use (as input) or calculate a value for deferred distribution capacity ("D") and for energy savings ("E"). Conversely, very few studies use or calculate values for ancillary services ("AS") or standby generation ("SG").

By scanning the Summary Matrix, the casual reader will also gain an understanding of the number of strong analytical studies (versus, say, the "qualitative" or survey-type studies), who the major sponsors of the work are, the balance between recent and early work, the complexity of the DER analytical world, and the multiplicity of benefits that are possible from DER implementation.

The reader looking for a more in-depth assessment of the quantifiable benefits of DER should refer to the Analysis and Observations section of this report. Here the authors compare and contrast the differing approaches employed by the various researchers, and describe the common themes, strengths and weaknesses of the methods used. The reader might also find it helpful to read selected reviews in the Appendix.

Those readers looking for a road map to follow for their own benefits assessment requirements are encouraged to search out the full references, in order to learn the full details behind the work.

METHODOLOGY

One hundred and twenty-four reports relating to DER were collected and scanned by the authors, constituting a "candidates list" from which to select the 30 "best" DER benefits studies. The first step was to screen out all reports that did not deal explicitly with the value or the benefits of DER. Specifically, the study should examine, either quantitatively (preferred) or qualitatively, the actual beneficial effects that result, or are expected to result, from the installation and operation of DER in the electric system.

Table 2 contains a (non-exhaustive) list of the benefits the authors looked for when scanning the DER studies. Names assigned to the benefits are shown in parentheses.

In any given study, DER benefits could be classified as input to the analysis (i.e., benefits values are assumed as givens or taken from another referenced study), or as the output of the analysis (i.e., calculated or derived from more basic data).

Table 1. List of Potential Benefits From the Use of DER

Benefit Type	Definition
Generation Capacity Deferral (G)	The financial value of deferring or avoiding a capital investment in central generation capacity.
Transmission Capacity Deferral (T)	The financial value of deferring or avoiding a capital investment in transmission system capacity.
Distribution Capacity Deferral (D)	The financial value of deferring or avoiding a capital investment in distribution system capacity.
Voltage Control/VAR Production (V)	The value (or potential revenue) of providing voltage/VAR control.
Ancillary Services (AS)	The value (or potential revenue) of providing spinning reserve, regulation, or other ancillary service(s).
Environmental/Emissions (Env.)	The value of emissions offsets or other environmental benefit.
System Losses (I^2R)	The value of the energy saved through reduced resistive system losses.
Energy Savings (E)	The monetary savings in energy production costs.
Reliability Enhancement (R)	The value of outage costs that can be avoided (system or customer).
Power Quality (PQ)	The value of improving the quality of the power at or nearby customer sites.
Combined Heat & Power (CHP)	The cost savings from utilizing waste heat

	from the DER in customer applications.
Demand Reduction (DR)	The cost savings from reducing peak monthly customer demand, thereby avoiding utility demand charges.
Standby Generation (SG)	The value (or potential revenue) of providing generation capacity dispatchable by the utility or the customer during emergencies.

The second step in the process was to evaluate the remaining studies according to a prioritized list of criteria. As Table 2 shows, quantification of benefits was most important, followed by quality of the methodology or analysis employed in the study, relevance to renewables specifically, availability and timeliness of the study.

Table 2. Criteria for Evaluating Benefits Analysis of DER Studies

Study Attribute	**Guide**
1. Quantitative DER benefits data or benefits analysis	Best = explicit calculations or statement of DR benefits (utility, customer and/or societal benefits) Good = qualitative assessment of benefits Poor = no assessment of DR benefits
2. Comprehensiveness, accuracy and completeness	Best = analysis complete and accurate Good = 1 or 2 key aspects not addressed or unclear Fair = several key aspects not addressed or analysis very unclear Poor = numerous weaknesses or inaccuracies in analysis
3. Clarity of benefits methodology	Best = explicit, auditable assumptions and data, accepted methods and models used and explained Good = models/methodology proprietary or confidential, or some aspects not clear Poor = models/methodology not explained or unclear

4. Applicability (across locations, technologies, applications, etc.)	Best = universally applicable results Good = some limitations (region, tech-nology or application) Fair = major limitations Poor = limited to very specific or localized conditions
5. Importance of study at the time of publication (allows for classics)	Best = original or groundbreaking work for its time Good = substantial contribution or improvement on previous work Poor = minor contribution to previous work
6. Relevance to renewable technologies	Best = results totally applicable to renewables Good = results partially applicable to renewables Poor = results not applicable to renewables
7. Availability of report	Best = publicly available Good = available by purchase Poor = not publicly available
8. Publication date	Best = within the last 2 years Good = within the last 5 years Fair = within the last 10 years Poor = older than 10 years

This process resulted in 31 studies that were judged the best, from the standpoint of their complete and comprehensive treatment of DER benefits.

THE "TOP 30" DER STUDIES

Summary of Study Attributes

Table 3 displays a summary matrix of the "vital statistics" of the 31 DER studies that were judged to be the best. These studies are listed in chronological order, with the most recent studies first. The matrix includes the following information for each study:

1. Title
2. Date of publication
3. Major category of study; examples are:
   - Electrical engineering
   - Environmental
   - Economic
   - Finance
   - Combination of above
   - Other
4. Time period or specific years for which the study applies. For example, a study may have used data from 1995 to evaluate DER applications in 2005. In this case, 2005 is the year the study applies.
5. Specific type of model(s) used, e.g., cash-flow, market estimation, etc.; model name, if known.
6. Quantities that are calculated or derived, whether from a model or other types of analysis.
7. Geographical coverage of the study, e.g., the United States or a specific state or utility's service territory.
8. Stakeholder perspectives; for example utility, customer, society, stockholder, etc.)
9. Applications analyzed; examples are:
   - Utility: generation, transmission/distribution deferral, bulk energy, reliability enhancement, planning under uncertainty, other
   - Customer: energy cost reduction, demand charge reduction, CHP, reliability enhancement, power quality, other
10. Technologies (and their general size); examples are:
    - Microturbines
    - Photovoltaics
    - Fuel cells
    - Natural Gas or Diesel Reciprocating Engines
    - Combustion turbines
    - Wind turbines
    - Solar
    - Biomass
    - Other
11. Benefits data; classified as either quantitative or qualitative; and whether assumed as input or calculated as output to the study.

12. Penetration level of DER used or calculated/derived in the study, if given; expressed as amount of megawatts (MW), % of available market, or % of feeder maximum load.

Table 3. Summary Matrix of the "Top 30" DER Benefits Studies

	Title	Date of Pub.	Category of Study	Period/ Year(s) Studied	Study Methodology		Geographical Coverage	Stakeholder Perspective(s)	Applications	Technologies	Benefits		Penetration Level		
					Models	Quantitative					Qualitative/ Quantitative	Input/ Output	MW	% of Market	% of Feeder
1	Economic Analysis of Distributed Energy Impacts	Feb-03	Economic	2002 - 2015	DUVal; GTI Building Energy Analyzer	T&D deferral; customer bill analysis	DTE (Detroit Edison)	Utility (wires), comm/ind end-users	Utility peak clipping; customer CHP, CCHP, demand charge reduction, energy supply, reliability	NG-fueled DGs, size < a few MW	Quantitative	Output	N/A	N/A	15
2	Analysis of NO_X Emissions Limits for Distributed Generation in Texas	Jun-02	Economic, engineering	2002, 2006, 2010	DUVal-C (DUA)	Market potential	Texas	Customer (C/I)	Standby generation, reliability, on-site energy, CHP, demand charge reduction, oilfield & landfill gas.	Fuel cells, microturbines, NG/diesel/dual-fuel engines, CTs.	Quantitative	Output	N/A	N/A	N/A
3	Value of Distributed Energy Options for Congested Transmission/Distribution Systems in the Southeastern United States: Mississippi and Florida Case Studies	Mar-02	Economic, engineering	2002 - 2006	Electricity Asset Evaluation Model (EAEM)	Combined load flow and economic model	Florida and Mississippi	Utility	Utility peak and baseload; C/I customer apps.	75 & 100 kW microturbine, 5.2 MW CT, 5-200 kW fuel cells, generic 2 MW baseload and 1 MW peaking units, 2-10 kW PV.	Quantitative	Output	N/A	N/A	N/A
4	Expansion of BPA Transmission Planning Capabilities	Nov-01	Economic, planning	2001 - 2006	N/A	Benefit/cost, using five different measures	BPA service territory (Pacific Northwest US)	Utility (primarily), customer	Peaking DG, DSM, curtailable rates	Merchant DG, customer DG, conservation DSM, fuel-switching DSM, curtailable load.	Quantitative	Input	N/A	N/A	N/A
5	Economic Market Potential for Utility Owned Distributed Generation	Oct-01	Economic	2002, 2010	DUVal	Market potential	United States	Utility	T&D deferral; Baseload energy; loss reduction	Microturbines, ATS, CTs; dual-fuel, NG and diesel engines; "small" sizes	Quantitative	Output	N/A	N/A	N/A
6	Distribution System Cost Methodologies for Distributed Generation	Sep-01	Economic	1995 - 1999	N/A	Marginal and deferral costs	United States	Utility (implied)	T&D deferral (implied)	Not specified	Quantitative	Output	N/A	N/A	N/A
7	Assessment of On-Site Power Opportunities in the Industrial Sector	Sep-01	Economic	2000 - 2020	NEMS (?)	Market potential	United States	Customer (industrial)	On-site energy and CHP	Steam turbines, 200 MW combined cycle, engines up to 1 MW, 5 MW gas turbines, fuel cells	Quantitative	Output	N/A	N/A	N/A
8	Real Option Valuation of Distributed Generation Interconnection	Mar-01	Finance	N/A	Black-Scholes option pricing	Option valuation	Not stated	Customer	On-site energy, energy sales, arbitrage, various options	Gas turbines and reciprocating engines	Qualitative	Output	N/A	N/A	N/A

	Title	Date of Pub.	Category of Study	Period/ Year(s) Studied	Study Methodology		Geographical Coverage	Stakeholder Perspective(s)	Applications	Technologies	Benefits		Penetration Level		
					Models	Quantitative					Qualitative/ Quantitative	Input/ Output	MW	% of Market	% of Feeder
9	Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand and Address Electric System Reliability Problems	Nov-00	Engineering	2000-2010	Engineering cost estimation	Peak demand, energy savings	United States	Utility, customer, society	Peak shaving	Energy efficiency, interruptible rates	Quantitative	Output	64,000	N/A	N/A
10	Air Pollution Impacts Associated with Economic Market Potential of Distributed Generation in California	Jun-00	Economic, engineering	2002, 2010	DUVal (utility); benefit/cost (customer)	Market potential, emissions	California (US)	Utility, customer	Utility peak and baseload; C/I customer apps.	45 kW microturbine, 3.5 MW CT, 4.2 MW ATS, 500 kW diesel, NG & dual fuel engines, 250-500 kW fuel cells	Quantitative	Input	N/A	N/A	N/A
11	The Market and Technical Potential for Combined Heat and Power in the Commercial/ Institutional Sector	Jan-00	Engineering	1999	Correlation of databases	estimation of CHP market potential by SIC	United States	Customer	Commercial CHP	Microturbines, fuel cells, reciprocating engines, CTs	Qualitative	Input	77,282	N/A	N/A
12	Western Division Load Pocket Study	Dec-98	Engineering/ Planning	2002	Least cost	capital and O&M costs	Orange & Rockland Utilities, New York	Utility	T&D deferral	Microturbines, fuel cells, reciprocating engines, CTs, PV, load curtailment and buy-back programs, peak TOU rates, DSM	Not stated	Input	N/A	N/A	N/A
13	Market Potential for Distributed Solar Dish-Stirling Power Plants in the Southwestern United States, Operated in Solar-Only and Solar/Natural Gas Hybrid Modes	Dec-98	Economic	2002	DUVal (DUA)	Market potential	NM, AZ, and southern halves of CA and NV.	Utility	Substation and feeder locations	Solar dish and Stirling engine (hybrid)	Quantitative	Input	N/A	N/A	N/A
14	Final Report on Photovoltaic Valuation	Dec-98	Economic	N/A	N/A	Breakeven costs	United States	Customer	Residential/commercial energy production and demand charge reduction	Photovoltaics	Quantitative	Output	N/A	N/A	N/A
15	Analysis of the Value of Battery Storage with Wind and Photovoltaic Generation to the Sacramento Municipal Utility District	Aug-98	Economic	1996 - 2014	Engineering	Benefit/cost	SMUD service area (Sacramento, CA)	Utility	Peak reduction, line losses, spinning reserve	Batteries, wind turbines, PV	Quantitative	Input	N/A	N/A	N/A
16	Microturbines - An Economic and Reliability Evaluation for Commercial, Residential, and Remote Load Applications	Jun-98	Economic	1998, 2002, 2003	cash-flow	capital and O&M costs; cost of serving loads	Not stated	Customer	Energy; reliability; demand charges	Microturbines	Not stated	N/A	N/A	N/A	N/A
17	Using Distributed Resources to Manage Risks Caused by Demand Uncertainty	Oct-97	Economic, finance	N/A	Options theory	Deferral value of DR	Not specified	Utility	T&D deferral	Not specified	Quantitative	Output	N/A	N/A	N/A
18	Applying Wind Turbines and Battery Storage to Defer Orcas Power & Light Co. Distribution Circuit Upgrades	Mar-97	Economic, engineering	2000 - 2002	N/A	benefit/cost analysis	San Juan Islands, WA	Utility	Reduce system peak demand	500 kW, 2-hr battery storage; 350 kW wind turbine	Quantitative	Input	N/A	N/A	N/A

	Title	Date of Pub.	Category of Study	Period/ Year(s) Studied	Study Methodology		Geographical Coverage	Stakeholder Perspective(s)	Applications	Technologies	Benefits		Penetration Level		
					Models	Quantitative					Qualitative/ Quantitative	Input/ Output	MW	% of Market	% of Feeder
19	Identifying Distributed Generation and Demand Side Management Investment Opportunities	Dec-96	Economic	1992	N/A	Breakeven costs	PG&E (No. CA) and APS	Utility	System and local peak reduction	Utility DG, customer DSM	Quantitative	Input	N/A	N/A	N/A
20	Distributed Utility Penetration Study	Mar-96	Economic	1996 - 2007	N/A	Benefit/cost	PG&E (No. CA)	Shareholder, society	G, T & D deferral, energy, losses	Batteries, NG gensets, PV, PAFCs, DSM and EE	Quantitative	Output	N/A	N/A	N/A
21	Gas Industry Distributed Utility Market Analysis	Jan-96	Economic	2005, 2010	Delta, DUGAS	MW of DR, gas use	United States	Utility	T&D deferral; Baseload energy	GTs, ICEs, SOFCs, MCFCs	Quantitative	Output	10,000	1.2	N/A
22	Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation	Jan-95	Economic	1994, 1999	Cost comparison	Marginal cost	California, Indiana	Utility	T&D deferral	Not specified	Quantitative	Input	N/A	N/A	N/A
23	The Value of Distributed Generation: The PVUSA Grid-Support Project Serving Kerman Substation	Oct-94	Economic	1994	Engineering	PV output	Kerman, CA (PG&E)	Utility	G, T, D, E deferral; losses, reliability, min. load	PV - 0.5 MW	Quantitative	Output	0.5	N/A	N/A
24	The Integration of Renewable Energy Sources into Electric Power Distribution Systems - National Assessments	Jun-94	Economic	1994-1998	N/A	Benefit/cost	United States	Utility	Energy & peak load reduction in distribution system	PV and wind turbines	Quantitative	Output	N/A	N/A	N/A
25	The Integration of Renewable Energy Sources into Electric power Distribution Systems - Utility Case Assessments	Jun-94	Economic, engineering	1994	SOLMET, ERSATZ, NRSDB	Solar insolation	CA, NM, VT, GA, FL, TN and WA	Utility	G, T & D deferral; PQ, reliability, line losses	PV, wind, batteries	Quantitative	Output	N/A	N/A	N/A
26	Potential for Feeder Equipment Upgrade Deferrals in a Distributed Utility	Jun-94	Economic, Statistical	10 years in future	Economic; cluster analysis	DG penetration	Not stated	Utility	T&D deferral	Fuel cells, load control, interruptible contracts	Quantitative	Input	N/A	N/A	10
27	Battery Enegy Storage: A Preliminary Assessment of National Benefits	Dec-93	Economic	1993-2010	Engineering	Benefit/cost ratio, market penetration	WSCC (11 western US states)	Utility	G, T & D deferral; DSM	Battery systems	Quantitative	Output	N/A	N/A	N/A
28	Distributed Utility Valuation Project Monograph	Aug-93	Economic, Electrical engineering, Policy	1990 - 2010	Survey of expert opinions		United States and Europe	Utility; some customer aspects	G, T & D deferral; PQ, reliability	N/A	Quantitative	Output	N/A	N/A	N/A
29	Photovoltaics as a Demand-Side Management Option: Benefits of a Utility-Customer Partnership	Oct-92	Economic	1992	Engineering	Benefit/cost tests	PG&E (No. CA)	Utility/ ratepayer	Utility: Peak load reduction Customer: energy and demand charges	PV, 15 kW (customer-side)	Quantitative	Input	N/A	N/A	N/A
30	Distributed Photovoltaic Generation: A Comparison of System Costs vs. Benefits for Cocopah Substation	Oct-92	Economic	1996 - 2026	Engineering	Benefit/cost	Yuma, AZ (Arizona Public Service Co.)	Utility	Peak load reduction	PV - 500 kW to 5 MW	Quantitative	Output	N/A	N/A	N/A
31	Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District	May-92	Economic	1993 - 2015	Delta (EPRI)	Benefit/cost analysis	PG&E's Delta District (near Brentwood, CA)	Society, ratepayer	DSM to avoid G, T, D & E costs	DSM programs	Quantitative	Output	N/A	N/A	N/A

Summary of Study Benefits

Table 4 provides an overview of the specific benefits addressed by the "Top 30" DER benefits studies, the sources for the data used in the analyses, and brief comments on the benefits methodologies employed in the studies. The studies are listed in chronological order, with recent studies first. Types of benefits (please see Table 1 for definitions) include:

G – generation capacity deferral
T – transmission capacity deferral
D – distribution capacity deferral
V – voltage control or VAR supply
AS – ancillary services
Env. – environmental or emissions benefits
I^2R – reduction in system losses
E – energy production savings
R – reliability enhancement
PQ – power quality improvement
CHP – combined heat & power
DR – demand (charge) reduction
SG – standby generation

In Table 4 these benefit categories are classified as "utility," "joint," and "customer." For example, generation capacity deferral (G) is shown as a utility benefit, because the utility can achieve capital savings by using DER to defer or avoid an investment in generation capacity. The utility also is the beneficiary of T, D, V, AS, Env., and I^2R, if they are achievable. On the other hand, the customer is the primary beneficiary of PQ, CHP, DR and SG. Energy savings (E) and reliability enhancement (R) are called joint benefits because they can be obtained by both utility and customer.

This list represents the commonly accepted types of benefits that are readily recognized in the DER community, but it is not an exhaustive list. The category of "Other" is included in the Benefits Matrix to capture those less common benefits mentioned in some reports. For example, while it is not very common, it is possible in some circumstances for customers to sell energy to third parties (see "energy sales" for project #8 in the Matrix). Utilities may ascribe value to the operating flexibility DER can provide, or to the ability to manage risk (project #17).

Table 4. Matrix of Benefits Addressed by the "Top 30" DER Benefits Studies

				Utility - Customer Benefit Spectrum																
				Utility								Joint		Customer						
	Title	Date of Pub.	Stakeholder Perspective	G	T	D	V	AS	Env.	I^2R	Other	E	R	PQ	CHP	DR	SG	Other	Data Sources	Benefits Methodology Comments
1	Economic Analysis of Distributed Energy Impacts	Feb-03	Utility (wires), comm/ind end-users	✓	✓	✓			✓			✓	✓		✓	✓			DTE, EEA	Investigate business cases for DER in 3 scenarios: business as usual, improved business/market conditions, and improved DER technologies.
2	Analysis of NO_X Emissions Limits for Distributed Generation in Texas	Jun-02	Customer (C/I)					✓				✓	✓		✓	✓	✓		Manufacturers, Public Utility Commission of Texas, EIA.	Uses customer bill analysis to determine market potential of DG in customer applications.
3	Value of Distributed Energy Options for Congested Transmission/Distribution Systems in the Southeastern United States: Mississippi and Florida Case Studies	Mar-02	Utility	✓	✓	✓						✓	✓						EIA, utilities	Uses a unique, combined load flow and economic model to determine the least-cost expansion plan among various alternatives.
4	Expansion of BPA Transmission Planning Capabilities	Nov-01	Utility (primarily), customer	✓	✓	✓			✓			✓							BPA	Clear and straightforward calculations of benefit/cost ratios using accepted economic engineering principles.
5	Economic Market Potential for Utility-Owned Distributed Generation	Oct-01	Utility	✓	✓	✓				✓		✓							Equipment manufacturers, EIA, FERC Form 1, NERC.	Estimate the market potential of DG technologies for utility applications.
6	Distribution System Cost Methodologies for Distributed Generation	Sep-01	Utility (implied)		✓	✓													FERC Form 1	Questionable methods for computing marginal costs from embedded costs.
7	Assessment of On-Site Power Opportunities in the Industrial Sector	Sep-01	Customer (industrial)						✓			✓			✓				Onsite Energy Corp., EIA	Estimate market potential, energy savings and emissions reductions for DG/CHP in the industrial sector.
8	Real Option Valuation of Distributed Generation Interconnection	Mar-01	Customer									✓						Energy sales	Hypothetical	High-level discussion of possible benefits.
9	Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand and Address Electric System Reliability Problems	Nov-00	Utility, customer, society									✓				✓			Various	Estimate the technical potential of DSM and EE; however, no cost-effectiveness analysis is done.
10	Air Pollution Impacts Associated with Economic Market Potential of Distributed Generation in California	Jun-00	Utility, customer	✓	✓	✓				✓		✓	✓		✓				CARB, US EPA, manufacturers, PG&E, SCE, SDG&E, EIA, CEC, Pupp & Woo	Estimate DG market potential in California, air emissions offsets.
11	The Market and Technical Potential for Combined Heat and Power in the Commercial/ Institutional Sector	Jan-00	Customer												✓				Hagler-Bailly, EIA, GRI, AGA, iMarket Inc., Wharton Econometric Forecasting	Straightforward engineering estimates of benefits of CHP.

	Title	Date of Pub.	Stakeholder Perspective	Utility - Customer Benefit Spectrum															Data Sources	Benefits Methodology Comments
				Utility								Joint		Customer						
				G	T	D	V	AS	Env.	I^2R	Other	E	R	PQ	CHP	DR	SG	Other		
12	Western Division Load Pocket Study	Dec-98	Utility		✓	✓						✓	✓			✓			Internal; DG vendors and analysts	Use various benefit/cost tests to determine best upgrade alternative for the Load Pocket.
13	Market Potential for Distributed Solar Dish-Stirling Power Plants in the Southwestern United States, Operated in Solar-Only and Solar/Natural Gas Hybrid Modes	Dec-98	Utility	✓	✓	✓				✓		✓	✓						GRI, EIA, FERC, Pupp & Woo	Estimate the market potential of solar/dish hybrid systems at varying price points.
14	Final Report on Photovoltaic Valuation	Dec-98	Customer									✓				✓		Finan-cial incent-ives for PV	Authors' previous studies	Survey paper, listing breakeven PV costs from authors' previous studies.
15	Analysis of the Value of Battery Storage with Wind and Photovoltaic Generation to the Sacramento Municipal Utility District	Aug-98	Utility	✓	✓	✓				✓	Spinning reserve								SMUD (internal documents)	Estimate the benefit/cost ratio and breakeven costs for the DG technologies.
16	Microturbines - An Economic and Reliability Evaluation for Commercial, Residential, and Remote Load Applications	Jun-98	Customer									✓	✓			✓	✓		Expert judgment of authors.	Comparison of capital and O&M costs of microturbines to energy purchases from grid.
17	Using Distributed Resources to Manage Risks Caused by Demand Uncertainty	Oct-97	Utility		✓	✓					Flexibil-ity, risk manage-ment								Hypothetical data is used	Author breaks new ground by attempting to incorporate load growth uncertainty and DG modularity into utility financial analysis.
18	Applying Wind Turbines and Battery Storage to Defer Orcas Power & Light Co. Distribution Circuit Upgrades	Mar-97	Utility			✓				✓	Obtain EPAct incent-ives	✓				✓			Orcas P&L Co., ORNL	Benefit/cost tests to determine potential for distribution upgrade deferral.
19	Identifying Distributed Generation and Demand Side Management Investment Opportunities	Dec-96	Utility		✓	✓						✓							PG&E, APS (1992)	A break-even model based on a benefit/cost test.
20	Distributed Utility Penetration Study	Mar-96	Shareholder, society	✓	✓	✓				✓		✓							PG&E 1990 and 1993 DUA technology costs	Shareholder and societal cost-benefit analyses.
21	Gas Industry Distributed Utility Market Analysis	Jan-96	Utility	✓	✓	✓				✓		✓			✓				PG&E, EIA, GRI, FERC, NERC	Deferral of capital expenditures.
22	Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation	Jan-95	Utility			✓										✓			PG&E, Public Service of Indiana	"Ideal" DGs assumed, no specifics on operating hours or effect on deferral period.

				Utility - Customer Benefit Spectrum																
				Utility								Joint		Customer						
	Title	Date of Pub.	Stakeholder Perspective	G	T	D	V	AS	Env.	I^2R	Other	E	R	PQ	CHP	DR	SG	Other	Data Sources	Benefits Methodology Comments
23	The Value of Distributed Generation: The PVUSA Grid-Support Project Serving Kerman Substation	Oct-94	Utility	✓	✓	✓				✓	Mini-mum load	✓	✓						PG&E field measurements	Quantify actual system benefits from PV plant through extensive measurements of actual operations.
24	The Integration of Renewable Energy Sources into Electric Power Distribution Systems - National Assessments	Jun-94	Utility	✓	✓	✓	✓		✓			✓	✓						Technology costs from expert judgment. Emissions costs from state regulations.	Standard benefit/cost approach; data assumptions questionable.
25	The Integration of Renewable Energy Sources into Electric power Distribution Systems - Utility Case Assessments	Jun-94	Utility	✓	✓	✓				✓			✓	✓					EPRI, various utilities	Actual utility projects are studied to determine system benefits.
26	Potential for Feeder Equipment Upgrade Deferrals in a Distributed Utility	Jun-94	Utility			✓													Not specified	Use real feeder data and benefits estimates to evaluate penetration levels on feeders.
27	Battery Enegy Storage: A Preliminary Assessment of National Benefits	Dec-93	Utility	✓	✓	✓										✓			DOE, Sandia Nat. Lab	Use battery systems to defer utility investments.
28	Distributed Utility Valuation Project Monograph	Aug-93	Utility; some customer aspects	✓	✓	✓							✓	✓					PG&E rate case, ca. 1990-1992	Individual task forces studied business aspects, technical strategies and R&D needs of the Distributed Utility.
29	Photovoltaics as a Demand-Side Management Option: Benefits of a Utility-Customer Partnership	Oct-92	Utility/ ratepayer	✓	✓	✓						✓				✓			PG&E	Determine benefit/cost of using PV in a utility-customer partnership arrangement.
30	Distributed Photovoltaic Generation: A Comparison of System Costs vs. Benefits for Cocopah Substation	Oct-92	Utility	✓	✓	✓	✓		✓	✓	Public percep-tion, reduced risk, flexibility.		✓						APS (internal documents)	Estimate the benefit/cost ratio of PV and the breakeven cost.
31	Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District	May-92	Society, ratepayer	✓	✓	✓						✓							PG&E 1990-1993	Ratepayer and society cost-benefit analyses.

ANALYSIS AND OBSERVATIONS

An analysis of Table 1 (Summary Matrix) resulted in the following observations:

1. In the course of this project, the authors concluded that it was difficult to find studies in the literature that had an excellent (or even adequate) treatment of the benefits attributable to the implementation of DER. There were quite a few studies that dealt with DER technologies, interconnection issues, philosophy, and so forth. A number of studies talked about the benefits in a qualitative sense, but comparatively few studies performed detailed quantitative analyses, and those usually concerned themselves with just a few of the benefits; no single study attempted to quantify all the possible benefits.

2. Over the eleven-year time span covered by the 31 studies selected for inclusion, the studies are fairly evenly spread, possibly indicating a uniform level of effort by researchers.

3. The majority of studies analyzed DER from an economic point of view, and were strong in terms of addressing DER on a fundamental economic basis (i.e., benefits vs. costs). The level of coverage and analysis of the engineering aspects of implementing DER was modest by comparison; this might be expected, given that the studies were selected from the pool of candidates on the basis of their economic treatment of benefits. The coverage of the subjects of finance and planning could only be described as weak. This is not a positive indicator, in that the financial and business aspects of DER installations are crucial to their cost-effectiveness. The typical approach in many studies was to look at first-cost, or a benefit/cost ratio, rather than a more comprehensive analysis based on realistic business cases.

4. It was observed that no two sponsoring organizations use the same analytical model. Some organizations use more than one model, especially to address customer vs. utility benefits.

5. The earlier studies were performed primarily from the utility perspective; the first study that really focused solely on the customer perspective was in 1998. Since that time, however, the studies have an almost 50/50 utility/customer balance in applications.

6. Geographically, the studies were very diverse. Some were very location-specific, e.g., the Delta District in PG&E, or a single feeder in the DTE system. Others were very broad, applying to the whole United States, or not stating a region, implying national relevance.

7. The technologies studied were very broad and diverse, covering the gamut of types and sizes typical of DER. Photovoltaics dominates in the first few years, fossil fuel fired technologies since then.

8. Almost all of the studies (27 out of the 31) were able to be quantitative about DER benefits to some degree.

9. Thirty-nine percent (12/31) of the studies were both quantitative and comprehensive enough to determine the benefits as outputs of their work. Fifty-eight percent (18/31) used quantitative benefits as inputs to their analysis (e.g., in calculating benefit-cost ratios or market potential).

10. Penetration levels of DER were rarely a factor in the analyses, either as a cause or an effect. Penetration levels are defined as the MW or percentage of DER capacity relative to a distribution feeder's total load or capacity, or as percentage of available market (in market estimation studies); please refer to the rightmost columns of Table 1. Penetration levels are beginning to be recognized as important factors in DER studies, for several reasons. Certain benefits may not be achievable unless DER is a minimum percentage of the feeder capacity (e.g., ancillary services). Many utilities limit DER implementation to a maximum amount (15% of feeder load is typical), which may limit benefits. And the results of market estimation studies are normally expressed as percent of available market.

From Table 4 (Benefits Matrix) it is observed that the benefits of DER are addressed by the Top 30 studies in the following rank order:

Table 5. Frequency of Occurrence of Benefits in DER Studies

Benefit Type	Occurrence	Type
D – Distribution Capacity Deferral	24	Utility
T – Transmission Capacity Deferral	21	Utility
E – Energy Savings	21	Joint
G – Generation Capacity Deferral	17	Utility
R – Reliability Enhancement	12	Joint
I^2R – System Loss Reduction	10	Utility
DR – Demand Charge Reduction	10	Customer
CHP – Combined Heat & Power	6	Customer
Env. – Environmental/Emissions Improvement	5	Utility
PQ – Power Quality Improvement	2	Customer
SG – Standby Generation	2	Customer
V – Voltage Control/VAR Supply	2	Utility
AS – Ancillary Services	1	Utility

It is logical that Distribution Capacity Deferral is the #1 benefit driver for DER. Distribution costs for new construction can be very high, depending on location. Installing DER at a feeder or substation location that is experiencing excessive peak loading, but for only a limited number of hours per year, can be an economical way to defer high-cost distribution projects.

Energy Savings and Transmission Capacity Deferral are the next-most-often referenced quantified benefits for DER. Energy cost savings are greatest for utility applications like baseload generation, and for customer applications like on-site energy and CHP, because the hours of operation are high.

No studies came close to including all of these 13 major benefits. Eight studies included six or more benefits (utility and customer combined). Only one study had as many as eight benefits.

SUMMARY AND CONCLUSIONS

Introduction

In an effort to synthesize some valuable conclusions from the collection of the best DER analysis studies, the authors examined the common themes, trends and research gaps in this set of selected reports.

Some cautions are in order at this point. The authors made every attempt to collect and examine as many quality DER reports and studies as possible in the process of compiling a list of candidates ("best" reports) from which to select the "Top 30" ("best of the best") studies quantifying DER benefits. It is entirely possible that some very good studies exist, but were not included as candidates, either because they were unknown to the authors or they are just not available to the general public (i.e., they are private and confidential). Also, the process of downselecting from the universe of DER-related reports to the candidates' list necessarily involved the authors' expert judgment as to the relevance and quality of each of the studies.

The "Top 30" designation for a report is based primarily on the authors' evaluation of the comprehensiveness of the treatment of quantified DER benefits. The objective of the report reviews was to evaluate the soundness and validity of the models and methodologies employed, and the quality and credibility of the data used in each analysis. Rigorous, detailed evaluation of the models and data is beyond the scope of this project. However, the report reviews were designed to highlight the significant strengths and shortcomings of each study.

That said, there were many excellent reports on DER, and numerous studies that talked about DER benefits (albeit some from a purely qualitative standpoint). The researchers bravely attempted to integrate data, models and methodologies to show the real benefits of DER implementation.

DER is a complex and multifaceted subject: there are many applications and a multiplicity of business situations in which DER can provide benefits. There are 13 major benefits that we identified in our study, and possibly others depending on the DER being studied, and it is frequently not an easy task to calculate them. Not the least of the obstacles is the fact that the data required to calculate the benefits are frequently nonexistent, very difficult to obtain, or not referenced.

Many analysis models are not standardized, leading to great variation in how the methods are applied to deriving values for the benefits. In regard to DER, most models are not verified or tested "in the field," i.e., against actual DER installation and operation experience.

Synopsis of Current Status

As explained previously, and as illustrated in Table 4, the authors identified 13 specific DER benefits: seven were classified as accruing only to the utility, four only to the customer, and two were "joint" benefits, meaning they could apply to both customer and utility.

Figure 1 illustrates the number of studies that addressed a given number of the 13 total DER benefit types. For example, three studies addressed only one benefit, five studies addressed two benefits, and so on. Only one study examined as many as eight out of the possible 13 benefits. In an ideal world, every one of the "best" studies would cover a large number of benefits. But this was not uniformly true. The empty area in Figure 1 to the right of the single study that addressed eight benefits clearly illustrates that current researchers do not yet include all of the major DER benefits when performing studies.

Figure 1. Frequency of Benefits Inclusion in the DER Studies

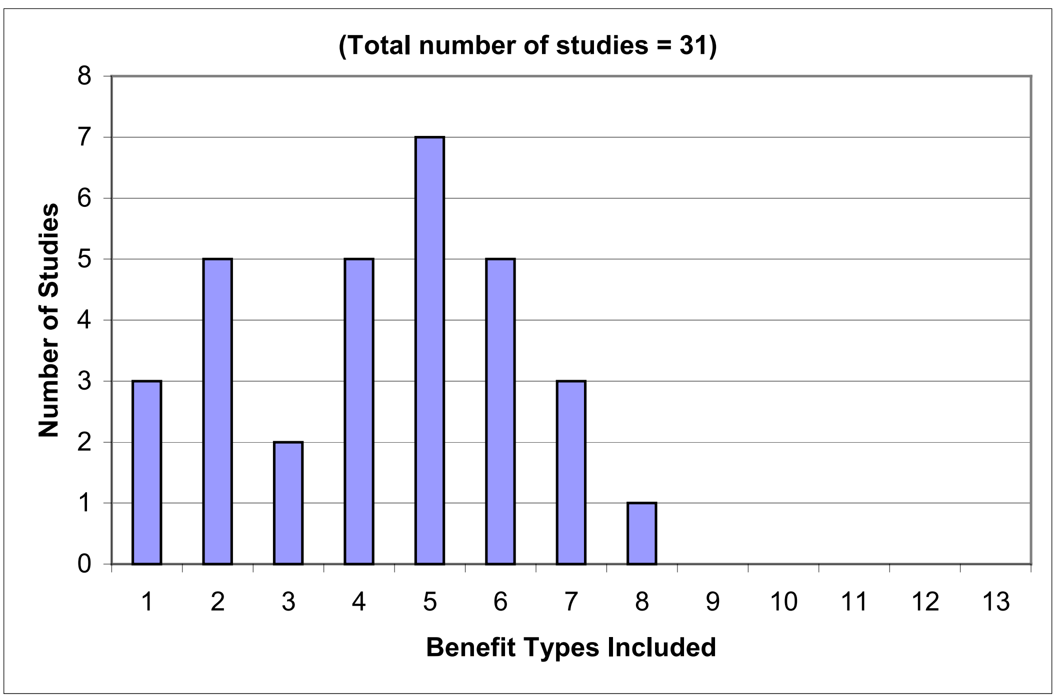


Figure 2 illustrates the number of studies that addressed a given number of the 9 DER benefit types (seven utility-only and two joint) that could accrue to utilities. One study did not address any utility benefits (it was a customer-focused study), five studies analyzed or used only one utility benefit, four studies addressed two benefits, and so forth; two studies covered seven of the possible 9 utility benefits. As Table 5 revealed, distribution and transmission capacity deferral, energy savings, and generation capacity deferral were the most frequent utility benefits studied, in that order.

Figure 2. Frequency of Utility Benefits Inclusion

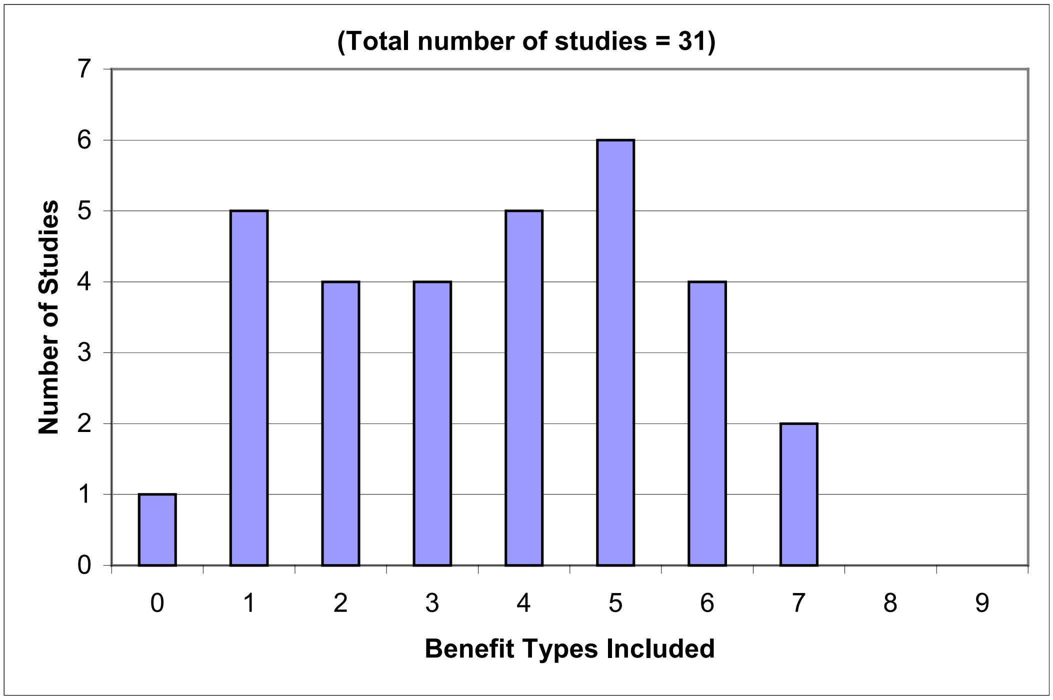


Figure 3 shows the distribution for the six customer benefits (four customer-only and two joint). Four studies addressed no customer benefits (they were exclusively utility-focused), ten addressed one benefit, twelve addressed two benefits, and so on. Only one study looked at as many as five of the possible six customer benefits. From Table 5 it is seen that energy savings, reliability enhancement and demand reduction were the most frequent customer benefits studied.

Figure 4 shows how the completeness of benefits coverage in the studies has evolved over time. The graphs represent the average fraction of the total possible benefits (utility, customer and total) that the studies address; this is called the "Benefits Inclusion Index." The studies are grouped into three time periods; the earliest group of studies spans the period from 1992 to 1996, the middle group from 1996 to 2000, and the most recent group from 2000 to 2003.

Ideally, the best studies would be expected to approach 100% inclusion of either utility or customer benefits, perhaps even a complete set of both types of benefits. This is not the case.

It can be seen that the early studies are characterized by a Benefits Inclusion Index of 0.47, representing a "coverage" of 47% of the full set of utility benefits. Another way of stating this is that the average study looked at about four of the possible nine utility

Figure 3. Frequency of Customer Benefits Inclusion

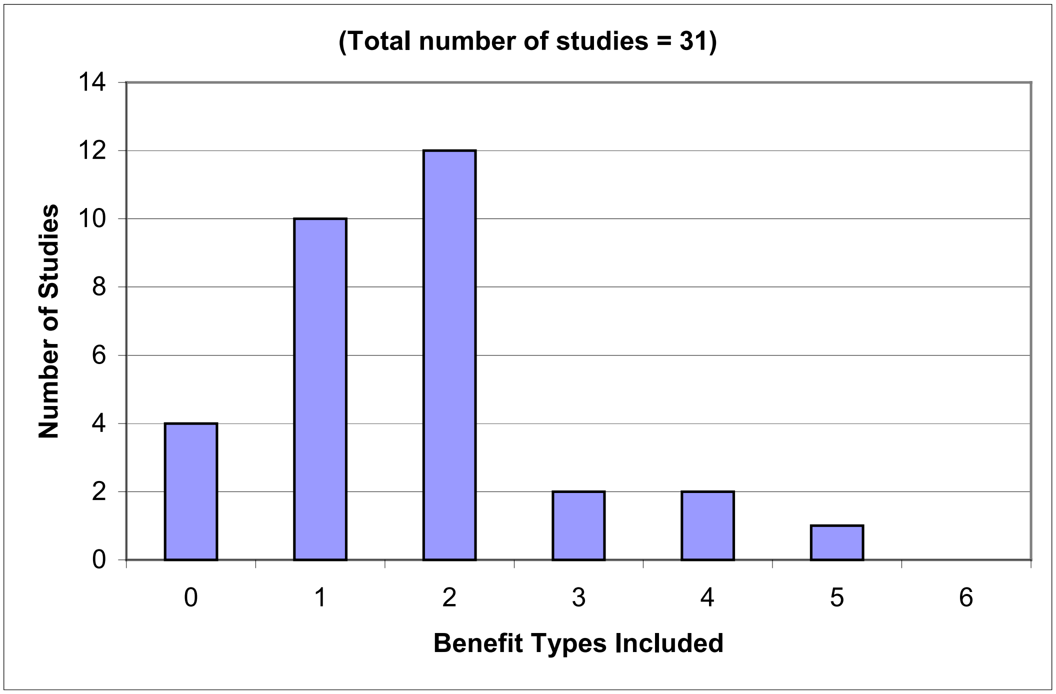
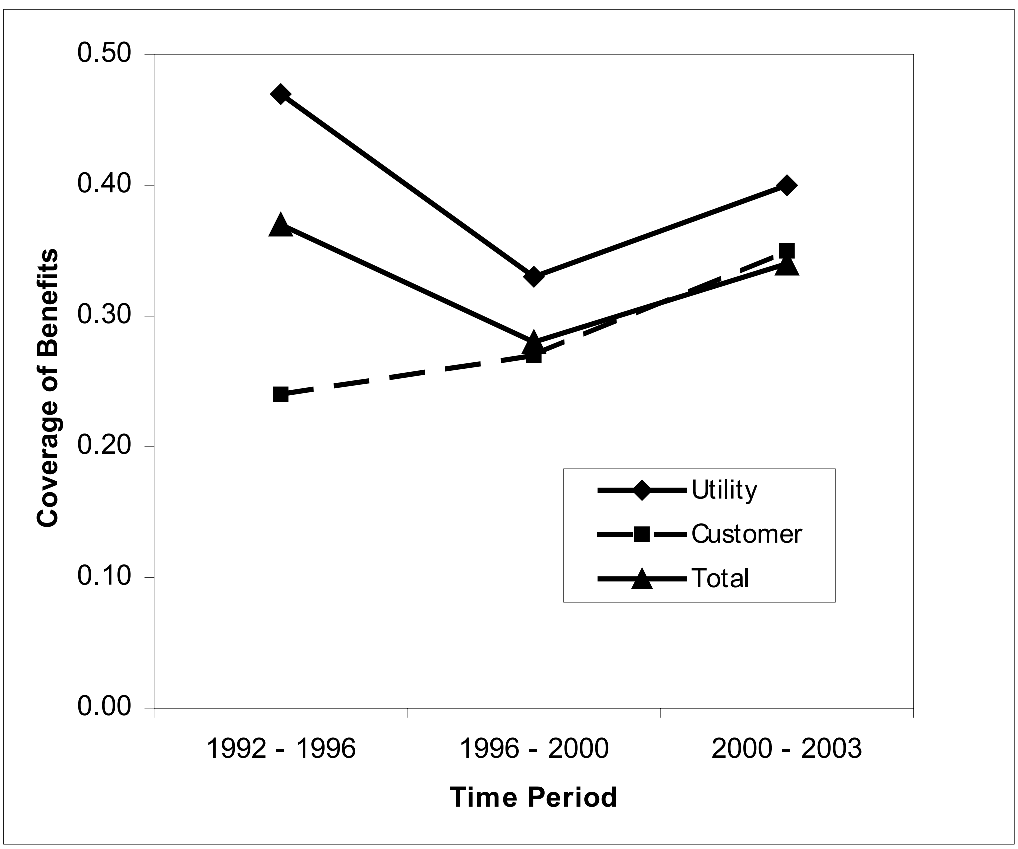


Figure 4. Benefits Inclusion Index vs. Time



benefits. This Index falls to 0.33 in the middle period, and then increases to 0.40 in the latest studies. Since the middle time period corresponds to the onset of deregulation trends in the US, the authors attribute the less complete benefits inclusion during this period to the uncertainty over who would tend to benefit from utility installation of DER and whether customers would really be the decisionmakers for most DER installations.

For customer benefits, the Benefits Inclusion Index starts out at a relatively low 0.24 for the early studies, increases to 0.27 in the middle period, and finally to 0.34 in the most recent years. One possible explanation is that deregulation has increased the interest in DER on the customer side, prompting more research into its potential benefits to customers. Alternatively, increases in performance, reductions in cost, and familiarity with DER technologies may be contributing to steadily improving the prospects for customer acceptance of DER in recent years.

Recommendations for Future Research

No single study looked at all the possible benefits, utility and customer, from a holistic perspective, i.e., using uniform data, financial assumptions, and models (to the extent possible). In fact, the typical study tends to look at either the utility or the customer perspective, but usually not at both. Based on this observation, the authors recommend the following five activities be considered:

1. What would be most useful at this time is an in-depth analysis of the models and methodologies employed in these studies, to determine which studies did the best job of analyzing each of the benefits. This would establish a benchmark approach for each benefit, as well as delineating the strengths and weaknesses of alternative benefit methodologies. At the very least, a recommendation as to the best methodology to use for determining a given benefit would be valuable, and future decisionmakers could apply it to their own situations given the proper input data.

2. Given that DER benefits are predominantly studied individually or in small groups, it would also be desirable to determine if the individual benefits are truly additive, or if conflicts (physical or business) arise multiple benefits are claimed. For example, can a reader of these studies use the results or methodology for distribution capacity deferral from one study, and add to it the reliability enhancement methodology from another, and have confidence that the combined result is valid? If these two quantities are truly independent of each other, the answer would be yes.

3. The subject of ancillary services clearly requires much more analysis. As electric systems become more deregulated, and more generation markets are dependent upon a diversity of independent suppliers, the potential for DER to provide ancillary services becomes greater, and a better understanding of the financial value of these services is required in order for markets to function properly.

4. On the customer side, more research is needed in the area of power quality. Very little quantifiable data is available, and not much is known about the PQ impacts if DER proliferates on the distribution system.

5. Only one study attempted to integrate economics and engineering principles in the same model. The methodology took the form of a load flow program with an economic optimization module that was designed to select the least-cost option of all the alternatives proposed for system expansion. Presumably this model benefited from the uniform system data and financial methods used by the sponsoring organization. Development of integrated models of this type would be a great improvement for system planners, allowing a more straightforward comparison of DER to traditional utility infrastructure alternatives.

This report clearly shows a need for studies that more comprehensively and authoritatively address the range of benefits that DER can provide. This is important to call out, because a mature DER industry would have already completed the research to fully determine the benefits. If the market success of DER depends upon demonstrating multiple benefits, the kinds that enable win/win utility-customer implementation, then the DER research is far from where it needs to be analytically.

APPENDIX: DER REPORT REVIEWS

This Appendix contains the reviews of the 31 DER studies that were judged to be the best from the perspective of evaluating the benefits of DER implementation. Each review is structured to give the following information:

1. Title
2. Bibliographic information
   - author, co-authors, principal investigators and their affiliations
   - sponsoring organization(s)
   - publisher
   - date of publication
3. Study objective
4. Major category of study (primary, secondary if any); examples are:
   - electrical engineering
   - environmental
   - economic
   - finance
   - combination of above
   - other
5. Methodology
6. Specific type of model(s) used (also, model name if available)
7. Geographical location or region
8. Stakeholder perspective(s); examples are:
   - utility
   - customer
   - ratepayer
   - society
   - stockholder
   - other
9. DER technologies and size/capacity
   - microturbines
   - photovoltaics
   - fuel cells
   - natural gas or diesel reciprocating engines
   - combustion turbines
   - wind turbines
   - solar
   - biomass
   - other
10. Applications analyzed; examples:
    - utility: generation, transmission or distribution deferral/avoidance; bulk energy; reliability enhancement; volt/VAR control; ancillary services; emissions/environmental; other

   - Customer: energy cost reduction; demand charge reduction; CHP; reliability enhancement; power quality; green power; other
11. Time period or specific years for which the study applies. (For example, a study may have used data from 1995 to estimate DU applications in 2005. In this case, 2005 is the year the study applies.)
12. Benefits data; categorized by applications in 10. above.
13. Type of data used (examples below); source(s), year
   - internal to utility/customer
   - state agencies
   - published/on-line prices or data
   - EIA
   - FERC
   - industry experts
   - expert judgment
   - survey
   - other
14. Overview of specific results and conclusions
15. Study limitations, strengths and weaknesses; examples:
   - methodology not fully described
   - survey data not applicable to other populations
   - engineering costs not applicable to other regions
   - data are ballpark estimates, not precise
   - data are proprietary and unavailable so results can't be duplicated
   - data are old
   - assumptions used are assailable
   - model too simple, not comprehensive or lacking in capabilities
   - benefits not clear or quantified
   - important factors not considered in the analysis
   - other

1. Economic Analysis of Distributed Energy Impacts

Bibliographic Information

Authors: Joe Iannucci (Distributed Utility Associates), John Kelly (GTI); Rich Scheer (Team Lead, Energetics), advisors: AEP and DTE (utility business practices), DTE (distribution data and tariffs), EEA (DG technology cost and performance)
Sponsor: US DOE/EERE
Publisher: none as of April 2003
Date of Publication: in progress April 2003

Study Objective

Determine the realistic business cases for DER in a real-world location with several diverse sets of policy-related assumptions. The assumption sets are: 1) business as usual with current technologies, 2) improved business and market conditions, and 3) improved distributed generation technologies. The analysis process must entail utility data and feedback, and the market potential should include both utility and end-user applications.

Study Category

Economic

Methodology Used

- Economic cost benefit analysis of the uses of distributed generation by utilities for transmission and distribution deferral.
- Customer uses of distributed generation to reduce their energy bills were analyzed. This included the capture of heat for CHP and CCHP, and the boiler fuel saved by doing so.
- The synthesis of the two perspectives was done by the analysis team in concert with extensive utility input from AEP.

Model(s) Used

Distributed Utility Associates utility perspective transmission and distribution deferral methodology adapted to a single distribution feeder, but also explicitly including the “lumpiness” of distribution investments and the value of temporary distributed generation installation.

GTI customer perspective bill analysis model “Building Energy Analyzer,” an InterEnergy Product.

Geographical Location or Region

Detroit Edison (DTE), Ann Arbor Michigan area, Pioneer Substation and Circuit 9796. Some minor extrapolation performed to higher electricity cost locations.

Stakeholder Perspectives

Utility wires company and end-user customer (commercial and industrial end-users only).

To some extent a synthesis of the two standpoints for the common good. Minimal environmental aspects were studied.

Technologies and DER Capacity

Natural gas fueled distributed generation technologies only. Sized for use specifically on this feeder, a few MW or less. Advanced technology scenario included substantial cost and performance improvements for the technologies by 2015.

Applications Analyzed

From a utility standpoint a distribution system peak clipping application was considered, base loaded utility applications did not appear worth studying due to very low wholesale energy costs in DTE and poor heat rates coupled with gas costs which made wholesale energy displacement unattractive.

From the customer perspective, the GTI model analyzed CHP, CCHP, demand charge reduction and full energy supply with the DG.

Study Period

2002 situation through 2015 to show the long term potential of distributed generation technologies and applications.

Benefits Data

Utility benefits derived from DTE distribution planning information, regional wholesale energy value was assumed to be equal to the wholesale energy tariff available to commercial and industrial customers.

Customer benefits (wholesale energy prices, demand charges, other fees, etc.) determined by analysis of current and projected tariffs for commercial and industrial customers

Type of Data Used, Source, Year

- All utility data obtained directly from DTE, December 2002
- Current tariff charges similarly from DTE rates department, December 2002
- Technology data (cost and performance, emissions etc supplied by EEA derived from Technology Characterizations under development by DOE in late 2002.

Overview of Specific Results and Conclusions

Under a business-as-usual set of assumptions the utility would not consider using DG as an alternative to transmission and distribution upgrades as it is neither common practice nor encouraged by the state regulators. With modest improvement in regulatory permission or encouragement (e.g., PBR, FERC SMD or locational rates) the utility would benefit substantially from installing 15% (of feeder maximum rating) of DG in its distribution system to clip severe but rare load peaks (current DG technologies are good enough in cost and performance already to be economical for this 200 hour per year peaking application). Adding the possibility of substantially improved DG technologies would not expand the market on this feeder much beyond 15% of feeder load.

From the customer/end-user perspective with business-as-usual assumptions, only nearly free onsite fuel sources make economic sense. When improved business experience and regulatory rules are assumed the market expands to about 15% of all customer demand as interconnection costs and permitting costs go down. As improved technology cost and performance is included the market potential expands to 32% of the feeder's load (which is in excess of the utilities market penetration).

Reconciling these perspectives leads to consideration and evaluation of: 1) a simple and revenue-neutral locational rate design (which had even higher market potential but lower annual energy production), 2) a bidding system to fairly allow customers to bid for the right to use the new tariff, and 3) a need to have the utility first prove the technical and economic efficacy of clipping peaks with DG on its feeders.

Examination of sensitivity of the results to higher energy costs showed the expected increase in customer DG market impact.

The existence of two parallel market entry strategies (capacity plays led by the utility, and energy plays led by the customers) was the most profound result. These paths have diverse policy and technology needs, and point to different federal roles.

Possible Study Limitations, Strengths and Weaknesses

As a strength this may be the first study to analyze both the utility and customer perspectives of the same location in parallel, with a completely consistent set of assumptions. This was accomplished by creating an Assumptions Bible containing all of the allowed, confirmed and defined economic, technical, utility, customer and technology data to be used; by itself this document required extensive data collection, processing and negotiating between the analysts evaluating the two business perspectives.

The major limitation is the difficulty of extrapolating the results from a single feeder to the broader context of all of DTE, Michigan and the United States. Examining other locations in an identical way would need to be done to accomplish this.

2. Analysis of NO_X Emissions Limits for Distributed Generation in Texas

Bibliographic Information

Authors: Joseph Iannucci, Susan Horgan, James Eyer, and Lloyd Cibulka - Distributed Utility Associates
Sponsor: Oak Ridge National Laboratory (ORNL)/DOE-EERE
Publisher: DOE-EERE [http://www.eren.doe.gov/der/pdfs/nox_emissions_tx.pdf]
Date of Publication: June 2002

Study Objective

Evaluate the economic market potential for customer use of leading distributed generation (DG) technologies in Texas for the years 2002, 2006 and 2010; for eight customer applications and five technologies; and for three different NO_X emissions scenarios. Specifically, will the proposed emissions regulations inhibit markets for DG? And what are the emissions implications?

Study Category

Economic; engineering

Methodology Used

DUVal-C uses prevailing energy supply and delivery information (energy tariffs), technology costs, fuel costs, etc., to compare the cost of using DG to serve customer load to the benefits of DG operation, and estimates the MW of market for which the DG is more cost-effective. The resulting NO_X emissions from the DG are calculated.

Model(s) Used

DUVal-C (proprietary to Distributed Utility Associates).

Geographical Location or Region

Texas.

Stakeholder Perspectives

Customer (commercial/industrial).

Technologies and DER Capacity

Fuel cells (phosphoric-acid, solid oxide, molten carbonate and PEM), natural gas engines, diesel engines, dual-fuel engines, microturbines, and combustion turbines. Sizes from 10 kW to 5 MW.

Applications Analyzed

Standby generator activation, reliability enhancement, on-site energy, small CHP (1 MW), large CHP (5 MW), demand charge reduction, oilfield/flare gas utilization, landfill gas utilization.

Study Period

Three discrete study years: 2002, 2006 and 2010.

Benefits Data

Electric energy, demand charges, reliability, ancillary services.

Type of Data Used, Source, Year

DG cost and performance data from equipment vendors (2002); electric rates and load data from the Public Utility Commission of Texas (PUCT)(2002); fuel price projections from Energy Information Administration; ancillary services values from Brendan Kirby (ORNL); VOS values for reliability from Pupp & Woo paper, 1/91.

Overview of Specific Results and Conclusions

1. Stricter emissions limits in some scenarios would inhibit DG markets significantly (~33% reduction) while net NO_X emissions are reduced by only 6% at most.

2. Markets would also be reduced significantly if ultra-clean microturbines and fuel cells are not available in 2006 and 2010; NO_X emissions would be higher since the markets would be met with existing (2002 vintage) technologies.
3. CHP, demand reduction, landfill gas and oilfield gas utilization were the predominantly economic markets; standby generation, on-site energy, and reliability enhancement were mostly not economic.
4. With more favorable financing (lower fixed charge rate) higher-cost but cleaner technologies will perform better in the marketplace, and market entry is accelerated.
5. Higher electric rates increase markets for DG; NO_X emissions also increase.

Possible Study Limitations, Strengths and Weaknesses

Strengths

1. Explicit calculation of customer-side benefits and costs of DG ownership and operation, using real-world data.
2. Methodology is applicable generally, not just to Texas.

Limitations

1. Specific results are limited to Texas because of the specificity of the data; theoretically can be extended anywhere with the proper data.
2. Model for calculating DG markets is proprietary to DUA.

3. Value of Distributed Energy Options for Congested Transmission/Distribution Systems in the Southeastern United States: Mississippi and Florida Case Studies

Bibliographic Information

Authors: S.A. McCusker and J.S. Siegel, Energy Resources International
Sponsor: National Renewable Energy Laboratory
Publisher: National Renewable Energy Laboratory, NREL/SR-620-31620
Date of Publishing: March 2002

Study Objective

The objective is to explore the ability of distributed generation (DG) to provide cost-effective alternatives to central station generation, transmission, and distribution upgrades to alleviate transmission and distribution congestion.

Study Category

Economics and Engineering

Methodology Used

Cost-effectiveness test and load flow model.

Model(s) Used

Electricity Asset Evaluation Model (EAEM) (The authors do not provide the source of this model.)

Strengths of Model(s)

This model is a combined load flow model and an economic model that measures the ability of both DG devices and traditional upgrades (generators and wires) to meet load growth using real load flow data and estimates the most cost-effective approach.

Weaknesses of Model(s)

Not transparent.

Geographical Location or Region

Florida and Mississippi

Stakeholder Perspectives

Utility

Technologies and DER Capacity

75 kW microturbines; 5.2 MW combustion turbine; generic 2 MW baseload and 1 MW peaking units; 5 kW to 200 kW fuel cells; 2 kW to 10 kW PV; 100 kW microturbines; 5 MW gas turbine.

Applications Analyzed

Utility installed to serve both peak and base load; customer.

Study Period

2002 to 2006

Benefits Data

Avoided central capital and production costs; decreases in unserved energy by using DG.

Type of Data Used, Source, Year

1) DER capital costs, fixed and variable O&M and heat rate from EIA, no year provided.
2) Fuel prices, unserved energy cost provided by utilities, no year provided.
3) Load flow data from Florida.

Overview of Specific Results and Conclusions

1) For the Mississippi case, DG is cost-effective in serving load growth. The benefit-cost ratio is 1.5.
2) Because transmission upgrade costs for the Florida case were not available, the authors estimated the breakeven cost of installing T&D upgrades. They found the breakeven value to be $823,000 meaning that if the T&D upgrade costs are greater than $823,000, then either a DG installation alone or a DG and other T&D upgrade would be cost-effective. Only peaking and baseload utility and microturbine CHP DG units are selected.

Possible Study Limitations, Strengths and Weaknesses

<u>Strengths</u>

1) The EAEM model that the authors use is an engineering power flow model combined with an economic module in which the lowest cost expansion plan is selected. Besides this study, almost no other study in this area combines engineering and economics in one model. The authors do not say is this is a proprietary model or who owns it. All they say is that it was funded by the NSF.

<u>Weaknesses</u>

1) DG and transmission equipment lives are not equal, so for the 2002 to 2006 study period the authors used "…only the costs that would occur between 2002-2006 were considered in the model." This is not the standard financial method to compare the costs of items with different lives.
2) The authors spend very little time in explaining how traditional expansion plan costs are translated into avoided costs. The differences in lives and costs of various devices are not presented leaving the reader unable to double check results.
3) The authors include customer fuel cell, PV, gas turbine and microturbines applications, but they do not explain how the benefit-cost test varies between utility and customer.

4. Expansion of BPA Transmission Planning Capabilities

Bibliographic Information

Authors: Ren Orans, Snuller Price, Debra Lloyd – Energy & Environmental Economics, Inc.; Ton Foley, consultant; Eric Hirst, consultant.
Sponsoring Organization: Bonneville Power Administration (BPA)
Publisher: BPA
Date of publication: November 2001

Study Objective

Define and evaluate proposed changes to the transmission planning process in BPA, to include consideration of "non-wires" alternatives to the "standard" wires-type solutions traditionally used.

Study Category

Economic/Planning

Methodology Used

E3 proposed a "project-specific" planning process for evaluating potential transmission expansion needs of BPA, to replace the transmission-only wires perspective BPA has used to date. A two-part screening process is used: a high-level screen to identify projects that cannot be addressed by "non-wires" alternatives (e.g., for interconnection, contract or safety reasons); followed by a cost screening of the non-wires alternatives to the given transmission project. Non-wires alternatives included strategically located and operated distributed generation and storage, DSM, and transmission-pricing programs. Evaluation of “non-wires” alternatives included five distinct cost tests, two of which attempted to include all achievable benefits, including avoided distribution costs. Cost tests resulted in benefit/cost ratios; however, details of the benefits and costs that were calculated were included in the Appendix.

Model(s) Used

No models were used. Cost-effectiveness was measured using five tests, each using simple benefit/cost ratios, and each with a different perspective: ratepayer impact, utility cost, total resource cost, societal cost and participant (i.e., customer installing and operating the DG or other measure) cost.

<u>Strengths of Model(s)</u>

- All cost tests were clear in concept and transparent in process.
- Methodology relies on accepted cost accounting methods, and is general enough that it can be extrapolated to other utilities. Data to perform the calculations should not be difficult to obtain for anyone attempting to copy this process elsewhere.

<u>Weaknesses of Model(s)</u>

- BPA owns only transmission, some of the cost tests consider primarily avoided transmission costs, and do not include other benefits that accrue to other entities. Two of the cost tests do include these other benefits, particular avoided distribution costs, but it is unclear how the use of these tests can be justified for BPA’s planning process vis-à-vis the others.

Study Location or Region

BPA service territory (Pacific Northwest region of United States).

Stakeholder Perspectives

Utility (primarily); customer.

Technologies and DER Capacity

Customer-owned DG (sited in distribution system), merchant plant DG (sited on BPA’s transmission system and subject to transmission tariffs), conservation DSM, fuel-switching DSM (switching residential electric heating to gas heating), curtailable load. MW sizes not specified.

Applications

Peaking DG, DSM, curtailable rates.

Study Period

2001 – 2006 time frame

Benefits Data

Generation capacity valued at 0 $/kW-yr, distribution capacity 20 $/kW-yr, energy 30 $/MWH, environmental adder 6 $/MWh, transmission lifecycle avoided costs ranged from 68 to 74 $/kW (3 to 15-year life), based on BPA’s planned projects.

Cost and DER Performance Data

Customer-owned DG: 600 $/kW, 10,000 MMBtu/kWh heat rate, annual load factor 10%
Merchant plant DG: 600 $/kW, 10,000 MMBtu/kWh heat rate, annual load factor 10%
Conservation DSM: $3 million/MW, 8760 MWh/yr
Fuel-switching DSM: winter peak load reduction of 2 kW, energy savings of 2500 kWh/yr
Curtailable load: 30 hr/yr, incentive payment of 100 $/MWh

Overview of Specific Results and Conclusions

- Customer DG has a B/C ratio of 1.31 for the ratepayer impact test, 2.05 for the utility cost test, 0.42 for the total resource and societal cost tests, and 0.52 for the participant cost test. The first two tests count incentive payments and administration in program costs, while the other three count DG costs, which accounts for the poorer economics.
- Merchant DG had a B/C ratio of 2.05 for both ratepayer impact and utility cost tests, 0.42 for the total resource and societal cost tests, and 0.03 for the participant cost test.
- Fuel-switching DSM was cost-effective for all tests except for the ratepayer impact test.
- Conservation DSM was cost-effective (1.06) for the participant test only.
- Curtailable load was cost-effective for the participant test (1.16) and very cost-effective (5.17 to 7.28) for the other four.

Possible Study Limitations, Strengths and Weaknesses

Strengths

- The study did a good job of describing how to calculate costs and benefits of the various alternatives in a clear and straightforward manner (albeit in the Appendix). The two-step screening process is practical and straightforward, and provides a useful strawman for others attempting to adopt this planning process template.
- While the specific results cited are applicable to the BPA service territory, the methods should be able to be applied to other utility systems without great difficulty.

5. Economic Market Potential for Utility Owned Distributed Generation

Bibliographic Information

Author: J. Iannucci, J. Eyer, L. Cibulka, Distributed Utility Associates (DUA)
Sponsor: Edison Electric Institute
Publisher: DUA
Date of Publishing: October 2001

Study Objective

The objective is to assist the Edison Electric Institute (EEI) and its members to gain an additional understanding of the *economic market potential* for utility use of leading distributed generation (DG) technologies. Economic market potential is the portion of new utility load (i.e., load growth) for which DG is the lowest cost option (vis-à-vis the more conventional utility solution: central generation and "wires"). Economic market potential is estimated for the near-term (2002) and mid-term (2010), for peak and baseload applications, for both a base case scenario and a high fuel price scenario. Six leading peaking technologies and six leading baseload technologies are evaluated.

Study Category

Economic

Methodology Used

Economic cost-benefit analysis

Model(s) Used

The DUVal model is used. It is a proprietary model developed by Distributed Utility Associates. The model is a cost-benefit model and it is run for the utility perspective.

Strengths of Model(s)

Estimates the economic potential adoptions of six DU devices for both peaking and baseload utility grid connected applications for both 2002 and 2010. Low and high fuel cost scenarios are used.

Weaknesses of Model(s)

No engineering analysis is done. It is assumed that DU can be installed in areas in which benefits exceed costs. Also, siting, environmental and permitting issues are ignored. No non-grid applications are studied.

Geographical Location or Region

United States

Stakeholder Perspectives

Utility

Technologies and DER Capacity

Microturbines, Advanced Turbine System (ATS), Combustion Turbine, Dual Fuel Engine, Otto/Spark Engine and Diesel Engine. Capacities not listed but by context are small.

Applications Analyzed

Peaking and baseload DU placement in the utility distribution system to defer T&D upgrade expenses, and save on system generation and transmission capacity and energy costs including line losses.

Study Period

Study periods are 2002 and 2010.

Benefits Data

The benefits data are avoided generation, transmission and distribution capacity costs, and system hourly marginal energy costs including line losses.

Type of Data Used, Source, Year

1) DU costs and performance taken from manufacturers as follows. Allied Signal Power Systems, Capstone Turbines, Solar Turbines Corp, ONSI Corp, Ballard Power Systems and MC Power Corp. Data are also taken from NYSERDA report 200 kW Fuel Cell Monitoring and Evaluation Program Final Report, 1997 and Joan Ogden of Princeton University.
2) Natural gas prices taken from EIA's Annual Energy Outlook, 2001 and energy futures prices from Wall Street Journal; Diesel fuel prices from EIA's Annual Energy Outlook, 2001
3) Utility generation avoided costs from EIA's Annual Energy Outlook, 2001; T&D avoided costs from FERC Form 1; load data from NERC Electric Supply and Demand data base

Overview of Specific Results and Conclusions

Peak Load Applications

Under the base case fuel price scenario, peaking distributed generation technologies are cost-effective for 47% to 98% of new load growth in both 2002 and 2010. In 2002, the Advanced Turbine System (ATS) has a 94.2% economic market potential (20,557 MW/yr). The microturbine has the lowest economic market potential at 47.3% (10,322 MW/yr) of new load. Economic market potential for the other four DGs is between those of the microturbine and the ATS.

In 2010, economic market potential for the ATS remains high, at 98.4% (21,850 MW/yr). Microturbines and conventional turbines are also cost-effective, for 93.3% and 96.7% of new load respectively. The dual fuel engine has the lowest economic market potential at 77.2% (17,142 MW/yr).

Baseload Applications

Distributed generation cannot compete well with new baseload central generation on a cost basis in 2002, primarily because of DG's lower fuel efficiency. Economic market potential is virtually nil for five DGs, the exception is the ATS. It is cost-effective for about 31% of load-in-play (6,765 MW/yr). In 2010, the ATS economic market potential drops to 5.5% (1,221 MW/yr), while the advanced fuel cell is cost-effective for 66.1% (14,677 MW/yr) of load-in-play.

Possible Study Limitations, Strengths and Weaknesses

Weaknesses

1. It is assumed that the installation of DU devices to delay a traditional build-out will not affect distribution reliability.
2. The cost-benefit estimates rely heavily on the avoided and DU costs that are available.

3. No air permitting costs are included.
4. DU manufacturer cost projections are likely optimistically on the lower side.

6. Distribution System Cost Methodologies for Distributed Generation

Bibliographic Information

Authors: Wayne Shirley, The Regulatory Assistance Project
Sponsor: National Renewable Energy Laboratory
Publisher: The Regulatory Assistance Project
Date of Publication: September 2001

Study Objective

The objective of this study is to estimate the average costs of increasing utility distribution capacity and to disseminate the data to regulators, utilities, customers, distributed resource (DR) vendors, system planners and ISOs, so that these groups may estimate if DR may be a cost-effective alternative to a traditional build-out.

Study Category

Economic

Methodology Used

Assemble the embedded costs of distribution system build-outs at the transformer and substation level and at the feeder level. Costs are obtained from FERC Form 1 and are divided by system peak demand (MW) to obtain \$/MW costs of distribution build-outs. These data are used to obtain marginal costs (\$/MW) and then deferral costs (\$/MW).

Model(s) Used

No model is used.

Geographical Location or Region

United States

Stakeholder Perspectives

Not specified, but utility implied.

Technologies and DER Capacity

N/A

Applications Analyzed

Not discussed but deferral of T&D expenses is implied as the application.

Study Period

N/A

Benefits Data

The benefits of DR are implied to be the deferral of distribution expenses. Step one is to assemble the embedded costs of distribution system build-outs at the transformer and substation level and at the feeder level. Costs are obtained from FERC Form 1 (years 1995 to 1999) and are divided by system peak demand (MW) to obtain $/MW costs of build-outs. The author does not mention where system peak demand is collected. Next, marginal costs are computed from embedded costs. The author does not reveal how this step is made. Last, deferral values ($/MW) are computed using the marginal costs.

Type of Data Used, Source, Year

Data on distribution expansion costs was collected from FERC Form 1 for each of 124 U.S. utilities for each of the years 1995 through 1999. FERC Form 1 capital (plant-in-service) for distribution accounts 360 to 373 and distribution expenses are collected. The distribution expenses are separated into operation (accounts 580 to 589) and maintenance (accounts 590 to 598). Peak system demand by utility are used, but the author does not reveal the source.

Overview of Specific Results and Conclusions

1. Peak demand is highly correlated with both transformer and substation plant investment costs and Lines and Feeders costs per MW.
2. Neither the number of customers nor energy consumption are highly correlated with the transformer and substation plant investment costs.
3. The average transformer and substation plant investment costs per MW of system peak over all utilities is $43,063, varying from $134,768 to $6,712 among the utilities.
4. The average lines & feeders plant investment per MW of system peak is $237,644 vary from $732,359 to $79,787 among the utilities.
5. Similarly, both the transformer and substations, and line & feeders O&M expenses varied widely among the utilities.
6. Given the wide variance in distribution costs, it is likely that some DR will be a cost-effective alternative to a traditional build-out.
7. The forward looking marginal costs are greater than embedded costs for costs for 109 of the 124 utilities in the sample indicating the DR are likely becoming more cost-effective.
8. Overall, it is likely that DR can be cost-effective in cases where the cost of distribution build-outs are above average.

Possible Study Limitations, Strengths and Weaknesses

Strengths

1. Overall, the strength of this study was collecting relevant data that would be used in a cost-benefit study of placing DR in the distribution system. It is very instructive to see the wide range of costs among utilities, because it is among the high cost areas that DR might be a cost-effective alternative.

Weaknesses

1. System peak demand is used to compute $/MW distribution build-out costs. The correct MW value to use is the peak demand of the distribution system. The author likely uses system demand because data on distribution loads is not available in FERC Form 1. Because distribution loads tend to have a higher coincidence factor than system loads, the $/MW distribution cost estimated by the author are likely about 1.5 to 2 times lower (on a $/MW basis) than what is presented.
2. The author computes marginal costs from embedded costs. Marginal costs are much higher than embedded costs. Three issues: First, he does not describe how this is done. Second, the embedded costs, as the author computes them, are already marginal costs. Third, he uses marginal costs to compute deferral costs. But if marginal costs are too high, the deferral costs are too high.
3. The author presents deferral values for up to 30 years. While a short deferral with a DR, say 3 years, may not affect distribution reliability a great deal, a long deferral period of 30 years may dramatically affect distribution reliability. The author does not discuss these issues. Therefore, his conclusion that his study "clearly demonstrate[s] that there are many opportunities to implement distributed resources in lieu of traditional wires and transformers" is premature.

7. Assessment of On-Site Power Opportunities in the Industrial Sector

Bibliographic Information

Authors: Teresa Bryson, William Major and Ken Darrow, Onsite Energy Corp. (OEC)
Sponsoring Organization: DOE/ORNL
Publisher: ORNL
Date of publication: September 2001

Study Objective

Estimate the potential for on-site power generation in the U. S. industrial sector, with emphasis on nine industrial sectors called the "Industries of the Future" by the U. S. DOE.

Study Category

Economic

Methodology Used

OEC analyzed several industrial databases to estimate the remaining (gross potential minus known installed capacity) industrial on-site energy potential, by industry SIC classification. Results categorized by energy-only and CHP.

Model(s) Used

Not explicitly stated. Possibly the NEMS models that OEC uses for the Energy Information Administration (EIA).

Strengths of Model(s)

N/A

Weaknesses of Model(s)

N/A

Study Location or Region

United States

Stakeholder Perspectives

Customer (industrial).

Technologies and DER Capacity

Steam turbines (unspecified size), 200 MW combined cycle, reciprocating engines up to 1 MW, 5 MW gas turbines, fuel cells (generic).

Applications

Industrial on-site energy generation and CHP.

Study Period

2000 – 2020

Benefits Data

Potential NO_X and CO_2 reductions; avoided electricity costs; total energy savings.

Cost and DER Performance Data

Presumably developed by OEC for the EIA.

Overview of Specific Results and Conclusions

- The nine focus SICs represent about 61 GW of CHP capacity out of a maximum of 88 GW. The largest share (26 GW) is in the pulp and paper industry sector.
- 46% of the 61 GW market potential is for installations larger than 50 MW, 9% is for installations between 20 and 50 MW, 13 % for 4 to 20 MW, 7% for 1 to 4 MW, and 25% for <1 MW.
- Existing CHP units save about 500,000 ton/yr of NO_X and 102 million ton/yr of CO_2 compared to the average utility and boiler emissions. New and cleaner CHP units will save about 34,000 ton/yr of NO_X and 185 million ton/yr of CO_2 when compared to the newer, cleaner utility power plants that would otherwise be used.

Possible Study Limitations, Strengths and Weaknesses

Strengths

- OEC is one of the more respected CHP authorities. Its analysis is founded on several industry databases which seem to be authoritative and comprehensive.

- Benefits of on-site energy and CHP are explained and quantified in detail for the industry SICs examined. Several other qualitative benefits (e.g., environmental, ancillary services) are mentioned.

Weaknesses

- The methodology for estimating market potential is not transparent, and depends upon industry information that is not accessible to the public.

8. Real Option Valuation of Distributed Generation Interconnection

Bibliographic Information

Authors: M.Pati, R.Ristau, G. B. Sheble and M. C. Wilhelm, M.C. Wilhelm Associates
Sponsor: Edison Electric Institute (EEI)
Publisher: M.C. Wilhelm Associates
Date of publication: March 2001

Study Objective

Utility customers may interconnect distributed generation (DG) with their utility system. As such, DG customers are given some options that can be valued by option theory. While no empirical estimates are provided, the authors describe various customer options and roughly describe how they would be valued using option theory.

Study Category

Finance

Methodology Used

Describe how to use finance real option theory to value options that a customer receives when they interconnect DG with a utility system.

Model(s) Used

Black-Scholes option pricing model. The major strength of this model is that it provides a method to value real options. It borrows the option formula that was developed to value financial options that are traded in a very liquid market and for which the underlying asset is easily identified and measured. The major weakness of applying this theory to real options is that the underlying asset is now the cash flow from the DG project and the volatility is changes in cash flow. These are key variables, but these are generally proprietary data, so it is unlikely that accurate measures of these variables are possible.

Geographical Location or Region

Not stated

Stakeholder Perspectives

Customer

Technologies and DER Capacity

Gas turbines and reciprocating engines. Sizes not mentioned.

Applications Analyzed

- On-site customer generation to avoid utility rates
- Option to sell energy back to the utility
- Option to buy supplementary power from the utility
- Option to shut down DG and come back to utility as a full requirements customer
- Option to perform wheeling
- Option to trade derivatives that require physical delivery
- Option to arbitrage gas and electricity markets by trading the "spark spread"

Study Period

Not specified.

Benefits Data

No benefits were measured. Only a discussion of possible benefits was presented in a very high-level manner.

Type of Data Used, Source, Year

Hypothetical data is developed by the authors. No year applies.

Overview of Specific Results and Conclusions

This study is a thought piece on how options theory may be used to measure the value of several real options that a utility customer obtains from the utility when they install a DG on their site. Options are granted to the customer when the customer: 1) is allowed (but is not required) to sell DG energy back to the utility; 2) may engage in wheeling; 3) may return to the utility if they decide not to run their DG; 4) decides to trade derivatives for physical delivery; and 5) engages in arbitrage between electric and gas prices through the spark spread.

Possible Study Limitations, Strengths and Weaknesses

The authors have no market data so they do not present any option values. The reader has no idea of the likely magnitude of option values. Also, the authors do not explain in detail how the utility demand charges, energy costs and stand-by charges (some of which vary by time and season) enter into the estimation of DG cash-flows.

The authors recognize some of the difficulties of valuing DG options with option theory, but they do not discuss how to overcome the hurdles. For example, the DG interconnection markets may not be competitive. They say that "the values (option premiums) determined by this approach are not the prices that will be charged by the UDCs for interconnection, which will be determined by regulation." (UDC stands for utility distribution company.) Option theory was developed under the notion of competitive markets; if the DG interconnection market is not competitive, the notion of applying option theory to it has to be rethought. The authors did not explain how to link option theory with wheeling and trading derivatives that require physical delivery.

9. Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand And Address Electric System Reliability Problems

Bibliographic Information

Authors: S. Nadel, ACEEE; F. Gordon, Pacific Energy Associates; C. Neme, Vermont Energy Investment Corporation
Sponsor: Not specified
Publisher: American Council for an Energy-Efficient Economy (ACEEE)
Date of Publication: November 2000

Study Objective

Discuss how demand-side efficiency could make a substantial and cost-effective contribution to addressing power reliability problems in the United States.

Study Category

Engineering

Methodology Used

Using technical/engineering estimates, the authors calculate the peak demand and energy savings that can be achieved by 2010 if all potential adoptions of energy efficient appliances occur. The authors claim that adoptions are cost-effective, but no cost-effectiveness tests are presented.

Model(s) Used

Engineering calculations of peak and energy reductions achievable if various demand-side devices are adopted.

<u>Strengths of Model(s)</u>

Engineering calculations provide a transparent method to show how potential peak and energy reductions can be achieved by various appliances.

<u>Weaknesses of Model(s)</u>

The existence of a technical potential does not imply that adoptions will be cost-effective. Cost-effectiveness depends on the cost savings achievable at the site at which it is placed given actual customer usage, utility rates and the complete costs of installation.

Geographical Location or Region

United States, although the analysis can be applied anywhere.

Stakeholder Perspectives

Not clearly stated, but implicitly they are the utility, customer and society perspectives.

Technologies and DER Capacity

Many demand-side devices are examined. Residential programs include new AC, AC repair, AC load control, water heater load control, and AC tune-up. Commercial programs include AC, retrocommissioning, lighting upgrade, lighting design, interruptible rate program, HVAC, and chillers. The industrial program includes an interruptible rate program. Specific sizes of various devices are listed in the Appendices.

Applications Analyzed

The adoption of state-of-the-art efficient lighting, AC, HVAC, AC repair, AC tune-up and interruptible rate programs among commercial, residential and industrial customers to reduce system peak demand and energy use.

Study Period

2000 to 2010

Benefits Data

The benefits data comprise the energy and peak demand savings that are achievable if all technically potential applications are adopted.

Type of Data Used, Source, Year

Data on efficiency of various demand-side appliances and utility costs come from numerous sources and various years. Sources are listed in the Appendices.

Overview of Specific Results and Conclusions

- Six recommended programs could reduce peak electrical demand in 2010 by about 64,000 MW representing about 40% of the projected peak load growth.
- About 45% of the savings would be achieved by a new residential AC program; 15% for each of a new commercial retrocommissioning program and a commercial lighting upgrade program; 11% from residential AC repair; 8% commercial lighting design; and 6% from commercial HVAC equipment

Possible Study Limitations, Strengths and Weaknesses

<u>Weaknesses</u>

- It is not possible to determine what proportion of the technical potential is cost-effective, because no detailed cost-effectiveness tests are done. The only comparison of costs and benefits occurs in Appendix A, which contains estimates of device incremental costs and ranges of utility avoided costs.
- Also, many high efficiency adoptions will occur in the future because federal laws exist that require higher minimum equipment efficiencies by certain dates regardless of cost-effectiveness.

10. Air Pollution Impacts Associated with Economic Market Potential of Distributed Generation in California

Bibliographic Information

Author(s): J. Iannucci, J. Eyer, S. Horgan, L. Cibulka – Distributed Utility Associates (DUA)

Sponsor(s): California Air Resources Board (CARB) and the California Environmental Protection Agency

Publisher: CARB
Date of Publishing: June 2000

Study Objective

Estimate the economic market potential for distributed generation in California, and the net air emissions impacts that would result from that amount of new DG, for the years 2002 and 2010. Both utility applications and end-user (customer) applications were evaluated.

Study Category

Economic; engineering.

Methodology Used

The total cost of owning and operating the DG on a yearly basis is compared to a statistical distribution of new service costs for a utility. The percentage of new installations (based on load growth) for which the DG is less expensive is the market potential. Customer applications are analyzed by comparing the customer's estimated benefits of DG operation to the costs of owning and operating the DG. The estimated air emissions from the total cost-effective amount of DG is then compared to the emissions that would be supplied by central generation.

Model(s) Used

DUVal, DUA's proprietary market model, was used for estimating potential of DG technologies for utility applications. No model was used for customer applications; a benefit/cost calculation was used.

Strengths of Model(s)

DUVal uses total cost of service measures, including energy generation, generation capacity, T&D capacity, losses, and electric service reliability, to determine total benefits of DG systems. This approach results in a statistical distribution of utility service option costs against which the DG cost is compared to determine economic market potential. The customer "model" is a straightforward bill analysis that allows direct comparison of DG benefits to costs.

Weaknesses of Model(s)

It is assumed that DU can be installed in areas in which benefits exceed costs. Also, fuel supply, siting, environmental and permitting issues are ignored.

Geographical Location or Region

California

Stakeholder Perspectives

Utility, customer

Technologies and DER Capacity

Microturbine (45 kW), combustion turbine (3.5 MW), Advanced Turbine System (4.2 MW), diesel engine (500 kW), natural gas engine (500 kW), dual-fuel engine (500 kW), PEM fuel cell (250 – 500 kW), phosphoric-acid fuel cell (250 – 500 kW).

Applications Analyzed

Utility peak and baseload generation; commercial/industrial customer installations (exact applications not specified).

Study Period

Discrete years 2002and 2010.

Benefits Data

Utility avoided costs for: generation capacity, fuel, transmission capacity, distribution capacity, losses, and reliability. Customer cost savings based on total energy bill analysis.

Type of Data Used, Source, Year

DG data from manufacturers (1999); emissions data from CARB (1996) and U. S. EPA (1998); electric tariffs from PG&E, SCE and SDG&E (1999); value of service data from Pupp & Woo (1991); natural gas and diesel fuel prices from EIA (1997); California load growth data from the California Energy Commission (1999).

Overview of Specific Results and Conclusions

1) Load growth in California in 2002 is 976 MW (total market). Utility peaking DGs are cost-effective for 29% of market (for a microturbine) to 75% (for a diesel engine) of this load, depending on their costs. Utility baseload DGs are less cost-effective: the ATS gets 33% of the market, CTs get 10% and microturbines 4%; fuel cells and engines are not cost-effective.
2) Load growth in California in 2010 is 1,144 MW (total market). Utility peaking DGs are more cost-effective than in 2002: 52% of market (dual-fuel engine) to 79% (CTs). Utility baseload DGs also improve: the ATS gets 42% of the market, CTs get 16%, microturbines 14% and PEM fuel cells about 2%; engines are still not cost-effective.
3) DGs are generally not cost-effective, given the electric utility tariffs in effect. Use of CHP brought some DGs to about 0.9 benefit/cost ratio.

Possible Study Limitations, Strengths and Weaknesses

Strengths

- The analysis of the utility perspective was performed in great detail, with current data.

Weaknesses

- Customer applications were not studied in detail, only "generically," via a bill analysis.

11. The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector

Bibliographic Information

Author: ONSITE SYCOM Energy Corp. (OSEC)
Sponsor: U. S. Department of Energy, Energy Information Agency
Publisher: N/A
Date of publication: January 2000

Study Objective

To determine the potential for cogeneration or combined heat and power (CHP) in the commercial/institutional market.

Study Category

Engineering

Methodology Used

ONSITE measured the technical market potential of CHP by estimating the ability of CHP technologies to fit existing customer energy needs. They identified applications where CHP provides a reasonable fit to the electric and thermal needs of user; quantified the number and size distribution of target applications; and estimated CHP potential in terms of MW capacity.

Model(s) Used

Used Hagler Bailly Independent Power Database to develop a profile of existing commercial cogeneration activity. Using this profile, the 1995 Commercial Buildings Energy Consumption Survey and various market summaries from AGA and GRI, identified applications where CHP provided a good fit to the electric and gas needs of various commercial users. Next, use the MarketPlace Database, to locate CHP sites by SIC code. Identify energy consumption by SIC by using Wharton Econometric Forecasting data. Total CHP potential is derived based on the number of target facilities in each category.

Geographical Location or Region

United States

Stakeholder Perspectives

Customer (although no economic analysis done).

Technologies and DER Capacity

The following CHP technologies are considered applicable to commercial applications: 100 kW microturbines; 200 kW fuel cells; 3 MW, 800 kW and 100 kW reciprocating engines; 1 MW, 5 MW and 10 MW combustion turbines.

Applications Analyzed

Commercial combined heat and power (CHP).

Study Period

End of 1999

Benefits Data

Total technical potential in the commercial/institutional sector is 77,282 MW while only 4,926 MW is currently installed. The potentials are 25,7397 MW, 22,216 MW and 20,638 MW for CHP capacities of 100 to 500 kW, 500 to 1000 kW and 1 to 5 MW, respectively. About 62% of the potential is for devices less than 1 MW. Office buildings, schools, hospitals, nursing homes and hotels/motels contribute 18,614 MW, 14,884 MW, 8,878 MW, 7,993 MW and 6,703 MW, respectively, to the total potential. Fifty percent of the potential is located in nine states: California, Florida, Illinois, Michigan, New Jersey, New York, Ohio, Pennsylvania and Texas.

Type of Data Used, Source, Year

- Data on existing cogeneration activity in the commercial sector taken from Hagler Bailly, Independent Power Database, 1999. OSEC added thermal heat capacity, thermal heat utilization, and yearly hours of operation to the Hagler Bailly database. Year of data not given.
- Commercial Buildings Energy Consumption Survey, EIA, 1995
- Commercial market summaries by GRI and American Gas Association, publication dates 1996 and 1998
- MarketPlace Database, iMarket Inc, 1999, Waltham, MA
- Electric and gas consumption and expenditures from Wharton Econometric Forecasting, no date provided

Overview of Specific Results and Conclusions

The current (1999) installed CHP capacity is 4,926 MW and the total potential is 77,282 MW. Most of the technical potential is in California, Texas, Florida, Illinois and the Northeast. That is, only 6.3% of the potential is currently installed.

Possible Study Limitations, Strengths and Weaknesses

Strengths

Straightforward engineering estimates make it clear why certain applications are good CHP candidates. The engineering approach indicates that the following applications have the most potential: 1) electric and thermal that are relatively coincident; 2) thermal energy loads in the form of steam or heat; 3) electric demand to thermal heat in ratios in the 0.5 to 2.5 range; and 4) moderate to high operating hours (> 4000 hours per year).

Weaknesses

- Does not estimate the cost-effective applications of CHP, which will be less than the technical potential.
- Classifications of applications (for example, health care that includes hospitals, clinics and outpatient services with very different energy and heat needs) are very broad, making it difficult to obtain more detailed estimates.

12. Western Division Load Pocket Study

Bibliographic Information

Authors: Brian Horii, Greg Ball, Snuller Price – Energy & Environmental Economics, Inc., San Francisco, CA
Sponsoring Organization(s): Orange & Rockland Utilities (O&RU)
Publisher: Orange & Rockland Utilities
Date of publication: December 11, 1998

Study Objective

Identify and evaluate T&D expansion alternatives in O&RU's Western Division. Alternatives include: the status quo (i.e., do nothing); the "Middletown Tap" T&D capital expansion project proposed by O&RU planning staff; and the deferral of that project through the potential use of DSM, targeted peak rates, "large-scale" combustion turbine generation, and "small-scale" DG systems.

Study Category

Electrical Engineering/Planning

Methodology Used

Evaluation of the costs of the various alternatives meeting the required electrical and reliability criteria. A multi-step screening process is used, with successively more detailed calculations of cost-effectiveness, to narrow the candidates for full, final analysis. It is assumed that the Middletown Tap project must be built eventually, so all alternatives are evaluated on their potential to <u>defer</u> the transmission project.

Model(s) Used

Distribution expansion planning: Comparison of annual operating and capital costs for each of the expansion alternatives. The option with the least cost that also supplies the required benefits is selected as the preferred option.

<u>Strengths of Model(s)</u>

- Uses accepted utility methods of cost accounting and economic evaluation.

<u>Weaknesses of Model(s)</u>

- Benefits were limited to the few peak hours (<200 hr/yr) when additional T&D capacity is needed. For DG, no allowance was made for any additional potential benefits that could be achieved outside of these hours.
- DG was assumed to be customer-owned; the utility makes incentive payments to customers based on the number of hours of operation it requires for clipping peaks.

Study Location or Region

O&RU's service territory areas in Southeast New York, Northern New Jersey, and Northeast Pennsylvania. The Western Division represents about 20% of O&RU's customers.

Stakeholder Perspectives

Utility: O&RU desires to install the best upgrade for its money. Customers (ratepayers): desire good service reliability and low rates.

Technologies and DER Capacity

"Traditional" T&D capital equipment, as represented by the proposed $16M Middletown Tap project; load curtailment and buy-back programs; peak-activated rates; end-use efficiency (DSM); existing customer generation; 1200 – 4200 kW combustion turbines; 50 – 200 kW fuel cells; 25 – 30 kW microturbines; 50 – 2000 kW diesel engines; 50 kW gas engine; and 1 kW PV system.

Applications

Peak shaving; T&D deferral; reliability enhancement.

Study Period

Summer 2002; corresponds to expected date of completion of the proposed transmission project. Data used in study was primarily from 1997 time frame.

Benefits Data

Benefits data are not explicitly given. The yearly costs of each alternative are calculated and compared to the yearly costs of the Middletown Tap project.

Cost and DER Performance Data

Load data (MW and MW/yr growth rate), T&D cost data, energy costs, value of reliability, inflation rate, cost of capital, cost of natural gas (both bulk for central generation and retail for DG), expected unserved energy, in-area generation data, and DSM historical data were all provided from internal O&RU sources, predominantly from 1997 company records. Customer value-of-service data is from Pupp & Woo paper [1992]. DG cost and performance data was obtained from "discussions with equipment vendors and analysis of trade publications and journals."

Overview of Specific Results and Conclusions

- The Western Division Load Pocket has relied on in-area DG resources for years to defer the need for T&D expansion. This is more expensive than building the proposed T&D project (Middletown Tap).
- The Status Quo option is unacceptable due to potential degradation of service reliability or excessively high costs of acquiring the necessary in-area resources.
- DG technologies were determined to be uneconomic in the initial technology screening step.
- DSM technologies were somewhat cost-effective during initial screening, but in the detailed analysis were found to be uneconomic.
- The Middletown Tap project, as proposed by O&RU staff, was selected as the preferred (least-cost) option.

Possible Study Limitations, Strengths and Weaknesses

- Strength – While a specific geographical area is studied, engineering costs should be typical of most utilities.

- Weakness – Assumptions for market penetration levels of DG and DSM in O&RU's customer classes may be open to question.
- Weakness – Benefits of alternatives were limited to the few hours of operation required for clipping system peaks.

13. Market Potential for Distributed Solar Dish-Stirling Power Plants in the Southwestern United States, Operated in Solar-Only and Solar/Natural Gas Hybrid Modes

Bibliographic Information

Author: Joseph Iannucci, James Eyer – Distributed Utility Associates (DUA)
Sponsor: National Renewable Energy Laboratory (NREL)
Publisher: NREL
Date of Publishing: December 1998

Study Objective

Estimate the market potential for solar dish-Stirling energy systems in the Southwestern United States, when operated in solar-only and solar/natural gas hybrid modes.

Study Category

Economic

Methodology Used

The total cost of owning and operating the DG on a yearly basis is compared to a statistical distribution of T&D upgrade costs for a utility. The percentage of new installations (based on load growth) for which the DG is less expensive is the market potential.

Model(s) Used

DUVal, DUA's proprietary market model for estimating potential of DG technologies for utility applications.

<u>Strengths of Model(s)</u>

DUVal uses total cost of service measures, including energy generation, generation capacity, T&D capacity, losses, and electric service reliability, to determine total benefits of DG systems. This approach results in a statistical distribution of utility service option costs against which the DG cost is compared to determine economic market potential.

<u>Weaknesses of Model(s)</u>

It is assumed that DU can be installed in areas in which benefits exceed costs. Also, fuel supply, siting, environmental and permitting issues are ignored. No non-grid or end-user (customer) applications are studied.

Geographical Location or Region

States of New Mexico, Arizona, and the southern halves of California and Nevada.

Stakeholder Perspectives
Utility

Technologies and DER Capacity
Solar dish/Stirling engine with natural gas as backup fuel (hybrid).

Applications Analyzed
Dish systems operating at substation locations and at feeder locations. Hours of operation at both locations are determined according to best economics.

Study Period
2002

Benefits Data
Avoided costs for: generation capacity, fuel, transmission capacity, distribution capacity, losses, and reliability.

Type of Data Used, Source, Year
Natural gas prices from GRI, Baseline Projection Data Book, 1995. Avoided cost and loss data from DUA's previous studies, derived from Energy Information Administration (EIA) and Federal Energy Regulatory Commission (FERC). Value of service data for reliability obtained from Pupp & Woo 1991 paper.

Overview of Specific Results and Conclusions

4) Solar-only dish systems costing about 1200 $/kW would be cost-effective for all new load in the Southwestern United States, or about 1800 MW/yr. At 1400 $/kW the market is about 750 MW/yr (40% of load growth). The upper limit on cost-effectiveness is 2000 $/kW.
5) Hybrid dishes are cost-effective for up to 25% more market than solar-only dishes, due to their increased effectiveness at providing capacity, which allows deferral of T&D investments. The greatest benefits accrue when hybrid dishes are located on feeders, closer to loads, rather than at substations.

Possible Study Limitations, Strengths and Weaknesses
Strengths

- Comprehensive treatment of benefits from a utility standpoint.

Weaknesses

- Only utility applications were analyzed. Off-grid and customer applications were not studied.
- Data sources are not documented adequately, leaving the reader with insufficient guidance on what data to acquire from what sources in order to replicate the study in other areas.

14. Final Report on Photovoltaic Valuation

Bibliographic Information

Authors: R. Perez and H. Wenger
Sponsor: National Renewable Energy Laboratory
Publisher: none provided
Date of Publishing: December 1998

Study Objective

The objective is to summarize and discuss the results of two PV grid-connected installation studies conducted by the authors. The studies focused on residential and commercial applications.

Study Category

Economic

Methodology Used

Breakeven analysis and PV output analysis.

Model(s) Used

This is a survey paper listing breakeven costs calculated in other papers conducted by the authors. A breakeven cost is the cost that the PV plant must equal so that the estimated benefit-cost ratio is one. The PVGRID model is used in the earlier studies to predict PV output by state.

Strengths of Model(s)

The PVGRID model and the breakeven model were run for each state using solar insolation and rate data for each state.

Weaknesses of Model(s)

Geographical Location or Region

50 states of the United States

Stakeholder Perspectives

Customer

Technologies and DER Capacity

Single array fixed axis tracking photovoltaic systems for residential applications. For commercial applications, five PV array configurations were used including 2 axis tracking, fixed tracking, horizontal, vertical south and vertical west.

Applications Analyzed

PV installed at residential and commercial customer sites for energy production and demand charge reduction.

Study Period

Not stated.

Benefits Data

1) For residential customers, energy production plus possible other financial incentives.
2) For commercial customers, energy production, demand charge reduction plus possible other financial incentives.
3) PV fiscal incentives by states.

Type of Data Used, Source, Year

The authors used data from earlier studies they performed so they simply site those earlier studies rather than providing the data. For residential applications, it includes seasonal energy production, residential retail rates, and fiscal incentives by state. For commercial applications, it includes local energy production, effective PV capacity, commercial utility energy rates, and fiscal incentives by state. PV fiscal incentives by states were obtained from the DSIRE database.

Overview of Specific Results and Conclusions

Residential breakeven costs are about $4.25/watt and $7.50/watt in Massachusetts, New York, Arizona, California and Hawaii. Then the breakeven costs drop from about $3.75/watt in North Carolina to about $1.10/watt in Washington.

Commercial PV breakeven costs are $11/watt in Hawaii; about $3 to $4/watt in California, Arizona and some of the eastern seaboard states; and about $1 to $2/watt in the Midwest, Northwest and upper New England. The 2-axis tracking systems provide more benefits than fixed PV systems. A 2-axis tracking system reduces the breakeven costs from about $0.50 to $1/watt depending on location.

Possible Study Limitations, Strengths and Weaknesses

Strengths

1) Analysis was done carefully state by state and the results are shown by states.

Weaknesses

1) Used the term ELCC in a graph but did not explain what it is.
2) The authors did not consider the footprint needed to serve the residential and commercial loads they study. For example, they estimated the PV breakeven costs for office buildings, but gave no thought to whether sufficient space was available to install PV.

15. Analysis of the Value of Battery Storage with Wind and Photovoltaic Generation to the Sacramento Municipal Utility District

Bibliographic Information

Author: H.W. Zaininger
Sponsor: Sandia National Laboratory and Sacramento Municipal Utility District

Publisher: Sandia National Laboratory SAND98-1094
Date of Publishing: August 1998

Study Objective

The report describes the results of an analysis to determine the economic and operational value of battery storage to wind and photovoltaic (PV) generation technologies in the Sacramento Municipal Utility District (SMUD) system. Specific objectives are to identify two sites for a potential battery installation. The first site is combined with a PV plant and the second with an installed wind turbine project. The benefits and costs of each site will be quantified.

Study Category

Economics

Methodology Used

Benefit-cost test

Model(s) Used

Author's benefit-cost test

<u>Strengths of Model(s)</u>

Transparent

<u>Weaknesses of Model(s)</u>

DG is not meant to permanently displace system and local upgrades but defer them. Therefore, benefits should be calculated as a deferral value. The author uses the present worth of revenue requirements approach. This is not based on a deferral approach.

Geographical Location or Region

SMUD service territory located in Sacramento, California

Stakeholder Perspectives

Utility

Technologies and DER Capacity

Light duty and heavy duty batteries; PV; Wind Turbines

Applications Analyzed

Peak load reduction to earn capacity benefits, reduce line losses, and add to spinning reserve

Study Period

1996 to 2014 study period

Benefits Data

Generation capacity, transmission and subtransmission capacity, spinning reserve and loss reduction benefits

Type of Data Used, Source, Year

1) Discount and inflation rates; SMUD; Dec 1993
2) Spinning reserve benefits; SMUD; 1994-1996
3) Transmission and Distribution Benefits; SMUD; 1994

Overview of Specific Results and Conclusions

Benefit-cost ratios are estimated for a 7.5 MW battery plant installed in tandem with a 50 MW wind turbine plant and a PV plant. The ratio range from 3.25 to 1 for batteries costing $400/kW to $1500/kW, respectively. The breakeven cost of batteries installed at a PV site is about $1300 /kW.

Possible Study Limitations, Strengths and Weaknesses

Weakness

1) Benefit data are taken from SMUD internal documents. The calculation method is not shown in this report, so it is impossible for the reader to compare the benefits to other utilities. Also, the exact method by which they are calculated is not shown. For example, the generation capacity benefits do not appear to be a standard deferral value.

16. Microturbines - An Economic and Reliability Evaluation for Commercial, Residential, and Remote Load Applications

Bibliographic Information

Authors: M. Davis, A.H. Gifford and T.J. Krupa, Detroit Edison Company
Sponsor: Not stated
Publisher: IEEE
Date of Publication: November 1998

Study Objective

Measure the costs and reliability of operating a microturbine off-grid at residential and commercial sites with and without utility standby, and at remote loads without utility standby.

Study Category

Economics

Methodology Used

Simulate capital and operating costs of microturbines under various load scenarios.

Model(s) Used

Comparison of operating and capital costs ($/kWh) of the microturbine to the cost of energy purchases from the grid. Also, computes $/kWh of serving loads depending on the loss-of-load expectation (LOLE) desired and the reliability of a microturbine or several units operated simultaneously.

Strengths of Model(s)

The results are very transparent and easily applied to similar applications.

Weaknesses of Model(s)

It is a rudimentary cost-benefit test.

Geographical Location or Region

Not applicable.

Stakeholder Perspectives

None stated, but customer perspective implied.

Technologies and DER Capacity

30 kW to 75 kW microturbines.

Applications Analyzed

Remote non-grid connected at customer site for energy and reliability. Grid connected at customer site with utility stand-by for the purpose of reducing total costs (demand charges, energy costs, and standby costs) but with reliability equal to various imposed levels.

Study Period

Projections apply for three periods. 1) Today – meaning 1998, because that is the data of publication. 2) 2002; and 3) 2 to 5 years into the future meaning 2000 to 2003.

Benefits Data

No benefits are directly computed. Rather, the authors compute the $/kWh costs of operating a microturbine at the customer site for a given LOLE and they leave it to a customer to compare these costs to their utility costs to determine cost-effectiveness.

Type of Data Used, Source, Year

Data used are the expert judgments of the authors who base it on typical utility levels of LOLE; diversified demand of residential and commercial customers; class load shapes and annual load factors by customer type and number of customers; typical reliability of microturbines of 92% (no source provided); and microturbine capital, fuel and operating costs (source not stated); and various costs projected into future based on expert judgment.

Overview of Specific Results and Conclusions

1. Strong preference for using microturbines for high load factor commercial load applications.
2. If use microturbines, it is cheaper to provide extra reliability by using more microturbines rather than paying utility for standby service.
3. The cost of remote microturbine installation is relatively high at about $0.75 / kWh (depending on desired reliability) due largely to the cost of having to install a natural gas line to the remote location.
4. $ /kWh total costs (i.e. operating and capital costs) are dependent on the assumptions made about the load, load factor, desired reliability, cost and capital costs.

Possible Study Limitations, Strengths and Weaknesses

Strengths

1. Calculated total microturbine costs (i.e. Operating and capital cost) based on expert opinion on what are typical loads, load factors, utility LOLEs and microturbine reliabilities.
2. Calculated microturbine costs at various levels of LOLEs, so that the user can make an informed trade-off between the reliability they desire and the costs they will incur

Weaknesses

1. Did not compare microturbine costs to actual utility rates; that is, no cost-benefit test was performed. Therefore, an economic microturbine penetration potential is not computed.

17. Using Distributed Resources to Manage Risks Caused by Demand Uncertainty

Bibliographic Information

Authors: T.E. Hoff
Sponsor: unsponsored
Publisher: unpublished
Date of Publishing: October 1997

Study Objective

The objective is to present a model that measures the extra value that distributed resources (DR) have because they can be installed in small sizes with a short lead time in contrast to traditional generation and T&D wires upgrades. The model incorporates demand uncertainty, decision-makers risk tolerance and the correlation between costs and firm profits.

Study Category

Economics/Finance

Methodology Used

Uncertainty analysis

Model(s) Used

A variant of a model based on a binomial approach to options theory.

Strengths of Model(s)

Formally incorporates uncertainty into electric utility expansion planning. Uncertainty analysis principles have not been sufficiently investigated for planning.

Weaknesses of Model(s)

The binomial approach assumes that the value of the underlying variable is independent of the observer. In this model it is not. Therefore, it is debatable if this type of uncertainty analysis is mathematically appropriate for the problem at hand.

Geographical Location or Region

Unspecified (model can be used for any area).

Stakeholder Perspectives

Utility

Technologies and DER Capacity

Not specified

Applications Analyzed

Installed in distribution system to defer expensive utility T&D upgrades.

Study Period

Not applicable

Benefits Data

Deferral value of expensive T&D upgrade; value of quickly increasing capacity with DR when there is an unexpected demand increase.

Type of Data Used, Source, Year

A stylized example is used based on hypothetical data.

Overview of Specific Results and Conclusions

This paper provides an approach to formally incorporate load growth uncertainty in utility financial analysis. It also explores the relationship between expansion planning lead-time and DR modularity. It also demonstrated how to incorporate a decision-maker's risk attitude into uncertainty analysis. These conclusions imply that DR modularity and short installation lead-time increases the financial and operational attractiveness of DR devices.

Possible Study Limitations, Strengths and Weaknesses

Strengths

1) The author is tackling one of the most difficult (and likely fruitful) areas describing the extra value of DR due to its modularity and short installation time frame. He is breaking new ground.

Weaknesses

1) In Equation 1, Hoff claims that the expected cost of an investment is the probability-weighted cost of installing a DR is demand growth is high and installing traditional wires upgrade if no growth occurs. But in Figure 1, he argues that only the DR upgrade will be completed if high growth occurs. If high growth doesn't occur, neither investment is needed.

2) Hoff assigns a time and state separable utility function to the utility decision-maker. (See footnote 2.) He does not carefully explain how other assumptions would result in different conclusions. Therefore, readers do not know how general this approach is.

3) The author takes results from his Ph.D. dissertation. To understand how various mathematical steps are derived, the reader would have to consult that source.

4) Hoff does not indicate the units in which the risk aversion coefficient is measured. Therefore, the reader is unsure how he derives the present value cost in hypothetical examples he provides.

5) Hoff models a combination of profits and demand growth into uncertainty analysis. He is not clear if he is modeling an investor-owned or public utility, so it is not clear how this approach applies to utilities. Rates are regulated (although differently) in both types of utilities, so profits and demand growth are not independent. He explicitly rejects independence, but he does not model a regulator behavioral response to the interaction between profits and demand growth.

6) The author does not discuss why he discarded other mathematical uncertainty techniques such as decision analysis. His paper would be much stronger if he shows what is wrong with other uncertainty techniques and how his approach amends, modifies or improves the previous deficiencies.

7) The author solves Eq. 9 in his paper recursively to obtain an expected present value cost of expansion. This equation is separated into a modularity benefit and a short lead-time benefit, but the reader is not shown how this makes sense.

18. Applying Wind Turbines and Battery Storage to Defer Orcas Power and Light Company Distribution Circuit Upgrades

Bibliographic Information

Authors: H.W. Zaininger and P.R. Barnes
Sponsor: Oak Ridge National Laboratory and Sandia National Laboratories
Publisher: Oak Ridge National Laboratory
Date of Publishing: ORNL-Sub/96-SV115/1, March 1997

Study Objective

The purpose of the study is to conduct a detailed assessment of the Orcas Power and Light Company (OPALCO) system to determine the potential for deferring the costly upgrade of the 25-kV Lopez-Eastsound circuit by installing a wind farm and battery storage facilities as appropriate.

Study Category

Economic engineering

Methodology Used

Engineering estimates combined with a cost-benefit test.

Model(s) Used

Author's cost-benefit test.

Strengths of Model(s)

Clearly indicates the benefit categories.

Weaknesses of Model(s)

Does not clearly describe how expansion plan deferral benefits are calculated.

Geographical Location or Region

St. Juan Islands in Puget Sound north of Seattle, Washington.

Stakeholder Perspectives

Utility

Technologies and DER Capacity

500 kW 2-hour battery storage plant and a 350 kW variable speed wind turbine.

Applications Analyzed

Utility installed to reduce system peak demand and defer costly expansion upgrade plan.

Study Period

2000 to 2002

Benefits Data

Deferment of expensive circuit upgrade, reduce energy usage from the central system, reduce monthly demand charges, reduction in energy losses, attainment of Energy Policy Act production incentives for wind energy.

Type of Data Used, Source, Year

1) Measured wind speed measured by OPALCO March 1994 to February 1995
2) Wind power curve provided by authors
3) OPALCO hourly load curve, 1995
4) Wind turbine and battery costs from Oak Ridge report "The Integration of Renewable Energy Sources into Electric Power Distribution Systems" ORNL-6675/V2, June 1994
5) Energy and demand charges from OPALCO, 1996
6) OPALCO discount rate, levelized fixed charged rate and escalation rate from OPALCO, Summer 1994

Overview of Specific Results and Conclusions

A single 350 kW wind turbine installed at the peak of Mt. Constitution (163') will defer the upgrade for 2 years and has a benefit-cost ratio of 1.96. Two 350 kW wind turbines can defer the upgrade for 3 years and has a benefit cost ratio of 1.6. Three 350 kW wind turbines can defer the upgrade for 4 years and has a benefit-cost ratio of 1.47. All the above results are based on the assumption that the wind speed is at least 26 mph during OPALCO peak hours. If the wind speed is 22 mph or greater, the above devices are slightly less cost-effective, but they still have benefit-cost ratios greater than 1.

A leased battery 500 kW battery storage plant for 2 years and combining it with a wind turbine has a benefit-cost ratio of 1.24. Combining the batteries and three 350 kW wind turbines produces a benefit-cost ratio of 1.71. They can defer the expansion plan for 2 years.

Possible Study Limitations, Strengths and Weaknesses

Weaknesses

1) The study relies on one year of measured wind speed from Mary 1994 to February 1995 to project wind turbine output by hour. It the wind speed varies greatly over hours, years and months, the benefits could be very different than those presented in the study.
2) A crucial assumption is that the wind speed will be at least 22 MPH always. But, the authors did not discuss the impact on outages if the wind does not blow with sufficient speed to serve total load.
3) The results depend on a subsidy to be given to wind turbines. As of the date of the report, the subsidy was passed in the Energy Policy Act, but was not funded. If not funded, the benefits will not be as high as estimated. The expected subsidy contributes 6.5% to 9% of the wind turbine total benefits.

19. Identifying Distributed Generation and Demand Side Management Investment Opportunities

Bibliographic Information

Author: T. E. Hoff
Sponsor: unsponsored
Publisher: unpublished
Date of Publishing: December 1996

Study Objective

The objective is to present a method to estimate how much a utility can afford to pay for either a distributed generation (DG) or a demand-side management (DSM) device as an alternative to system transmission and distribution capacity upgrades.

Study Category

Economics

Methodology Used

Benefit-cost test

Model(s) Used

A break-even model based on a benefit-cost test. Inputs into the model are the costs of generation, transmission and distribution expansion plans and the output is the maximum amount the utility would be willing to pay to defer the plan for one year.

Strengths of Model(s)

The model is straightforward because hourly system and local load data are unneeded. Therefore, the model predicts the maximum value of a "perfect" device. A perfect device is one that is available whenever the utility needs it.

Weaknesses of Model(s)

This approach is not very useful to value DSM devices because many DSM devices (e.g. air conditioning) are needed during specific hours. If a DSM device is used at a time that the system and local areas do not peak, the model should not be used to impute a deferral value for it. Unfortunately, the author does not alert the reader to this issue.

Geographical Location or Region

The model is applied to a Pacific Gas and Electric (Northern California) and an Arizona Public Service example. The model, though, is general and can be applied in any service territory.

Stakeholder Perspectives

Utility

Technologies and DER Capacity

No specific DSM device or DG device is used.

Applications Analyzed

DSM placed on customer premises and DG placed in utility distribution systems to clip local and system peaks and save energy.

Study Period

1992

Benefits Data

PG&E data from 1992; Arizona Public Service data from 1992.

Type of Data Used, Source, Year

System generation, transmission and distribution capacity costs and system energy costs from PG&E; 1992.

System generation, bulk transmission and local transmission and distribution capacity costs from Arizona Public Service; 1992.

Overview of Specific Results and Conclusions

The author presents an approach to estimate the maximum amount a utility is willing to pay for a DG or DSM device. This amount equals the difference between the present value discounted cost of generation, bulk transmission and local transmission and distribution expansion costs less the present value cost of the device. It provides a quick useful approach to estimate the value of a non-traditional device with requiring only a minimum amount of data. The author applied his simple approach to complicated ones requiring much data. His simple model provided results similar to the more complicated approaches.

Possible Study Limitations, Strengths and Weaknesses

Weaknesses

1) To greatly simplify the analysis, the author assumes that the lives of the DG and DSM devices equal the life of a traditional capacity expansion plan. This is an unrealistic assumption, because wires and transformers typically last 60 years and over 100 years, respectively. Many DSM devices may last as little as 10 years and DG devices last 20 to 30 years. This simplification overestimates the maximum benefit of both DG and DSM devices.
2) The author calculates the present value capital cost of a DG or DSM in equation 13. This does not equal a life cycle cost because operating and maintenance costs are ignored. This is not important for most DSM programs, but it underestimates the cost of DG devices such as gensets that have energy operating and maintenance costs. Therefore, the benefits of DG and DSM are overvalued.
3) The author says that every 1 kW of photovoltaics can increase system output by 0.83 kW. This may be true during when the sun shines, but the author did not adjust the benefit-cost test to allow for energy production by time. Therefore, the model is not very useful to value devices that cannot be dispatched on demand.

20. Distributed Utility Penetration Study

Bibliographic Information

Author: R. Pupp, Econix
Sponsor: Electric Power Research Institute (EPRI)
Publisher: Electric Power Research Institute
Date of Publication: March 1996

Study Objective

The objective is to measure the monetary savings that can be achieved by Pacific Gas and Electric Co. (PG&E) if all cost-effective applications of distributed utility (DU) devices, direct load control and demand-side management programs are adopted. DU devices include batteries, gensets, fuel cells, photovoltaics, direct load control, and demand-side management programs.

Study Category

Economic

Methodology Used

A statistical cluster analysis is performed to place each of PG&E's 200 distribution planning areas into one of 10 representative areas. A distribution planning area is randomly selected from each of the 10 representative areas and a cost-benefit study is performed on each. Total costs and benefits are obtained by scaling the results from the 10 areas up to the 200 areas.

Model(s) Used

A cost-benefit model is used, and run from both the shareholder and society perspectives.

Strengths of Model(s)

The study bases the costs on actual distribution planning expansion plans, generation T&D costs, and system energy costs that vary by hour.

Weaknesses of Model(s)

No engineering analysis is done. It is assumed that DU can be installed in areas in which benefits exceed costs. Also, siting, environmental and permitting issues are ignored.

Geographical Location or Region

Applies to PG&E service territory which runs approximately from the Oregon border to the middle of California.

Stakeholder Perspectives

Shareholder and societal.

Technologies and DER Capacity

1) 0.5 MW to 5 MW flooded lead acid batteries; 2) 0.5 MW to 5 MW natural gas fired generator sets; 3) 0.5MW to 5 MW ground mounted photovoltaics; 4) 0.5MW to 5 MW phosphoric acid fuel cells; 5) an assortment of small demand-side management devices such as efficient refrigeration and direct load control programs.

Applications Analyzed

DU placement in the utility distribution system to defer T&D upgrade expenses, and save on system generation and transmission capacity and energy costs including line losses.

Study Period

Avoided cost data is collected from 1990 and 1993. The analysis was completed in the Fall 1995 and the savings projections apply over the 1996 to 2007 study period.

Benefits Data

The benefits data are avoided generation and transmission capacity costs, distribution expansion planning costs, and system hourly energy costs including line losses. Except for an adjustment for anticipated inflation, these costs are assumed constant for a 30 year planning period. This is a crucial assumption that is unlikely to be achieved. Generation and transmission capacity costs are marginal costs, while distribution planning costs are based on the value of deferring an expansion plan. Savings are estimated under four avoided cost scenarios. They involve low and high estimates for generation capacity costs and the ability (yes or no) to defer annual distribution upgrade costs. Some engineers believe that most annual distribution costs are not related to load growth and therefore cannot be deferred; others believe they can be deferred.

Type of Data Used, Source, Year

4) Industrial, commercial, and residential load data from 1990, PG&E; 2) Distribution planning expansion costs from 1993, PG&E; 3) Generation and transmission capacity

costs, and system energy costs including line losses, 1993, PG&E; 4) DU technology costs from various years between 1990 and 1995, PG&E and DUA
5) Crucial assumption is that avoided costs, hourly loads, DU costs and utility regulations remain constant over the 10 year period 1996 to 2006.

Overview of Specific Results and Conclusions

- Using the societal cost-benefit test, PG&E can reduce system and local costs from 30% to 50% if they adopt cost-effective DU devices in their distribution system. The range depends on the cost scenario used. If the shareholder test is used, the saving range from 2% to 20%.
- The DU devices that are cost-effective depend highly on the level of avoided cost and the cost-benefit test employed. When avoided costs are high and the shareholder test is used, 1 to 5MW gensets, residential AC and commercial thermal energy storage, and residential and commercial AC direct load control are cost-effective. Under the societal test, a wider range of devices are cost-effective including residential water heating, commercial refrigeration, lighting and AC, and various commercial and residential direct load control devices. Photovoltaics, batteries, and fuel cells are never cost-effective.

Possible Study Limitations, Strengths and Weaknesses

Weaknesses

- It is assumed that the installation of DU devices to delay a traditional build-out will not affect distribution reliability.
- The cost-benefit estimates rely heavily on the avoided and DU costs that are available. The savings estimates are highly dependent on future costs and some are projected up to 30 years into the future.
- No uncertainty analysis is performed to determine the effect of changing avoided and DU cost assumptions on the results.

21. Gas Industry Distributed Utility Market Analysis

Bibliographic Information

Authors: J.Iannucci, J.Eyer, S.Horgan, Distributed Utility Associates and R.Pupp, Econix
Sponsor: Gas Research Institute
Publisher: Gas Research Institute
Date of Publication: January 1996

Study Objective

1) Undertake a high level evaluation of the potential increase in demand for natural gas which could result from expanded use of distributed power generation resources through the year 2010. 2) Create an easy to understand intuitive method that used minimal data to evaluate the economics of distributed utility (DU) technology applications. 3) Include the uncertainties about future values of utility G, T and D capital costs in the economic analysis

Study Category

Economic

Methodology Used

Two complementary methods are used. Use the results of an extensive DU penetration study performed for PG&E that is based on detailed data; extrapolate PG&E cost-effective penetrations to the U. S. The second approach is to use a new model, DUGAS, that can be run for the U. S. and that relies on a minimal amount of data and can easily perform sensitivity analysis.

Model(s) Used

Both the Delta and DUGAS models are used. Delta requires a tremendous amount of detailed system and customer data that few utilities can afford to collect. It provides precise estimates of cost-effective DU adoptions by year, but sensitivity analysis is cumbersome to perform. The model is intricate and non-transparent making it difficult to interpret results. The DUGAS model does not provide precise estimates, but it is easy to understand and a Monte Carlo sensitivity analysis is built into the model. The Delta model is run for peaking applications only while the DUGAS model is run to analyze both peaking and baseload applications.

Geographical Location or Region

United States

Stakeholder Perspectives

Utility

Technologies and DER Capacity

Small gas turbines, internal combustion engine gensets, and phosphoric and molten carbonate fuel cells. Capacities are not specified, but they need to be sufficiently small to be able to be placed in the distribution system.

Applications Analyzed

To reduce utility system peaks and for baseload energy applications.

Study Period

2000 to 2010

Benefits Data

In both the Delta and DUGAS models, the benefits of operating a DU in a utility's distribution system are avoided generation, transmission and distribution capacity costs, and system energy costs including line losses. Delta only analyzes peaking applications while DUGAS analyzes both peaking and baseload applications.

Type of Data Used, Source, Year

The Delta model uses PG&E data from various years. Industrial, commercial, and residential load data from 1990; distribution planning expansion costs from 1993; generation and transmission capacity costs, and system energy costs including line losses from 1993 and DU technology costs from various years between 1990 and 1995 from PG&E and DUA. A crucial assumption is that avoided costs, hourly loads, DU costs and utility regulations remain constant over the 10 year period 1996 to 2006.

DUGAS use both peaking and baseload generation and transmission avoided costs determined by expert judgement. T&D avoided costs are developed based on EIA, FERC and NERC data tempered with expert judgement. Environmental and cogeneration values (0 to $0.01/kWh for both) are determined by expert judgement. Utility baseload and peak energy costs are taken from EIA. Gas costs obtained from GRI. DU costs based on GRI and DUA data various years.

Overview of Specific Results and Conclusions

- For peaking applications, DER penetration will use between 10 to 60 BCF and 30 to 140 BCF of natural gas by 2005 and 2010, respectively. In 2010, DER peaking applications will total 10 GW.
- For baseload applications, DER penetration will use between 60 to 200 BCF and 200 to 1000 BCF by 2005 and 2010, respectively. Fuel cells and small turbines will share most of this increase.

Possible Study Limitations, Strengths and Weaknesses

- Neither Delta nor DUGAS calculate the effect of DU adoptions on utility reliability.
- Only the utility perspective was analyzed. As DU prices drop, other applications such as remote or customer on-site installations may additionally increase gas demand.
- DU is expected to meet a portion of load growth and is not expected to replace embedded generation. If it replaces embedded non-gas-fired central generation, gas use may be higher. On the other hand, if DU replaces gas using central station generation, gas demand will not increase as much as estimated.
- A major strength of DUGAS is that it uses a statistical spread of avoided costs to explicitly recognize that these costs vary across utilities and time.
- Gas is assumed to be physically available where a DU device is to be sited. It is possible that a gas line will have to be installed increasing DU costs.

22. Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation

Bibliographic Information

Authors: C.Woo, D.Lloyd-Zannetti, R.Orans, B.Horii, Energy and Environmental Economics and G.Heffner, EPRI
Sponsor: None
Publisher: The Energy Journal
Date of Publication: 1995

Study Objective

To show the large variations that exist in distribution marginal costs within a utility's service territory; to show how these costs vary among utilities; and to demonstrate the usefulness of these costs in determining the technical potential for distributed generation (DG) within two utilities.

Study Category

Economic

Methodology Used

Present worth distribution marginal costs are calculated for Pacific Gas & Electric (PG&E) and Public Service of Indiana (PSI). These costs are ordered from high to low for each utility. Then the net cost ($/kW) of a DG device is computed. (The net cost equals the DG capital cost less the sum of DG operating costs and the avoided system generation and transmission costs achieved by placing the DG in the distribution system.) DG devices are cost-effective in planning areas in which the net DG cost is less than the present worth marginal capacity cost.

Model(s) Used

The present worth marginal cost method is used to determine distribution marginal costs. A one-year present worth marginal cost equals the savings of deferring a traditional distribution planning area plan for one year divided by the load growth that is expected during the deferral year. Specifically, let A equal the discounted cost of a traditional build-out plan where the plan generally consists of numerous small steps stretched over several years. Let B equal the discounted cost of the identical plan, but with each small step pushed back exactly one year. A one-year marginal cost equals (A - B)/(one-year load growth). A two-year marginal cost equals (A - C)/(two-year load growth) where C is the discounted cost of the plan with all steps deferred exactly two years. These marginal costs are called marginal distribution capacity costs (MDCC).

<u>Strengths of Model(s)</u>

Provides a transparent method to determine how distribution planning costs vary over planning areas and time.

<u>Weaknesses of Model(s)</u>

The present value method has not been accepted by regulatory agencies around the country as the preferred method of capacity costing. The preferred method remains the traditional economic marginal cost. That is, it equals the cost of providing 1 MW of additional capacity in a traditional build-out. These costs are computed from embedded costs and any changes in inflation or device costs anticipated in the future.

Geographical Location or Region

Data from California and Indiana, but the approach can be used by any utility.

Stakeholder Perspectives

Utility

Technologies and DER Capacity

Not specified.

Applications Analyzed

DG placement in the distribution system to defer costly distribution upgrades

Study Period

1994 and 1999

Benefits Data

Benefits equal the savings achieved by placing DGs in planning areas in which the MDCC is greater than the net DG cost. In a particular planning area, assume that the MDCC equals $800/kW and the net DG cost is $300/kW. Then savings are $500/kW if the DG is placed in the planning area to serve load growth rather than proceeding with a traditional build-out.

Potential savings are based on many implicit crucial assumptions. First, it is assumed that an expansion plan can be deferred with no affect on reliability. Second, if an expansion plan is deferred one year, say, then the sequence of "mini" projects that comprise an expansion plan can be deferred exactly one year. Third, there is no effect on reliability if a DG is "installed" to defer an expansion plan. Fourth, there are no costs due to environmental, siting, permitting, or operating issues.

Type of Data Used, Source, Year

Data on 201 distribution planning areas from PG&E. Year of data not provided. Data on 152 distribution planning areas from PSI. Year of data not provided. However, MDCCs are provided for 1994 and 1999, so these data must have been collected before 1994.

Overview of Specific Results and Conclusions

- 1994 MDCCs vary widely among PG&E's distribution planning areas; 19% have zero MDCCs; the average and maximum MDCCs are $230/kW and $1,173/kW.
- 1994 MDCCs vary widely among PSI's distribution planning areas; 73% have zero MDCCs; the average and maximum MDCCs are $64/kW and $1,040/kW.
- The average MDCCs between 1994 and 1999 vary little for either utility, but the MDCCs between planning areas change. This can happen as follows. Planning area 1 might have had the highest MDCC in 1994, but after a build-out in 1995, it has the lowest costs in 1999. Similarly, planning area 2 might have had a zero MDCC, but due to high load growth prompted the need for an expensive upgrade, the MDCC jumped between the two years.
- If the net life-cycle DG capacity cost is $300/kW, then PG&E has 5,300 MW of cost-effective DG applications in 1994; the corresponding figure for PSI is 184 MW.
- If the net life-cycle DG capacity cost is $500/kW, then PG&E has 450 MW of cost-effective DG applications in 1994; the corresponding figure for PSI is 147 MW.

Possible Study Limitations, Strengths and Weaknesses

- There is no discussion of change in reliability due to deferring an expansion plan. No data on the reliability of DGs. No mention of safety, siting, operational, or permitting issues and how these may affect the DG lifecycle costs. Therefore, the penetration estimates are only a technical potential.

- No discussion of the types of DG used. Perfect DGs are implicitly assumed.
- No information is provided on DG operating hours and operating costs per kW, generation and transmission avoided costs, DG life, or discounting factors. (The salvage cost is zero.) Therefore, the reader is unable to determine how each factor contributes to DG net cost, leaving the reader unable to perform a "back of the envelope" DG penetration estimate for another utility.
- No discussion of how many hours a DG needs to be operated to defer an expansion plan and no recognition that DG operating hours must increase for longer deferral periods. Both affect net DG cost. Pratt et al. in Potential for Feeder Equipment Upgrade Deferrals in a Distributed Utility properly recognize this as an important operating issue.

23. The Value of Distributed Generation: The PVUSA Grid-Support Project Serving Kerman Substation

Bibliographic Information

Authors: Tom Hoff, Howard Wenger
Sponsor: Pacific Gas and Electric Co. (PG&E)
Publisher: Pacific Gas and Electric Co.
Date of Publishing: Oct 15, 1994 (draft)

Study Objective

This study has three objectives. First, photovoltaic (PV) output from an installed plant is used to measure the magnitude of distributed benefits and to determine if these benefits exceed central station PV benefits. Second, this study improves methods used to calculate the value of distributed generation. Third, it begins to develop a simplified distributed generation valuation method.

Study Category

Economic

Methodology Used

Benefit analysis

Model(s) Used

Various engineering models are used to measure attributes needed to calculate benefits.

Strengths of Model(s)

Benefits are based on field measurements on an installed 500 kW PV plant rather than basing them on engineering estimates. The level of measurement detail is great.

Weaknesses of Model(s)

Does not provide a generalized model to value distributed generation.

Geographical Location or Region

Kerman, California in PG&E's service territory.

Stakeholder Perspectives

Utility

Technologies and DER Capacity

500 kW PV plant

Applications Analyzed

The PV plant is installed in the distribution system (on a feeder) of the utility for generation, transmission and distribution deferred capacity benefits, energy and line loss savings, reliability enhancement, and minimum load benefits.

Study Period

1994

Benefits Data

Generation, transmission and distribution deferred capacity benefits, energy and line loss savings, reliability enhancement, and minimum load benefits.

Type of Data Used, Source, Year

Engineering estimates are made in the field and presented in the report. For example, actual kW and kWh PV output are measured and these numbers are used in the benefit analysis. Field measurements from 1994.

Overview of Specific Results and Conclusions

1) System and distributed benefits measured in the field equal $2,655 / kW while pre-installation engineering economic estimates are $5,655/kW. Therefore, actual benefits are lower than estimated benefits.
2) Actual benefits are lower than estimated benefits for the following reasons. Solar insolation at the installed site is less than the hypothetical pre-installation site. Actual load growth is higher than projected load growth. Actual reliability benefits are not as high as projected. After the PV installation, energy prices, generation capacity avoided costs and environmental values fell.
3) Actual engineering estimates show that the 500 kW PV plant: a) increases feeder capacity; b) cools substation transformer by 4° C on a peak load day; c) increases substation transformer capacity by 400 kW; d) provides almost 3 volts (on a 120 volt base) of voltage support; e) reduces the number of transformer load tap changes; f) increases transmission system capacity by 450 kW; g) increases generation system capacity by almost 400 kW; h) produces over 1 GWh of energy per year with the output highly correlated with daily peak energy requirements; i) reduces energy losses by 5%; and j) reduces yearly pollution by 150 tons of CO_2 and ½ ton of NO_X.

Possible Study Limitations, Strengths and Weaknesses

Strengths

1. The authors very carefully describe the engineering estimates that are made in the field and how these estimates are used to determine economic benefits.
2. While the authors do not develop a generalized model of distributed utility benefits, they do make headway in evaluating the uncertainty and modularity benefits of distributed generation.

24. The Integration of Renewable Energy Sources into Electric Power Distribution Systems – National Assessments

Bibliographic Information

Authors: P. R. Barnes, J. W. Van Dyke, F. M. Tesche, H. W. Zaininger
Sponsor: Oak Ridge National Laboratory (ORNL)
Publisher: Oak Ridge National Laboratory, report # ORNL-6775/V1
Date of Publishing: June 1994

Study Objective

The study objective is to measure the benefit-cost ratios of PV and wind turbine systems in every state. Three PV and two wind turbine price scenarios are used. Both system and local benefits are included and the analysis is done from the utility perspective.

Study Category

Economic

Methodology Used

Benefit cost analysis

Model(s) Used

A standard benefit-cost approach.

Strengths of Model(s)

Transparent

Weaknesses of Model(s)

Results depend heavily on the cost assumptions made.

Geographical Location or Region

Each state in the United States.

Stakeholder Perspectives

Utility

Technologies and DER Capacity

Photovoltaic and wind turbine systems; size not mentioned.

Applications Analyzed

Utility applications in the distribution system for energy and peak load reduction.

Study Period

1994 to 1998

Benefits Data

Generation benefits include fuel savings, avoided generation capacity, and reduced emission penalties. Distribution benefits include additional capacity credit, reduced T&D losses, credit for externalities, deferred T&D upgrades, voltage and VAR control, and enhanced distribution circuit reliability.

Type of Data Used, Source, Year

PV and wind turbine current and projected costs are selected by expert judgment. Emissions cost taken from state regulations.

Overview of Specific Results and Conclusions

The benefit/cost ratio for PV systems is calculated for capital costs of $7000/kW, $3250/kW and $2500/kW. (The latter costs are expected to be achieved by 1998.) O&M costs of 4 mills/kWh are used. Ratios are presented graphically by states. Even at the low PV price, the benefit/cost ratios are not greater than one in any state. In the best area, Southern California, they range from about 0.7 to 0.9 for the lowest price PV plant.

The benefit/cost ratio for wind turbine systems is calculated for capital costs of $1000/kW and $750/kW and O&M costs of 10 mills/kWh. At $1000/kW, wind turbines are cost-effective in much of New England, California, Nevada, Hawaii and Alaska. At $750/kW, wind turbines are more cost-effective in the above states and Wisconsin is added to the list of cost-effective states.

In general, the greatest potential for PV and wind turbines is in states with high fuel costs, good wind and solar insolation, high environmental externality charges, and high generation and distribution utility avoided costs.

Possible Study Limitations, Strengths and Weaknesses

1. The authors are very hazy on where various data come from. For example, the source of generation capacity costs is not discussed.
2. The authors assume that PV and wind turbines increase rather than decrease reliability.
3. Balance of system costs for both turbines and PV do not include land, permitting and siting costs. Analysis is done by state with the PV capacity factor used for installations throughout a state being highest that exist within the state. The authors use a real discount rate of 7%, because the White House Office of Management and Budget uses it. In finance theory, the discount rate is a weighted average cost of

capital unique to each firm and depending on the risk of projects, and for these projects is likely higher. These issues all lead to an overestimated benefit-cost ratio.

25. The Integration of Renewable Energy Sources into Electric Power Distribution Systems – Utility Case Assessments

Bibliographic Information

Authors: H. W. Zaininger, P. R. Ellis, J. C. Schaefer
Sponsor: Oak Ridge National Laboratory ORNL)
Publisher: Oak Ridge National Laboratory, ORNL/SUB/92-SK724
Date of Publishing: June 1994

Study Objective

The objective is to study the engineering issues and economic benefits of installing photovoltaics (PV), wind turbines (WT) and battery storage systems at various places in seven U. S. utility distribution systems. Engineering issues include individual utility design standards, voltage levels and regulation, VAR analysis, load density, reliability, load profiles, solar insolation, and wind resources. Economic benefits include distribution deferrals, line loss reduction, power factor correction benefits, reliability enhancements, pollution reduction credits, and generation, transmission and distribution deferrals.

Study Category

Engineering economic analysis

Methodology Used

Benefit-cost model

Model(s) Used

SOLMET, ERSATZ and NRSDB models used to estimate insolation at various locations.

<u>Strengths of Model(s)</u>

These models predict solar insolation based on historical data.

<u>Weaknesses of Model(s)</u>

Each physical area has unique characteristics of light and wind that is not predicted by the models.

Geographical Location or Region

Seven U. S. utility service territories in California, New Mexico, Vermont, Georgia, Florida, Tennessee and Washington.

Stakeholder Perspectives

Utility

Technologies and DER Capacity

Photovoltaics, wind turbines and battery storage; sizes not discussed.

Applications Analyzed

Utility-installed applications for energy supplementation and peak load reduction on the central system.

Study Period

1994

Benefits Data

Economic benefits include distribution deferrals, line loss reduction, power factor correction benefits, reliability enhancements, and generation, transmission and distribution deferrals

Type of Data Used, Source, Year

1) Wind turbine installed cost $1013/kW with O&M of 0.7 ¢/kWh. Data from EPRI, 1989.
2) 3-hour battery plant cost $950/kW with turnaround efficiency of 75%. EPRI, 1989.
3) PV fixed and two-axis tracking cost $7070/kW and $8270/kW. O&M is 0.6 ¢/kWh. SMUD 1994 and EPRI 1989.
4) Each of the seven utilities in this study has different design characteristics and equipment costs. The data are too numerous to individually list here.

Overview of Specific Results and Conclusions

Seven utility case studies are used to determine the benefit-cost of wind turbines and PV at various spots in the distribution systems of these utilities. PV is not cost-effective in any utility at any distribution location. The ratios are 0.5 and lower.

On the other hand, wind turbines are cost-effective in each of the three applications discussed. The lowest benefit-cost ratio is 1.20. One wind turbine and battery system application is analyzed. It has a benefit-cost ratio of 1.03.

Possible Study Limitations, Strengths and Weaknesses

<u>Strengths</u>

Actual utility projects are used to evaluate wind turbines and PV rather than a hypothetical siting. Various suburban distribution locations are analyzed along with a PV plant at the end of a rural feeder. Each of the seven utilities in this study has different engineering design criteria. The PV and wind turbines had to be designed to fit with utility design requirements. Therefore, the study is based on “real-world” applications.

26. Potential for Feeder Equipment Upgrade Deferrals in a Distributed Utility

Bibliographic Information

Authors and Affiliations: R. G. Pratt, Z. T. Taylor, L. A. Kievgard, A. G. Wood, Pacific Northwest Laboratory

Sponsoring Agency: Pacific Northwest Laboratory
Publisher: Not provided
Date of Publication: Mid-1994

Study Objectives

- Simulate the penetration of DU assets into feeder equipment utilization under several scenarios for the purpose of providing capacity on feeders to defer traditional feeder upgrades.
- Develop algorithms to assess utilization of feeder equipment and DU assets.
- Begin to develop a model that can be used to analyze the economics of DU in the distribution system and then in the utility system.
- Conduct a cluster analysis on the feeders using the load data to identify prototypical feeders on which simulated penetrations may be performed.

Study Category

Economic; Statistical

Methodology Used

Economic: estimate the DU penetration on each of 3000 feeders.
Statistical: use cluster analysis to assign each of 3000 feeders to 30 prototypical feeders. A representative feeder from each of the 30 groups is selected and used in the analysis.

Model(s) Used

Analyses run on each of the 30 prototypical feeders and DU penetration is estimated for each over a 10 year simulation period. If the feeder's load exceeds its capacity, either the feeder is upgraded or a genset is "installed" to displace peak loads. If a genset needs to operate more than the maximum hours per year assumed in the analysis, the genset is removed (or deactivated) and a traditional feeder upgrade is done. The analysis is done for various scenarios in which feeder growth rates, capacity factors, and maximum DU operating hours are varied. All the feeders that belong to a particular prototypical feeder are assigned the DU penetration estimated for the prototypical feeder. The DU penetration for all 3000 feeders is obtained by summing the estimated DU penetration over all feeders.

<u>Strengths of Model(s)</u>

Strength is that model is based on real feeder data with realistic growth rate increases, DU operating characteristics and upgrade factors.

<u>Weaknesses of Model(s)</u>

- Cannot use their approach to model value of demand-side management, because they employ dispatchable DU devices only.
- Results specific to utility studied, because feeder load patterns are specific to utility's customers.
- Recognize but do not model feeder capacity that varies with temperature, season variation.
- Recognize but do not model that in some cases growing feeder loads may be shifted to another substation to avoid a capacity upgrade on a feeder.

- Recognize but ignore the associated costs of upgrading substations and transformers when feeders are upgraded.
- Assume feeder loads grow at a uniform rate.
- "Genset" assets are dispatchable capacity relief technologies. Therefore, technologies such as demand-side management, photovoltaics, batteries, and wind turbines can not be analyzed in this study.
- Recognized but ignored costs and difficulties of obtaining siting, permitting and complying with air quality regulations.
- If a genset is "installed" on a feeder, it is assumed that there is a physical place for installation.

Geographical Coverage of the Study

Geographical location of customers not revealed.

Stakeholder Perspectives

N/A

Technologies and DER Capacity

- Gensets or "genset" assets which are dispatchable; these include fuel cells, load control, or interruptible service contracts.
- Gensets and "genset" assets are limited to 3 MW per feeder because feeders have a maximum capacity.

Applications Analyzed

- Feeder demand support to defer traditional upgrades.

Study Period

A hypothetical period of time 10 years in the future.

Benefits Data

Simulated DU penetration crucially depends on the assumptions made about feeder growth rates, capacity upgrade factors, and maximum DU operating hours. Simulated DU penetration increases with higher feeder growth rates, decreases with higher capacity factors (the percentage increase in feeder capacity when a traditional feeder upgrade is done), and decreases with lower maximum DU operating hours. With a 10% load growth, maximum DU operating hours of 200, and a capacity upgrade factor of 25%, feeder capacity grows from 25 GW to 40 GW over 10 years with DU providing over 3.5 GW (10%) of the load. If the growth rate is 2% per year (other factors constant), DU penetration is only 1% of total feeder capacity over 10 years. If the capacity upgrade factor is higher, say 100%, then DU penetration is only about 50% of the penetration when the capacity upgrade factor is only 25%. Little additional DU penetration is obtained if the maximum number of operating hours of the DU is greater than 438 per year. However, if the maximum hours are dropped to 200 (upgrade factor 25% and 10% load growth), DU penetration drops from about 3.4 GW after 10 years to above 3 GW. Depending on the assumptions made, DU penetrations range from 1% to 10% of total feeder peak load.

Type of Data Used (Source, year)

Used hourly load for about 3000 feeders from 1990 (source of data not revealed). Estimated loads for each feeder were calculated by using actual metered load from about 6 feeders on which each of about 3500 customers from each rate class had their load measured each 1/2 hour. Customers are stratified by region, average daily consumption, average monthly peak demand, and standard industry classification. Customers are assigned to one of the classifications and a simulated hourly load is created for each customer. Individual feeder loads are created by aggregating the simulated hourly load of each customer on that feeder.

Specific Results, Conclusions and Overview

Study has shown that gensets and dispatchable genset assets may play a large role in the feeder distribution system under various load growth assumptions. Under conditions of high load growth, low capacity upgrade factor, and a high number of maximum operating hours per year, DU penetration can serve as high as 10% of feeder peak load in 10 years. While not studied, the study mentions in passing that many feeders are very "peaky." That is, they peak for only about 30 hours or less per year. These feeder peaks might be able to be shaved with batteries or other storage.

Possible Study Limitations, Strengths and Weaknesses

Strengths

- A great strength is that the study is based on actual feeder data.

Weaknesses

- The study did not examine the effects that genset reliability and greater DU penetration have on feeder reliability.
- The data are specific to the utility studied and may not be transferable to other utility systems.

27. Battery Energy Storage: A Preliminary Assessment of National Benefits

Bibliographic Information

Authors: A. Akhil, H. Zaininger, J. Hurwitch, J. Badin
Sponsor: Sandia National Laboratories
Publisher: DOE/Sandia Report SAND93-3900
Date of Publishing: December 1993

Study Objective

The objective is to estimate the combined benefits of battery energy storage for generation spinning reserve and dispatch; generation, transmission and distribution substation deferral; and customer monthly demand charge reductions. Benefits are estimated from 1995 to 2010. An economic market potential for battery applications is estimated.

Study Category

Economic

Methodology Used

Rudimentary economic cost-benefit analysis

Model(s) Used

No model used.

Strengths of Model(s)

Very straightforward presentation that provides an initial cost-benefit ratio and market penetration.

Weaknesses of Model(s)

Much of the analysis relies on expert judgment on costs and benefits.

Geographical Location or Region

The study is done on the eleven states in the Western States Coordinating Council and then the results from the WSCC are extrapolated to the U.S.

Stakeholder Perspectives

Utility

Technologies and DER Capacity

Battery energy storage. The type and size of batteries is not discussed.

Applications Analyzed

Utility grid-connected to serve as a substitute for generation spinning reserve and dispatch; generation, transmission and distribution substation capacity deferrals; demand-side management applications on customer site

Study Period

1993 to 2010

Benefits Data

Generation spinning reserve and dispatch value. Generation, transmission and distribution substation deferral values. Customer monthly demand charge reductions.

Type of Data Used, Source, Year

Expected market penetrations are selected by expert judgment. Generation loads, transmission miles, etc. taken from various DOE and SNL publications.

Overview of Specific Results and Conclusions

By 2010, there will be a market potential of 11.3 GW of battery storage. Benefits for generation (spinning reserve, dispatch and capacity deferral) is $10.3 billion; transmission and distribution benefits are $3.9 billion and customer benefits are $3 billion. Battery costs are $9.1 billion and the benefit-to-cost ratio is 1.9.

Possible Study Limitations, Strengths and Weaknesses

The study claims to be estimating the deferral benefits of battery systems, but actually the study estimates the value of displacing generation. This is an extremely important distinction, because deferral benefits are much less than displacement benefits. It does not seem reasonable that batteries will displace peaking generation when batteries cost $800/kW and peaking generation only costs $500/kW (authors' estimates).

It appears that some benefits may be counted twice. For example, batteries may be installed as demand side management devices on the customer site to reduce demand charges. But it simultaneously defers generation, transmission and distribution substation upgrades. Therefore, the benefits are not independent and should not be counted twice.

Spinning reserve and customer demand side management benefits are discounted at 6% between 1995 and 2010. Six percent is the weighted average cost of capital. This is an extremely low cost of capital. It should be about 12% that, if used, would reduce the authors' benefits.

Authors assume that battery storage is perfectly reliable and batteries are always charged when needed.

28. Distributed Utility Valuation Project Monograph

Bibliographic Information

Authors: Joe Iannucci, PG&E; Steve Chapel, EPRI; Lynn Coles and Yih-huei Wan, NREL; Ren Orans, Energy and Environmental Economics; Roger Pupp, Quantitative Solutions; John Grainger, North Carolina State University; Charles Feinstein, Santa Clara University
Sponsors: PG&E (Joe Iannucci), EPRI (Steve Chapel), NREL (Lynn Coles)
Publishers: PG&E Report 005-93.12, EPRI Report TR-102807
Date of Publication: August 1993

Study Objective

To explore and quantify where possible, the business, economic, technical and policy issues in moving toward the Distributed Utility concept for the utility of the future.

Study Category

Policy, electrical engineering and economics in equal emphasis.

Methodology Used

Opinions and consensus of national and international experts wee used. The team determined what was known and not known about the forces which might lead to (or block) a distributed utility future. Task forces were setup to individually study the:

- Business Aspects (regulatory, institutional, rates, ownership issues, planning issues (models, planning approaches, data needs, uncertainty))

- Technical Strategies (characterizations of the distributed generation technologies, distribution planning and operation methods, generation and transmission planning with distributed generation embedded, current impacts of distributed generation)
- Research and development needs (planning and economic research, technology research, institutional issues)

These task forces met separately and then reported back bi-monthly to the team in formal review meetings throughout the country. A national consensus was developed on these issues which were documented in this landmark report.

Model(s) Used

None.

Geographical Location or Region

US and Europe.

Stakeholder Perspectives

Primarily utility, some customer aspects studied.

Technologies and DER Capacity

No quantitative analysis was included.

Applications Analyzed

All utility applications: distribution, transmission, generation replacement or deferrals, power quality and reliability enhancements. All of these were examined individually and holistically to see if they could potentially be better served at least partially by an alternative, the distributed utility concept.

Study Period

Approximately 1990 through 2010.

Benefits Data

Mostly transmission and distribution upgrade projections, current generation expansion plans and plant costs, current reliability and power quality levels. The national and international review and research team also brought in broader data and analyses. Load duration curves from thousands of feeders.

Type of Data Used, Source, Year

Multiple PG&E rate case data, circa 1990-1992, national perspective brought in by NREL and EPRI participation, national and international review team from two dozen utilities and research and development organizations.

Overview of Specific Results and Conclusions

- The economies of scale in central generation have saturated.
- There are new competitive pressures on utilities.
- Real marginal costs of transmission and distribution have increased.
- Environmental pressures have increased.

- Real costs of modular distributed generation technologies decreasing moderately.
- Utilities must find ways to make capital more productive; the use of the Distributed Utility concept may allow this if new planning methods are developed.
- The vertically integrated utility may have to be altered.
- The potential benefits of using the Distributed Utility concept appear great.
- An extensive Distributed Utility research and development plan was developed.

Possible Study Limitations, Strengths and Weaknesses

Although this study was non-quantitative in large measure, this was the first concerted effort to look at the possibility of a Distributed Utility future. It was national in scope (sponsored by three strong research and development organizations) and drew prominent advisors from the US and Europe. It did not yet address the restructuring trends which were still five years in the future in 1993, nor did it fully address all customer issues, only those customer side of the meter issues which were in the purview of the utility.

29. Photovoltaics as a Demand-Side Management Option: Benefits of a Utility-Customer Partnership

Bibliographic Information

Authors: H. Wenger, PG&E; T. Hoff, Innovative Analysis; R. Perez, AWS Scientific
Sponsor: unlisted
Publisher: World Energy Engineering Congress
Date of Publishing: October 1992

Study Objective

Neither customer nor utility installed photovoltaic (PV) systems are cost-effective at current costs. However, a combined utility and customer PV plant installed on the customer side of the meter might be cost-effective. The objective of this study is to measure the cost-effectiveness of a PV plant under a utility-customer partnership.

Study Category

Economics

Methodology Used

Benefit-Cost Tests

Model(s) Used

The Ratepayer Impact Measure (RIM), total resource cost (TRC), participant and a "suggested" TRC benefit-cost test are used.

<u>Strengths of Model(s)</u>

The RIM, participant and TRC tests are well known and accepted and were developed to evaluate demand-side management (DSM) programs.

Weaknesses of Model(s)

The "suggested" TRC test includes tax impacts in the standard TRC test. The "suggested" TRC test is not a accepted by regulators, and the results that are drawn from this test will be contentious.

Geographical Location or Region

Pacific Gas and Electric (PG&E), San Francisco, CA

Stakeholder Perspectives

Utility, ratepayer and a utility/ratepayer combination
Technologies and DER Capacity
PV plants; 15 kW

Applications Analyzed

Installed on customer side of meter for both utility benefits (deferral of costly upgrades) and customer benefits (reduction of energy and demand charges)

Study Period

1992

Benefits Data

System (generation and bulk transmission avoided capacity and energy) benefits and distributed (local T&D deferral costs, hardware life extension, loss reduction and voltage support); PV tax credits and utility rebate.

Type of Data Used, Source, Year

1) PG&E bulk system and distributed benefits taken from an earlier PG&E report by Shugar, et. al.: "Benefits of Distributed Generation in PG&E's T&D System: A Case Study of Photovoltaics Serving Kerman Substation."
2) PV costs are assumed (author's term); no date provided
3) PV tax credits and rebate; neither source nor date provided

Overview of Specific Results and Conclusions

Using PG&E benefits data and a PV capital and O&M cost of about $6500 per kW, the RIM and participant cost tests both have a benefit-cost ratio of 1.01. The TRC test has a ratio of 0.56. The "suggested" TRC test has a ratio of 1.02. Therefore, the utility-customer partnership is cost-effective from three perspectives. The results are sensitive to the amount of tax benefits and rebates given. If no tax benefits were given, the benefit-cost ratio would be greater than one only if the PV cost fell to about $4000 per kW or less.

Possible Study Limitations, Strengths and Weaknesses

Strength

The authors provide a general procedure to estimate benefit-costs tests within a utility-customer partnership. The actual estimates are less important than the concept, which they elucidate well.

Weakness

The authors do not give sufficient detail to understand how costs and benefits of the PV plant are calculated. For example, they provide a PV cost of about $6500 per kW in capital and O&M costs, but they do not provide PV output, the energy cost at which the PV output is valued, etc. Also, they don't reveal if the PV cost is an expected cost or market cost.

30. Distributed Photovoltaic Generation: A Comparison of System Costs vs. Benefits for Cocopah Substation

Bibliographic Information

Author: R.A. Lambeth, Project Manager
Sponsor: Sandia National Laboratories
Publisher: Arizona Public Service (APS)
Date of Publishing: October 1992

Study Objective

The objective was to evaluate the cost-effectiveness of using distributed PV generation on APS' distribution grid as an alternative to conventional power production, transmission and distribution capacity additions.

Study Category

Economics

Methodology Used

Benefit-cost

Model(s) Used

Standard benefit-cost test

Strengths of Model(s)

Transparent

Weaknesses of Model(s)

Geographical Location or Region

Yuma, Arizona in the APS service territory.

Stakeholder Perspectives

Utility

Technologies and DER Capacity

Single axis PV arrays between 500 kW to 5 MW.

Applications Analyzed

Generation located near or at the end of a distribution feeder for energy augmentation and peak load relief. The PV plant also defers a substation and feeder upgrade.

Study Period

1996 to 2026 (the study provides 1996 base year costs for all benefits implying that the study period begins in 1996).

Benefits Data

Displaced central station energy and capacity; reduced line and transformer losses; reduced reactive power requirements; deferred transmission and distribution facilities; enhanced reliability; environmental mitigation; other benefits. Other benefits include improved public opinion, reduced capital risk, increased siting flexibility, close match of PV output to demand, and increased solar research experience.

Type of Data Used, Source, Year

Energy and capacity values supplied by internal APS documents. Forecasts 30 years in the future beginning 1996. Other benefits assumed to be 5% of the total of non-other benefits.

Overview of Specific Results and Conclusions

APS scanned all their feeders to find the site with the highest potential for benefits. This site was used in the benefit-cost analysis. The breakeven point is defined as the value of benefits when the benefit-cost ratio is 1. APS estimates that the breakeven value for PV installed in their high cost area is $3.44/Watt. This is about 2 ½ times the cost of PV as of 1992. This number includes all benefit categories. If "soft" benefits comprising reliability, environmental and other are excluded, the breakeven value of PV is $2.34/Watt. The authors conclude: "Given the above results, PV-Gen is not economically competitive with other alternatives until the net cost (including any special tax credits or other subsidies that might be granted) is at or below $3.44/Watt."

Possible Study Limitations, Strengths and Weaknesses

Strengths

1) The authors very neatly describe each benefit and how each is calculated. This is very helpful to the reader.
2) Much background information such as feeder hourly load profiles and engineering characteristics of the feeders are provided.

31. Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District

Bibliographic Information

Authors: R. Orans, C.K. Woo, J.N. Swisher, B. Wiersma and B. Horii
Sponsors: Pacific Gas and Electric and Electric Power Research Institute
Publisher: EPRI – Report #TR-100487

Date of Publishing: May 1992

Study Objective

The objective is to determine whether or not demand-side management (DSM) programs can provide a lower-cost alternative to traditional capacity planning. If yes, a second objective is to determine which DSM programs are cost-effective and how many of each type should be installed to develop a least cost integrated plan.

Study Category

Economic

Methodology Used

Benefit-cost analysis

Model(s) Used

Delta model – a giant benefit-cost calculator developed for, and owned by, EPRI.

Strengths of Model(s)

It is dynamic. That is, DSM programs continue to be "placed" into a planning area until the local peak is sufficiently reduced so that additional DSM units are no longer cost-effective.

Weaknesses of Model(s)

Not transparent. It is difficult to understand how the model determines which programs are cost-effective. Also, while the model is dynamic, the number of DSM programs installed generally equal the number of residential and commercial sites in a planning area.

Geographical Location or Region

Brentwood, California; 25 miles east of San Francisco in the service territory of Pacific Gas and Electric Co.

Stakeholder Perspectives

Society (ratepayer and utility combined) and ratepayer

Technologies and DER Capacity

The number of DSM technologies included is too numerous to list, so a general list is given. They include: a) residential AC, cooking, drying, refrigeration, water heating and load management; and 2) commercial cooling, lighting, refrigeration, water heating and load management.

Applications Analyzed

DSM installed at customer sites to reduce distribution upgrade costs and avoid system generation and transmission capacity costs and system energy costs adjusted for line losses.

Study Period

1993 to 2015

Benefits Data

Reduced distribution upgrade costs, and avoided system generation and transmission capacity costs and system energy costs adjusted for line losses.

Type of Data Used, Source, Year

Data of many types are used. All data are from PG&E from various years between 1990 and 1993. Data include: 1) generation and transmission avoided costs for 20 years into the future; 2) system hourly energy and line losses; 3) distribution expansion plans and costs; 4) DSM prices and installation costs; 5) 8760 end-use commercial and residential hourly load curves; 6) number of commercial and residential customers in the distribution planning area. Data on DSM efficiencies and technical specifications taken from various years from sources as follows: PG&E, CEC, LBL, ACEEE, SERI, NPPC Electric Power Plan, and FSEC Passive Cooling Handbook.

Overview of Specific Results and Conclusions

The results demonstrate that there is a significant opportunity for PG&E to improve the cost-effectiveness of DSM programs by placing them in the distribution system. This is true because the DSM programs can earn distribution deferral benefits in addition to system benefits. DSM programs that clip the local peak are more cost-effective, because they earn distribution benefits in addition to reducing system energy requirements.

The above study conclusion depends on the benefit-cost test used. If the Ratepayer Impact Measure is used, no commercial or residential DSM programs have a ratio greater than 1. If the Total Resource Cost test is used, many of these programs surpass a ratio of 1 and the conclusion above holds.

DSM programs reduced "on paper" the local peak by 9.0 MW and 7.0 MW in the first and second years of analysis, respectively. Load growth is predicted to be 7.7 MW per year, so DSM can only defer the distribution expansion plan about 1 year.

Possible Study Limitations, Strengths and Weaknesses

<u>Strengths:</u>

1) Developed a new methodology to evaluate the deferral of distribution upgrades. It is called area and time specific costs to denote that distribution costs vary by area within a utility's service territory and by year.
2) Benefit-cost ratios are determined from two stakeholder perspectives.

<u>Weaknesses:</u>

1) An enormous amount of data is needed, much of which utilities do not have, because it is very expensive to collect. For example, most utilities do not have 8760 end-use hourly customer class load. Its capture requires special hourly electrical meters, and staff to process the data. Data collection costs should be included in the analysis, but the study did not mention if it did or didn't include these costs.
2) Costs need to be projected far into the future. For example, generation capacity costs for 20 years into the future are required. These data are assumed to be known with certainty and only a rudimentary uncertainty analysis is performed.

3) It is assumed that DSM does not affect the reliability of the system.
4) No modeling of the relationship between energy prices and energy usage is done. With energy price changes, the hourly load curves shift and the benefit-cost tests change value. For example, it might be more cost-effective to simply rely on peak load pricing to shave peaks, but this is not discussed.
5) The model determines a 25-year integrated investment plan that delineates the particular DSM devices and traditional upgrades required in each year of the plan. The study does not entertain the likelihood that important future events may occur that may render the plan irrelevant.

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ABSTRACT *(Maximum 200 word).*
The electric power industry in the United States is undergoing dramatic change. Once totally controlled by utilities that had monopolistic holds on the supply, transmission and distribution of electricity in their service areas, the electric power system is being deregulated, introducing competition among electricity providers who can distinguish themselves by price, services and other factors. The new electric power system will feature advanced technologies and services that can be used on-site or located in close proximity to the load, instead of depending solely upon large, central station generation and transmission. Using a variety of advanced modular generating technologies (including small-scale renewables), distributed energy resource (DER) plants supply base-load power, peaking power, backup power, remote power and/or heating and cooling, and in some cases supply higher and more reliable quality power. Currently, DER represent a minor part of the electric supply system. If the potential of DER is to be realized in the new electric power market, a full understanding of the value and benefits these technologies provide to the electric system is necessary. This report includes 30 key quantitative studies reporting on the values and benefits of distributed energy generation technologies (including renewables) in various applications, as well as a matrix that permits key comparisons.

14. SUBJECT TERMS
analysis; distributed energy resource; DER; electric power; utilities; deregulation; transmission; distribution; renewables; base-load power; peaking power; backup power; remote power; heating and cooling; Distributed Utility Associates; Larry Goldstein

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