EPAct 2005 Section 1817
Public Comments

Following are all comments received by the U.S. Department of Energy on the February 2007 draft of the Study, “The Potential Benefits of Distributed Generation and Rate-Related Issued That May Impede Their Expansion.” All comments are provided in their original, unedited format.

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1. Idaho Energy Division

I have not made an exhaustive analysis of the study, but in the process of skimming the test believe noticed two omissions, and will be brief.

1. Combined Heat and Power is mentioned in the definition of terms section, but I did not see any further elaboration on its potential benefits as a utility owned DG source, particularly if the fuels envisioned are a combination of biomass and natural gas in a fluidized be combustion process. If such a DG station were properly sited to provide heat for industrial processes or space conditioning (even summertime cooling using adsorption technologies) the entire process immediately becomes more that twice an energy efficient, and with biomass fuels, largely carbon dioxide neutral, while providing all the other DG benefits to electrical system reliability and resiliency. If I have missed this I apologize. If it is missing, it represents a huge omission and suggest you view the Short Video on DE at the WADE website. (worldwide Alliance for Decentralized Electricity).

2. Again, if this point is made my apologies. for the past many years electric utilities have used transmission wheeling fees as a method to increase the cost of DE and, in many cases, defeat its economics and make projects unviable, claiming that space on the transmission line is already fully subscribed. The fact is that wheeling bulk power may represent a wheeling issue, or it may not. The physics of electricity demand that electricity will seek the shortest least resistant path to ground. for much DE this means the power supposedly being wheeled, is actually being consumed by the nearest electricity customer and may in fact be unloading the transmission system. This is a difficult proposition to prove, but the science is undeniable, and a uniform mechanism to estimate the benefit or harm in this regard should be developed so that utilities are not left to their own devices and then back those with self serving statistics and studies for Public Utility Commission approval.

Thank you.

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2. Mark B. Lively, Lively Utility (Consulting)

Page 4-12 of the report discusses the use of distributed generation in regard to providing frequency response. The analysis focuses on a rate structure that relates to the capacity of the DG and thus the potential benefits that DG can provide. India has structured its market on an energy basis, with the price for Unscheduled Interchange being a function of the frequency.

India has found that this pricing structure has improved its metric for frequency control by a factor of 10 relative to before introducing this pricing structure. I have included a discussion of the Indian pricing of UI in "Reply Comments Of Mark B. Lively In Regard To Using Prices Instead Of Penalties For (1) Regulation And Frequency Response, (2) Energy Imbalance, (3) Generator Imbalance, And (4) Inadvertent Energy", Preventing Undue Discrimination and Preference in Transmission Services, FERC Docket No. RM05-25-000 and RM05-17-000, 2006 September 20, which is available for free download from my web site.

I have described a similar approach for paying DG for assisting utilities in regard to reactive power and the use of the distribution grid in "
Constructing a Competitive Distribution Market in Reactive Power: Comments of Mark B.
Lively to the Office of Gas and Electricity Markets," 2005 December 15.
Office of Gas and Electricity Markets refers to the UK regulator. This paper is also available for free download from my web site.

Call me with any questions.

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3. Steve Hall

My name is steve hall I built the first bio mass plant in Arizona under the 2001 E.P.S I started it with a grant from the forest service.i bought wood from forest health work on public lands. the cost of wood continued to rise and was only able to get about 10% of my total supply the 1st year. the rest of my fuel came from a green waste operation in showlow,and lakeside. The 2nd year I was only able to get 15% of my total supply from the forest service.the remaining supply came from fortapache timber co.both the green waste and the f.a.t.co.supply was dirty wood and hard to burn...the dirt in the wood also destroyed the multi cones,and I failed an emissions test.during this time,. we had problems with the utility. it seems no one new that there there would be an inbalance on the system, and we would be limited to 1.5 MWH for a 9hour period of time,also an oil recloser trip, the utility caused that triped the plant over 500 times, to make a long story short,D.G is good for a small community. It needs a professional operator,a utility that is not threatened by it.and will take responsibility.and public servent needs to remember who they work for.if your not going to support the public policy then don't waste the tax payer money.the plant is down right now.wating for a better time.

4. Therese Stovall, ORNL

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1. Introductory Comments

These comments all refer to the file named "1817_Study_2_05_07_(2).pdf. The technical editors did an incredible job, especially given the broad scope and the widely varying writing styles of the original material. The Executive Summary is a masterful improvement compared to the last draft I saw. The addition of "Summary and Overview" and "Major Findings and Conclusions" to each chapter was a wonderful idea and well executed.

However, even though the editors got it 95+% correct – there are some significant problems. A Department of Energy report shouldn't include an erroneous definition of the word, "energy", or an incorrect interpretation of a load-duration curve. Many direct quotes lost that notation, and proper attribution must be corrected. Chapter 6, land-use benefits, is so full of errors and inconsistencies that it threatens the credibility of the whole report.

I've divided my review comments into four categories. The first I've called priority comments. These include errors in technical content and plagiarism issues. The second I've called editorial comments. These are mostly simple corrections that I noticed in passing. I strongly urge you to make the changes noted in these two categories. The third section discusses problems in Chapter 6. The fourth category I've called suggestions. These are just my opinions offered for consideration.

2. Priority Comments

2.1 Plagiarism Issues

I used a Word style to mark direct quotes, and I suspect that notation was lost in the many handoffs between versions. It's important that all quotes be indicated correctly.

1. Please add a credit section for the 'Definitions and Terms", because many of these were lifted verbatim from one of the following sources. Also, you may want to put a note to this effect at the start of the section. ("power reliability" includes quote marks but no attribution; I'm not sure which of these sources it came from.)

Sources for Definitions and Terms:

OSHA's Electric Power glossary of terms, at (http://www.osha.gov/SLTC/etools/electric_power/glossary.html#t)

NERC Glossary of Terms Used in Reliability Standards, Effective Date April 1, 2005, found at: ftp://www.nerc.com/pub/sys/all_updl/standards/sar/Glossary_Clean_1-07-05.pdf

MISO Glossary of Terms: http://www.midwestiso.org/glossary.shtml

Matthew H. Brown, Richard P. Sedano, Electricity Transmission: A Primer, National Council on Electricity Policy, June 2004, http://www.raponline.org/pubs/electricitytransmission.pdf

"Measurement Practices for Reliability and Power Quality," Kueck, John and Kirby, Brendan, ORNL, 2004. http://www.ornl.gov/sci/btc/apps/Restructuring/ORNLTM200491FINAL.pdf

Tom Short, Reliability Indices, EPRI PEAC, T&D World Expo 2002, Indianapolis, IN, May 7-9, 2002, http://www.epri-peac.com/td/pdfs/reliability2002.pdf

2. Page 2-4, bottom half: all the paragraphs starting with the one labeled, "SAIFI," are a direct quote from Kueck, J.D., B.J. Kirby, P.N. Overholt, and L. C. Markel, 2004, "Measurement Practices for Reliability and Power Quality: A Toolkit of Reliability Measurement Practices" ORNL/TM-2004/91, June.
The first paragraph on page 2-5 is not a quote, but should cite the same source.

3. Page 3-7 last full paragraph is a direct quote – the citation shown is correct.

4. Page 3-9, second paragraph is a continuation of the direct quote in the first paragraph, except that the figure number has been changed.

5. Pages 3-13 and 3-14: Last paragraph on page 3-13 and first 4 full paragraphs on page 3-14 are all part of a direct quote from Kingston and Stovall, 2006.

6. Page 3-16: Central paragraph is a continuation of the direct quote from Hoff et al 2006.

6.a. Page 3-17: Figure 3-11 should have the same footnote as figure 3-10.

7. Page 4-3: Top paragraph is not a quote, but should show a reference at the end of the paragraph to (Kirby and Hirst, 1997) Figure 4-1 should show the same source.

7.a. Page 4-3, last paragraph, lost citation should be inserted:
Two studies that include detailed grid analysis for strategic locations illustrate significant reactive power savings associated with DG. The first of these studies estimates that a 500 kW DG installation would save losses in the following amounts: 114 kVAR on the distribution system, 113 kVAR on the transformer, and 225 kVAR on the transmission line(Shugar 1990). The second study examines specific feeders in Silicon Valley; results show that siting DG reactive sources close to the load in these geographic areas could reduce overall reactive power consumption by about 30% (Evans 2005).

8. Page 4-5, last paragraph is a direct quote – citation for Perekhodstev is correct.

9. Page 4-6, Central section with bold list is a direct quote from Perekhodstev.

10. Page 4-11 and 4-12:
The bullet list that starts on the bottom of page 4-11, continues on 4-12, and inclusive of the paragraph following the last bullet, is a direct excerpt from Ilex Energy Consulting 2004

11. Page 5-1, paragraph following the bullets:
Very minor changes were made to the verbiage so that it is no longer a direct quote, but it is still so similar to the original that the Kueck et al 2004 citation should go at the end of the paragraph.

12. Page 5-2:
The second paragraph below figure 5-1 (starts with "Voltage sags…") is a direct quote – the attribution shown is correct.

13. Page 5-3, last paragraph continued on top of page 5-4: This paragraph was closely adapted but is not a direct quote.

14. Page 5-5: First 3 indented paragraphs are from a quoted bullet list from the GE report. The 4th indented paragraph is not a bullet and not a quote, although the citation shown is correct for the information.

15. Page 5-6: First non-indented paragraph should be indented because it is part of the quote.

16. Page 5-7: "For example" should be indented because it is part of the quote.

2.2 Text Issues

Page 1-13, last paragraph and figure and table on 1-14:
"Utility rate structures can inadvertently discourage investment in local energy sources that bypass much of the energy losses outlined in Figure 1.10. Table 1.2 provides a few examples of the impact of rate design on the simple payback of DE."
PROBLEM – Figure 1-10 doesn't outline any losses at all, it defines jurisdictions.
PROBLEM - Table 1.2 cannot stand alone. You need to add a citation/reference and to give at least some outline of the host of implicit assumptions that go into these numbers – e.g., system size/capacity, investment amount before the factors listed in the table, operating strategy – peak hours only or base loaded, is it a chp system?

Page 2-1, first 2 paragraphs: (rationale, again to be consistent with NERC terminology)
Electric system reliability is a measure of the system's adequacy to meet the electricity needs of customers. …...

System operational reliability is also dependent on events that affect daily operations, including the decisions made by grid operators in real-time in response to changing system conditions.

Page 3-1 (rationale, THE WORDING DESCRIBING THE LOAD DURATION CURVE WAS CHANGED AND IS NOW **WRONG**; first the graph was misread and second "peak demand" was equated with "capacity")
Electricity demand fluctuates throughout each 24-hour period. Demand is typically lowest overnight, when commercial and residential buildings are inactive. Demand typically "peaks" in mid-afternoon, with the highest system-wide peaks typically occurring during hot summer afternoons. If the 8,760 hours in each year are shown in aggregate, with the total demand plotted for the year as in Figure 3.1, the number of hours each year in which demand peaks is clearly quite small. In this example, 80% of the time this feeder line is being used to about 37% of its peak demand. This is a typical pattern of usage in the electric distribution system for feeder lines that serve primarily commercial and residential customers.

Other possible substitutions for the next to last sentence:
A: In this example, the demand exceeds 80% of its peak demand only 3% of the time, or approximately 300 hours per year.
B: In this example, the demand exceeds 50% of its peak load only about 40% of the time.

Page 5-8, last paragraph, last sentence: We don't report any examples where DG led to power quality problems because we didn't find any such measurements. We do report concerns and simulations to this effect. I suggest changing the last sentence to read:
However, there are also concerns that the use of DG could lead to power quality problems.

Page 7-8: second paragraph under nuclear: I can just see this last sentence being quoted out of context. Does DOE really want to promote such speculative hyperbole? It's not needed, especially in light of the more complete information provided in the text's next paragraph.
Nuclear plants use electricity for regulation and control of energy production, as well as for emergency warning systems. A loss of power in this sector could result in the complete shutdown of a nuclear power plant, which could in turn disrupt the production of significant amounts of electricity, potentially affecting a large number of households and businesses.

Page 8-18, bottom of page, last full sentence – reason: convoluted phrase, implies the meter would be 'drawing energy'
A simple method is to install the generation on the customer side of the meter and allow the meter to run backwards when the generator produces more energy than the customer needs.

Page 8-21, last sentence in last paragraph appears to precede a missing list. If the list is made up of the remainder of the chapter, that is not clear from the outline/title levels.

2.3 Organization Problem in Chapter 4

Page 4-9, 3 lines from the top:
There has been a misunderstanding regarding the organization from here to the end of the section. If you want a subsection within 4.5.1.2 labeled "Organized Wholesale Power Markets", it should be populated with the material currently contained in the shaded box on pages 4-10 and 4-11.

The material on page 4-9 that starts on the 4^{th} line with "PJM" must be preceded with a label, "4.5.1.3 Black Start". Note that there is no material related to "traditional vertically integrated markets" for the Black Start section, so you really don't need the sub-head of "organized wholesale power markets" within that section.

The subsection labeled "United Kingdom…." on page 4-11 should be designated 4.5.1.4 because this section covers both reserves and reactive power.

2.4 Definitions

<u>Page xxii</u>
SAIDI equation is wrong, mea culpa, denominator should be "total number of customers served"

$$SAIDI = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customers served}}$$

<u>Page xvi (</u>rationale: <u>– if you correct nothing else in the whole report, please make this correction – it's just plain wrong.)</u>
demand: The rate at which energy is used by the customer, or the rate at which energy is flowing through a particular system element, usually expressed in kilowatts or megawatts. (Energy is expressed in kilowatt hours or megawatt hours; power is expressed in kilowatts or megawatts.) The demand may be quoted on an instantaneous basis or may be averaged over a designated period of time. Demand should not be confused with load. Types of demand are defined below.

Page xix (rationale: the current definition conflicts with the correct definition on page 2-3)
loss-of-load probability: The amount of time that generation is expected to be insufficient to meet demand over a specific period of time, based upon a probabilistic analysis. A typical LOLP is "one day in ten years" or "0.1 days in a year."

Page xix(rationale: many on-site installations are owned by third parties, and this report gives examples where a few are owned by utilities – also the motivations are myriad)

on-site distributed generation includes photovoltaic solar arrays, micro-turbines, reciprocating engines, gas turbines, and fuel cells, as well as combined heat and power, which are installed on site.

Page xxi (rationale: policy decision to follow recent NERC verbiage, change made in Chap 2 text but I missed the change here)
reliability: Electric system reliability has two components–adequacy and operational reliability. Adequacy is the ability of the electric system to supply to aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Operational reliability is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer services. Also see power reliability.

Page xxiii (ditto rationale re NERC verbiage)
transmission reliability margin: This is reserved transmission capacity to address unanticipated system conditions such as normal operating margin, parallel flows, load forecast uncertainty and other external system conditions. It is the amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be operationally reliable.

3. Editorial Comments

3.1 Acronyms and Definitions

These acronyms are defined but never used:
Delete "(AESC)" on list of references and pp A-4.
Delete "(ICF)" on page A-3.

Add to Acronyms and Abbreviations:
CBEMA Computer and Business Equipment Manufacturers' Association
DR Demand Reduction
ERO Electric Reliability Organization
FACTs Flexible Alternating Current Transmission system
ITIC Information Technology Industry Council
KVA kilovolt-amperes
LOLE loss-of-load expectation
MMBtu million Btu
MW million Watts
MWh million Watt hours
NIPP National Infrastructure Protection Plan
ORNL Oak Ridge National Laboratory

PNNL Pacific Northwest National Laboratory
RDC Resource Dynamics Corporation
RMS root mean square
SEMI Semiconductor and Materials International
VLR Value of Reduced Load
VRI Value of Reliability Improvement

Modify in Definitions and Terms:
ASIDI: Average System Interruption Duration, reliability measure that includes the magnitude ($kVA_{sustained}$)of the load unserved during an outage of duration ($D_{sustained}$), and the number of customers served (N_{served}). Expressed mathematically as:

ASIFI: Average System Interruption Frequency, reliability measure that includes the magnitude of the load unserved during an outage ($kVA_{sustained}$) and the total load served by the system (KVA_{served}). Expressed mathematically as:

base load plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to serve all or part of the minimum load of a system,

real power, reactive power – add a period at end of first paragraph. Make the word change shown in the following paragraph for consistency and clarity:

Both voltage and current travel in the form of sine waves. These two waveforms travel over the same line but are never in perfect sync with each other. If they were in synch that would mean there would be no reactive power, and total power would equal real power. …

Add these two to Definitions and Terms:
RMS Voltage An AC voltage follows a sinusoidal wave form that varies from $-V_{peak}$ to $+V_{peak}$, so it's average voltage is zero, which is not useful in determining the amount of power available. Therefore, a mathematical process is followed that squares the voltage, takes the average of the square, and then takes the square root of that average. This produces the root mean square voltage, which is also the DC voltage that would deliver the same power to a resistive load as would the sinusoidal AC waveform. For a sinusoidal wave form, the $V_{RMS}=0.707 \times V_{peak}$.

Volt RMS see RMS Voltage

3.2 Miscellaneous Corrections

Format: Figure numbers in captions use hyphens, text references use periods – they should be consistent.

Page xiii – why is there a box around the first definition?

Page 1-2 Extra period at end of last paragraph

Page 1-4, top:
expand electricity distribution capacity to power air conditioning systems during hot afternoons, but that expanded capacity came with a very poor "load factor." There were very few hours each day in which those kilowatt-hours of electricity were being purchased, but revenues were needed to pay for the additional wire, transformer, and substation capacity (Figure 1.2).

Page 1-5 – delete "," after "Pacific" in first line of second paragraph.

Page 1-6, last paragraph of section 1.4
Distributed generation systems … physical needs. For example, space heating and cooling require thermal as well as electric energy. By employing ...

Page 1-6 Delete "," in last line of next to last paragraph.

Page 1-8, figure 1-7
This figure is almost impossible to read, especially since more than half of the information presented is too small to be visible on the scale chosen. Considering the broad range of the data, it would take a logarithmic scale to make it meaningful – but that is not generally understood by non-technical readers. I suggest strongly that you replace this figure by a simple table. I can help you harvest the numbers you need from the RDC report, but am unfamiliar with the renewable numbers that you used to supplement the RDC values.

Page 1-11 – last word of top paragraph is "shaving", not sharing.

Page 1-11 – first paragraph in section 1.9 – add a "," after "All such DG systems"

Page 1-15, line 2, delete extra period.

Page 3-11, first full paragraph:
The capacity of the transmission system is an even more complex concept, because it changes with system conditions on a moment-by-moment basis and is dependent on the location of generation injections and demand withdrawals.

Page 2-14, caption for figure 2-3, all caps VOS

Page 2-14, caption for table 2.1, add "(VRI)"

Page 3-7, caption for table 3.1, add "(VLR)" – then remove "VLR=value of reduced load" below table (font size problem if you keep it there).

Page 3-7, use "keep with next" to keep fig 3-5 caption with the figure

Page 3-11, last sentence of section 3.6
Appendix A provides a detailed example of how one of the methodologies can be applied.

Page 3-13, next to last paragraph, subject / predicate agreement
A recent examination of deferred T&D costs and long-run marginal costs from multiple perspectives in the SCE region has been made (Kingston and Stovall 2006).

Page 4-2, line 3, ‘gird’ should be ‘grid’

Page 4-10 – funny box line around the NYISO part of the box

Page 5-2, last line above “5.2 Power Quality Metrics”, delete extra period.

Page 5-2, last paragraph, referral to “Section 5”, should be to “Section 2”.

Page 5-2, next to last line, insert “and” before “Crest”.

Page 5-2, line 3, change ITI to ITIC

Figure 5-1 legend, change ITI to ITIC

Page 5-4, last paragraph, second line, change “cases” to “case”.

Chapters 7 and 8, I question whether some of the footnotes should properly be references given in chapter 9 (e.g. footnote 76 on page 8-17 and 77 on page 8-19)? Is it proper to cite a plan unavailable to the public (footnote 50)?

Page 7-2: Footnote 52 appears to be referring to page numbers in an ibid that points to a one-page EIA table of generating plant statistics.

Page 7-2, first paragraph, “100,000 transformers”, change to “100,000 large transformers” – because small transformers hang on poles outside almost every house, so there have to be more than 100,000.

Page 7-7, next to last paragraph, first line, change “transportations” to “transportation”
Page 8-1, 6th line of text, change “contain” to “contains”

Chapter 8 – there are some table call-out problems that appear to be the result of some previous reorganization. Table 8.4 (page 8-7 and 8-8) is never referenced, but the material in Table 8.4 appears to match the text reference to Table 8.6 on page 8-32. (Table 8.6 was previously referenced in a manner appropriate to its contents.) Table 8.10 is not referenced anywhere.

Page 8-9, 2nd line of last paragraph, wording problem “charges that provide service to load utilities” – I don’t know what it’s trying to say.

Page 8-10, 3rt line of text, delete first occurrence of word “costs”

Page 8-15, first full paragraph, font size inconsistency

Page 8-17: Figure 8-1 needs to be larger to be readable

Page 8-23 – phrasing/word problem in second full paragraph – also, I would urge you to consider moving footnote 81 material up into the body of the text where it can be more easily read:
One of the benefits of DG is that transmission and distribution capacity and energy losses are eliminated or reduced by local generation, sited close to the load. This means that the purchases of excess supply from the DG or CHP facility at or near a load’s site is worth more than the same amount of capacity and energy purchased from a remote site.81 For example, a utility purchase of capacity and energy could be delivered to other nearby loads with losses that are negligible when compared to delivery from central plants located miles away. A lack of price recognition for these loss reductions can be an impediment to the expansion of DG facilities.

Page 8-29, table 8.8, New York entry – shouldn’t “>” be a “<”?

Page 8-29, table 8.8, Wisconsin – alignment problem between 4 lines in col 2 and 4 lines in col 3

Page 8-31, bottom paragraph, change “SGP” to “SGIP”

Page A-4, first full paragraph, reference to Section 2 should be reference to Section 3.5.

Add a bookmark for Appendix A in the pdf file.

Page A-5, paragraph introducing list at the bottom:
The peak demand growth over a specific historical and/or future time period consistent with the investment data is used to determine the incremental load growth for which T&D investments are planned. Special consideration should be given to the following factors:

Page A-6
The portion of this investment …. The sum of the square of these two components gives the square of the total power capability, which is measured in …

Page A-7 first full paragraph:
The first 2 sentences should be appended to the previous paragraph. The rest of that paragraph should be deleted because it exactly duplicates the previous paragraph.

Page A-7, last line before Figure A.3, change “has” to “have” (subject is “numbers”)

Page A-8, 3rd line of text, change “costs” to “cost”

3.3 “Sentech Study” References

Page 2-15 and 2-16. The Sentech report has now been published and can be cited:
Hinrichs, D. and M. Goggin, 2006, 2006 Update of Business Downtime Costs, ORNL/TM-2006/592, ORNL/SUB/06-4000049375, Oak Ridge National Laboratory, December
Suggest the following changes to that text:

Recent studies generally indicate that outage costs can be as high as 100 times the average price of electricity, depending on the type of customer. Some surveys indicate the cost to be between \$0.25/kWh to approximately \$7/kWh. For example, Navigant Consulting estimates the reliability benefit from avoided downtime at \$1/kWh (Navigant Consulting 2006).

A recent study involved the review of a set of commonly cited power outage cost data ranging from \$41,000/h for cellular communications to \$6,500,000/h for brokerage operations. That study sought “to assess the cost of power outages to businesses in the commercial and industrial sectors using the best and most current data available, short of surveying a statistically significant pool of building owners.” Downtime cost components were categorized as either tangible or intangible as shown in Figure 2.4.The study used existing literature based on surveys of actual end users that covered outages of 20 minutes, 1 hour and 4 hours in duration. The data from the surveys show that the duration of an outage has a large effect on estimated downtime costs. Although all sub-sectors estimate similar downtime costs during short outages, as the duration increases, the costs identified by different commercial sub-sectors begins to vary more widely (Hinrichs and Goggin, 2006).

At the 20 minute duration, almost all commercial sub-sectors have comparable downtime costs. However, as an outage persists and food spoilage sets in, costs for restaurants (food service) and grocery stores (food sales) increase faster than for other sectors. Figures 2-5 and 2-6 provide another way to illustrate these changes in the distribution of costs for commercial sub-sectors over the duration of a blackout. One can see that the share of costs experienced by food service and sales grows until it accounts for the majority of costs after four hours of outage duration. These figures also illustrate that offices incur large costs during the initial minutes of a blackout, but subsequent losses are much smaller. Presumably, this is because of the high cost of data loss and damage to computer equipment that occurs during the initial moments of a blackout; more data collection and analysis would be needed to confirm this assumption (Hinrichs and Goggin, 2006).

Figure.2-5. Commercial Sub Sector Power Outage Costs (Hinrichs and Goggin, 2006)
Figure 2-6. Outage Costs after 20 Minutes and After 4 Hours (Hinrichs and Goggin, 2006)

4. Chapter 6 Problems (including Appendices B and C)

Chapter 6 contains valuable material, especially the AEP transmission study, the pipeline ROW data, RDC estimates of DG land use, and the value of conserved agricultural lands. However, Chapter 6 also contains so many errors that it damages the credibility of the remainder of the chapter. Significant revision is required.

4.1 Major Content Errors

Pages 6-1 and 6-2: There is a major problem with the discussion of land use for central generating stations. The text at the top of page 6-2 talks about land per plant and the table makes a switch to land per MW. I suspect the EIA would be upset/outraged to be blamed as the source for Table 6.1. Also, even though the footnotes say that the estimates are dependent on an assumed plant size, the numbers in the last column equal the numbers in the third column, translated to acres and multiplied by the fifth column – so it looks like plant size was never used and these are really per plant numbers, not per MW values. It makes sense to produce a weighted (by national production) average of the land use per kW or land use per kWh. It does not make sense to produce some weighted average plant size, because it would characterize no real plant size and would represent no "average" capacity size.

Footnote 40 lists assumed plant sizes and the numbers make no sense:

- I checked out the nuclear category by downloading an EIA data set for 2005(existingunits2005.xls from http://www.eia.doe.gov/cneaf/electricity/epa/epat2p2.html). It showed 104 nuclear units at 64 plant sites, for an average of 1,650 MW per plant, or 1,015 MW per unit, both of which are much larger than footnote 40's 467 MW for the typical nuclear plant.
- I didn't make the calculation for coal, but the value of 202 MW for the average coal plant looks even more absurd.
- I looked up the Spitzley and Keoleian 04 report, which was revised in 05. They assumed plant sizes of 360 MW for coal, 505 for natural gas, and 1000 for nuclear – so the Chapter 6 values didn't come from that source. It should also be noted that S and K's values for coal plants are for prototype new technology plants, not representative of an average coal plant.
- Footnote 40 talks about the MWh for each plant type, where it should obviously be MW.

Conflicting Chapter 6 values for central station power land requirements:

- Table 6.1: 1217.86 Acre/MW (my conversion shows this = 53,000

ft^2/kW)

- Footnote 49: 233.18 ft^2/kW (too high and artificially precise)
- Table 6.6 and 6.9, coal: 69 ft^2/kW
- Table 6.6, Natural gas: 12 ft^2/kW
- Table 6.9, Natural gas: 11 ft^2/kW
- Table 6.6 and 6.9, Nuclear: 42 ft^2/kW
- Note that table 6.9 applies an unrealistic central station capacity to these values to come up with unrealistic plant sizes.
- A limited survey of plant data for several coal and nuclear central stations gave me numbers ranging from 0.2 to 0.6 acres/MW (eg, see http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/arkansas.html, 1100 acre/(846+930 MW)=0.6 acre/MW=26 ft^2/kW.)

In Table 6.1, the technology for natural gas is listed as "Integrated Gasification Combined Cycle Plant" – that is a coal technology, not a natural gas technology. (Apparently, this error originated with Spitzley and Keoleian.)

Page 6-3 refers to EIA 2003 – A better citation (I couldn't find this one in chap 9) is needed to help understand if the numbers quoted come from an examination of ROW or from other general EIA data bases. That is, did EIA give the 3rd bullet of 76 miles/unit, or did the authors get that by dividing 1140 by 15? If the latter, there's a problem (besides that appearance that it comes from EIA), because the 1,140 miles of transmission line may not have anything to do with the additional 15 units – the generating units could have been added to existing sites and been within the existing line capacity. The transmission could have been added to serve new load demographics. I may have found the pertinent EIA file, f412sch1103.xls at http://www.eia.doe.gov/cneaf/electricity/page/eia412.html. If so, it shows 108 separate transmission line projects, which wouldn't show any correspondence to the addition of 15 "units".

Page 6-3: last paragraph and 3 bullets before 6.4 section head. When it says "This data is based on the following assumptions," what data is it talking about? Were these assumptions used by AEP to derive the data quoted in Table 6.3? It doesn't seem likely. Note that the 2nd bullet in the second set is the same as the 3rd bullet in the first set, although it's presented as a 'fact' in the first set and as an 'assumption' in the second.

Page 6-8 top of page, 2nd sentence – this conclusion is not supported until/unless the problems at the beginning of this chapter are fixed and there is a clear and defendable comparison of acre/kW between central and dg resources.

Page 6-8, table 6.6, much improved over Table 6.1, but I suspect these numbers are still too high based on erroneous values used for average plant capacity.

Page 6-10: (rationale – no basis given for these numbers)
This comparison does not include a reduction in ROW acquisition costs

Page 6-11/12: The fuel cell at Columbia Blvd was deactivated in 05. Microturbines were installed in 03 with plans for recip additions in late 07.

Page 6-13: How can you suggest that a central station plant, requiring 1200 acres, would be built to generate 13 kW, or 200 kW, or even 1.6 MW???

Page 6-14: Where did the 9.21 acres come from in Table 6.13? Again a reference to EIA 2003 - EIA put out a large number of publications in 2003; please provide a more complete citation.

Section 6.11: re "DG systems that are incorporated into buildings, in an engine room, on a rooftop, or immediately adjacent, result in a smaller land use footprint." The space inside, or on top, of a building in an urban area can have a much higher value than open space. Consider the $/ft^2 rental costs inside an urban high rise. Or consider the significant roofing support that had to be added to our demo grocery store's roof-top installation.

Appendix B is a reiteration of the material already published in Chapter 6. It adds little if any new information. This appendix should be deleted. One redeeming difference – table B.1 quotes 1200 acres, not 1200 acres/MW.

The information contained in <u>Appendix C</u> may be a useful addition to chapter 6. However it is so poorly written that that you may just want to delete it. Examples: (1) first paragraph – 'literary justification'…. 'following this appendix', (2) second paragraph – 'assumed to range'… 'information used to choose', (3) third paragraph tells us twice that the Irwin high range estimate is excessive – but then tells us that it 'was chosen…for this analysis'….. Not to mention, another reference to the EIA 2003 with the addition of a new undefined EIA 2002.

4.2 Other Corrections

NUMBERS: The numbers in chapter 6 tables need to be stated on a comparable basis, not ft^2/kW for one and acre/MW for the other.

NUMBERS: Please scan all of chapter 6 for significant digits. Example, first bullet on page 6-4 should read "from $13,000 to $59,000/acre in 2003, or $14,000 to $64,000/acre in 2006 values."

NUMBERS: Is it even necessary to translate from 03 to 06 when the numbers are broad range ball-park estimates? (If you keep the 3 year inflation: was general inflation used, or was Florida land inflation used?)

Page 6-4, section 6.5 heading – isn't this backwards? Shouldn't it be the impact of ROW on T&D costs rather than the other way around?

Page 6-4, next to last paragraph last sentence. $400,000/mile comes out of nowhere and begs the question re why it is conservative. The next paragraph helps to put it in perspective – so you might want to move some of the AEP #s up ahead of this overall statement. In the last paragraph, we switch from miles/ft/acres. Not having those conversion factors easily at hand, it would be nice if the last value of $39,075/acre were also given in $/mile. Also, is the EIA citation correct here? Wouldn't it be the AEP citation?

Page 6-4, last sentence:(rationale – logic)
Accordingly, AEP has revealed that it will construct the 765-kV line and will expend ROW acquisition costs of $39,075 per acre

Page 6-6
Central power facilities in the U.S. are sited in rural, urban, and suburban areas. Land values in urban areas have greater per-acre values in comparison to rural areas. Land values in urban areas vary drastically across the United States, making it difficult to estimate national averages.

Figure 6-2 on page 6-7 needs to be larger to be readable.

Caption on Fig 6-3 doesn't follow text and doesn't match content, unless an acre is a unit of value?

Page 6-8, first bullet –"campus"?? just say Multiple DG equipment and systems are used to provide a capacity of 250 MW including 2 MW PV, 50 MW residential CHP, 98 MW industrial CHP, 100 MW commercial CHP.

Table 6.6: Delete this table, and the 1-line paragraph that introduces it, because the first line is repeated in table 6.9 and the other two lines are never used.

Table 6.7: Choose between table 6.2 and 6.7, don't need them both.

Table 6.8: (1) how do you get 12 MW from a 2 MW PV array? (2) footnote 44 refers to a previous subsection that isn't here.

Table 6.10 – I suggest deleting the last line because land price escalation seldom follows general inflation numbers, especially near urban centers.

5. Suggestions

5.1 Definitions and Introduction

Page xvi:
peak demand: The highest electric requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the

sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system at that particular point in time.

Page xx:
peak load distributed generation is normally installed, owned, and operated by utilities, located at a substation, or in close proximity to load centers and is used to meet period of high demand. These units are most often natural gas-fired engines or combustion turbines.

Page xxii:
SARFIx: System Average RMS Variation Frequency Index is a power quality metric that provides a count or rate of voltage sags, swells, and/or interruptions that occurred over the assessment period per customer served, where the specified disturbances are those with a magnitude less than x for sags or a magnitude greater than x for swells.

Page xxiii:(note, Watt and Joule are both capitalized)
Watt (W): The unit of electric power, 1 Watt=1 Joule/second. One ampere of current flowing at a potential of one volt produces one watt of power.

Page 1-1, box:
But steam turbines (circa 1884) were more energy efficient, smaller, and quieter than reciprocating engine generators.

Page 1-1, bottom 2 paragraphs:
During the latter part of the century, smaller scale electric power technologies also advanced. For example, improved materials and engineering designs for photovoltaic panels, microturbines, fuel cells, digital controls, and remote monitoring made it possible to tailor energy supplies for specific customers.

The savings realized from mass production (i.e., building ever bigger power plants and using modern materials to increase their operating temperature and efficiency) reached its peak in the 1960s, and the economic benefits of mass customization (smaller, modular systems sized for the energy required) eventually began to outpace the production cost savings of legacy technologies (Hirsh 1989).
…

Page 1-2, first full paragraph:
In such instances, it is often the case that DG is a financially attractive option that can be installed and operated safely, and in concert, with the grid, thus producing benefits both for the consumer and the electric power system overall (Kingston et al. 2005).

Page 1-4 last paragraph and figure 1-3 on page 1-5.

The North American Electric Reliability Council (NERC) consists of Regional Reliability Councils representing NERC regions across the country. By comparing annual peak demand to annual average demand[2] in one region, the Electric Reliability Council of Texas, Inc. (ERCOT), it can be seen that the two factors track in a fairly proportional manner, with peak demand growing slightly faster than average (Figure 1.3).

Change the figure title from “aggregate” to “average.” Change the figure legend from “consumption” to “average”. Change footnote 2 to read: “The average annual demand was calculated by dividing the annual consumption by 8766 hours/year.” There is no need to explain how you translated GW to MW, and the “factor of 1,000” just adds confusion.

Page 1-5: There are too many insignificant digits in the first paragraph – the numbers should read, “2.5% (from 56.4% in 1993 to 55.0% ...)

Pages 1-5 and 1-6: Figures 1-4 , 1-5, and 1-6 have been made too small, or the font size should have been larger to start with.

Page 1-6, top text:
and SCE. Demand analysts hypothesized that as more houses were built inland, as house size increased, and as electricity bills declined as a percent of total income, more air conditioning would be used, and the residential load factor would decline. The utilities collected data to document how central air conditioning affected load factors. In PG&E’s service area, only 7% of homes had central air conditioning in 1970 compared to 26% in 1990 and 30% in 2004. During that period, the load factor dropped from 0.63 in 1970 to 0.60 in 1990.

Page 1-6, section 1.4 (rationale – dg is an ALTERNATIVE to capacitors)
…
equipment or processes requiring electricity—to ride through voltage anomalies without disruption. DG, particularly when it employs battery energy storage, provides site-specific electricity management options for load-sensitive customers.

Page 1-7, last paragraph (rationale – confusing, looks like recips need inverters):
Over 99% of these units are small emergency reciprocating engine generators or photovoltaic systems that do not feed electricity directly into the distribution grid5.

Page 1-8, last paragraph
Delete “But” before September…., because this sentence supports previous material – there’s no contrast.

5.2 Suggestions for Chapters 2 to 5

Page 2-5, 2nd paragraph
Delete last sentence because it is repeated exactly 3 paragraphs down. Separate issue – I would really like to see this sentence repeated in the intro/summary section for this chapter.

Page 2-10, first full paragraph after the bullets:
It would be nice if the concept (re physical assurance) described in the last sentence could get more exposure – in the intro/summary and/or exec summary.

Page 2-12, last paragraph
The economic benefits of using DG to improve electric system reliability can be estimated by determining the avoided costs of traditional forms of investment in electric reliability. (See Appendix A for an example of one methodology used to calculate these avoided costs.) Under this approach, …

Page 3-5, suggest you add new paragraph between 3.4 and 3.4.1 (Reason – need to fight the perception that dg always displaces more-efficient combined cycle generation. The text came from the deleted chapter on efficiency improvements, but it fits here):
The economic benefits of peak load reductions come from savings in production costs of energy and improvements in the utilization of existing T&D infrastructure and potential long-run deferral of capital investments in Generating and T&D expansion. One study explicitly examined the issue of which central station units would be displaced if significant amounts of DG were added to the PJM system. Contrary to a common perception, the displaced units were found not to consist solely of new combined-cycle power plants, but rather to be a mixture of coal-, gas-, and oil-fired units of varying heat rates and with varying fuel costs(Hadley, S. W.; Van Dyke, J. W.; Stovall, T. K., *The Effect of Distributed Energy Resource Competition With Central Generation*, ORNL/TM-2003/236, Oak Ridge National Laboratory, October 2003).

Page 3-9, last paragraph:
There are important distinctions between traditional vertically-integrated and the new organized wholesale markets when it comes to the economic impacts of reducing peak demand.

Page 3-12, middle paragraph: – reason – figure 3-8 is not referenced anywhere that I could find.
Generally speaking, utilities …. While the costs ranged from $20 to $340/kW for the installed capacity, the costs ranged from $100 to almost $1100/kW on a capacity-shortfall basis. (One resulting installation is shown in Figure 3-8.) Therefore, from an ...

Page 3-19, suggest you add a section:
3.7.3 Value of Line Loss Reductions
Transmission losses are priced on the margin in many of the new organized wholesale markets. Incremental transmission loss pricing correctly accounts for higher loss charges for remotely located generation and also higher charges for peak utilization periods. Thus, the loss charge for the same amount of power transferred from Point A to point B will differ depending on the time of day, and the loss charge from Point C to Point B will differ from that of Point A to Point B depending on distance. MISO and NYISO price transmission on the margin and PJM has indicated that it will soon begin pricing losses on the margin.

In traditional vertically-integrated markets, transmission losses are sometimes charged at a flat rate regardless of distance. For example, TVA levies a 3% charge to its transmission customers for transmission losses. Some regulated utilities use loss factors generated from a power flow snapshot of the system as the basis for levying transmission loss charges. Loss factors, when properly calculated, are an improvement over the flat transmission charge because they account for higher loss charges for remotely located generation. Long distance power sales that cross multiple service territories must pay for their transmission losses in each of those territories.

Page 4-2, suggest you add at end of top paragraph:
For example, the NYISO operates a program, the Special Case Resources Program, that is open to customers with on site generators and enables these customers to participate in a day-ahead reserves market.

Page 4-2
Footnotes 32 and 33 are pretty important and the reader would be better served if they were a part of the main text. They were both originally placed in boxes to give the subject matter more prominence.

Page 4-9
Add to the end of the first partial paragraph (second line of the page):
The AEP methodology is described more fully in Appendix A.

Page 5-4 – I especially like the intro paragraph added to 5.3.

Page 5-4 – The second and third sentences of the last paragraph were originally underlined because they explain the basis of the “15%” value that is now currently cited as a gospel limitation for DG capacity on a feeder. That was a direct response to a DOE sponsor’s request that we identify the source of that value. You may want to highlight this in some form.

Page 5-5 section 5.3.2:

In order to investigate power quality concerns, a monitoring program was set up to examine both the effect of DG on the grid and the effect of the grid on the DG for 11 generators at 6 sites in California. This program logged over 230,000 hours of data (Overdomain, LLC, and Reflective Energies, 2005b). They summarized their results as:

Page 5-8, first paragraph:
The economic benefit of power quality benefits due to on-site cogeneration and small power production could also be large for the utility because the utility would have to invest less in improving grid-wide power quality. Gumerman et al. (2003) indicate that "…costs can potentially be lowered because the wider power system does not have to be tailored to sensitive loads."

Page 5-8, last sentence before 5.5 heading:
If DG power can substitute for feeder loading and enhance reliability by avoiding T&D and/or generation capacity upgrades, then the economic benefits can be determined from deferred T&D and/or central station capacity.

5.3 Suggestions for Chapters 7 and 8

Page 7-1: I think some of the recip manufacturers might object to the second paragraph. Some possible changes are suggested:
In addition to the vulnerability of critical infrastructure facilities resulting from their dependence on the primary electricity grid, these facilities most often rely on traditional backup technologies as their sole source of electricity in an emergency—primarily diesel generators with limited fuel storage and only average power quality. If these backup generators prove incapable of meeting emergency power needs—as was the case during Hurricanes Katrina and Rita—the resilience of the entire network of critical infrastructure is in jeopardy at the very time when the infrastructure is most needed. Alternatively, if critical infrastructure facilities were to rely instead on primary and secondary power sources not exposed to these weaknesses, the entire system of critical infrastructure would be more resilient and thus more secure.

Page 7-6:2nd paragraph under Telecommunications:
The high-tech facilities associated with this sector have high load factors, and concentrated electronics produce large cooling loads.

Chapter 7 – should prisons be mentioned here somewhere, perhaps in govt facilities?

Page 8-2 , near top of page:
… If these barriers were not sufficient to stop the project, many utilities are allowed to offer a subsidized rate to induce customers to continue to buy power from the utility, rather than generate their own. Table 8.3 shows the impact of lowering the rate from 18 to 15¢/kWh, which, by itself, would increase the simple payback to 8.1 years.

Page 8-8, footnote 67 contains such good information, it's a shame to bury it in such a tiny font.

Page 8-8, last sentence on the page, "problem" is all in the point of view –
If sales exceed the expectations on which tariffs have been set, shareholders can benefit handsomely at the ratepayers expense, particularly in jurisdictions where tariffs are not routinely revisited by regulators and any additional fuel costs are automatically recovered.

Page 8-10 – Kudos – I especially like the second paragraph on this page. We've tried to make the same points in the reliability section as well.

Page 8-17, when reading the "compensation for output" section, I thought one thing was missing – that is: Some/many/most(?) customers are flat out not allowed to export any electricity any way any how any time, and must install control systems to make darn sure that not one solitary electron goes the wrong way through the interconnect. (can you tell this suggestion is coming at the end of the day and my eyes are more than slightly crossed?)

5.4 Suggestions for Appendices

Page A-4, 3rd full paragraph:
Unlike deferred real power generation investments, estimating deferred T&D investment does not readily lend itself to linear programming production cost model-based analytic techniques. This example methodology includes estimating deferred T&D capacity for a defined T&D system. (An example for a single transmission feeder can be found in EPRI 2005.)

Where EPRI 2005 refers to: EPRI's 2005 Annual Report prepared for the Massachusetts Distributed Generation Collaborative entitled "A Framework for Developing Win-Win Strategies for Distributed Energy Resources in Massachusetts."

5. Solar Electric Power Association

COMMENTS

* Under "Major Findings" on page 5, it would be instructive to state up front, the proportion of these DG units that come from various fuel types. I suspect that the majority are diesel fueled back-up units, and while DG is often lumped in the same categories with renewable and energy efficiency strategies, I suspect that many DG advocates don't appreciate the magnitude of diesel-fueled DG in making up the majority. An unpublished survey of DG units in Minnesota by the Minnesota Department of Commerce estimates that diesel DG units exceeded 1500 MW, well in excess of the largest nuclear power plant in the state, and when operated in some aggregate during periods of high demand that forces utilities to enact interruptible service options, can add significantly to poor regional air quality.

* On p33, the discussion of emergency power units could be expanded to included "emergency and back-up," as some amount of diesel DG is used under interruptible rate structures, which are utility-customer economic decisions more than emergencies.

* I would reword the following sentence on page 33 (note new space after "99%"): "Over 99% of these units are small off-grid emergency reciprocating engine generators or photovoltaic systems, physically isolated from the distribution grid, serving back-up or niche electricity needs."
You could then delete the footnote, or change it to the following, "Emergency generators are generally interconnected to the building on the customer's side of the utility meter, and do not feed the grid itself. The majority of photovoltaic systems provide niche small power needs for lighting, communication, signage, or off-grid homes, although this has shifted to on-grid applications in the last two years." The UL inverter discussion is not particularly relevant to the big picture discussion. The word "machines" could be changed to "installations."

* This statement on page 34 about a hospital using their DG unit to reduce their electricity bills on a "daily" basis may be generous given diesel fuel and O&M costs.

* Can the graphic on p35 be broken down further to < 1 kW, 1-100 kW, 100-1000, > 1000? It maybe be illustrative of the small nature of many of the off-grid uses.

* The concept of "interruptible rates" is introduced on page 35, but not explicitly identified: "While some power companies offer incentives to consumers to run their back-up power units during peak load periods."

* On page 61, a minor edit "Other plants operate outside of this dispatch order because they are outside the control of dispatchers, such as combined heat and power plants, photovoltaic arrays, wind farms, and other customer-owned DG."

* On page 65, the title of figure 3-5 should be pushed to the same page as the figure.

* On page 68, figure 3-7 "vallue" has two ll's. Since it is very similar to figure 3-4, would it be possible to have both be exactly the same design and color, with a specific highlight to what is different between them (supply at average cost)?

* On page 82 and 83, it would be helpful to identify the type of DG(technology and fuel) that is pictured in the examples.

* On page 101, in Table 6.1 a weighted average per MWh would be helpful as well.

* On page 132, Table 8.4 really seems like it should be on page 151, under interconnection.

* On page 133, "Lost sales during high-price, on-peak periods are more damaging than sales lost during other hours, when lower revenues from demand charges might cause an inflated net revenue reduction." Could they also save a utility money, to the extent that the DG energy contract price is lower than the prevailing electricity market rates during this same high demand period? It's dependent on a lot of things, but the word "are" if definitive, while "can be" allows for other situations, which could be mentioned as well.

* The concept of "decoupling" is introduced briefly on page 134, but is not mentioned elsewhere. This section could be expanded and the concept of decoupling mentioned in the last bullet on page 6 ("Regulation by the states of electric rates.") to give it greater emphasis as a tool for improving customer-sited DG and utility financial relationships. Similarly, it could be added to the definitions.

* On page 134, "This problem was long ago addressed by some states with the intention of making utilities indifferent to their level of sales."
"Long-ago" could be changed to "initially" since decoupling activity is not necessarily widespread or common. A couple of sentences about decoupling's history, relationship in regulated and unregulated markets, and the status of current activities might be helpful background.

*	On page 138, Table 8.5 is incorrectly labeled "Portland" and not "Minnesota"

*	On page 143, "Some allow for full credit at the retail rate and others establish other, typically lower, credit values BASED ON AVOIDED COST OR SOME OTHER METRIC, OVER A KNOWN TIME PERIOD, TYPICALLY MONTHLY OR ANNUALLY."

*	On page 143, it may be instructive to reference some of the following in the discussion:

- Map of net metering by state:
http://www.dsireusa.org/documents/SummaryMaps/NetMetering_Map.ppt

- Interconnection tables by state:
http://irecusa.org/connect/state-by-state.pdf

- Progress of states in considering net metering and interconnection under EPAct: www.irecusa.org/articles/static/1/binaries/
<http://www.irecusa.org/articles/static/1/binaries/EPAct.doc> EPAct.doc

*	On page 150, Table 8.7 - this is the first mention of "performance based regulation" (PBR), which may or may not be related to decoupling, which isn't listed under "loss of utility revenue" but should be.

*	On page 151, Interconnection section, it may be instructive to reference some of the following in the discussion:

- Interconnection tables by state:
http://irecusa.org/connect/state-by-state.pdf

- Progress of states in considering net metering and interconnection under EPAct: www.irecusa.org/articles/static/1/binaries/
<http://www.irecusa.org/articles/static/1/binaries/EPAct.doc> EPAct.doc

*	General - It would be helpful to have a table of the major DG types (diesel generators, natural gas turbines, photovoltaic panels, wind turbines, etc) and their ability to provide a variety of DG benefits across the columns - all can provide energy, some can provide dispatchable power, some can provide full capacity/others partial or statistical, but then the ancillary benefits - VAR, line loss reductions, black start, reactive, etc.
I know some wind turbines can provide some type of VAR support now, but not PV panels on the customer side of the meter (UL standards on the inverter tolerances prevent it).

6. National Rural Electric Cooperative Association

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY

Comments of the National Rural Electric Cooperative Association On The Potential Benefits of Distributed Generation and Rate Related Issues that May Impede Their Expansion: A Study Pursuant to Section 1817 of the Energy Policy Act of 2005

The National Rural Electric Cooperative Association (NRECA) appreciates this opportunity to comment on the Department of Energy's Study "The Potential Benefits of Distributed Generation and Rate Related Issues that May Impede Their Expansion: A Study Pursuant to Section 1817 of the Energy Policy Act of 2005" (DG Study). NRECA believes that the DG Study represents a positive effort to provide a balanced evaluation of the potential benefits of distributed generation (DG). For example, unlike many reports that make sweeping generalizations concerning the benefits of DG, the DG Study appropriately concludes that "the economics of DG are such that financial attractiveness is largely determined on a case-by-case basis, and is very site specific." (DG Study at iii). Nevertheless, NRECA believes it is important to clarify and correct a few elements of the DG Study, particularly those relating to rates and interconnection policies and procedures. Those elements of the DG Study improperly accept DG developers' self-interested characterization of certain rates and policies as "impediments" even where those rates and policies are necessary to preserve the safety, reliability, quality, and affordability of service to other electric consumers.

BACKGROUND

NRECA is a not-for-profit national service organization representing approximately 930 not-for-profit member-owned rural electric cooperatives. The great majority of these cooperatives are distribution cooperatives that provide retail service to over 40 million consumer owners in 47 states. Nationally rural electric cooperatives provide electric service in all or parts of 83% of the counties in the nation. Kilowatt-hour sales by rural electric cooperatives account for approximately 10% of total electricity sales in the United States. NRECA members include approximately 65 generation and transmission (G&T) cooperatives that supply wholesale power to their distribution cooperative owners. NRECA's membership includes both transmission owning and transmission dependent utilities.

Rural electric cooperatives, both G&T and distribution, were formed by their member owners to provide long-term reliable electric service to their members at the lowest reasonable cost consistent with sound business practices. While certain NRECA members generate their own power and make sales of power in excess of their own members needs, most electric cooperatives are net buyers of power. Overall, cooperatives purchase slightly over half of their energy requirements from other wholesale suppliers.

NRECA and its members have significant experience with and strongly support DG. Across the country, cooperatives are installing, interconnecting, and even selling DG. Cooperatives are using their own and customer-owned DG for reliability, power quality, energy, and capacity.

NRECA actively participated in the development of the Federal Energy Regulatory Commission's (FERC) Small Generator Interconnection Rule, in the NARUC-led process to develop model interconnection procedures and agreements for the states, and in the development of the Institute for Electrical and Electronics Engineers (IEEE) standard for the interconnection of small generators, IEEE 1547. Prior to those projects, NRECA developed its own Distributed Generation Interconnection Tool Kit, which was updated in 2006. The updated Tool Kit can be accessed by the public at http://www.nreca.org/PublicPolicy/ElectricIndustry/dgtoolkit.htm. NRECA and its research arm, the Cooperative Research Network also spend significant resources on DG-related RD&D and education efforts.

COMMENTS

1) The DG Study Confuses DG, Cogeneration, and Small Power Production

On page 1-6, the DG study states that the terms "distributed generation," "cogeneration," and "small power production," are interchangeable. Unfortunately, that statement perpetuates a common, but confusing, error. Under the Public Utility Regulatory Policies Act of 1978 (PURPA), "cogeneration facility" is a defined term that is equivalent to what is commonly called "combined heat and power." (codified at 16 U.S.C. § 796(18) (Federal Power Act § 3(18)) It is a specific type of DG from which the owner or another entity receives benefit from both the electric and heat output of the generator. Not all DG is cogeneration. Wind and photovoltaics cannot be operated in cogeneration mode as they have no waste heat. Most back-up generation is not operated in cogeneration mode because the heat recovery equipment is not economic for a generator that will only be operated on occasion. Moreover, not all cogeneration fits the classic definition of "DG." There are cogenerators large enough to produce several hundred MW of energy.

"Small power production facility" is also a defined term under PURPA. (codified at 16 U.S.C. § 796(17) (FPA § 3(17)). Small power production facilities consist of renewable generators of 80MW capacity or smaller. While most such facilities are DG, at the larger end, they may well be operated as central station generators producing primarily for wholesale sale rather than for local load. Fossil fired DG would not constitute small power production facilities under PURPA.

2) The DG Study Fails to Understand the Need for Customer Assurances Where DG is Relied Upon for Reliability Purposes

At page 2-13, the DG Study states that utilities generally require customers to provide performance guarantees or physical assurances when their DG is used for reliability purposes. The DG Study criticizes those requirements as adding to the costs and risks of DG ownership because, the DG Study claims, utilities do not require such guarantees for their own equipment. This criticism is unfounded for several reasons.

First, the performance guarantees or physical assurances the DG Study mentions are critically important to the operation of the distribution system, and thus to public health and safety. The DG Study posits that the DG units are being used for reliability purposes. That means that under certain system conditions, the DG units are needed to continue to provide service to consumers on one or more distribution circuits. If the customer-owner is unable or unwilling to operate the DG unit under those system conditions, customers will lose service – a potentially life-threatening situation. The utility has a choice therefore. It can either refuse to use the DG for reliability purposes and meet system contingencies with its own equipment or it can demand performance guarantees and/or physical assurances. The utility cannot depend on the DG for reliability without those assurances. Without the guarantees or assurances, the utility would have to install other measures to ensure reliability in the place of the DG. If the compensation a consumer-owner receives for providing reliability service is inadequate to cover the cost of guarantees or physical assurances, it should not agree to provide the service and it will not incur the cost of the guarantees. If the compensation is adequate, then there is no "barrier."

Second, utilities do incur equivalent costs for their own equipment. In place of the guarantees that a customer would provide, the utility must invest in whatever maintenance, staff training, fuel, and operations costs are necessary to ensure that its own equipment is available and properly operated when needed to preserve reliability.

Third, the guarantees required of customer-owners are the same that the utility requires of any other vender. If a utility buys energy, capacity, or ancillary services from another utility or an independent power producer, the purchase agreement will include similar terms to those required of DG owners. Often, the commercial contracts will include even more stringent terms than those imposed in DG owners. Accordingly, DG owners are not singled out for discriminatory treatment. Rather, if they offer to provide a service that can be self-provided or purchased from another provider – such as helping to preserve the reliability of the system – then they are treated like any other provider.

True, there are times that the DG owner's scale makes it uneconomic for them to sign such an agreement. The problem in that case is not the agreement, but the economics of the DG unit. If the DG cannot economically provide a service that the utility or another provider can provide economically, it simply is not efficient to use DG for that purpose.

3) The DG Study Inappropriately Conflates Reducing Vulnerability to Terrorism With Improving the Resilience of Electrical Infrastructure

Section 7 of the DG Study provides a number of excellent examples of where back-up generation and DG-based uninterrupted power supplies can significantly enhance national security. Unfortunately, in the Conclusions section (page 7-12) the DG Study finds that DG both reduces vulnerability to terrorism and improves the resilience of the electrical infrastructure. While the examples provided in the DG Study strongly make the first point, they do not support the latter point.

Most readers would understand the latter statement as suggesting that the presence of DG on the system will prevent widespread outages. That is unlikely to be the case. The kinds of back-up generation described by this chapter do not support the grid as a whole. Rather, they support individual loads on the grid. For example, if a government facility installs back-up generation that comes on when central station power is lost due to terrorist attacks or other events (such as rogue squirrels), that back up generator will not have any effect on the length or geographic extent of the broader outage. After the grid fails, that facility will still have power but other power customers surrounding that facility will not have power.

Although the DG Study fails to discuss it, the presence of DG operating in parallel with the system can actually increase the challenges faced by utilities during system contingencies. DG operating in parallel with the system is required to isolate from the grid if system voltage or frequency changes rapidly. If it fails to do so, the generator could create an electric "island" that creates a significant danger to utility employees and the public as well as to utility equipment. If a large amount of DG drops off at the same time in response to a system disturbance, it could cause system conditions to deteriorate even more rapidly. For example, if a short circuit on the system causes voltage to sag, the loss of large amounts of DG could cause a further loss of voltage, preventing the system from recovering and either lengthening the disturbance or causing the disturbance to spread over a larger geographic area. Rather than making the system more resilient under these conditions, the presence of the DG makes it more vulnerable.

After DG drops off the system in response to a disturbance, it cannot be permitted to operate in parallel with the system again until the system stabilizes – often a minimum of five minutes after system conditions return to normal. When the DG reconnects, it can cause minor disturbances to the system as it re-parallels. That is not an issue once the system recovers from the disturbance. Until then, however, those additional disturbances could prevent the system from recovering from the initial disturbance. Also, if the DG tries to reconnect too soon, before the system stabilizes, it could drop off again adding to the disturbance as discussed in the paragraph above. Finally, if the DG tries to reconnect before the system stabilizes, the DG itself could be damaged. Because of these challenges, DG cannot be relied upon to help the system recover from outages. The presence of the DG, therefore, cannot limit the geographic or temporal scope of an outage.

4) Section 8 of the DG Study Reflects an Inappropriate Developer Bias

a) The DG Study Inaccurately Describes Rates as the Greatest Influence On The Practicality of DG

At page 8-1, the DG Study claims that "[u]tility rates have the greatest impact on the practicality of DG because they affect the payback rate and time period for the DG investment. Unfortunately, this statement is not only inaccurate, but also provides support for DG developers' efforts to obtain subsidies for their products at the expense of other electric consumers.

The statement is inaccurate for several reasons. The first is that by far the largest number of consumers who install DG do not use their DG to replace utility purchases. As the DG Study acknowledges, most DG is used for back-up generation. The DG provides value to the consumer in proportion to their cost of being without power, not their cost of grid power.

Similarly, most other customers installing DG today are doing so for reasons other than – or in addition to – the value of displacing utility power. Most customers installing DG in parallel with the utility are doing so for reliability, power quality, for the combined benefit of the electric energy and the heat output of the generator, or to meet environmental goals. Only a relatively small percentage of DG owners are relying entirely on the value of displacing utility power to justify their investment.

Even for the small number of customers installing DG solely to reduce their purchases from a utility, the value of displacing utility power is only one element of a much larger calculation. Any customer properly doing its due diligence to determine whether there is a good business case for installing DG will perform a complicated calculation that includes the cost of the DG's prime mover; the cost of ancillary equipment such as compressors for gas-fired generators or the cost of inverters for solar generation; the cost of installation; the cost of fuel for generators that require fuel; the cost of maintenance; environmental permitting costs; and a variety of other related costs.

All of these elements to the calculation are part of the costs and benefits of doing business. There is no reason to separate out one element – utility rates in this case – as more important than the others. For gas-fired generators, the DG Study could have as easily stated that "Gas costs have the greatest impact on the practicality of DG . . . ." For diesel generators, the DG Study could have as easily stated that "Diesel costs have the greatest impact on the practicality of DG . . . ." For all DG technologies today, the DG Study could more accurately have stated "the cost of the DG technology itself has the greatest impact on the practicality of DG because it affects the payback rate and time period of the DG investment."

Unfortunately, DG developers have effectively convinced many in the regulatory arena to take the cost of the technologies, associated equipment, and fuel as a given and have shifted the analysis to the utility-side elements of the investment calculation. It would be as if Tiffany's© convinced regulators to force box makers to discount their signature little blue boxes, because the cost of boxes was keeping jewelry customers from buying their products.

In fact, there is a very good reason why very few customers install DG solely to reduce purchases from their electric utility: it is seldom economically efficient for them or for society. Despite advances in technology, the electric utility industry is still a scale industry. The fully installed cost of DG technologies per kW capacity is significantly more expensive than central station generation. Photovoltaic and small wind (<100 kW) generation usually costs \$3,000-\$10,000/kW installed capacity. Larger cogeneration facilities can cost \$2,000-\$5,000/kW installed capacity. This compares unfavorably to central station gas generation at \$800-\$1,200/kW and coal generation at 1,200-\$1,800/kW. The exception to that is the simple diesel powered internal combustion engine which can cost as little as \$500/kW. The fuel for such engines, however, puts the cost of diesel gensets significantly above the cost of most central station generation.

Of course, there are some exceptions. Power costs in remote Alaska and Hawaii do not reflect the same economics as those in most of the Continental U.S.

Under the right circumstances, those power costs alone might make some DG installations economic. Similarly, some customers in California, Texas, and New York are facing extraordinarily high power costs. For some of them, those costs too could overcome the ordinary economics of DG. For most customers, however, the ordinary electric industry economics make DG the less efficient choice. That is why most DG today is – appropriately – installed where it can provide additional value to customers besides replacing utility power.

b) The DG Study Improperly Accepts DG Developers' Characterizations of Utility Rates as "Impediments"

Based on the characterizations of DG developers (page 8-6), chapter 8 of the DG Study broadly characterizes such rate structures as standby charges, demand charges, and interconnection charges as "impediments" to DG. The DG Study acknowledges that these rates recover costs that "would shift to other non-DG customers if the utility did not recover them specifically from DG customers. This constitutes a subsidy of DG customers by other rate payers." Nevertheless, the DG Study accepts the developers' characterization of the rates as "impediments" throughout the chapter based on the "potential" benefits of DG to other customers that the DG Study itself recognizes are "very site-specific." (page iii).

Unfortunately, the characterization of utility cost-based rates as impediments is simply inaccurate. If truly cost-based, those rates are simply another cost of doing business. If the project is economic in light of the full panoply of costs and benefits in the calculation, including rates, then it should go forward. If the project is not economic in light of the full panoply of costs and benefits in the calculation, including rates, then it should not go forward. In that case, the rates are no more the reason the project failed than any of the other costs in the evaluation.

Moreover, the DG Study's characterization of cost-based rates as "impediments" is unnecessarily one-sided and seriously undermines the value of the DG Study. The DG Study could easily point out that excessive rates not designed to protect ratepayers from unduly subsidizing customers with DG undermine the economics of DG, without overly broad pejorative language applying equally to well designed rates.

It is not surprising that DG developers should characterize utility rates as "impediments." Certainly, there may be extreme cases where this is true, where rates are excessive and designed to prevent the installation of DG. Often, however, the reference to utility rates is intended to distract customers and regulators from the costs of DG technologies, maintenance, and fuel.

Take for example, the case study reflected in Tables 8.1-8.3. Here, the installed cost of the generator is $2,000/kW. By way of comparison, at the time this example was developed, the cost of a new simple cycle central station gas generator was $500/kW. The cost of a new coal plant was $1000-1200/kW. (All three have gone up since). Yet, the cost of the DG is taken for granted. It is not described as an impediment. Similarly, the cost of maintenance is not even listed, let alone described as an impediment. The difference between the cost of power and the cost of fuel is very small, with a spark spread of only $0.1/kW [sic (it ought to be kWh?)]. The cost of gas or diesel is not described as an impediment. Only the utility side of the calculation is described as an impediment.

Developers' proclivity to refer to utility rates as an impediment may also be based on the desire of some to extract a subsidy from the utility's other customers for their economic benefit.

Look again at the same case study. Table 8.3 is titled "Tariff Impediments," even though there is no analysis whatsoever whether the rates described therein are cost-based or otherwise just and reasonable. If those rates are cost-based, then failure to impose them on the hospital would shift costs to other customers. In that case, then they cannot be properly called "impediments." Rather, they are reasonable costs of doing business no different from the cost of the generator, maintenance, and fuel. The pejorative description of them can only be intended to obtain relief from them: that is, a subsidy that comes at the expense of other customers. If those rates are not cost-based, then they should be criticized for poor design, not for their very existence.

c) The DG Study Fails to Note Serious Shortcomings in DG Developers' Arguments Against Standby Charges

Please see the attached article on standby charges (Att. 1) that addresses this issue in detail.

d) The DG Study Inappropriately Characterizes the Absence of Net Metering as an "Impediment"

At page 8-18, the DG Study states that the absence of net metering can be viewed as a barrier to deployment of DG. For a variety of reasons discussed in detail in NRECA's white paper on net metering (Att. 2), net metering provides owners of DG a significant subsidy. Most simply, net metering permits DG-owners to be paid a fully-loaded retail rate for wholesale power that the utility cannot dispatch or rely upon at peak times. Net metering also permits DG-owners to avoid paying for the distribution, transmission, and generation capacity that the utility invests in to serve them when their generators are not operating at peak. Because net metering is a subsidy, its absence cannot be properly characterized as either an impediment or a barrier to DG. Its absence does not prevent the installation of any economically justifiable DG installation.

The DG Study notes without analysis or critique the DG proponents' counter argument that net metering captures DG's benefit to the system. (Page 8-19). Yet, net metering provides benefits to all qualifying DG. And, as the report itself notes, the benefits of DG are "very site-specific" That means net metering "compensates" many DG owners for benefits they do not provide, while possibly under compensating those few that may provide system benefits given their individual circumstances.

The DG Study also suggests that policymakers typically target net metering to smaller systems. While this was once true, and most net metering programs are still limited, the trend today is to increase the size, and range of technologies, of generators entitled to net metering. This trend significantly increases the level of cross-subsidization and thus the level of burden on other customers.

e) The DG Study Inappropriately Characterizes Interconnection Procedures and Costs Required for Safety and Reliability as "Impediments"

On the same page (Page 8-26), the DG Study explains that DG interconnection requirements are needed to ensure the safety and integrity of the grid and then characterizes those same essential interconnection requirements as barriers to DG. This dichotomy does not make sense. Of course, excessive fees, unnecessary delays, and unjustified technical requirements would constitute barriers. But, it is inappropriate for the DG Study to repeat the broad claims of DG developers that interconnection requirements, the costs of studies, or other contractual terms including liability, insurance, and indemnification, are all barriers to DG projects when properly designed requirements are all necessary for safety, reliability, power quality, and financial equity.

DG developers must be required to be good "grid citizens." Their effort to sell products should not be permitted to undermine the quality, reliability or safety of service received by other consumers. Nor should their effort to sell products be subsidized by other customers on the grid.

It is not possible to interconnect DG safely and reliably without appropriate study, and in some cases without upgrades to the grid. Those steps cannot be bypassed for the economic benefit or convenience of project developers. Moreover, the necessary studies and upgrades take time and require utility resources. Those costs should be borne by DG developers just as they are borne by all other developers who seek to interconnect generation to the grid, regardless of size. Sometimes, these studies and the equipment or upgrades required for interconnection can be expensive. If the studies are responsibly conducted according to good utility practice, and the upgrades are needed to preserve power quality, safety, and reliability, then those costs are not "barriers." They are ordinary costs of doing business. If those costs, together with all of the other factors that go into evaluating a DG project, price the DG project out of market, then it was not an economic project. The problem is not with the study and upgrade costs, the problem is with the project. If the regulatory rules are changed to protect the DG developer from the costs, and to make the project "appear" economic, then those costs must be borne by other users of the system. That is neither economically efficient nor equitable.

Similarly, DG, like any other generator interconnected with the system, poses some risks to people and property. DG owners, therefore, like the owners of any other generator interconnected with the system, should be required to hold other users of the system harmless from those risks. That means that DG owners, like the owners of any other generator interconnected with the system, should have an obligation to accept financial responsibility for that potential harm. To make certain that happens, the interconnection contract needs to include liability, indemnification, and insurance provisions. If those provisions are reasonably related to the risks that the project imposes on other users of the grid, they are not "barriers." If those provisions, together with all of the other factors that going into evaluating a DG project, price the DG project out of market, then it was not an economic project. The problem is not with the contractual provisions relating to financial responsibility, the problem is with the project. If the regulatory rules are changed to protect the DG developer from the provisions, and to make the project "appear" economic, then those economic risks and costs must be borne by other users of the system. That is neither economically efficient nor equitable.

Respectfully submitted,

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

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NET METERING

An issue paper of the National Rural Electric Cooperative Association

What is Net Metering?

- Net metering is one of many techniques available to measure and value the output of customer-owned generation.
- Net metering rules generally provide that consumers with certain self generation capabilities should have a meter that rolls forwards when the customer consumes power from the grid and rolls backwards when the customer exports power to the grid.
- If the consumer uses more energy over the course of a billing period than they have generated, they pay only for the net energy that they have imported from the system.

- The 30+ states with net metering handle very differently the situation where a consumer generates more than they have used over the course of a billing period. Some states prohibit any payment to consumers fo r net exports. Some states require net credits to be rolled over to the next month, generally up to one year. Others states require utilities to pay consumers “avoided cost” (like with PURPA) for net exports at the end of a billing period or at the end of a year.
- The range of technologies and applications entitled to benefit differ widely in different states.
- Many states like Illinois, Connecticut and Montana limit net metering only to renewable technologies. Others include qualifying facilities under PURPA.
- Most states have size limits on the units that qualify for net metering. For example, Indiana and New Mexico limit qualifying units to no larger than 10 kW.
- Some states have also imposed a limit on the total number of consumers, or total capacity of consumer-owned generation, for which any utility has to provide net metering service. Illinois, New York, and Washington all limit net metering to between 0.1% and 0.5% of the utility’s historic peak load.

Why Do So Many States Have Net Metering Rules?

- Many states adopted net metering in the early 1980s as a way of implementing PURPA Section 210’s requirement that utilities buy the output of qualifying small power production facilities.
- Other states adopted net metering because it provides a simple, easily administered way of compensating consumers for their generation, particularly where the customer is unsophisticated, the unit is small, and the output of the unit cannot closely track the customer’s demand, as with wind and solar energy.
- Some states have adopted net metering to subsidize the use of environmentally friendly renewable technologies.

Why Are Utilities Concerned About Net Metering?

- Net metering policies require utilities to pay consumers the retail price for wholesale power. The retail rate utilities charge includes not only the marginal cost of power, but also recovers costs incurred by utilities’ for transmission, distribution, generating capacity, and other utility services not provided by the customer-generator.
- The policies require utilities to pay high costs for what is often low-value power. Power from wind and photovoltaic systems is intermittent, cannot be scheduled or dispatched reliably to meet system requirements. Even those forms of customer generation that could technically be dispatched at times when utilities need the power do not need to enter into operating agreements with utilities in order to obtain net metering under state net metering mandates.
- Net meters allow customers to under-pay the fixed costs they impose on the system. A utility has to install sufficient facilities to meet the peak requirement of the consumer and recover the costs of those facilities through a kWh charge. When the net meter rolls backwards, it understates the total energy used by the consumer, and thus understates the consumer’s impact on the fixed costs of the system. It also understates the consumer’s total share of other fixed charges borne by all consumers such as taxes, stranded costs, transition costs, and public benefits charges.

- Net meters can also be deliberately or inadvertently gamed. Consumers can take power from the system at peak times when it costs the utility the most to provide it, and then roll their meters backwards by generating power at non-peak times when the utility has little need for it. That is a particular risk, for example, with gas and diesel fueled units that can be operated on demand.

How Can We Gain the Benefits Of Net Metering Without Unfair Cost Shifting?

- Adopt policies that support renewable technologies without shifting costs between consumers:
- Provide tax credits for consumers that install renewable generation;
- Appropriate funds for research, development, and demonstration projects aimed at lowering the costs of DG; and,
- Remove federal regulatory burdens on consumers who generate their own power.

- Implement net billing programs. Such programs typically:
- Permit interconnection of customer generation to the grid;
- Permit consumers to use their generation to reduce their consumption of utility power;
- Ensure appropriate compensation to consumers for their net excess generation at reasonable rates;
- Ensure consumer generators pay an appropriate share of system costs, protecting other consumers from cross-subsidies.

- If net metering policies are adopted, impose appropriate limits:
- They should apply only to small residential generators (≤10 kW) that use renewable energy, such as wind, solar, and hydro;
- They should only be permitted up to a small percentage (*i.e.*, 0.1%) of the utility's historic peak load;
- They should not be available to:
- larger, more sophisticated consumers who do not need the leg up;
- larger units or large numbers of units, which can exacerbate the cost shifting problem; or,
- gas or diesel powered units that can more easily be used to game net metering rules;
- They should be available only to consumers on marginal cost time-of-use rates that ensure that excess generation is credited at the appropriate value.
- Federal rules, if any, should not preempt state net metering rules, including those that put limitations on the availability of net metering.

For additional information, contact Jay Morrison, NRECA Senior Regulatory Counsel at (703) 907-5825 or jay.morrison@nreca.coop

7. U.S. Combined Heat and Power Association

March 30, 2007

TO: U.S. Department of Energy
Office of Electricity Deliverability and Energy Reliability
Submitted via E-mail EPACT1817@hq.doe.gov

FROM: Sean Casten
Chair
U.S. Combined Heat and Power Association
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RE: Section 1817: Study of Distributed Generation Benefits

The United States Combined Heat and Power Association (USCHPA) would like to thank the U.S. Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability (OE) for the opportunity to comment on the "The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion" report dated February, 2007 in response to Section 1817 of the Energy Policy Act of 2005. This important document will shape the understanding of distributed generation (DG) as a solution to the energy issues facing our nation. It is likely to be a referenced in the ongoing dialogue to develop the best policy framework in which the benefits of distributed energy can be optimized. We are pleased to provide comments (attached) in the spirit of industry collaboration to support the worthwhile continued discussion on DG and its role and value in both the current and an improved market and regulatory environment.

The 1817 study report is structured as a compilation of existing DG benefits analyses. However, we are concerned that by failing to synthesize aggregated conclusions from these disparate analyses, the report inaccurately represents the the benefits of DG and therefore does not completely responsive to the EPACT statute mandating the study. These limitations compromise the usefulness of the report with respect to future congressional policy and at worst could lead to erroneous conclusions to the nature of the existing obstacles to and benefits from DG deployment. Of particular concern, we note that the report does not adequately address the regulatory and rate-related issues that may impede the expansion of DG, giving the false impression that problems induced by current regulatory models are caused by technological limitations. Finally the report does not provide a comprehensive means of benefit valuation for DG.

Our comments address three issues within the report:

- The underlying presumption providing context to most of the benefits and rate structure analysis in the report is that the current command-and-control grid system will continue to exist and that the quantification of DG benefits is therefore dependent on DG’s ability to conform to the current i regulatory paradigm.
- The report suggests that the primary impediment to market development is the site-specific nature of DG. DG as a class of technology is no more site specific than many other energy producing/consuming devices that are currently financed by ratepayers and supported by utility and government programs.
- The report does not appropriately characterize nor value the proven and potential benefits[1] of CHP and other climate-friendly DG applications. In particular, the report omits energy efficiency, emissions reductions that result from that energy efficiency, renewable bio-power, and utility infrastructure load factor optimization.

USCHPA is an association of over 80 companies, organizations and individuals in the clean distributed energy equipment and services industries. USCHPA promotes energy security, environmental stewardship and energy efficiency through the use of clean and efficient distributed energy technology and energy policy that fosters the use of clean heat and power systems as a major source of electric power and thermal energy in the United States. USCHPA believes that while clean and efficient distributed energy technologies have demonstrated their value, CHP will achieve full market recognition only with federal energy policy reform that removes existing disincentives to energy efficiency.
We hope that our comments facilitate a broader policy discussion as government and industry craft regulatory reform to ensure a reliable, low cost and clean national power grid.

Sincerely,

Sean Casten
Chair,
US Combined Heat and Power Association

United States Combined Heat and Power Association (USCHPA) Comments

The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion

A Study Pursuant to Section 1817 of the Energy Policy Act of 2005

Requested by the Office of Electricity Delivery and Energy Reliability (OE), U.S. Department of Energy (DOE)

[1] The report was tasked with delineating non-transaction benefits that would accrue to non-owner/operator ratepayers, the grid and society at large for the purpose of valuation and policy stimulation of DG.

USCHPA is an association of over 80 companies, organizations and individuals in the clean distributed energy equipment and services industries. USCHPA promotes energy security, environmental stewardship and energy efficiency through the use of clean and efficient distributed energy technology and energy policy that fosters the use of clean heat and power systems as a major source of electric power and thermal energy in the United States.

As a class, CHP is cleaner and cheaper than the current central power model by virtue of its higher efficiency and lower first cost when sited at the load (thereby displacing the need for upstream transmission and distribution). However, the technologies are significantly under-deployed due to a combination of regulatory barriers and inaccurate market signals that do not fully compensate CHP for the societal benefits it creates. In partnership with the DOE and the U.S. Environmental Protection Agency (EPA), we have been working toward the goal of increasing the nation's capacity of the cleanest and most efficient form of distributed generation (DG), combined heat and power (CHP) to 92 GW by the year 2010.

USCHPA commends the DOE's historic and on-going efforts to work with industry on DG technology, market and regulatory issues and the attempt made in this report to analyze the very complex issues of benefits of DG to parties other than DG users.

However, we are concerned by the number of errors in the report, some of which are factual errors and some of which suffer from flawed underlying assumptions. Absent a correction of these errors, the conclusions of the report are at best vague and at worst misleading.

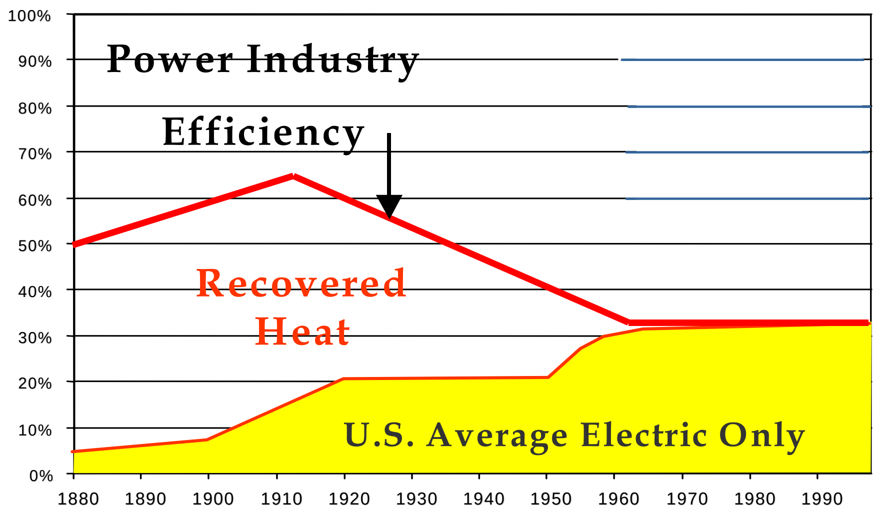
Our concerns fall into the following six broad categories:

1. The report is founded on the inaccurate presumption that the current central-power paradigm is optimal, and therefore DG must fit into that flawed model in order to create societal benefit.
2. The report confuses power (GW) and energy (GWh) production, thereby giving the incorrect impression that DG is primarily driven by standby generators that make up a significant fraction of the installed GW, but contribute relatively little to total GWh from DG.
3. The report fails to consider the emissions-reduction benefits (including both criteria and greenhouse gas emissions) innate to high efficiency generation.
4. The report does not include an appropriate methodology to correctly value benefits, making it difficult to draw apples-to-apples comparisons.
5. The report is largely silent on the regulatory causes underlying most of the current barriers to DG deployment, and therefore cannot provide useful guidance on the necessary policy changes to address.

6. The report fails to appreciate the magnitude of DG currently on the grid (84 GW of CHP is approximately 9% of U.S. capacity), thereby leading to the incorrect conclusion that lack of experience is a primary obstacle to DG utilization

Each of these concerns is addressed in more detail below.

<u>Presumption that DG must comply with an imperfect model</u>
The underlying presumption providing context to most of the benefits analysis in the report is that the current command-and-control paradigm will continue to exist and that any DG must comply with this regulatory construct. However, the reality of our power grid is that its efficiency is less than half what it was in 1910. This fact is at odds with Figure 1.1 in the report only because that figure fails to include heat recovery which used to be the dominant practice in the industry prior to the cost-plus regulatory model that emerged in the early part of the last century. Understanding this reality and its underlying causes is critical to understanding the barriers and causes to efficient power generation, and by omitting this perspective from the report, it fails to accurately represent historic realities. The actual historic efficiency, inclusive of heat recovery is shown below.



Once this efficiency history is understood, several points become apparent, and must be reconciled for any meaningful appreciation of the challenges and opportunities facing our electric grid:

a) The biggest industry in the country is less efficient today than it has been at any time in its history.

b) As a country, we emit far too much CO_2 and pay far too much for energy as a direct result of the way in which regulations isolate the electric sector from competition.

c) The U.S. has an opportunity to reduce greenhouse gas emissions and save money by deploying already-proven CHP technologies. Indeed, if the industry returned to the efficiency that existed in 1910, electricity rates would decrease by approximately 40% and the U.S. would exceed its obligations under the Kyoto protocol. The reasons for the shift away from local, high efficiency generation ought to form the basis of any intelligent energy or greenhouse gas policy, including this report.

Clearly, the regulatory environment that has caused the efficiency collapse we have seen in the electric sector must change. However, the report not only fails to acknowledge this collapse, but also assumes that DG can succeed only by being force-fit into a failed central station model. The reality is that the regulatory paradigm must be changed – for the sake of both our economy and our environment – to one that provides the same incentives for efficiency found in the unregulated sectors of our economy.

<u>Incorrect assessment of CHP</u>

The report conveys the impression that emergency and standby power generation is the DG resource from which the grid gains the most benefit. The proven and potential benefits of other more promising DG applications, in particular high efficiency baseload combined heat and power (CHP) and distributed renewably fueled systems, are not appropriately characterized. We are concerned that this omission is founded in a failure to envision a regulatory paradigm other than the current model. While we do not dispute the narrow point that emergency generators (which cannot displace significant revenue from regulated utilities) provide the most benefit to investor-owned utilities, societal benefits are maximally realized by ensuring the maximum supply of efficient, reliable and low-cost baseload power. Any consideration of the benefits of DG must recognize this conflict between utility shareholders and utility customers in order to fully represent the barriers and benefits from greater DG deployment.

<u>Absence of Environmental Benefits</u>

The environmental benefits of DG that accrue to society and other rate-payers (lower greenhouse gas and criteria pollutants per output of energy than central station generation) are ignored. These are real benefits that consumers other than users of DG on the utility system do receive as a result of DG. High efficiency CHP is widely recognized as a key element of any greenhouse gas reduction strategy. It is also one of the few, proven ways to lower greenhouse gas emissions and save money. As Congress begins to consider national greenhouse gas legislation, it is critical for them to understand the power of energy efficiency as a tool to cost-effectively reduce the threat of global warming. By remaining silent on this issue, the report has missed an important opportunity to constructively contribute to the greenhouse gas policy discussion.

<u>Inappropriate methodology to correctly value benefits</u>

The report fails to provide an appropriate method of valuing potential benefits under varying circumstances for individual cogeneration or small power production units. Because of the approach taken to produce the report, the benefits accruing from the energy efficiency of CHP that create benefits for users, utilities, and other ratepayers (energy savings, reduced need for ratepayer financed power system infrastructure, permanent demand reduction, and environmentally responsible energy generation) are not accounted for. The method used to quantify the benefits of DG looks at each potential benefit in isolation and from a set of previously completed analyses that are not necessarily directly comparable and likewise characterizes the value to just one specific beneficiary (the electric utility). A holistic approach and an assessment of the cumulative effect of these benefits are critical to the formulation of any policies based on DG as a population, rather than simply as a set of isolated technologies. By failing to provide such a methodology, Congress is left with no meaningful data to formulate future policy.

<u>Incomplete characterization of regulatory framework in analysis of rates/regulatory issues</u>

The report conveys that one of the major problems with efficiency-driven DG is that it runs counter to the need for utilities to maximize throughput created by cost-plus pricing. However, the report is silent on the manner in which this throughput bias creates a financial incentive for regulated utilities to erect barriers to efficient electricity consumption and production by their customers.

<u>Inexperience is not the issue</u>

The report states that lack of familiarity in the power industry with DG is an obstacle to its acceptance. While this may be true within the context of regulated utilities (who own a tiny fraction of the total installed DG capacity on the system), it is categorically false for the grid as a whole. Indeed, the report states that there are over 12 million DG units with over 200 GW of capacity. CHP currently accounts for approximately 84 GW of the generation capacity in the U.S., and is the majority of the installed DG base on a GWh basis, accounting for approximately 9% of all US power consumption. By comparison, hydroelectric power accounts for approximately 7% of all US power consumption. Thus, while the potential for CHP deployment is significantly higher than is represented by current deployment, it is no more accurate to assert a lack of experience with DG/CHP than it is to assert a lack of experience with hydroelectric power. What makes DG unique relative to other generation sources is that it is deployed almost exclusively by unregulated market participants. As such, while one may accurately assert that regulated utilities have a lack of experience *owning* DG, this points to flawed incentives for regulated utilities rather than to an underlying lack of experience *operating* a grid that relies upon DG.

Conclusions

DG provides benefits often overlooked from the perspective of traditional economics of the existing central station model and regulation. Analyses completed to date by various energy industry stakeholders strongly suggest that *DG offers the most value when all of its value streams are considered*.

Under current regulatory structures, DG owners and investors cannot realize full value for the benefits they enable, including reduced pollution, enhanced energy efficiency, improved productivity, and reduced infrastructure costs. As pointed out in the report, today's market paradigm provides negative incentive for electric utilities to encourage the development of local distributed energy systems, technologies, equipment, and/or business models.

We hope that our comments facilitate a broader policy discussion as government and industry craft regulatory reform to ensure a reliable, low cost and clean national power grid.

8. U.S. Environmental Protection Agency

TO: U.S. Department of Energy
Office of Electricity Deliverability and Energy Reliability
Submitted via E-mail EPACT1817@hq.doe.gov

FROM: Kathleen Hogan
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RE: U.S. Department of Energy Study "The Potential Benefits of Distributed Generation and Rate-Related Issues that may Impede their Expansion" in response to Section 1817 of the Energy Policy Act of 2005

I. INTRODUCTION

The U.S. Environmental Protection Agency (EPA) respectfully submits these comments to the U.S. Department of Energy (DOE) on its February 2007 study "The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion" pursuant to Section 1817 of the Energy Policy Act of 2005. The study does a commendable job addressing the environmental issues covered within the report: potential benefits of distributed generation (DG) to reduce land use effects and rights-of-way. However, the study has major omissions as it does not describe the significant emission benefits of clean DG (such as combined heat and power) – significant reductions in the air pollutants contributing to ground-level ozone (smog) and acid rain, and greenhouse gases contributing to climate change. The study scope should be expanded to address air emissions benefits. In addition, further elaboration on the emission impacts from DG participating in demand response (DR) programs should be included in the study, as a discussion of DG participating in DR programs that is done without an understanding of emission impacts can lead to negative environmental impacts.

Finally, an expanded discussion of the utility throughput issue would be beneficial since this is a primary barrier to increased clean DG.

EPA operates numerous voluntary efforts to promote clean energy, including the Combined Heat and Power Partnership, which is a voluntary effort that seeks to reduce air emissions through implementation of environmentally beneficial, cost-effective combined heat and power projects. The Partnership works closely with energy users, the CHP industry, state and local governments, and other stakeholders to support the development of new projects and promote their energy, economic, and environmental benefits.

EPA's experience over the past several years of implementing the CHP Partnership is that end users, air regulators and other key stakeholders lack knowledge about the true environmental footprint of DG technologies, including CHP. Based on this consideration, EPA recommended in its February 17, 2006 comments that the DOE study includes these significant benefits. Specifically, there are two key aspects EPA requested be included in the assessment: a) key characteristics of the environmental benefits of DG, and b) discussion of existing methodologies for quantifying the environmental benefits of CHP. Discussion of these aspects is not repeated in these comments, rather we provide a brief summary of the emission benefits of CHP, information on emission impacts from DG participating in DR programs, and share tools and analysis EPA has developed to support this. This information demonstrates that the study scope could be expanded without significant additional effort. EPA is happy to assist with this. We also include updated information from the National Action Plan for Energy Efficiency on addressing policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments. These topics are focused on energy efficiency in the Action Plan but also address barriers to increased DG.

II. COMMENTS

A. Emissions Benefits of CHP

The EPA supports CHP because there are significant cost-effective emissions reductions that can be achieved by increasing efficient energy supply. The average efficiency of fossil-fueled power plants in the U.S. is 33% and has remained virtually unchanged for 40 years. When purchased electricity is combined with on-site thermal generation (assuming 80% boiler efficiency), the typical combined efficiency is 49%. CHP systems typically achieve overall fuel efficiencies of 55% to 80% and reduce fuel use 20% to 50% over separate heat and power.

This improvement in efficiency is a proven pollution prevention strategy that reduces emissions of air pollutants and carbon dioxide, the leading greenhouse gas associated with climate change. Recently, as part of the High Electricity Demand Day Initiative of the Ozone Transport Commission (comprised of the environmental commissioners of the twelve northern most states and the District of Columbia), the US EPA assessed the potential role for energy efficiency and combined heat and power to help address these states' persistent ozone non-attainment episodes which tend to coincide with high electricity-use days. The analysis found that there were significant, cost-effective NOx and CO2 emissions reductions achievable in the near-term from increased use of energy efficiency and combined heat and power. The states are currently working to incorporate these measures in their attainment strategy.

EPA has developed or provided support for several tools and analysis to quantify or recognize the environmental attributes of DG. The CHP Emissions Calculator[2], developed by EPA and DOE, quantifies the direct and indirect emission reductions of onsite combined heat and power as compared to central generation

[2] CHP Emissions Calculator available at http://www.epa.gov/chp/project_resources/calculator.htm

on a project-by-project basis. The tool quantifies the significant emission reductions of CHP projects compared to separate heat and power generation. Based on this recognized benefit, many states have begun to monetize the environmental attributes of CHP projects through Energy Efficiency and Renewable Energy Set Asides for cap and trade programs of criteria pollutants or by qualifying for offsets for greenhouse gas emission reduction programs. For example the Climate Trust recently issued a Request for Offers (RFO) for EERE projects including CHP worth up to 10.5 short tons of carbon reductions (MMTCE). Also, in many states CHP is eligible for Renewable Energy Credits (RECs) as part of their Renewable Portfolio Standards (RPS). Currently, six states - Connecticut, Hawaii, Maine, Nevada, Pennsylvania and Washington - include CHP and/or waste heat recovery as an eligible resource, with Arizona explicitly including renewably fueled CHP systems. There is legislation in North Carolina and Florida that would include CHP in a Renewable Portfolio Standard/Energy Efficiency Portfolio Standard.

B. Emission impacts from DG participating in demand response programs

A major finding in the Report is that on a local basis there are opportunities for electric utilities to use DG to reduce peak loads, to provide ancillary services such as reactive power and voltage support, and to improve power quality. The report states: "Using DG to meet these local system needs can add up to improvements in overall electric system reliability. For example, several utilities have programs that provide financial incentives to customer owners of emergency DG units to make them available to electric system operators during peak demand periods, and at other times of system need. In addition, several regions have employed demand response (DR) programs, where financial incentives and/or price signals are provided to customers to reduce their electricity consumption during peak periods. Some customers who participate in these programs use DG to maintain near-normal operations while they reduce their use of grid-connected power."

While there are a variety of DG technologies available to support these programs, including advanced and very low-emitting technologies, the most common DG technology used in DR programs is a conventional diesel engine generator with high emissions, particularly of NOx. It is unfortunate that the Report does not address the emission impacts of diesel engine use in DR programs. To provide some context, many installed diesel engine generators have NOx emissions greater than 20 lb/MWh[3]. The cleanest current diesel engine generators have emissions greater than 13 lb/MWh[4]. In contrast, the national average NOx emission rate for all U.S. fossil generators is less than 3 lb/MWh[5]. New combustion turbine peaker units have NOx emissions of 0.7 lb/MWh or lower[6]. New gas-fired DG resources typically have NOx emissions of 6 lb/MWh on the high side, with some technologies having emission rates below 1 lb/MWh.[7]

The FERC Assessment of Demand Response and Advanced Metering report reviews nine DR programs[8]. There are at least four types of DR programs in which the DG technologies could be used and for which emissions impacts should be considered[9]:

[3] Emissions Rates for New DG Technologies, Regulatory Assistance Project, http://www.raponline.org/ProjDocs/DREmsRul/Collfile/DGEmissionsMay2001.pdf
[4] Gas-Fired Distributed Energy Resource Technology Characterizations, US DOE, October 2003
[5] eGRID2002 version 2.01
[6] EPA Base Case 2006, http://epa.gov/airmarkets/progsregs/epa-ipm/index.html#docs
[7] Emissions Rates for New DG Technologies, Regulatory Assistance Project, http://www.raponline.org/ProjDocs/DREmsRul/Collfile/DGEmissionsMay2001.pdf
[8] Incentive-based DR: direct load control; interruptible/curtailable rates; demand bidding/buyback programs; emergency DR programs; capacity market programs; ancillary-services market programs. Time-based rates: time-of-use; critical-peak pricing; real-time pricing.
[9] For a complete discussion of DR program types, see the FERC Assessment of Demand Response and Advanced Metering, August 2006.

- Emergency – Emergency DR programs provide an incentive to the customer for reducing their load during a reliability-triggered event. Some regions allow the use of DG, including diesel generators, to help prevent a blackout as demand exceeds central generation capacity. The philosophy is that it is worth using these high-emitting resources in order to avoid the wide-spread disruption of a grid blackout. Nevertheless, some regions exclude diesel generators from these programs due to emission concerns. This is particularly true since the high electricity demand days often occur on hot summer days when high emissions are most significant.
    - Ancillary services – These programs allow customers to bid load curtailments in ISO/RTO markets as operating reserves[10]. Often the resources used in these programs are industrial processes that can be quickly curtailed. However, when DG resources are used, high-emitting resources are usually excluded from the program since these are purely discretionary programs and there is no justification for increasing emissions.
    - Economic price response/demand bidding – These programs provide the customer the ability to choose if they want to participate in the DR program based on either the cost of the grid purchased electricity reaching a previously identified threshold, or reduce grid purchased electricity and receive a payment based on the cost of electricity during the time of the grid reduction. This is typically done on a real-time or day-ahead basis. These programs can incentivize DG units to run during peak that have higher emissions than the typical central station natural gas peak generator that they are offsetting.

[10] FERC Assessment of Demand Response and Advanced Metering, August 2006.

- Emission reduction - A recent focus of interest in demand response programs has been the potential to displace high-emitting central grid resources that operate during periods of very high electricity demand in order to reduce emissions on those days. To date, this has not been implemented. Since the driver for these programs is emission reductions, it is obviously not productive to replace the high-emitting central station resources with even higher-emitting DG resources. There are few if any central station peak generators that would have NOx emissions higher than even the cleanest diesel engines.

These emission characteristics should be considered in an evaluation of the benefits of DG.

Some states have addressed concerns surrounding DG emissions from participating in DR programs by including requirements for the types of load reductions that are eligible for non-emergency DR programs (e.g., NY ISO's Day Ahead Demand Response Program prohibits the use of back up generation) and/or selecting programs that tend to elicit curtailment rather than the use of backup generation (e.g., California's Critical Peak Pricing program). New York Department of Environmental Conservation has a proposed DG rule, part 222, which specifically defines requirements for DR sources.[11] How these emissions can be addressed should be described in the study.

C. Aligning utility incentives and modifying ratemaking practices: information from the National Action Plan for Energy Efficiency

The National Action Plan for Energy Efficiency (Action Plan) presents policy recommendations for creating a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations.[12] The Action Plan Leadership Group consists of more than 50 leading privately, publicly, and cooperatively owned electric and gas utilities, utility regulators, state agencies, large

[11] For more information, visit http://www.eea-inc.com/rrdb/DGRegProject/LatestNews/NYlatestDGdraftrule.pdf

[12] More information on the National Action Plan for Energy Efficiency is available at http://www.epa.gov/eeactionplan

energy users, consumer advocates, energy service providers, and environmental and energy efficiency organizations.[13] The Leadership Group offers five recommendations as ways to overcome many of the barriers that have limited greater investment in programs to deliver energy efficiency to customers of electric and gas utilities. The fifth recommendation is to modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments. While this effort is focused on energy efficiency, this recommendation highlights areas that are currently a significant barrier to increased DG.

It is unfortunate that discussion of these important topics is only given two pages in the Report. This could be significantly expanded in the final Report. For example, the Action Plan Report includes an entire chapter of more than 18 pages to these issues. This chapter discusses options to eliminate the utility disincentive to invest in energy efficiency based on successful efforts in states to implement these solutions, as well as discussing shareholder incentives and energy efficiency program cost recovery. Information from the Action Plan Report could be used to inform a richer discussion in the DOE Report. The Action Plan is developing a follow-up paper on Aligning Utility Incentives with Delivery of Cost-Effective Energy Efficiency, which will be completed in summer 2007.

III. CONCLUSION

It would be unfortunate if DOE missed the opportunity to recognize the full benefits of distributed generation in an assessment required to be comprehensive. The study scope should be expanded to include discussion of the air emission benefits of clean DG, elaboration on the emission impacts from DG participating in DR programs, and an expanded discussion of the utility throughput issue. Please contact me if EPA can be of any assistance in helping DOE identify and quantify the benefits of distributed generation.

[13] US EPA and US DOE facilitate the work of the Action Plan Leadership Group.

Respectfully submitted,

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April 2, 2007

9. Peter McKay

Comments to
Study: The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion
By

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I have read THE POTENTIAL BENEFITS OF DISTRIBUTED GENERATION AND RATE-RELATED ISSUES THAT MAY IMPEDE THEIR EXPANSION
A STUDY PURSUANT TO SECTION 1817 OF THE ENERGY POLICY ACT OF 2005.
It is a very comprehensive document and I congratulate the DOE for the even and fair presentation of the material.
I am an advocate for small Renewable Energy (RE) Distributed Generation (DG).
The single largest impediment for me is that current Federal regulations apply only to "qualified facilities" thus creating a loophole that smaller member owned cooperatives can exploit. I think the standard should apply to all utilities regulated by the state.

I live in Alaska and my local utility company is a member owned cooperative.
I have petitioned the Regulatory Commission of Alaska (RCA) to adopt several elements of EPAct of 2005 – In particular the Net Metering and Interconnect standards. I have encouraged them to apply the standards to all state regulated utilities.
Strong Federal support for application of the standard to all state utilities would benefit me and make the application of the EPAct more equitable.

Thank you for considering my opinion.
Peter McKay

10. Jane P. Hill

Comments by: Jane P. Hill

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April 1, 2007

Overview

Section 1817 of the Energy Policy Act of 2005 represents an important step toward encouraging the development of cogeneration and small power production. There are benefits associated with distributed generation (DG) which may not be immediately obvious in traditional generation planning, and Section 1817 may encourage new approaches to development.

However, the draft report fails to emphasize strongly enough the two most important impediments to DG development by electric utilities:

(1) the fundamental reason why electric utilities have failed to embrace DG is that DG cannot capture the economies of scale available with conventional central station power plants, and

(2) there is indeed higher risk with DG than with conventional generation technologies, and there is no risk/reward incentive for electric utilities.

In addition, non-utilities wishing to invest in DG typically can only accrue economic benefits based on existing electric tariffs. These tariffs usually include only the cost of financing power plants, fuel, O&M, and administration. These costs do not represent the entire cost to society of supplying central station power.

While incorporating additional costs into electric tariffs would make DG more attractive, it would not be palatable for elected public service commissioners. No one ever got elected to a PSC on a platform of raising electric rates.

To expand the role of DG to its full potential, it is very likely that DG must be developed on a scale only attainable through the participation of electric utilities. To achieve this, meaningful incentives must be provided and serious impediments removed.

On the other hand, there are activities in the energy field, outside of traditional utility generation expansion planning, that may encourage DG. For example,

(1) the U. S. Green Building Council's LEED (Leadership in Energy and Environmental Design) program may allow credits toward certification for the improved efficiency available with cogeneration versus conventional systems;

(2) the development work in fuel cells for vehicles may reap benefits for stationary fuel cells, much like development work for military jets provided technological improvements for combustion turbines used for power generation; and

(3) concerns about global warming have increased interest in reducing carbon dioxide emissions.

Keys to DG expansion will probably be financial incentives—most likely through tax credits; an increased awareness of the environmental consequences of conventional central station power plants; and coordinated technological improvements, pooling research for similar technologies used for different applications.

Other incentives might include some sort of fuel purchasing arrangement, allowing multiple DG developers to combine their demand to obtain more favorable fuel prices; a requirement for true life cycle analysis, not simply life cycle *cost* analysis, to determine the actual impact of DG versus conventional generation; and increased government and private sector support for energy-related research.

Disincentives for Utility Investment in DG

The major impediment to utility investment in DG is the additional cost per kilowatt of installed capacity relative to central station plants. This occurs for several reasons. One reason is that some components of the investment in a generating plant are relatively fixed or increase only moderately for larger installations. Therefore, for these components, the more kilowatts of capacity installed, the lower the investment required for each kilowatt. In addition, the generating equipment itself—turbines, generators, boilers, etc.—is likely to cost less at higher capacities on a unit (dollar per kilowatt) basis.

Larger generating units are also likely to be more efficient. For example, it typically takes more Btus of fuel to produce a kilowatt-hour using a small combustion turbine than with a large turbine, assuming both are operated at a fairly high load relative to their capacity.

Taking these two issues together, for a utility to invest in DG instead of central station power plants will require some compelling arguments. Section 1817 provides many excellent examples when DG might be preferable, but these are often exceptions rather than typical cases.

Electric utilities are risk averse because there is no motivation for taking risks. Utilities have an *obligation to serve,* and customer expectations of reliable power are very high. To invest in new technologies (or even new applications of "old" technologies) involves an increased risk with no accompanying increase in return on investment for a utility. As DG technologies continue to improve, early adopters could be stuck with obsolete technology early in the life of the equipment.

In addition, changes in environmental regulations can reduce or even eliminate the ability to operate DG in some instances. An example of this occurred at Georgia Power Company. Georgia Power approached its customers who had emergency generators, offering to install paralleling switchgear and provide routine maintenance. In return, Georgia Power would have the ability to dispatch the emergency generators during times of very high demand on its system.

Georgia Power was able to attract enough participants to delay installing one planned combustion turbine. However, air quality issues ultimately forced Georgia Power to abandon the program, after significant investment and a large expenditure of manpower.

It is probably not a fair statement to say that utilities have a "lack of familiarity with DG technologies." (Page 6) Utilities are certainly knowledgeable about diesel generators and combustion turbines, which are important DG technologies and found in almost all utilities, either as generating capacity, for starting large units, or for backup power. In addition, numerous utilities have installed test sites for DG equipment, including particularly solar and fuel cells. Nor is hydropower new to utilities. Because utilities have experience with DG technologies in real world situations, they may perceive a higher degree of risk than developers, whose experience may often be limited to the lab.

Another example of an impediment to a utility's installing DG involves cogeneration applications. Cogeneration, or combined heat and power (CHP), can provide greatly improved efficiencies relative to conventional systems, if an appropriate operating scheme can be worked out. Otherwise, cogeneration can present a situation with conflicting objectives.

For example, a utility typically wishes to dispatch electric generating units in merit order, i.e. in ascending order of marginal cost, to minimize its total production cost. The marginal cost of cogeneration at any point in time will depend on the degree to which heat can be recovered in a "useful thermal process." That is, the marginal cost will be the operating cost of the cogeneration plant (fuel and variable O&M), less the value of the steam or hot water produced simultaneously. Thermal requirements may require operation of the cogeneration facility when the cogeneration unit is not the next lowest cost unit. In this case, the utility will be paying more to supply power to its customers than it would without the cogeneration unit in its mix. (These additional costs will typically be passed along to customers through a "fuel cost recovery rider").

In other instances, the utility may need the electric output of the cogeneration plant when there is little or no thermal requirement. In this case, there may be no thermal savings to offset the cost of producing electricity—resulting in higher net production cost for electricity than anticipated.

The statement on Page 6 that "this lack of familiarity has also contributed to a lack of standard data, models, or analysis tools for evaluating DG, or standard practices for incorporating DG into electric generating planning and operations" is probably not entirely accurate. First, utilities certainly have production costing models which can include DG, using heat rates and other data, just like any other technology. The problem is that DG capacity is normally so small compared to conventional generating technologies, that DG can get lost in the noise in the model when modeling the entire generating stack.

Secondly, standard data for many DG technologies, such as diesel generators, combustion turbines, fuel cells, and microturbines, are readily available from vendors, using the same parameters as conventional technologies. Sometime adjustments have to be made for issues such as higher heating value versus lower heating value, but this is often necessary with data for conventional technologies as well.

And finally, models *are* available, developed specifically for DG, which estimate electric and thermal output, as well as fuel requirements on an hourly basis. These values are modeled as functions of ambient temperature and part load requirements, based on technology-specific performance curves. Because these models produce values for both electric and thermal output on an hour-by-hour basis, detailed rate impacts can be determined. The models even prepare after-tax net present value analysis.

Suggestions

This assessment of Section 1817 is not meant to be critical of the document, but rather to point out areas that might need additional work. Many in the industry think DG is a concept whose time has come, but there are impediments for which realistic solutions must be found.

In some instances, the reader can almost infer that the document assumes a utility-led conspiracy to squash DG. That may well have been the case years ago, especially when utilities routinely had reserve margins of 20 percent or more and revenue preservation was a primary objective. It may still be the case in some areas.

However, as utilities become more aware of the difficulty in expanding transmission and distribution facilities and as the country becomes more conscious of the exposure with having so many generation eggs in so few baskets, attitudes are likely to change. Any new central station power plants are likely to have substantial NIMBY problems. And concerns about carbon dioxide are exploding—a situation especially critical to a country that relies so much on coal for its electricity.

Listed below are some specific suggestions that might be incorporated into the document to make it more comprehensive:

- Analysis of the economics of DG are shown consistently in the document using simple payback. While payback is often used in documents of this type, it is not appealing to tax-paying investors. Many documents relating to DG and even models developed for analysis have been developed by universities and government agencies, who pay no income taxes. In the private sector, this is not the case. Tax paying entities tend to evaluate investments on some form of after-tax life cycle cost (LCC) or internal rate of return (IRR). Because capital is not infinite, they compare projects on the basis of the expected return over some time period, taking into account the relative risk of the various options. While this approach is probably beyond the scope of Section 1817, after-tax LCC or IRR analysis would be very useful to non-governmental investors in DG, such as investor-owned utilities.

- Section 7 gives many examples of how DG has supplied electric power when grid-supplied power was not available, because of weather and other catastrophes. However, there appears to be no mention that some DG applications are not appropriate for quick-start, backup power. For example, a diesel generator can come up to full load in a matter of seconds, while a fuel cell could takes hours. Therefore, a fuel cell would not be appropriate for standby power, but might be quite appropriate for continuous operation in a hospital, providing electricity and hot water.

- Section 8 gives an excellent overview of electric utility rates, explaining the history and much of the philosophy of rate-making. However, it only deals with traditional rates. Many utilities offer some form of real time pricing rate, which was mentioned only once in the document. Understanding a utility's real time pricing rate provides considerable insight into the utility's costs and constraints, since the hourly rates are designed to give pricing signals to customers, to encourage certain usage patterns as well as to generate revenue.

11. National Propane Gas Association

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April 2, 2007

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RE: Study of the Potential Benefits of Distributed Generation and Rate-Related issues That May Impede Their Expansion

The following comments represent those of the National Propane Gas Association (NPGA) on the U.S. Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability's (OE) study titled; *"The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion."* which was authorized by Section 1817 of the Energy Policy Act of 2005. These comments were developed in cooperation with the Propane Education Research Council (PERC) in response to the March 1, 2007 *Federal Register* Notice announcing the availability of the study for public comment.

As a matter of background, NPGA represent the interests of the U.S propane industry that includes, in combination, retail marketers of propane gas, propane suppliers, transporters, wholesalers, manufacturers and distributors of equipment, containers and appliances. PERC has invested a significant amount of money in Distributed Generation (DG) research focusing on the development and commercialization of propane technologies that include fuel cells, generator sets and microturbines.
Propane is a $30 billion industry in the United States, and in 2004, the U.S. consumed nearly 20 billion gallons of propane for home, agricultural, industrial, and commercial uses. Approximately 7 million households depend on propane for their primary heating and cooking fuel. An additional 10 million households use propane in one or more appliances, and 47 million homes use propane for outdoor grills. Propane is used in commercial applications that represent approximately 7 billion square feet of commercial space.

The propane industry believes that Distributed Generation powered by clean-burning fuels such as propane and propane-compatible renewable fuel blends can provide a significant contribution to the nation's efforts to develop a sustainable energy future and provide an increased measure of energy security because more than 90 percent of propane consumed in the U.S. is produced domestically. Moreover, the portability of propane in DG applications such as generator sets makes it an extremely valuable commodity when responding to the needs of those who have suffered the consequences of either natural or man-made disasters. Additionally, propane can contribute to the economic development of rural America because of its existing widespread usage in this realm.

We believe that this DG study will form the basis for future Federal policy development and research needs with regard to distributed generation. This study could also have a substantial impact on many State programs as well. Because of this, the propane industry is interested in working closely with the Department to develop a robust DG program, and we hope our comments will lead to further discussions with the DOE on how the propane industry can partner with the agency to achieve this successful outcome.

This study is a compilation of existing DG benefit studies, but we believe it could benefit from additional analyses to strengthen the rationale of using many reports with different assumptions. Our specific comments are as follows:

- The study concludes that central power generation is the optimal result, yet we believe that this would not necessarily be the case if other perspectives are analyzed. For example, the report could have included a broader basis for the development of the benefit and rate structure rather than just the local electric distribution company (LEDC). Therefore, we would have preferred to have seen other perspectives included.
- The study states that a key problem for DG is "….the economics of DG are such that financial attractiveness is largely determined on a case-by-case basis, and is very site-specific." We believe that with broader perspectives, site selection with DG systems is comparable to most other engineered systems.
- The inclusion of essential public and local grid benefits like energy efficiency, emissions reductions, feeder and network resiliency and utility infrastructure load factor improvement would have further improved the study's results.
- The study should have included the rural development benefits of propane-based DG systems, which would eliminate the need for long, low-voltage lines servicing sparsely populated areas, which technically and financially burden rural electric networks.
- The study lacked a broader analysis of generated power to include systems that would ameliorate concerns of energy efficiency and pollution inherent in standby diesel systems.
- The study did not include the Congressionally-requested methodology to correctly value DG benefits.
- The study failed to address or explain the current regulatory approach that forms barriers to distributed generation deployment. Under current regulatory schemes, DG owners and investors cannot realize the full value for the benefits they

provide, including reduced pollution, enhanced energy efficiency, improved productivity, and reduced infrastructure costs. Furthermore, today's market paradigm provides no incentives for electric utilities to encourage the development of local distributed energy systems, technologies, equipment, and/or business models.

The propane industry would like to join DOE in advancing the use of clean-burning fuels for DG and Combined Heat and Power (CHP) system applications. The goal of such an effort would be the development of a sustainable and secure energy infrastructure.

We thank you for the opportunity to comment on this study. Please feel free to contact us if you have any questions.

Sincerely,

Michael A. Caldarera
Vice-President, Regulatory and Technical Services

12. Edison Electric Institute

March 30, 2007

Mr. Mario Sciulli
National Energy Technology Laboratory
P.O. Box 10940
MS 922-342C
Pittsburgh, PA 15236

RE: Comments on the "Study of the Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion"

Dear Mr. Sciulli:

The Edison Electric Institute (EEI) appreciates the opportunity to submit comments regarding the Department's draft DG Study that was called for by Section 1817 of the Energy Policy Act of 2005. This letter is written in response to the Federal Register notice which was published at 72 Fed. Reg. 9318 (March 1, 2007).

EEI is the association of the U.S. shareholder-owned electric companies, international affiliates and industry associates worldwide. Our U.S. members serve over 97 percent of all customers served by the shareholder-owned segment of the industry. They service 71% of all ultimate customers in the United States. Many of our members are combination electric/gas companies, and provide efficiency services for both fuel types.

These comments will (1) state our views on the draft study, (2) provide feedback based on the information provided in early 2006 (3) respond to specific issues in the draft study.

EEI believes that in certain applications, DG can be of benefit to customers and the electric grid.

However, this report glosses over or ignores many of the technical obstacles and many other technical and economic and environmental issues that were discussed in detail in the EEI member company comments that were provided to DOE in early 2006.

EEI suggests that DOE review the detailed information that was provided and incorporate the information into the report.

There are two key issues that EEI would like to highlight with the draft report: Section 6 (DG and Reducing Land Use Effects) and Section 7 (DG and Reducing the Vulnerability of the Electric System to Terrorism and Providing Infrastructure Resilience) and current technologies used for DG.

In terms of DG and land use effects, the study shows detailed data on the cost of various types of land and right of ways and implies that DG systems would reduce their use for electric supply infrastructure. The study does not discuss several key facts:

- If the DG system only operates during emergency situations, then the customer is using the grid for 100% of its power needs, and 100% of the infrastructure will need to be built;

- If the DG system only operates during peak periods of the day, and relies on grid power for other time periods, then the customer is using the grid for 100% of its "non-peak" power needs, and 100% of the "non-peak" infrastructure will need to be built. For many customers, the non-peak loads can be as high or equal to the "peak" loads;

- If the customer installs a DG system after the customer has been using electricity for some time, 100% of the infrastructure has already been built, and there will be no reduction in land use. If anything, more land is used for providing parts and labor and fuel for the DG system;

- If the customer uses the DG system for 100% of its power needs, but decides that they want grid power to back up the DG system (100% standby power), then the customer is using the grid for 100% of its standby power needs, and 100% of the infrastructure will need to be built, along with the land use and infrastructure for supporting the DG system and fuel;

- If the customer uses the DG system for 100% of its power needs and is not connected to the grid, then there may be some land use savings, if the DG system is large (e.g., over 1 or 10 MW). The smaller the system is, and the more near urban areas it is, the less likely that there will be land use savings.

DOE should revise Section 6 to take these facts into account.

In terms of Section 7, DG and terrorism, the study does not discuss the fact that the presence of a DG system at a customer site does not make central station generation, transmission lines, or distribution systems any less vulnerable to a terrorist attack. The DG system does not provide any protection to the electric grid whatsoever.

In the case of an emergency or terrorist attack, a DG system, as shown in the report, is very helpful or even critical for on-site facility needs. However, building owners may be reluctant to send the power needed for facility operations out to the grid. Also, if nearby lines are down, then a DG system could not send power to the rest of the grid any way.

There is one other key comment that EEI would like to point out. By far, the most prevalent form of distributed generation systems in the United States are diesel generator sets with no emission controls. Policies that increase their use, especially in urban non-attainment areas, would increase the US dependence on foreign oil, have negative impacts on urban air quality, and could lower the overall fuel to electric efficiency (heat rate) of the US electric system. Such an outcome could happen if some of the suggestions in the current report are adopted.

EEI sincerely appreciates the opportunity to submit these comments.

Respectfully submitted,

Edward H. Comer
Vice President and General Counsel
Edison Electric Institute
701 Pennsylvania Avenue N.W.
Washington, D.C. 20004-2696

cc: Rick Tempchin, EEI
Steve Rosenstock, EEI

13. World Alliance for Decentralized Energy (WADE), US Affiliate

TO: U.S. Department of Energy
Office of Electricity Deliverability and Energy Reliability
Submitted via E-mail EPACT1817@hq.doe.gov

FROM: David M. Sweet
Executive Director
WADE USA
1513 16th St., NW
Washington, DC 20036
Phone: 202 667-5600
E-Mail: dsweet@localpower.org

RE: Section 1817: Study of Distributed Generation Benefits

WADE USA Comments on

The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion
A Study Pursuant to Section 1817 of the Energy Policy Act of 2005
Requested by the Office of Electricity Delivery and Energy Reliability (OE), U.S. Department of Energy (DOE)

I.
Background and Identification of Party

Pursuant to the notice issued in the Federal Register of March 1, 2007, and the report issued by the United States Department of Energy ("DOE") on Section 1817 of the Energy Policy Act ("1817 Report") WADE USA hereby submits the comments below.
WADE USA is the U.S. affiliate of the World Alliance for Decentralized Energy (collectively referred to as "WADE"), a non-profit association based in Edinburgh, Scotland. The World Alliance for Decentralized Energy (WADE) was established in 2002 as a non-profit research and promotion organization whose mission is to accelerate the worldwide development of high efficiency cogeneration (CHP) and decentralized renewable energy systems that deliver substantial economic and environmental benefits. WADE has established a tradition of thorough and comprehensive research on DE, efficiency and a wide range of energy and environmental issues. In addition to WADE's publications, reports and market studies, WADE has participated in successful projects around the world, working with a range of governments, national and international

organizations to highlight the many benefits of DE. The following person should be contacted with respect to these comments:

David M. Sweet
Executive Director
WADE USA
1513 16th St., NW
Washington, DC 20036
Phone: 202 667-5600
E-Mail: dsweet@localpower.org

II.
Comments

The WADE membership includes a number of country specific organizations with similar interests and objectives. The United States Combined Heat and Power Association ("USCHPA"), a member of WADE, filed comments on the 1817 Report on March 30, 2007. WADE supports those comments and echoes the concerns raised by USCHPA. However, we seek to supplement those comments based on WADE's global experience in quantifying the benefits of distributed generation (DG). We believe that this body of WADE research will be helpful to DOE as it further evaluates the role that DG can play going forward.
Through use of the proprietary WADE Economic Model has demonstrated the impact of moving from a centralized power system to a more decentralized approach. Specifically, the purpose of the WADE Model is to calculate the economic and environmental impacts of supplying incremental electric load growth with varying mixes of decentralized and central generation. With changed input assumptions, the model can be adapted to any country, region or city in the world. Starting with generating capacity for year 0 and estimates of retirement and load growth, the model builds user-specified capacity to meet future growth and retirement over a 20 year period.
The model's data input requirements are detailed and extensive, requiring comprehensive information on a range of factors including:

- Existing capacity and generation by technology type
- Current and future load factors by technology type
- Current and future pollutant emissions by technology type (NO_x, SO_x, PM_{10}, CO_2)
- Future and current heat rates and fuel consumption by technology type
- Future and current capital and investment costs by technology type and for transmission and distribution (T&D)
- Future and current average operation and maintenance (O&M) costs and fuel expenses by technology type
- Annual growth rates for the chosen geographic area
- Network losses and capacity reserve margins

- Estimates of existing yearly capacity retirement by technology type, to be entered year-on-year
- Estimates of future growth in capacity by technology type, to be entered year-on-year

The Model outputs are:

- Total capital costs for investment (generation capacity + T&D) over 20 years
- Retail costs in year 20 (T&D amortization + generation plant amortization + O&M + fuel costs) for the new generation capacity
- Fossil fuel use by the new capacity in year 20
- CO_2 and other pollutant (SO_2, NO_x, PM_{10}) emissions from new generation mix and capacity in year 20

The model can build scenarios for new capacity to meet incremental demand over 20 years, ranging from scenarios with 0% distributed generation / 100% central generation to 100% distributed generation / 0% central generation. The model also builds cases between these extremes. The WADE Economic Model also enables users to run any number of scenarios to explore how changes fuel prices, changes demand growth, effect over all costs how financial support mechanisms change the attractiveness of various technologies or how specific environmental goals can be achieved using various investment mixes.

A summary of results from application of the WADE Model is illustrated in the chart below. Based on our analysis, the efficiencies gained from moving away from a centralized system can consistently offer less expensive delivered power **and** lower emissions of CO_2. Additional benefits quantified by the model include reduced criteria air contaminants and considerable fuel savings.

Summary of Results from Past WADE Economic Model Runs

	Brazil	China	EU	Germany	Ireland	Ontario	UK	USA	World
Capital cost	46%	38%	45%	-5%	29%	58%	27%	44%	30%
Retail costs	40%	28%	37%	40%	16%	42%	15%	40%	29%
CO2 emissions	-22%	56%	12%	91%	34%	41%	17%	49%	47%
Fossil fuel use	-17%	30%	5%	83%	64%	32%	12%	14%	11%
NO_2 emissions	-169%	89%	60%	N/A	43%	29%	77%	58%	66%
SO2 emissions	-8%	89%	22%	N/A	40%	2%	36%	68%	72%
PM10 emissions	-171%	58%	39%	N/A	39%	38%	-217%	43%	44%

Source: Compiled from various WADE studies

In all likelihood the benefits outlined above are conservative. There is a growing body of evidence that DG offers a wide range of benefits not reflected in the modeling results summarized above. Reliability, security and health benefits, for example, could have a multiplier effect on the cost savings that appear possible based on the modeling exercises outlined above.

Additional economic growth and diversification benefits are other likely outcomes from increased investment in DG. Investment in DG will allow the US to stay internationally competitive in the long term.

III.
Conclusion

WADE thanks DOE for its efforts in preparing this report and respectfully requests that the comments above be considered as part of the record.

Respectfully submitted,

David M. Sweet
Executive Director
WADE USA

14. Connecticut Department of Public Utility Control

Re: DG Study Pursuant to Section 1817 of the Energy Policy Act of 2005

Dear Secretary Bodman:

Enclosed for electronic filing in the above-captioned proceeding is the Connecticut Department of Public Utility Control's Comments in response to the U.S. Department of Energy's Distributed Generation Study.

Please contact Peggy Diaz at telephone number (860) 827-2680 or at peggy.diaz@po.state.ct.us if you have any questions regarding this filing.

Respectfully Submitted,

/s/

Anne C. George

April 2, 2007

The Honorable Samuel W. Bodman
Secretary of Energy
U.S. Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

Dear Secretary Bodman,

The Connecticut Department of Public Utility Control (CT DPUC) provides the following comments to express our support of the U.S. Department of Energy's (DOE) Distributed Generation (DG) Study issued in February, 2007, pursuant to Section 1817 of the Energy Policy Act of 2005.

The CT DPUC is the state public utility commission charged with regulating electric and gas companies and setting retail rates for electricity and gas used within the state. The CT DPUC is authorized by General Statutes of Connecticut § 16-6a to participate in proceedings before federal agencies and courts on matters affecting utility services rendered or to be rendered in Connecticut. The CT DPUC appreciates the opportunity to provide written comments regarding the Department of Energy's DG study.

As the study indicates, DG has many potential benefits including increasing system reliability, power quality and ancillary services along with addressing (decreasing) peak power demand, reducing overall vulnerability of the system, increasing emergency generation supply and at the same time decreasing the need for additional investments in generation, transmission and distribution facilities. The study also accurately highlights numerous potential impediments to encouraging the expansion of small power production facilities. Furthermore, the study appropriately acknowledges the reality that different regions and thus market structures have differing abilities in terms of implementing and funding DG facilities.

Currently, the CT DPUC on behalf of the citizens of Connecticut has implemented an aggressive DG incentive program with the intent of achieving many of the benefits discussed within this study. The Connecticut General Assembly in 2005 enacted Public Act 05-01, An Act Concerning Energy Independence, (Act 05-01) and in part authorized the CT DPUC to establish various incentive programs for customer-side DG. The Act 05-01 specifies that its provisions apply to distributed resources developed in Connecticut that add capacity on or after January 1, 2006 and in accordance with its provisions. These resources include small- and medium-size generating facilities and conservation and load management measures. The incentives include capital- and operating-cost subsidies and the provision of long-term financing.

The DG incentive program authorizes ratepayer funds to be utilized in support of new customer-side DG facilities. This DG program created by the Connecticut General Assembly and implemented by the CT DPUC, provides monetary grants, low interest loans, a waiver on backup rates, gas discounts and qualification as Class III renewable resources.

Under the DG grant program, emergency DG generators may receive up to \$200/kW, while base load generators including combined heat and power are eligible for up to \$450/kW. An additional bonus of \$50/kW is given to projects located in Southwestern Connecticut. See DPUC Docket No. 05-07-16.

The CT DPUC has established eligibility requirements for the DG incentive grant program to ensure greater overall benefits to Connecticut and ultimately our ratepayers. For example, emergency generators must participate in the Independent System Operator of New England's (ISO-NE) load response program. Base load generators must operate at an 85% load factor or greater and must be available during peak load periods. DG projects up to 65 MW are eligible for incentive grants and there are no minimum size restrictions.

The long-term financing aspect of the incentive program is offered through Banc of America Leasing and Capital, LLC (BAL). Interest rates for project financing are set at a fixed rate for the entire period of financing and are intended to be used for capital costs and other project development costs. See DPUC Docket No. 05-07-19. The CT DPUC recognizes that a major determinant in developing generation resources is the initial upfront costs and thus these incentive programs are intended to alleviate or at least reduce these barriers to entry. The maximum size of projects eligible for the long-term financing is 65 MW, while the minimum project size for financing is 50 kW.

Furthermore, under this new DG program. eligible projects include but are not limited to, combined heat and power systems, emergency generation facilities, fuel cells, photovoltaic systems, small wind turbines, peak reduction systems and demand response systems. As with the DG incentive grant program, new or incremental capacity is eligible for financing, while existing capacity is not eligible . Lastly, grants and long-term financing are not available for emergency generation at locations that are required to have emergency generation under state and federal law, such as hospitals and nursing homes.

There are additional incentives available as part of the overall DG incentive programs. For example, natural gas rates will be reduced for DG projects that use natural gas and gas distribution charges will be waived. Additionally, eliminating backup rates and eliminating demand ratchets for these projects will reduce electricity rates for power used when base load customer-side generators are out of service.

Act 05-01 requires the electric companies and competitive suppliers to acquire 1% of their supply from Class III resources starting in 2007. This requirement increases to 4% by 2010. Class III eligible resources include efficient combined heat and power facilities, demand response (curtailment) facilities and other conservation, efficiency and load management measures. Qualifying resources that receive certification from the CT DPUC are eligible for renewable energy certificates (RECs), which may be subsequently sold to load-serving entities that must meet the appropriate RPS standards or in other voluntary markets.

The Act facilitates the siting of the DG projects approved or ordered by DPUC and makes other changes in the Siting Council law. See DPUC Docket No. 05-07-19. The Act 05-01 also provides awards to electric companies for their efforts in connection with the installation of these new DG projects.

Since the commencement of the DG grant program in early 2006, the CT DPUC has approved **46** DG generators under the incentive programs totaling **145** MW of new DG in Connecticut.

In conclusion, the CT DPUC agrees with the DOE that DG is an effective tool which is currently underutilized in this energy market. Moreover, the CT DPUC strongly believes that there are numerous aspects that must be considered as part of the larger electricity market solution. Resources such as conservation and load management, renewable generation resources, as well as smaller yet efficient customer-side DG facilities are legitimate pieces that should be further encouraged and utilized to address the electricity supply and demand puzzle. Again, the CT DPUC thanks the DOE for this opportunity to provide comments in this proceeding.

15. State of New York

New York State Comments on US DOE's February 2007
"Study: The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion
A Study Pursuant To Section 1817 of The Energy Policy Act of 2005"

New York State (the New York State Public Service Commission and the New York State Energy Research and Development Authority) welcomes the opportunity to provide comments on the United States Department of Energy's (USDOE's) well-researched February 2007 report on the potential benefits of distributed generation (DG)[14]. New York shares the view of USDOE and many stakeholders on the importance of DG and the need to better understand and quantify the benefits, as well as the barriers to its continued and expanded use. As evidenced by discussion in various sections of the study report, New York has been a leader in developing policies and fostering an environment that encourages development of DG resources.

In terms of specific comments, New York State notes the following:

- New York applauds Congress for taking notice of the potential benefits of distributed generation, recognizing that there are issues that may impede its expansion, and seeking information and guidance regarding pro-active measures. The study does an excellent job of highlighting the issues. New York urges that USDOE explicitly establish recommendations for actions to be undertaken and addressed by Congress at its earliest opportunity.

- Among the actions Congress should consider are tax benefits and Federal incentives for clean, efficient CHP [spell out first time you use it] installed at commercial and industrial sites. In cooperation with organizations like NARUC, NASEO and ASERTTI, federal leverage and leadership could be used to develop methods and data for utilities to use in considering DG/CHP in resource option planning. Expanded federal resources would also be very helpful in the dissemination of DG/CHP project results through national organizations like the USDOE-funded Regional CHP Applications Centers, NASEO, ASERTTI and the national DG performance database (www.dgdata.org). Federal funding, leadership and expertise should be applied to developing methodologies for determining location-based DG/CHP benefits that would allow utilities and funding entities to invest more in projects with the greatest benefit to the grid.

[14] New York also submitted comments to USDOE on February 23, 2006, in response to the Federal Notice of Inquiry issued on January 30, 2006 soliciting comments for the DG study.

- New York also recognizes the value of the USDOE program (which does not appear to be mentioned in the report) which has advanced the availability of factory-integrated CHP systems. New York believes continued development of factory-integrated DG will help lower market barriers as technologies mature and are demonstrated to be more easily integrated within the system.

16. Puerto Rico Electric Power Authority

Puerto Rico Electric Power Authority
PO BOX 364267
San Juan Puerto Rico 00936-4267

Comments to the Study:

THE POTENTIAL BENEFITS OF DISTRIBUTED GENERATION
AND RATE-RELATED ISSUES THAT MAY IMPEDE THEIR EXPANSION

Sonia Miranda Vega, Head
Planning and Research Division
Tel 787-289-4893
Fax 787-289-4893

April 2, 2007
Submitted by email to: EPACT1817@hq.doe.gov

For questions or comments contact: Yolanda Ramos
y-ramos@prepa.com

Puerto Rico Electric Power Authority Comments to the Study:

THE POTENTIAL BENEFITS OF DISTRIBUTED GENERATION
AND RATE-RELATED ISSUES THAT MAY IMPEDE THEIR EXPANSION

The Puerto Rico Electric Power Authority is committed to comply with the Energy Policy Act 2005 (EPACT05) requirements. The document "THE POTENTIAL BENEFITS OF DISTRIBUTED GENERATION AND RATE-RELATED ISSUES THAT MAY IMPEDE THEIR EXPANSION (the Study) refers directly to issues related to the distributed generation standard we are currently considering.

The Puerto Rico Electric Power Authority recognized distributed generation as a tool to diversify energy sources, diversify the location of power generators, and promote renewable energy alternatives and conservation. Therefore we studied the DOE report as a contribution to the effort of promoting distributed generation.

It is possible to expand distributed generation use giving proper attention to electric service reliability, safety and quality. Customers should find distributed generation more attractive if they can use the electric grid to provide reliability. This reduces the capital cost needed to own a system that can provide the electric service quality needed for today's life styles and comfort. The advantage of providing interconnection to the electric grid is that the utility provides ancillary services needed to maintain reliability and safety as electric load changes. At the same time, if adequate and sufficient measures are taken to guarantee safety, reliability and quality of service, distributed generation under certain circumstances can support the electric grid operation.

Executive Summary

The importance of the electric grid reliability does not seem to be considered in the Study. Particularly, the 2006 Long-Term Reliability Assessment of the Electric Reliability Organization (ERO) is not considered in any way. Since the ERO actions are part of EPACT05 mandate, we strongly recommend that the Study considers the ERO report issued in October 2006.

As the ERO, the North American Electric Reliability Council (NERC) NERC has legal authority to enforce reliability standards on all owners, operators, and users of the bulk power system. The 2006 Long-Term Reliability Assessment is the first assessment filed by NERC in its capacity as the ERO. The 2006 report is based on data and information provided by the eighth regional reliability organizations. It identifies necessary actions that encompass all areas of the bulk power system including generation, transmission, demand response and fuel supply and delivery. Specific recommended actions include: addition of power generation facilities, new and upgraded transmission facilities, stronger contracts and other arrangements for the reliable supply and delivery of fuel to power generation facilities; more demand-side measures such as business and customer energy efficiency programs.

Reliability of electric service is important to ensure the safety and prosperity of all citizens. This important issue is not properly addressed in the Study. Procedures for developing distributed generator alternatives must provide ways to guarantee electric service reliability.

Section 1.4 The Era of Customized Energy

We understand the information under this section does not present correctly the current condition of the electric system. In particular the potential benefit or limitation of a DG system to provide reliable service

to the owner is not properly described. A load sensitive customer such as a pharmaceutical or electronic equipment manufacturer can justify the cost of a generator to provide an extra level of reliability. This is because even a very small system failure for these customers can cause a very high monetary loss.

However, it is not common for a homeowner or a commercial customer with a typical load to experience continuous equipment disruptions., therefore usually it is difficult for them to justify the ownership of generation because they don't need to have such high reliability.

The motivation for a customer to invest in power equipment may be incentives, environmental protection wants to buy less energy from a utility or wants to reduce the electric service invoice.

Another reason may be net metering, which as a special case of distributed generation, promotes expensive generation alternatives such as renewable energy technologies. In these cases the utility service is a support to the development of distributed generators.

The Study also fails to take into account the use of energy storage equipments as Uninterrupted Power Supply (UPS) to support power quality. UPS systems are designed to protect electrical equipment from momentary but potentially damaging power sags and outages. Other technologies as flywheels can provide this advantages too.

Power quality is an important concern for many commercial and industrial customers. Customers have increasing expectations from their electric service. Most of the power quality disturbances are short-term, according to the Electric Power Research Institute (EPRI), with 98% lasting less than 30 seconds and 90% slanting less than 2 seconds. What these customers want is a means to provide a capability for loss prevention from these transient frequency variations or voltage surges or sags. Generally, 15 to 20 seconds are needed to either bring online a backup power generator or switch to a different local circuit. Maintaining a backup generator on site remains a popular strategy to ensure power for critical loads. However, many firms requiring utility-comparable power quality (or better) from their on-site power units have found their capability inadequate because the on-site generators will have a far more difficult time in responding to any changing load than the utility's system power would have.

Section 1.5 Distributed Generation Defined

The description of a distributed generator is confusing, since states that "distributed generation", "cogeneration" and "small power producers" are interchangeable.
Under this generalization, any cogenerator is a DG. The 507 MW Ecoeléctrica plant in Puerto Rico would be DG. Also the AES 454 MW plant would be a DG. Emergency generators are also called DG. We understand that this view is confusing, particularly if we consider EPACT05 requirements under the Public Utility Regulatory Policies Act (PURPA).

The Public Utility Regulatory Policies Act describes what is a qualifying facility. It specifies requirements that are not necessarily met by all distributed generators. The report is broad in what it calls a Distributed Generation (DG).

Section 1.9 Potential Regulatory Impediments and Distributed Generation

We understand that this section should have included more information regarding the power grid reliability for customers with DG and without DG. An example of this are the comments in the Executive Summary, page iv, 2nd paragraph should be included and discussed in this section and throughout the document. It reads *A key for using DG as a resource option for electric utilities is the successful integration of DG with system planning and operations. Often this depends on whether or not grid operators can effect or control the operation of the DG units during times of system need. In certain circumstances, DG can pose potentially negative consequences to electric system operations, particularly when units are not dispatchable, or when local utilities are not aware of DG operations schedules, or when the lack of proper interconnection equipment causes potential safety hazards. These instances depend on local system conditions and needs and must be properly assessed by a full review of all operational data.*

Section 8 Rate-Related Issues that May Impede the Expansion of Distributed Generation

This section falls short in presenting in an organized and clear manner two important issues for DG: interconnection standards and rate related issues. EPACT 2005 requires the consideration of interconnection standards for DG. It also made mandatory the consideration of such standard and to validate in a written report the final decision.

The development of such standard would ease the process of interconnecting to a utility, reduce the time necessary to interconnect a DG and standardize the process to determine if system upgrades are necessary. The utility must provide in the standard procedure all possible alternatives for the customer to interconnect. The evaluations of each solicitation must take into consideration the safety, reliability and quality of service of all customers. They also must see for the safety of equipment owned by the customer and the utility; and for the safety of human life.

The conclusions of this section do not take into account the broad definition of DG presented in Section 1.5, that we consider unacceptable. For instance depending on the size of a DG, the process to evaluate the adequacy for interconnection may take more or less time and resources and as such requires a larger or smaller payment for such study.

On the other hand a customer with a 5 MW DG that uses it for its own consumption requires the utility to provide the electricity that is usually produce by the DG, when it is in maintenance. Thus the 5 MW DG may not reduce the utility need for generation capacity, neither the utility responsibility to provide such energy and capacity at the instant it is demanded by the customer, so its benefit to the electric system may be overstated

Standby service rates must be used in certain circumstances as a just and reasonable price for the electricity service. In the same way the interconnection fees and studies fees that certain cases require are a just and reasonable way to provide alternatives to the DG customers for interconnection.

In addition a DG customer can benefit from the time of use rates that are not discussed in the section. Times of use rates are ways to ease the development of distributed generators. Depending on the size of a DG and other parameters an exit fee, a standby service, certain interconnection charges (studies and equipment) are just and reasonable measures to provide equitable rates to customers.

One of the must important issues to evaluate when considering the interconnection and net metering standards is the impact to electricity rates to all customers. Standards must contribute to the stated purposes of the PURPA Title I: to encourage (1) conservation of energy supplied by electric utilities, (2) optimal efficiency of electric utility facilities and resources, and (3) equitable rates for electric consumers. Providing equitable rates to the DG customers and at the same time to all other customers is a paramount issue not properly addressed in the report.