BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 128

In the Matter of:	)	
Investigation of Integrated Resource	)	**COMMENTS**
Planning in North Carolina – 2011	)	

In accordance with the 25 October 2011 Order issued by the North Carolina Utilities Commission ("Commission") in the above-referenced docket, the North Carolina Sustainable Energy Association ("NCSEA") hereby submits the following comments:

NCSEA'S COMMENTS

1. Despite the best intentions, large organizations can find it difficult to move beyond "business as usual" on their own. Investor-owned utilities ("IOUs") are no exception. North Carolina has started to experience an on-going dynamic, fundamental re-alignment of the factors that determine the resource mix options and technological and economic functionalities of a "least cost" electricity supply and demand portfolio. In this proceeding – designed to familiarize the Commission with the most affordable energy options on a going-forward basis – the Commission should assist the IOUs in embracing the challenge of change, starting with their least-cost integrated resources plans ("LCIRPs").

Neither the 2010 LCIRPs, nor the 2011 updates adequately reflect the aforementioned re-alignment. Today, energy management, renewable energy, energy conservation, and smart grid are achieving meaningful market penetration rates. Yet these heralds of this on-going paradigm shift appear to have been given short shrift in the LCIRPs. Without more candor on the part of the IOUs, a reasonable person is left to surmise that "business as usual" explains the deficient LCIRPs.

NCSEA wants to give the IOUs the benefit of the doubt; it would like to work with the IOUs to better understand their LCIRPs and then find a path forward that is lower cost than "business as usual"[1] . . . but, first, the IOUs must be encouraged to disclose more information about their LCIRPs.

The Commission is in a position to offer this "encouragement;" it should require the IOUs to make additional disclosures in their LCIRPs. (*See* Paragraph 5 *infra* for the particular information that should be disclosed.) By directing the IOUs to be more candid, the Commission will help the Public Staff and intervenors – including NCSEA – to participate more fully in the vetting[2] of the LCIRPs to make sure they form a reliable analytical foundation for future Commission decisions.

Integrated Resource Planning

2. Integrated resource planning ("IRP") is an annual information gathering proceeding. IRP resembles "a legislative hearing, wherein a legislative committee gathers facts and opinions so that informed decisions may be made at a later time." *Utilities Comm. v. N.C. Electric Membership Corp.*, 105 N.C. App. 136, 144, 412 S.E.2d 166, 170 (1992). The facts and opinions to be gathered are those that will assist the Commission in fulfilling its obligation to develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina. *State ex rel. Utils. Comm'n v. Carolina Power & Light Co.*, 359 N.C. 516, 522, 614 S.E.2d 281, 285 (2005); *N.C. Electric Membership Corp.*, 105 N.C. App. at 143-44, 412 S.E.2d at 170. The Commission's ability to

[1] Collaboration can identify where opportunities lie to strike a balance between the concerns of the utilities' shareholders and the needs of their ratepaying customers, in ways that can result in more affordable electricity throughout the planning period.

[2] Commission Rule R8-60(j) provides in pertinent part that "the Public Staff or any other intervenor may file an integrated resource plan or report of its own as to any utility or may file an evaluation of or comments on the reports filed by the utilities, or both."

gauge the State's long-range needs hinges on the quality of the information – *i.e.*, the facts and opinions – the Commission gathers during IRP.

3. A two-step process determines the quality of the information gathered. First, consistent with Commission Rule R8-60(i), the Commission – on its own initiative or at the request of a party – must ensure that the IOUs' LCIRPs contain a certain threshold amount of analyzable data. Conclusory statements, standing alone, are insufficient. Second, once the first step is complete, the LCIRPs must be subjected to a peer review of sorts, during which the Public Staff, intervenors, and the general public evaluate – *i.e.*, scrutinize and test – the reliability of the representations and opinions contained in the LCIRPs. Going forward, these two steps can ensure that the Commission has information of sufficient quality to perform its statutorily-mandated analysis.

Content of the LCIRPs

4. The first LCIRPs were filed in the late 1980s. *N.C. Electric Membership Corp.*, 105 N.C. App. at 139, 412 S.E.2d at 167. These first LCIRPs were "at an early stage in their evolution," *id.* at 140, 412 S.E.2d at 168, but the expectation was that they would evolve "in the [then-]near future[.]" *Id.* With the IOUs' laudable collaboration, the LCIRPs have evolved over the last two decades – but they are not yet fully evolved. With additional candor by the IOUs, the LCIRPs can continue to evolve and, in doing so, highlight the IRP as a process that gives our citizens, businesses and governments confidence that we are, in fact, on a path to an affordable electricity future.

5. Specifically, Duke Energy Carolinas ("DEC"), Progress Energy Carolinas ("PEC"), and Dominion North Carolina Power ("DNCP") should as a matter of practice make express[3] in their LCIRPs the

- Levelized cost of energy – in a standardized metric, cents per kilowatt-hour – for each resource option for each year in the planning period *and* the delivered fuel costs for each resource option for each year in the planning period; and
- Quantitative data used in creating the levelized busbar cost curves presented in the LCIRPs, including (i) projected delivered fuel costs during the planning period, (ii) the utility's fixed charge rates, (iii) technology specific unit capacity factors, and (iv) data for the remaining variables needed to create a levelized busbar cost curve as set out in **Exhibit A** (an excerpt from a power engineering text outlining the quantitative data needed to create a levelized busbar cost curve).

Examples of how such candor will enhance the quality of the information developed in this process are set out in the ensuing two numbered paragraphs.

6. Commission Rule R8-60(i)(9) directs the IOUs to "provide information on levelized busbar costs for various generation technologies." The rule was doubtless intended to enable the Commission to compare projected costs – on an apples-to-apples basis – across technologies *and* across LCIRPs.

Each IOU has provided some information on levelized busbar costs. Unfortunately, the information provided is presented in conclusory fashion and each IOU has provided the information in a non-standardized manner. *Compare, e.g., The DEC IRP Annual Report* at pp. 138-142 (1 September 2011) *with PEC IRP* at pp. 12-16 (1 September 2011). If the IOUs were to provide the standardized information identified in one or both of the bullet points *supra,* it would enable the Commission, the Public Staff, intervenors, and any other person permitted access to the information to perform cost comparisons across technologies and across IOUs, and

[3] To the extent it is impractical to include the information in print form, it should be disclosed in electronic form – for example, on a CD that accompanies the LCIRP.

thereby enable them to scrutinize and begin testing the LCIRPs' least cost representations. Absent this information, it is nearly impossible to evaluate the levelized busbar cost curves in the IOUs' LCIRPs.

DEC and PEC appear to have an entrenched perception – rooted in a "business as usual" mentality – that "clean energy costs more than dirty energy."[4] This perception of renewables, reflected in their LCIRPs, inadequately accounts for the emergent cost-competitiveness of renewables.[5] DEC, for example, acknowledges "the downward trend in solar equipment costs over the past several years[,]" *DEC's 2011 REPS Compliance Plan* at p. 15 (1 September 2011), but it is unclear if the trend has been fully factored into their levelized busbar cost curve for solar. NCSEA's own analysis[6] – based, of necessity, on independently-obtained data – finds that the levelized busbar costs of all sizes of solar PV installations in North Carolina fell *dramatically* over the past several years, suggesting that residential and commercial solar PV systems in North Carolina are falling in price more rapidly than previously believed. This trend could have major implications for energy delivery within this proceeding's analytical timeframe,[7] yet does not appear to be accounted for in any scenario presented in any of the IOUs' LCIRPs. If, through the IOUs' candor, the LCIRPs included either the levelized cost of energy in standardized cents per kilowatt-hour form or the quantitative data underlying the IOUs' levelized busbar cost curves, this kind of apparent inconsistency could be reconciled or at least accounted for. Barring such

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[4] Downey, J., *Charlotte Business Journal*, "Duke Energy's Rogers finalizing his biggest deal and looking to the future" (29 December 2011) (excerpt from interview of Jim Rogers).

[5] *See* Perez, R., Zweibel K. and Hoff T.E. (2011) "Solar power generation in the US: Too expensive, or a bargain?" *Energy Policy* Vol. 39, pp. 7290-7297 (copy attached as **Exhibit B**).

[6] The paper containing the NCSEA analysis is in final review; publication is expected in the coming weeks.

[7] A high-solar scenario brought on by rapidly declining solar PV costs (in line with NCSEA's analysis) could result in reduced on-peak energy needs, which could in turn dramatically reduce the need for new peaking gas-fired generation investments and the corresponding capital and fuel costs that get passed through to ratepayers.

candor, it will continue to be extremely difficult if not impossible to directly scrutinize and test the LCIRPs to gauge the reasonableness of their representations and opinions.

The Commission can and should direct the IOUs in their current and future LCIRPs to provide the information identified in the bullet points set out in Paragraph 5 *supra*.

7. Similarly, Commission Rule R8-60(g) provides in pertinent part that

> each utility shall consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system . . . taking into account the sensitivity of its analysis to variations in . . . significant assumptions, including . . . the risks associated with . . . fuel costs[.]

Sensitivity analyses enable the Commission to gauge the robustness of the IOUs' planned handling of likely variations in fuel costs.

Each IOU has provided some measure of sensitivity analysis. Unfortunately, as with the levelized busbar cost curves, the analysis provided is presented in conclusory fashion and each IOU has provided its analyses in a non-standardized manner. If the IOUs were to provide the delivered fuel costs underlying their various projections and plans, it would enable the Commission, the Public Staff, intervenors, and any other person permitted access to the information to evaluate the LCIRPs' least cost representations. Going forward, non-renewables' fuel costs are likely to be subject to "significant fuel price volatility." *PEC IRP* at p. 3. Disclosure by the IOUs of projected delivered fuel costs in a standardized format would enable all interested parties to determine the reasonableness of a key assumption on which the IOUs base the affordability of their plans – the risk associated with fuel costs. Absent this standardized information, NCSEA and other interested parties will remain skeptical of the LCIRPs' usefulness as a foundation for affordable long-range planning, particularly in light of the divergent future scenarios being espoused by the IOUs in various dockets.

For example, the DEC LCIRP includes two sensitivity analyses of coal, one in which a 25% coal cost increase is modeled and another in which a 40% coal cost *decrease* is modeled. *The DEC IRP Annual Report* at p. 100. This choice of alternate scenarios appears almost arbitrarily disconnected from what DEC has testified elsewhere that it expects. According to one of DEC's most recent filings in Docket No. E-7, Sub 989, the cost of Central Appalachian ("CAPP") coal – to which most of DEC's plants are currently calibrated – increased 39% for DEC and 15% for PEC between 2007 and 2010. DEC's *Late-Filed Exhibit No. 1* (12 December 2011). In addition to these observed increases, DEC projects the cost to rise an additional 20%-50% by 2012.[8] *The DEC IRP Annual Report* at p. 51. One might surmise that DEC's sensitivity modeling choices reflect the possibility of switching from CAPP coal to an alternative, but this appears to be an inadequate explanation in light of testimony in the rate case. DEC has indicated that it will work to diversify its coal purchases to include supplies procured from other areas, but a DEC witness suggested that further diversification as a result of the upward trend in CAPP coal costs would be a "difficult" process that could require North Carolina coal plant operators to undertake costly retrofits of and "test burn" studies at units currently optimized to consume CAPP coal. Docket No. E-7, Sub 989, *Transcript of Hearing Vol. 2* at pp. 190-91 (Dhiaa Jamil testimony on 29 November 2011). This same witness also noted that transporting coal over longer distances exposes plant operators to greater coal transportation costs, *id.* at p. 192; such

[8] This upside price volatility is not limited to coal. DEC asserts that the "imbalance" between supplies of unconventional natural gas and the related demand that recently yielded historically low natural gas prices "should start to wane in 2012 . . . as several new factors begin to weigh on the market." *The DEC IRP Annual Report* at p. 52. These factors could foreseeably drive natural gas prices to the highs observed in 2008. A sustained increase in delivered natural gas prices could also render the operation of both existing and planned natural gas units uneconomical and/or dramatically increase fuel costs, seriously affecting the reliability of any plan that is not sensitized to this risk.

costs could eventually offset any ratepayer cost savings associated with diversifying coal supplies, assuming cost savings are possible.

Without long-term delivered coal and natural gas cost projections – which, encouragingly, were supplied by DNCP in its 2010 LCIRP and 2011 update – it will be difficult for NCSEA and other interested parties to give credence to the IOUs' assertions that the more or less "business as usual" plans selected by them are in fact reliably least-cost, taking into account reasonable sensitivity analyses. NCSEA believes a higher, more standardized degree of openness and transparency on the part of the IOUs will foster collaboration between the IOUs and those evaluating their LCIRPs and, ultimately, help ensure the development of high quality information in IRP.

The Commission can and should direct the IOUs in their current and future LCIRPs to provide delivered fuel cost information, which is included in the bullet points set out in Paragraph 5 *supra*.

<u>Accessing the Unredacted LCIRPs</u>

8. Any notion of enhancing the quality of information through a "peer review"-like scrutiny of the LCIRPs presupposes that a pool of "peers" will have access to the information to be scrutinized. To date, the IOUs have kept this pool of "peers" fairly small, in part by confidentially filing key portions of their LCIRPs so that they are not accessible by the general public.

9. NCSEA challenged this practice in the 2010 IRP and received the following response from DEC:

> Duke Energy Carolinas will comprehensively review and revisit the necessity to maintain the confidentiality of all of the redacted information contained within its REPS compliance filings. To the extent the Company believes that its customers will not be harmed by the disclosure of certain information relating to REPS, we

> commit to make any appropriate adjustments in our next REPS compliance plan filing, to be made on September 1, 2011.

Docket No. E-7, Sub 984, *Transcript of Hearing Vol. 1* at pp. 62-3 (Emily O. Felt testimony on 8 June 2011). It remains unclear whether the comprehensive review took place and, if it did, whether it yielded any changes in DEC's practices.

10. NCSEA understands the need for a certain level of guardedness on the part of the IOUs. At the same time, NCSEA believes non-intervening business-persons are being deprived of access to information critical to their investment decisions, and in this way the REPS law's private business development purpose, *see* N.C. Gen. Stat. § 62-2(a)(10), is being thwarted by the nondisclosure. In Docket No. E-7, Sub 819, the Commission entered an Order on 11 June 2008 in which it stated that "the Commission believes that it is in the public interest for [future cost] estimates to be disclosed at the earliest possible time that disclosure will no longer prejudice Duke's negotiations." *Order Approving Decision to Incur Project Development Costs* at p. 6. The same species of public interest is at play in these proceedings and should be countenanced by directing the IOUs to review all (or some older portion) of their past REPS-related confidential filings and show cause why they should not be made public at this time. Alternatively, should the Commission decline to issue such a directive, NCSEA requests the Commission's specific guidance as to whether IRP is an appropriate setting in which an interested party could file a motion for disclosure. *See id.* (indicating that the Commission is willing to hear motions for disclosure); Docket Nos. E-100, Subs 113 and 121, *Order Requesting Comments on Modifications to Rules R8-64 Through R8-69 and Interim Operating Procedures for NC-RETS* at p. 27 (3 August 2010) (indicating that a rulemaking proceeding was not the appropriate setting for addressing the issue but that it would be appropriate "in the context of a specific case with specific facts").

Conclusion

The Commission should encourage the continuing evolution of LCIRPs to better ensure long-term affordability of electricity in the State of North Carolina. The Commission can do so by requiring the IOUs to disclose in their LCIRPs the

- Levelized cost of energy – in a standardized metric, cents per kilowatt-hour – for each resource option for each year in the planning period *and* the delivered fuel costs for each resource option for each year in the planning period; and

- Quantitative data used in creating the levelized busbar cost curves presented in the LCIRPs, including (i) projected delivered fuel costs during the planning period, (ii) the utility's fixed charge rates, (iii) expected unit capacity factors, and (iv) data for the remaining variables needed to create a levelized busbar cost curve as set out in **Exhibit A.**

Additionally, the Commission should direct the IOUs to show cause why their past REPS-related LCIRP filings should not be unsealed and made public at this time. Alternatively, the Commission should provide NCSEA and others guidance as to whether IRP is an appropriate docket within which to file a motion for disclosure of some or all of the IOUs' past REPS-related LCIRP filings.

Respectfully submitted,

Michael D. Youth
Counsel for NCSEA
N.C. State Bar No. 29533
1111 Haynes Street, Suite 109
P.O. Box 6465
Raleigh, NC 27628
(919) 832-7601 Ext. 118
michael@energync.org

CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing Comments and any exhibits attached thereto by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

The Public Staff was served by first class mail addressed to: Antoinette R. Wike, Chief Counsel, Public Staff, 4326 Mail Service Center, Raleigh, NC 27699-4326.

This the 13th day of January, 2012.

Michael D. Youth
Counsel for NCSEA
N.C. State Bar No. 29533
1111 Haynes Street, Suite 109
P.O. Box 6465
Raleigh, NC 27628
(919) 832-7601 Ext. 118
michael@energync.org

EXHIBIT A

Renewable and Efficient Electric Power Systems

Gilbert M. Masters
Stanford University

WILEY-INTERSCIENCE
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with some utilities seeing their annual highest loads on hot summer days and others on cold winter mornings.

These fluctuations in demand suggest that during the peak demand, most of a utility's power plants will be operating, while in the valleys, many are likely to be idling or shut off entirely. In other words, many power plants don't operate with a schedule anything like full output all of the time. It has also been mentioned that some power plants, especially large coal-fired plants as well as hydroelectric plants, are expensive to build but relatively cheap to operate, so they should be run more or less continuously as *baseload* plants; others, such as simple-cycle gas turbines, are relatively inexpensive to build but expensive to operate. They are most appropriately used as *peaking* power plants, turned on only during periods of highest demand. *Other plants have characteristics that are somewhere* in between; these *intermediate* load plants are often run for most of the daytime and then cycled as necessary to follow the evening load. Figure 3.26 suggests these designations of baseload, intermediate, and peaking power plants applied to a weeklong demand curve.

An important question for utility planners is what combination of power plants will most economically meet the hour-by-hour power demands of their customers. While the details of such generation planning is beyond the scope of this book, *we can get a good feel for the fundamentals with a few simple notions involving* the economic characteristics of different types of power plants and how they relate to the loads they must serve.

3.9.1 Screening Curves

A very simple model of the economics of a given power plant takes all of the costs and puts them into two categories: fixed costs and variable costs. Fixed costs are monies that must be spent even if the power plant is never turned on, and they include such things as capital costs, taxes, insurance, and any fixed operations and maintenance costs that will be incurred even when the plant isn't operated. Variable costs are the added costs associated with actually running the plant. These are mostly fuel plus operations and maintenance costs. The first step *in finding the optimum mix of power plants is to develop screening curves* that show annual revenues required to pay fixed and variable costs as a function of hours per year that the plant is operated.

The capital costs of a power plant can be annualized by multiplying it by a quantity called the *fixed charge rate (FCR)*. The fixed charge rate accounts for interest on loans, acceptable returns for investors, fixed operation and maintenance (O&M) charges, taxes, and so forth. The FCR depends primarily on the cost of capital, so it may vary as interest rates change, but it is a number usually between 11% and 18% per year. On a per-kilowatt of rated power basis, the annualized fixed costs are computed from

$$\text{Fixed (\$/yr-kW)} = \text{Capital cost (\$/kW)} \times \text{Fixed charge rate (yr}^{-1}\text{)} \quad (3.18)$$

The variable costs, which are also annualized, depend on the unit cost of fuel, the O&M rate for actual operation of the plant, and the number of hours per year the plant is operated:

$$\text{Variable (\$/yr-kW)} = [\text{Fuel (\$/Btu)} \times \text{Heat rate (Btu/kWh)} + \text{O\&M (\$/kWh)}] \times \text{h/yr} \tag{3.19}$$

In (3.19) it is assumed that the plant runs at full rated power while it is operated, but no power at other times. Adjusting for less than full power is an easy modification that will be introduced later. Also, (3.19) assumes that the fuel cost is fixed, but it too is easily adjusted to account for fuel escalation and inflation. For our purposes here, these modifications are not important. They will, however, be included in the economic analysis of power plants presented in Chapter 5. Table 3.3 provides some representative costs for some of the most commonly used power plants.

Example 3.3 Cost of Electricity from a Coal-Fired Steam Plant. Find the annual revenue required for a pulverized-coal steam plant using parameters given in Table 3.3. Assume a fixed charge rate of 0.16/yr and assume that the plant operates at the equivalent rate of full power for 8000 hours per year. What should be the price of electricity from this plant?

Solution From (3.18) the annual fixed revenue required would be

$$\text{Fixed costs} = \$1400/\text{kW} \times 0.16/\text{yr} = \$224/\text{kW-yr}$$

TABLE 3.3 Example Cost Parameters for Power Plants

Technology	Fuel	Capital Cost ($/kW)	Heat Rate (Btu/kWh)	Fuel Cost ($/million Btu)	Variable O&M (¢/kWh)
Pulverized coal steam	Coal	1400	9,700	1.50	0.43
Advanced coal steam	Coal	1600	8,800	1.50	0.43
Oil/gas steam	Oil/Gas	900	9,500	4.60	0.52
Combined cycle	Natural gas	600	7,700	4.50	0.37
Combustion turbine	Natural gas	400	11,400	4.50	0.62
STIG gas turbine	Natural gas	600	9,100	4.50	0.50
New hydroelectric	Water	1900	—	0.00	0.30

Source: Based on data from Petchers (2002) and UCS (1992).

The variable cost for fuel and O&M, o

$$\text{Variable} = (\$1.50/10^6\ \text{Btu} \times 9700$$
$$= \$150.80/\text{kW-yr}$$

For a 1-kW plant,

$$\text{Electricity generated} = 1\ \text{kW} \times 8$$

$$\text{Price} = 1\ \text{kW} \times \frac{(224 + 150.80)\$}{8000\ \text{kWh/}}$$

In the above example, it was assur would operate at full power for 80C same 8000 kWh/yr could, of course but not always at the full rated outp be the same in either case. One way notion of a *capacity factor* (CF):

$$\text{Annual output (kWh/yr)} = \text{Rate}$$

Solving (3.20) for CF gives another of average power to rated power:

$$\text{CF} = \frac{\text{Average power (kW)} \times}{\text{Rated power (kW)} \times}$$

Figure 3.27 shows how total reven vary as a function of its capacity fac power). Under the circumstances in ($0.0469/kWh) is the slope of a line c to the 8000 hours of operation (CF = as CF decreases, which helps explair a few hours each day have such high

When plots like that shown in different power plants, the resultin determining the optimum mix of diff for the pulverized coal plant in Fig combined-cycle plant and the com shown in Fig. 3.28. What these sc turbine, which is cheap to build but as long as it doesn't operate more best choice for peaking power plant cost and low fuel cost, is the least e

The variable cost for fuel and O&M, operating 8000 hours at full power, would be

$$\text{Variable} = (\$1.50/10^6 \text{ Btu} \times 9700 \text{ Btu/kWh} + 0.0043\$/\text{kWh}) \times 8000 \text{ hr/yr}$$
$$= \$150.80/\text{kW-yr}$$

For a 1-kW plant,

$$\text{Electricity generated} = 1 \text{ kW} \times 8000 \text{ hr/yr} = 8000 \text{ kWh/yr}$$

$$\text{Price} = 1 \text{ kW} \times \frac{(224 + 150.80)\$/\text{yr-kW}}{8000 \text{ kWh/yr}} = \$0.0469/\text{kWh} = 4.69¢/\text{kWh}$$

In the above example, it was assumed that in a year with 8760 hours, the plant would operate at full power for 8000 hours and no power for 760 hours. The same 8000 kWh/yr could, of course, be the result of operating all 8760 hours, but not always at the full rated output. The resulting price of electricity would be the same in either case. One way to capture this subtlety is to introduce the notion of a *capacity factor* (CF):

$$\text{Annual output (kWh/yr)} = \text{Rated power (kW)} \times 8760 \text{ h/yr} \times \text{CF} \tag{3.20}$$

Solving (3.20) for CF gives another way to interpret capacity factor as the ratio of average power to rated power:

$$\text{CF} = \frac{\text{Average power (kW)} \times 8760 \text{ h/yr}}{\text{Rated power (kW)} \times 8760 \text{ h/yr}} = \frac{\text{Average power}}{\text{Rated power}} \tag{3.21}$$

Figure 3.27 shows how total revenues required for the coal plant in Example 3.3 vary as a function of its capacity factor (or as a function of hours per year at full power). Under the circumstances in the example, the average cost of electricity ($0.0469/kWh) is the slope of a line drawn to the point on the curve corresponding to the 8000 hours of operation (CF = 0.9132). Clearly, the average cost increases as CF decreases, which helps explain why peaking power plants that operate only a few hours each day have such high average cost of electricity.

When plots like that shown in Fig. 3.27 are drawn on the same axes for different power plants, the resulting screening curves provide the first step in determining the optimum mix of different power plant types. The screening curve for the pulverized coal plant in Fig. 3.27, along with analogous curves for the combined-cycle plant and the combustion turbine described in Table 3.3, are shown in Fig. 3.28. What these screening curves show is that the combustion turbine, which is cheap to build but expensive to operate, is the least-cost option as long as it doesn't operate more than 1675 h/yr (CF $\leq$ 0.19), making it the best choice for peaking power plants. The coal-steam plant, with its high capital cost and low fuel cost, is the least expensive as long as it runs at least 6565 h/yr

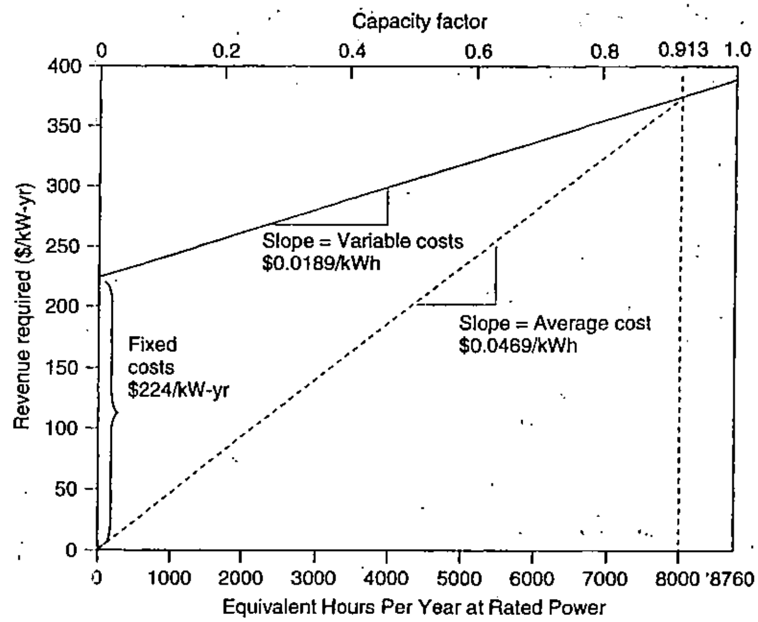

Figure 3.27 The average cost of electricity is the slope of the line drawn from the origin to point on the revenue curve that corresponds to the capacity factor. The data shown are for the coal plant in Example 3.3.

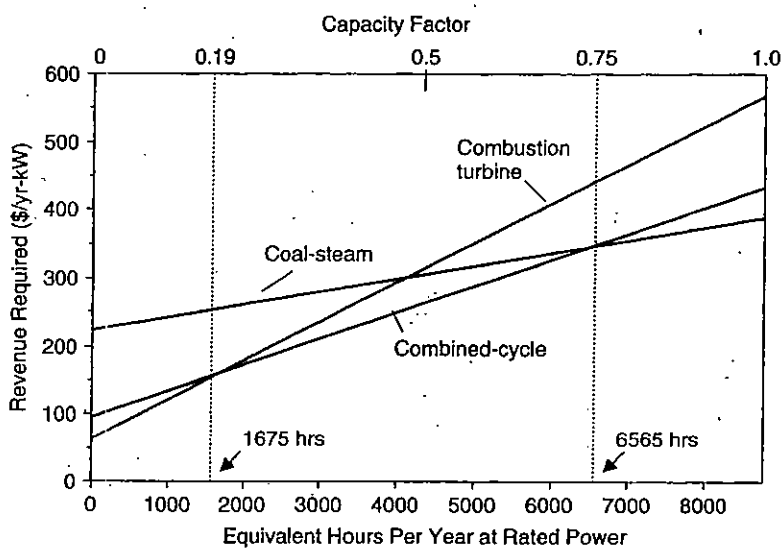

Figure 3.28 Screening curves for coal-steam, combustion turbine, and combined-cycle plants based on data in Table 3.3. For plants operated less than 1675 h/yr, combustion turbines are least expensive; for plants operated more than 6565 h/yr, a coal-steam plant is cheapest; otherwise, a combined-cycle plant is least expensive.

(CF $\geq$ 0.75), making it an ideal b
cheapest option if it runs somewh
0.75), which makes it well suited

3.9.2 Load–Duration Curves

We can imagine a load–time cur
series of one-hour power deman
of the load curve has a height e
(1 h), so its area is kWh of energ
if we rearrange those vertical slic
lowest through an entire year of 8
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A smooth version of a load-d
the x axis is still measured in hou
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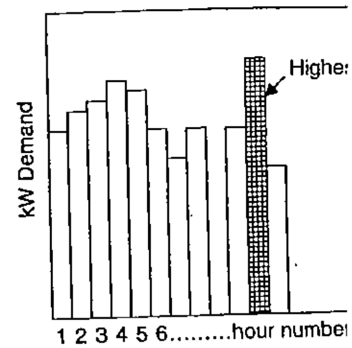

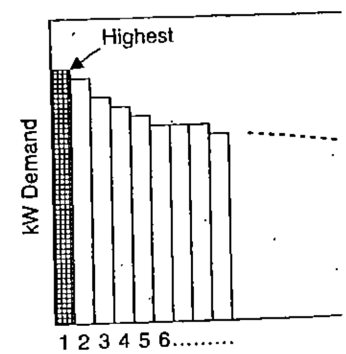

Figure 3.29 A load–duration cu
from chronological order into an c
the total kWh/yr.

($CF \geq 0.75$), making it an ideal baseload plant. The combined cycle plant is the cheapest option if it runs somewhere between 1675 and 6565 h/yr ($0.19 \leq CF \leq 0.75$), which makes it well suited as an intermediate load plant.

3.9.2 Load–Duration Curves

We can imagine a load–time curve, such as that shown in Fig. 3.26, as being a series of one-hour power demands arranged in chronological order. Each slice of the load curve has a height equal to power (kW) and width equal to time (1 h), so its area is kWh of energy used in that hour. As suggested in Fig. 3.29, if we rearrange those vertical slices, ordering them from highest kW demand to lowest through an entire year of 8760 h, we get something called a *load–duration curve*. The area under the load–duration curve is the total kWh of electricity used per year.

A smooth version of a load-duration curve is shown in Fig. 3.30. Notice that the x axis is still measured in hours, but now a different way to interpret the curve presents itself. The graph tells how many hours per year the load is equal to or above a particular value. For example, in Fig. 3.30, the load is above 3000 MW

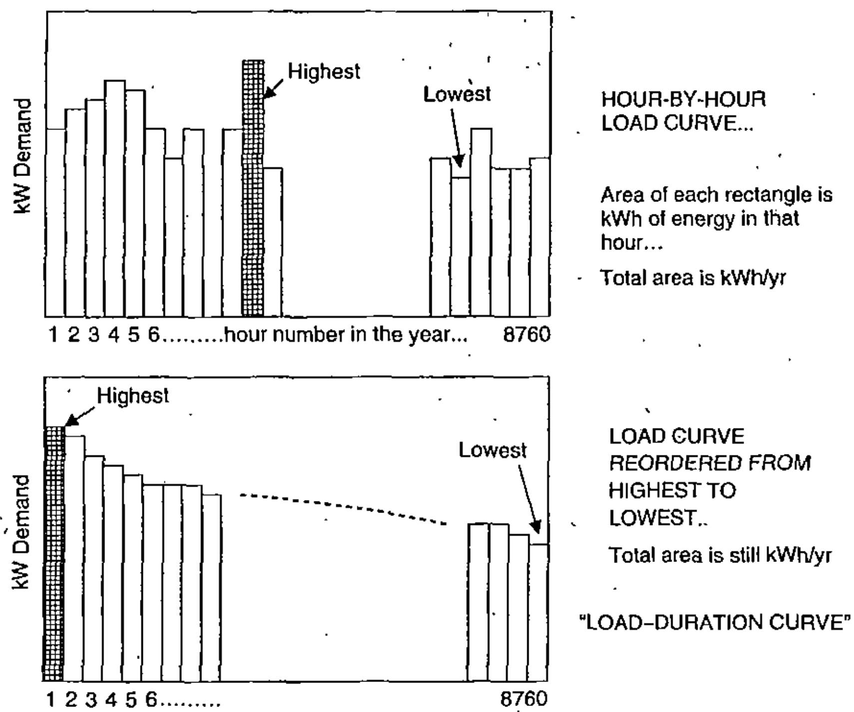

Figure 3.29 A load–duration curve is simply the hour-by-hour load curve rearranged from chronological order into an order based on magnitude. The area under the curve is the total kWh/yr.

EXHIBIT B

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Solar power generation in the US: Too expensive, or a bargain?

Richard Perez [a,*], Ken Zweibel [b], Thomas E. Hoff [c]

[a] Atmospheric Sciences Research Center, University at Albany, SUNY, USA
[b] GW Solar Institute, George Washington University, USA
[c] Clean Power Research, Napa, CA, USA

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ABSTRACT

This article identifies the combined value that solar electric power plants deliver to utilities' rate payers and society's tax payers. Benefits that are relevant to utilities and their rate payers include traditional, measures of energy and capacity. Benefits that are tangible to tax payers include environmental, fuel price mitigation, outage risk protection, and long-term economic growth components. Results for the state of New York suggest that solar electric installations deliver between 15 and 40 ¢/kWh to ratepayers and tax payers. These results provide economic justification for the existence of payment structures (often referred to as incentives) that transfer value from those who benefit from solar electric generation to those who invest in solar electric generation.

1. Introduction

"Economically viable" solar power generation remains a remote and elusive goal for the solar energy skeptics because the cost of unsubsidized solar power appears to be much higher than the cost of conventional generation. Indeed without incentives, considering turnkey cost of $4–5/Watt, it does take a revenue stream of around 20–30 ¢/kWh to justify a business investment in small to medium distributed solar electrical generation today. Large centralized solar installations with a lower turnkey cost in the southwestern US are below a breakeven range of 15 ¢/kWh without incentives.

A mix of federal and state incentives, whether tax-based, or ratepayers-levied, can make solar an attractive investment in many parts of the US; feed-in-tariffs (FITs) have been particularly effective in Europe and Asia. Without incentives, however, the needed revenue stream for solar generation is still considerably higher than the least expensive way to generate electricity today, i.e., via mine-mouth coal generation. This large apparent "grid-parity gap" can hinder constructive dialog with key decision makers and constitutes a powerful argument to weaken political support for solar incentives, especially during tight budgetary times.

In this paper, we approach the apparent grid parity gap question on the basis of the full value delivered by solar power generation. We argue that the real parity gap – i.e., the difference between this value and the cost to deploy the resource – is *considerably smaller than the apparent gap, and that it may well* have already been bridged in several parts of the US. This argumentation is substantiated and quantified by focusing on the case of PV deployment in the greater New York City area noting that much of the argumentation developed for PV in New York should be applicable to other regions and/or solar technologies.

1.1. Solar resource fundamentals

It is useful to first review a couple of fundamental facts about the solar resource that are relevant to its value.

1.1.1. Vast potential

First and foremost, the solar energy resource is very large (Perez and Perez, 2009). Fig. 1 compares the current annual energy consumption of the world to (1) the known planetary reserves of the finite fossil and nuclear resources, and (2) to the yearly potential of the renewable alternatives. The volume of each sphere represents the *total* amount of energy recoverable from the finite reserves and the *annual* consumption, and potential renewable sources' yield. While finite fossil and nuclear resources are very large (totaling nearly 2000-TW-year), they are not infinite and would last at most a few generations (with an annual global energy consumption expected to approach 30-TW-year per year in 2050) notwithstanding the environmental impact that will result from their full exploitation if now uncertain carbon capture technologies do not fully materialize. Nuclear energy may not be the carbon-free silver bullet solution claimed by some: putting aside the environmental and proliferation unknowns and risks

* Corresponding author.
E-mail addresses: perez@asrc.albany.edu (R. Perez), zweibel@gwu.edu (K. Zweibel), tomhoff@cleanpower.com (T.E. Hoff).

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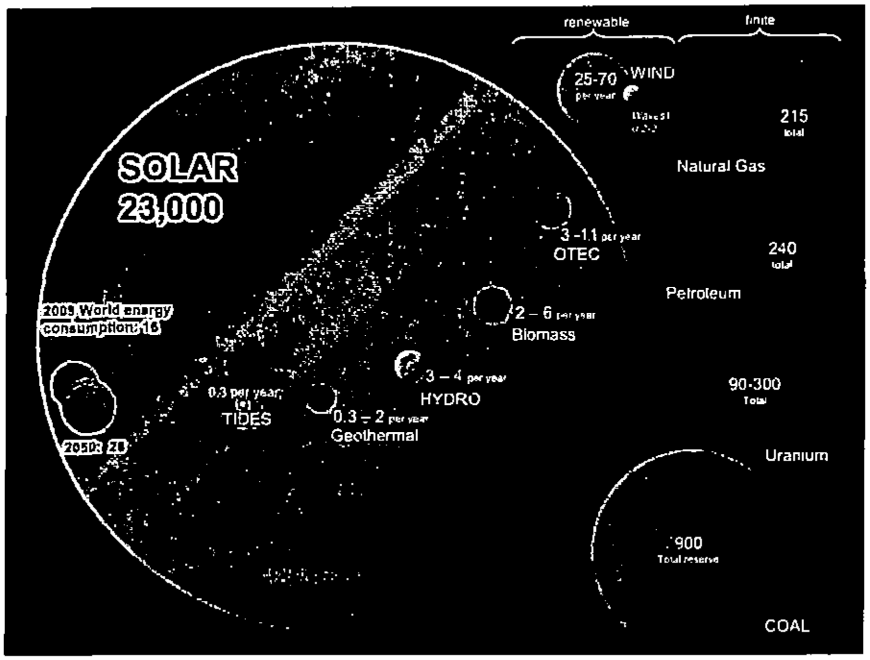

Fig. 1. Comparing finite and renewable planetary energy reserves (Terawatt-years). Annual amounts are shown for renewables and world energy consumption. Total recoverable reserves are shown for the finite resources. Yearly potential is shown for the renewables.
source: Perez and Perez, 2009.

associated with this resource, there would not be enough nuclear fuel to take over the role of fossil fuels.[1]

The renewable sources are not all equivalent. The solar resource is more than 200 times larger than all the others combined. Wind energy could probably supply all of the planet's energy requirements if pushed to a considerable portion of its exploitable potential. However, none of the others – most of which are first and second order byproducts of the solar resource – could, alone, meet the demand. Biomass, in particular, is probably too small a resource to globally replace the entire fossil based energy (Whittaker and Likens, 1975) and will have to be reserved for important specialty sectors—the rises in food cost that paralleled recent rises in oil prices and the demand for biofuels is symptomatic of this underlying reality.

On the other hand, exploiting only a very small fraction of the earth's solar potential could meet the demand with considerable room for growth. Thus, leaving the cost/value argumentation aside for now, logic alone tells us, in view of available potentials, that the planetary energy future will be solar-based. Solar energy is the only ready-to-mass-deploy resource that is both large enough and acceptable enough to carry the planet for the long haul.

1.1.2. *Built-in peak load reduction capability*

For a utility company, Combined Cycle Gas Turbines (CCGTs) are an ideal source of variable power generation because they are modular, can be quickly ramped up or down, and thereby provide power at will. As such CCGT have a high *capacity value*.

Solar generators, distributed PV in particular, are not available at will,[2] but often do provide power when most needed, and as such can capture substantial *effective capacity value* (Perez et al., 2009). This is because peak electrical demand is driven by commercial daytime air conditioning (A/C) in much of the US reaching a maximum during heat waves. The fuel of heat waves is the sun; a heat wave cannot take place without a massive local solar energy influx. The bottom part of Fig. 2 illustrates an example of a heat wave in the southeastern US in the spring of 2010 and the top part of the figure shows the cloud cover at the same time: the qualitative agreement between solar availability and the regional heat wave is striking. Quantitative evidence has also shown that the mean availability of solar generation during the largest heat wave-driven rolling blackouts in the US was nearly 90% ideal (Letendre and Perez, 2006). One of the most convincing examples, however, is the August 2003 Northeast blackout that lasted several days and cost nearly $8 billion region-wide (Perez et al., 2005). The blackout was indirectly caused by high demand, fueled by a regional heat wave3. As little as 500 MW of distributed PV region-wide would have kept every single cascading failure from feeding into one another and precipitating the outage. The analysis of a similar subcontinental-scale blackout in the Western US a few years before that led to nearly identical conclusions (Perez et al., 1997).

In essence, the peak load driver, the sun via heat waves and A/C demand, is also the fuel powering solar electric technologies. Because of this natural synergy, the solar technologies deliver hard-wired peak shaving capability for the locations/regions with the appropriate demand mix – peak loads driven by commercial/industrial A/C – that is to say, much of America. This capability remains significant up to 30% capacity penetration (Perez et al., 2010), representing a deployment potential of nearly 375 GW in the US.

1.1.3. *Renewable energy breeder*

The mainstream (crystalline silicon PV) solar electric technology has a proven record of low degradation (< 1%/year) and long life (Chianese et al., 2003). After 50 years of operation, a well-built PV module should still generate at least 60% of its initial rating. In addition, the energy embedded in the manufacture a PV system

[1] Of course this statement would have to be revisited if an acceptable breeder technology or nuclear fusion became deployable. Nevertheless, short of fusion itself, even with the most speculative uranium reserves scenario and assuming deployment of advanced fast reactors and fuel recycling, the total finite nuclear potential would remain well below the one-year solar energy potential.

[2] Concentrating Solar Power (CSP) technology has several hours of built-in storage and could be partially available at will.

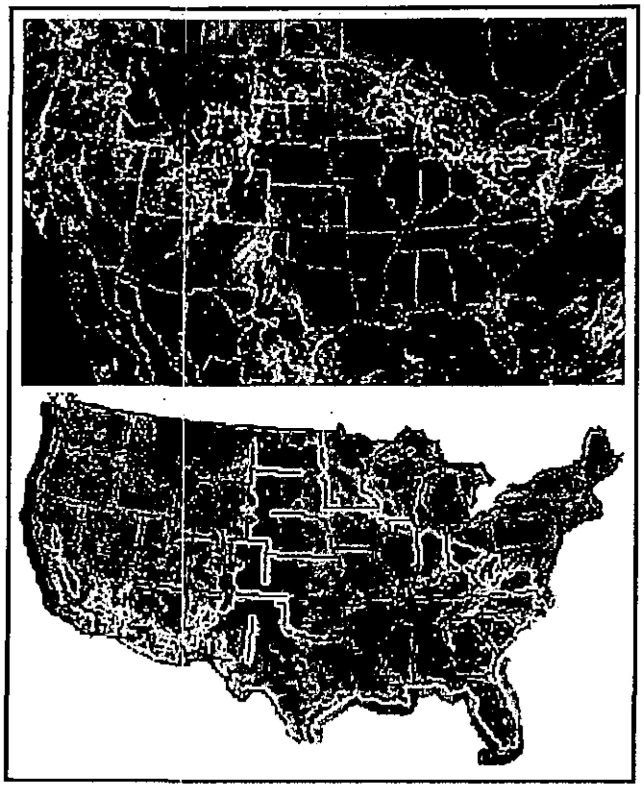

Fig. 2. Cloud cover during a heat wave in the southeastern US.

today would be recovered in less than 3 years if it operated in a climate representative of the central US. Several other PV technologies and CSP are capable of producing tens of times their embodied energy during their operating lifetime.

Thus, in effect, solar generators are efficient *energy breeders*, and after a startup period relying on finite energies for initial deployment, a solar economy could easily supply the energy necessary to fuel its own growth.

2. Too expensive?

When posing the cost/value question, it is important to identify the relevant parties: i.e., who pays for, and who receives, what.

The three parties involved in a solar electric transaction can be summarized as:

(1) The investor/developer who purchases/builds a plant;
(2) The utility and its ratepayers who purchase the energy produced by the plant[3,4];
(3) The society at large and its tax payers who contribute via public R&D and tax-based incentives and receive benefits from the plant.

The transaction is often perceived as one-sided in favor of the investor/developer whose return on investment – e.g., the necessary 20–30 cents breakeven cash flow-equivalent for distributed PV – is forced upon the two other parties. However, these parties do receive tangible value from solar generation.

Value to the utility and its ratepayers accrues from:

- Transmission (wholesale) energy, 6–11 ¢/kWh: energy generated locally by solar systems is energy that does not need to be purchased on the wholesale markets at the *Locational-based Marginal Pricing* (LMP). Perez and Hoff (2008) have shown that in New York State, the value of transmission energy avoided by locally delivered solar energy ranged from 6 to 11 ¢/kWh, with the lower number applying to the well-interconnected western NY State area, and the higher number applying to the electrically congested New York City/Long Island area. This is more than the mean LMP in both cases (respectively, 5 and 9 ¢/kWh) because solar electricity naturally coincides with periods of high LMP.
- Transmission capacity, 0–5 ¢/kWh:. because of demand/resource synergy discussed above, PV installations can deliver the equivalent of capacity, displacing the need to purchase this capacity elsewhere, e.g., via demand response (Perez and Hoff, 2008). In this study, they calculated the effective capacity credit of low penetration PV in metropolitan New York and showed that PV could reliably displace an annual demand response expense of $60 per installed solar kW, i.e., amounting to 4.5 cents per produced solar kWh.[5]
- Distribution energy (loss savings), 0–1 ¢/kWh: distributed solar plants can be sited near the load within the distribution system – whether this system is radial or gridded – therefore, they can displace electrical losses incurred when energy is transmitted from power plants to loads on distribution networks (this is in addition to transmission energy losses). This loss savings value is of course dependent upon the location and size of the solar resource relative to the load, and upon the specs of the distribution grid carrying power to the customer. A detailed site-specific study in the Austin Electric utility network (Hoff et al., 2006) showed that loss savings were worth on average 5–10% of energy generation. In the case of New York this would thus amount to 0.5–1 ¢/kWh.
- Distribution capacity, 0–3 ¢/kWh: as with transmission capacity, distributed PV can deliver effective capacity at the feeder level when the feeder load is driven by industrial or commercial A/C, hence can reduce the wear and tear of the feeder's equipment – e.g., transformers – as well as defer upgrades, particularly when the concerned distribution system experiences growth. As above, this distribution capacity value is highly dependent upon the feeder and location of the solar resource and can vary from no value up to more than 3 cents per generated solar KWh (e.g., see Shugar and Hoff, 1993; Hoff et al., 1996; Wenger et al., 1996; Hoff, 1997).
- Fuel price mitigation, 3–5 ¢/kWh: solar energy production does not depend on commodities[6] whose prices fluctuate on short term scales and will likely escalate substantially over the long term. When considering Fig. 1, it is hard to imagine how

[3] The High A/C demand in the northeast required large power transfers (7 GW) from the South and West into the Northeast. These transfers and the inattention of the grid operators caused power lines to overload and disconnect, leaving fewer and fewer energy transfer paths open as the afternoon progressed, until the point when the last major link, near Cleveland, failed and the path closing failure accelerated exponentially, leaving the northeast as an electrical island disconnected from the rest of the continent with 7 GW power generation deficit—the text book example of a blackout. The solar resource region-wide at the time of the blackout was nearly ideal, representing a text-book example of heat wave conditions.

[4] Sometimes this producer–utility relationship may be replaced by a power purchase agreement (PPA) directly with a site's host. However, because the utility grid is always the buffer/conduit of solar energy generation, PPA or not, the "big-picture" cost value equation remains the same.

[5] 1 kW of PV in New York State generates on ~1350 KWh/year. Therefore $60 per kW per year amounts to 4.5 ¢/kWh produced.

[6] Conventional energy is currently required for the manufacture of solar systems but, as argued above, this input will eventually be displaced because of the resource's breeder effect.

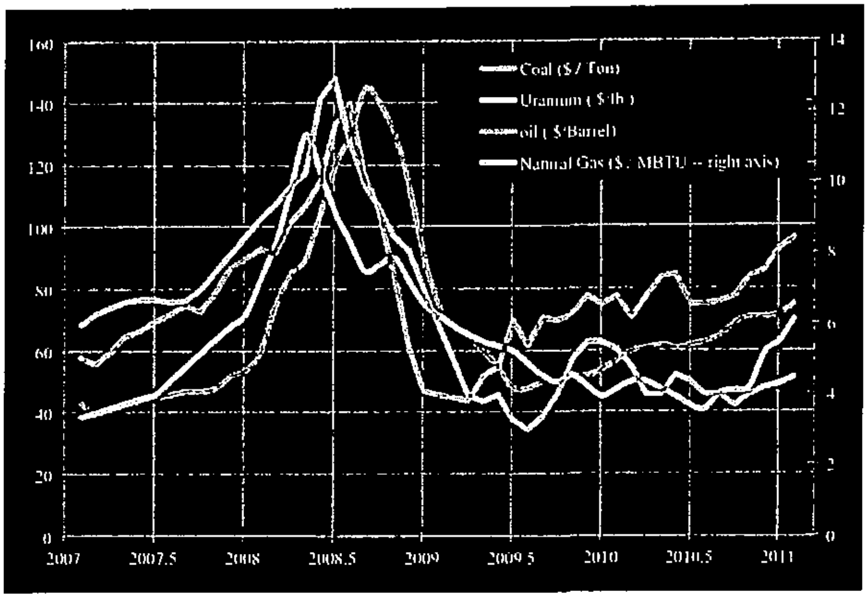

Fig. 3. Finite energy commodity price trends 2007–2011.

the cost of the finite fuels underlying the current wholesale electrical generation will not be pressured up exponentially as the available pool of resources contracts and the demand from the new economies of the world accelerates. The cost of oil may be the most apparent, but all finite energy commodities, including coal, uranium and natural gas, tend to follow suit, as they are all subject to the same global energy demand contingencies. Even before the 2011 Middle East political disruptions, in a still sluggish economy, energy commodity prices had ramped up past their 2007 levels when the world economy was stronger (see Fig. 3). Solar energy production represents a very low risk investment that will probably pan out well beyond a standard 30 year business cycle (Zweibel, 2010). In a study conducted for Austin Energy, Hoff et al. (2006) quantified the value of PV generation as a hedge against fluctuating natural gas prices. They showed that the hedge value of a low risk generator such as PV can be assessed from two key inputs: (1) the price of the displaced finite energy over the life of the PV system as reflected by futures contracts, and (2) a risk-free discount rate[7] for each year of system operation. Focusing on the short term gas futures market (less than 5 years) of relevance to a utility company such as Austin Energy, and taking a stable outlook on gas prices beyond this horizon, they quantified the hedged value of PV at roughly 50% of current generation cost—i.e., 3–5 ¢/kWh in the context of this article, assuming that wholesale energy cost (see above) is representative of generation cost.

It is important to remark that although a measurable value for the utilities and/or its ratepayers is created when PV generation comes on line, it is not entirely monetizable today because the current pricing structures and regulatory frameworks are not adapted to transfer this value. For example, the utilities bear no costs when there is fuel price uncertainty. If the regulatory scheme required utilities to care about this then we would see a way for this value to be monetized.

There are additional benefits that accrue to the society at large and its tax payers:

- Grid security enhancement, 2–3 ¢/kWh: because solar generation can be synergistic with peak demand in much of the US, the injection of solar energy near point of use can deliver effective capacity, and therefore reduce the risk of the power outages and rolling blackouts that are caused by high demand and resulting stresses on the transmission and distribution systems. The capacity value of PV accrues to the ratepayer as mentioned above. However, when the grid goes down, the resulting goods and business losses are not the utility's responsibility: society pays the price, via losses of goods and business, compounded impacts on the economy and taxes, insurance premiums, etc. The total cost of all power outages from all causes to the US economy has been estimated at $100 billion per year (Gellings and Yeager, 2004). Making the conservative assumption that a small fraction of these outages, say 5–10%, are of the high-demand stress type that can be effectively mitigated by dispersed solar generation at a capacity penetration of 20%, it is straightforward to calculate that the value of each kWh generated by such a dispersed solar base would be worth around 3 ¢/kWh to the New York tax payer (see Appendix A).
- Environment/health, 3–6 ¢/kWh: it is well established that the environmental footprint of solar generation (PV and CSP) is considerably smaller than that of the fossil fuel technologies generating most of our electricity (e.g., Fthenakis et al., 2008), displacing pollution associated with drilling/mining, and emissions. Utilities have to account for this environmental impact to some degree today, but this is still only largely a potential cost to them. Rate-based Solar Renewable Energy Credits (SRECs) markets that exist in some states as a means to meet Renewable Portfolio Standards (RPSs) are a preliminary embodiment of including external costs, but they are largely driven more by politically negotiated processes than by a reflection of inherent physical realities. The intrinsic physical value of

[7] Discount rates are used to measure the present decision-making weight of future expenses/revenues as a function of their distance to the present. A high discount rate minimizes the impact of future events such as fuel cost increases, while a low rate gives more weight to these events (e.g., see Tol et al., 2006). From an investor's stand point, the discount rate represents the return of a hypothetical investment against which to benchmark a particular venture. Low risk investments are characterized by low return rates (e.g., T-bills) while high risk ventures require high rates to attract prospective investors.

displacing pollution is very real however: each solar kWh displaces an otherwise dirty kWh and commensurately mitigates several of the following factors: greenhouse gases, So_x/No_x emissions, mining degradations, ground water contamination, toxic releases and wastes, etc., which are all present or postponed costs to society. Several exhaustive studies emanating from such diverse sources as the nuclear industry or the medical community (Devezeaux, 2000, Epstein, 2011) estimate the environmental/health cost of 1 kWh generated by coal at 9–25 cents, while a [non-shale[8]] natural gas kWh has an environmental cost of 3–6 ¢/kWh. Given New York's generation mix (15% coal, 29% natural gas), and ignoring the environmental costs associated with nuclear and hydropower, the environmental cost of a New York kWh is thus 2–6 ¢/kWh It is important to note however that the New York grid does not operate in a vacuum but operates within – and is sustained by – a larger grid whose coal footprint is considerably larger (more than 45% coal in the US) with a corresponding cost of 5–12 ¢/kWh. In Appendix A, we show that pricing one single factor – the greenhouse gas CO_2 – delivers at a minimum 2 cents per solar generated PV kWh in New York and that an argument could be made to claim a much higher number. Therefore taking a range of 3–6 ¢/kWh to characterize the environmental value of each PV generated KWh is certainly a conservative range.

- Long Term Societal Value, 3–4 ¢/kWh: beyond the commodity futures' fuel price mitigation hedge horizon of relevance to a utility company and worth 3–5 ¢/kWh (see above), society could claim additional long term value from solar generation on two grounds:
  1. Given the relentless growth of large new world economies (e.g., the BRIC countries), and the finite reserves of conventional energies (Fig. 1) now fueling the world economies, it is arguable, if not very likely, that their long term costs will be pressured upward exponentially fast.
  2. The present-day importance of long-term expenses/benefits is largely disregarded in business practice, because discount rates are used to quantify the present worth of future events—even when using moderate discount rates based on risk free securities. Therefore long-term risks – such as alluded to in point (1) – are largely irrelevant to current decision making. Nevertheless, the intergenerational, long-term societal value of present-day solar installation is very real because these installations will deliver long term-clean energy at a nearly fixed price. "Societal" discount rates are sometimes used by governments to justify investments, which are deemed appropriate for the long term well-being of the society (Tol et al., 2006)—solar generation clearly fits this definition.

  As shown in Appendix A a long-term societal present value of 3–4 ¢/kWh can be claimed by making reasonable assumptions on both accounts.
- Economic growth, 3+ ¢/kWh: the German and Ontario experiences, where fast PV growth is occurring, show that solar energy sustains more jobs per kWh than conventional energy (Louw et al., 2010; Ban-Weiss et al., 2010, and see Appendix A). Job creation implies value to society in many ways, including increased tax revenues, reduced unemployment, and an increase in general confidence conducive to business development. Counting only tax revenue enhancement provides a tangible low estimate of solar energy's multifaceted economic growth value. In New York this low estimate amounts to nearly 3 ¢/kWh, even under the extremely conservative, but thus far realistic, assumption that 80% of the manufacturing jobs would be either out-of-state or foreign (see Appendix A). The total economic growth value induced by solar deployment is not quantified as part of this article as it would depend on economic model choices and assumptions beyond the present scope. It is evident, however, that the total value would be higher than the tax revenues enhancement component presently quantified.

[8] Shale natural gas may have a higher environmental impact than conventional natural gas, including higher greenhouse gas emissions (Howarth, 2011) and contaminations associated with the practice hydraulic fracturing.

2.1. Cost

It is important to recognize that there is also a cost associated with the deployment of solar generation on the power grid, which accrues against the utility/rate payers. This cost represents the infrastructural and operational expense that will be necessary to manage the flow of non-controllable solar energy generation while continuing to reliably meet demand. A recent study by Perez et al. (2010) showed that in much of the US, this cost is negligible at low penetration and remains manageable for a solar capacity penetration of 30% (less than 5 ¢/kWh in the greater New York area at that high penetration level). Up to this level of penetration, the infrastructural and operational expense would consist of localized (demand side) load management, storage and/or backup operations. At higher penetration, localized measures would quickly become too expensive and the infrastructure expense would consist of long distance continental interconnection of solar resources, such as considered in projects such as Desertec (Talal et al., 2009).

3. Bottom line

Table 1 summarizes the costs and values accruing to/against the solar developer, the utility/ratepayer and the society at large represented by its tax payers. The combined value of distributed solar generation to New York's rate and tax payers is estimated to be in the range of 15–41 ¢/kWh. The upper bound of the range applies to solar systems located in the New York metro/Long Island area and the lower bound applies to very high solar penetration for systems in non-summer peaking areas of upstate New York. In effect, Table 1 shows that grid parity already exists in parts of New York – and by extension in other parts of the country – since the value delivered by solar generation exceeds its costs. This observation justifies the existence of (or requests for) incentives as a means to transfer value from those who benefit to those who invest.

3.1. Conservative estimate

It is important to stress that this result was arrived at while taking a conservative floor estimate for the determination of most benefits, and that a solid case could be made for higher numbers particularly in terms of environment, fuel hedge, and business development value. In addition, several other likely benefits were not accounted for because deemed either too indirect or too controversial. Some of these unaccounted value adders are worth a brief qualitative mention:

- No value was claimed beyond 30 year life cycle operation for solar systems, although the likelihood of much longer quasi-free operation is high (Zweibel, 2010).
- The positive impact on international tensions and the reduction of military expense to secure ever more limited sources of

Table 1

	Developer/investor (¢/kWh)	Utility/rate payer (¢/kWh)	Society/tax payer (¢/kWh)
Unsubsidized distributed solar[a] system cost	20–30		
Transmission energy value		6–11	
Transmission capacity value		0–5	
Distribution energy value		0–1	
Distribution capacity value		0–3	
Fuel price mitigation		3–5	
Total ratepayer value		**9–25**	
Solar penetration cost		*0–5*	
Net ratepayer value		***4–25***	
Grid security enhancement value			2–3
Environment/health Value			3–6
Long-term societal value			3–4
Economic growth value			3+
Total tax payer value			**11–16**
Total cost/value	**20–30**	**15–41**	

[a] Centralized solar has achieved an unsubsidized cost of 15–20 ¢/kWh today. However fewer of the above value items would apply. The distribution value items would not apply. Transmission capacity, and grid security items would generally be towards the bottom of the above ranges, while penetration cost would be towards the top of the ranges because of the burden placed on transmission and the possible need for new transmission lines. The job creation tax feedback would also be less because of lower system cost (see Appendix A). Nevertheless, the total value for such large centralized systems would be ~ 13–29 ¢/kWh under the assumptions of this study.

energy and increasing environmental disruptions was not quantified.

- The fact dispersed solar generation creates the basis for a strategically more secure grid than the current "hub and spoke" power grid in an age of growing terrorism and global disruptions concerns was not quantified.
- Economic growth impact was not quantified beyond tax revenue enhancement.
- The question of government subsidies awarded to current finite energy sources (i.e., existing taxpayer expense that could be displaced) was not addressed.

3.2. Tax payer vs. rate payer

Unlike conventional electricity generation, the value of solar energy accrues to two parties. This may explain why the perception of value is not as evident as the above numbers would suggest. In particular, public utility commissions are focused on defending the interests of utility ratepayers, and if only the utility/rate payers' value is considered, the case for solar is marginal at best (4–25 cents of value per kWh). However, focusing on the ratepayers' interest alone ignores the fact that ratepayers and the tax payers are one and the same. Supporting one to the exclusion of the other ends up penalizing the whole person.

3.3. Tangible value

Another reason why perception of value is not evident is because those who pay for the costs that solar would displace are often not aware of these costs. For the ratepayers items (energy and capacity), the tradeoff is obvious, but not so for the other items. However, costs are incurred in many indirect, diffuse, but nevertheless very real ways—e.g., insurance premiums, higher taxes to mitigate impacts, deferred costs (environment, future replacements of short term infrastructures, energy increases), and missed economic growth opportunities.

3.4. Stable value

One of the characteristics of the solar resource is its ubiquity and stability: it is present everywhere and does not vary much from one year to the next although short term variability (clouds, weather, seasons) often tend to overshadow this perception (Perez and Hoff, 2011). Similarly, the value delivered by solar generators is very stable and predictable.

The two primary factors that do determine value per kWh produced are (1) location and (2) solar penetration.[9] Location is important because the value delivered by solar generation in terms of transmission and distribution energy and capacity, as well as blackout protection is location-dependent: a system in winter-peaking rural upstate New York will deliver less value than a system in a growing commercial sector of Long Island. Penetration is important, because some of the benefits, in particular the capacity benefits, tend to erode with penetration; and the cost to locally mitigate this erosion increases (see, Perez et al., 2010).

Therefore, if one were to design an effective system to provide solar generation with the fair value it deserves from rate/tax payers, it would have to be a stable and predictable system that accounts for the location and penetration factors. Auction-based SRECS could be engineered to meet these criteria, but a smart value-based FIT that is stable and tunable by design, appears to be a more logical match.[10]

4. Very high penetration solar?

Some of the benefits identified in this article apply roughly up to 30% solar penetration. This already represents a 375 GW high-value solar deployment opportunity for the US — a very large prospective market with a large national payoff; but what happens beyond that point? At very high penetration, the issues facing solar would become similar to wind generation's issues, albeit with a much smaller footprint. Many of the value items mentioned above would remain (long-term, wholesale energy, fuel price hedge, environment) while others would not (regional and localized capacity). The solutions envisaged today, including large scale storage and continental/international interconnections

[9] Technology and solar system specs (e.g., array geometry) are also relevant: highest value in NYC would be for systems delivering near maximum output at 4 PM—i.e., fixed tilt, oriented SW.

[10] It is important to state that we are talking here about a value-based FIT, where the FIT is the instrument to transfer value from those who benefit to those who invest. This is unlike FIT implementations in other parts of the world, notably in Spain, where FITs were primarily designed to provide a boost to solar business development.

to mitigate/eliminate weather, seasons and daily variability, are currently on the drawing board (e.g., Perez, 2011; Lorec, 2010; Talal et al., 2009).

5. Final word: the value of solar

It is clear that some possibly large value of solar energy is missed by traditional analysis. Most of us recognize this in our perception of solar as more sustainable than traditional energy sources. The purpose of this article is to begin the quantification of this value so that we can better come to terms with the difficult investments we may make in solar despite its apparent grid parity gap with conventional energy. Society gains back the extra we pay for solar. It gains it back in a healthier, more sustainable world, economically, environmentally, and in terms of energy security.

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Appendix A

Grid security enhancement

20% US penetration would represent roughly 250 GW of solar generating capacity. Using a New York-representative production level of 1350 kWh per KW per year, the solar production would thus amount to 375 billion kWh/year, worth \$5–10 billions in outage prevention value under the conservative assumption selected here, amounting to 2–3 ¢/kWh.

Estimating solar CO_2 mitigation value

The value of solar generation towards CO_2 displacement may be gauged using several different approaches.

(1) By starting from the carbon tax /cap-and-trade penalty levels that are being envisaged today—at \$30–40/ton of CO_2 (e.g., Nordhaus and William 2008): given the energy generation mix in a state like New York, each locally displaced kWh (i.e., solar generated) would remove 500–600 g of CO_2, and thus would be worth nearly 2 cents. Note that a similar estimate could be obtained by starting from the figure of 1.5% of world GDP per year advanced by the IPCC as the minimum necessary to prevent a runaway climate change (IPCC, 2007). 1.5% of GDP represents \$900 billions. Global CO_2 emissions are ~30 billions tons. Displacing 2/3rds of these emissions to bring us back to a 1960s level, and again, and taking New York's current generation mix as an emission reference amounts to a value of 3 cents for each kWh displaced by solar generation.

(2) By starting from the 1.5% GDP figure, but recognizing that solutions to displace greenhouse gases need to be primed and encouraged before they can be effective and reach their mitigation objectives. If we assume, very conservatively, that solar energy represents only 10% of the global warming solution and should thus be fully encouraged to the tune of 0.15% GDP, then given the size of this industry today, each new solar kWh generated should be rewarded with a value many times higher than estimated in point (1) above. This value would then decrease gradually over the years as the installed solar capacity grows, ultimately reaching a value commensurate with points (1).

Long term societal value

The long term societal value of a solar kWh can be estimated as the present value of the difference between what one would have to pay for energy escalating over the life of the solar system and what one would have to pay if energy cost remained constant. This present value depends on (1) the conventional energy escalation rate and (2) the discount rate used to account for future values.

The 3–5 ¢/kWh ratepayer's fuel price hedge benefit already accounted for was estimated by effectively converting the fossil-based generation investment from one that has substantial fuel price uncertainty to one that has no fuel price uncertainty —accomplished by entering into a binding commitment to purchase a lifetime's worth of fuel to be delivered as needed, whereby the utility could set aside the entire fuel cost obligation up front, investing it in risk-fee securities to be drawn from each year as required to meet the obligation. The approach uses two financial instruments: risk-free, zero-coupon bonds and a set of natural gas futures contracts. In effect, this approach amounts to (1) use the risk free bond rate as an effective discount rate and (2) assume moderately escalating prices beyond a five year natural gas futures contract over the life of the PV system.

Taking a societal perspective using a societal discount rate of 2% justifiable for investments deemed appropriate for the long term well-being of society (Tol et al., 2006) and a conventional energy escalation rate of 3.5%—amounting to an increase of ~150% in 25 years, the present value delivered by a non-escalating resource such as solar is nearly double that of the conventional generation value, i.e., 6–11 ¢/kWh in the context of this study.

Therefore, subtracting the utility fuel price hedge of 3–5 ¢/kWh already claimed as a ratepayer benefit, it is reasonable to claim an extra 3–4 ¢/kWh as a long-term societal benefit of solar generation to account for probable events beyond a utility's business-as-usual decision making horizon, but relevant to the long-term well-being of society.

Interestingly, this estimate is commensurate with the International Energy Agency's contention that a CO_2 tax worth \$175 per ton should be necessary to encourage the development of renewables and displace fossil fuel depletion (Tanaka, 2010) while mitigating their depletion and keeping their long term prices near the present range. Based on the New York's generation mix, \$175 per ton amounts to 9–10 ¢/kWh.

Tax revenue enhancement

The German experience indicates that each MW of PV installed implies 10–15 module manufacturing jobs, 8–15 installation jobs and 0.3 maintenance jobs, as confirmed by recent numbers from Ontario (Louw et al., 2010; Peters, 2010). Solar jobs represent more than ten times conventional energy jobs per unit of energy produced – i.e., ten new solar jobs would only displace one conventional energy job.

Although these numbers may be skewed by the fact that a still expensive and nascent solar industry is overly job-intensive, a quick reality check reveals that the relative higher price of the solar technology today also implies a higher job density: the necessary 20–30 c/kWh solar revenue stream underlying discussions in this article corresponds to a turnkey cost of \$4 million per solar MW. In the case of PV, this cost can be assumed to divide evenly between technology (modules/inverters) and system installation (construction, structures) representing $2 M per MW for each. Conservatively assuming that 50% of technology and 75% of installation costs are directly traceable to solar-related jobs and assuming a job+overhead rate of $100 K/year, this simple reality check yields 10 manufacturing and 15 construction-related jobs. Demonstrating that the solar job density of the solar resource is higher than that of conventional energy is also straightforward to ascertain from first principles: comparing a $4/Watt turnkey solar system producing 1350 kWh/KW/year to a $1/Watt turnkey CCGT producing 5000 kWh/kW/year, and assuming that the job density per turnkey dollar is the same in both cases, yields 14 times more jobs for the solar option per kWh generated.

As the turnkey cost of solar systems expectedly goes down, the job density will of course be reduced, but, more importantly, so will the necessary breakeven revenue stream.

For now, given the premise of this paper — a required solar energy revenue stream of 20–30 cents per solar kWh — let us calculate the value that society receives under this assumption.

The following assumptions are used for this calculation:

- Each new solar MW results in 17 new jobs. There are 2 new manufacturing jobs (it is assumed that 80% of the manufacturing jobs are foreign—and do not generate any federal or state tax revenue) and there are 15 new installation jobs.
- Solar systems are replaced after 30 years, so the amount of jobs corresponding to each installed MW is the present value of a 30 year job replacement stream. With a discount rate of 7%, 17 jobs times an annualized factor of 0.08 translates to 1.36 jobs per MW per year.
- System maintenance-related jobs amount to 0.3 jobs per MW[11] (German experience)
- The total amount of sustained jobs per MW is therefore equal to 1.66.
- Assuming that ten solar jobs displace one conventional energy job, the net sustainable new jobs per solar MW are therefore equal to 1.49 (90% of 1.66).
- The salary for each solar job is $70 K/year.
- Current federal and New York tax rates for an employee making $70,000 per year pays a combined effective income tax rate of 23%.
- MW of PV generates 1,350,000 kWh per year.
- Finally, direct job creation translates to the additional creation of indirect jobs. It is conservatively assumed that the indirect multiplier equals 1.7 (i.e. every solar job has an indirect effect in the economy of creating an additional 0.7 jobs).[12]

Putting the pieces together, the tax benefit from job creation equals about 3 ¢/kWh.

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[11] This corresponds to a very reasonable O&M rate of 0.5% under the assumptions of this study.

[12] Indirect base multipliers are used to estimate the local jobs not related to the considered job source (here solar energy) but created indirectly by the new revenues emanating from the new [solar] jobs.