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Investing in photovoltaics: risk, accounting and the value of new technology☆

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Abstract

In Europe and the US, national energy planning agencies value resource alternatives using outmoded techniques, conceived around the time of the Model-T Ford. These models, long since discarded in manufacturing and other industries, bias in favor of riskier fossil alternatives while understating the true value of photovoltaics (PV) and similar low-risk, passive, capital-intensive technologies. PV and similar renewables offer a unique cost-risk menu along with other valuable attributes that traditional valuation models, conceived long before such attributes became technologically feasible, cannot "see" because they are steeped in the vocabulary and measurement concepts of a different technological era. Properly understood and exploited, the attributes of PV could undoubtedly form the basis for reengineering the electricity production and delivery process to deliver cost reductions in ways that can yet not be imagined. Lenders and investors likewise do not yet fully understand the unique financial properties of PV as differentiated from traditional resource alternatives. Policy makers have a responsibility to broaden the analytic horizons to include new valuation models and concepts that more properly reflect the unique attributes of PV.

Keywords: Renewables; Valuation; New technology; Risk; Managerial options

1. Introduction: The technology is not the problem

It puzzles me that 40 years after the development of the Capital Asset Pricing Model (CAPM) and its widespread acceptance as a basis for financial valuation,[1] the comparative valuation of Photovoltaics (PV) relative to other resource alternatives is still largely performed using outmoded *engineering-economics* ideas.[2] These concepts, which date back to the early part of the century, were formalized in the post World-War II era (Awerbuch *et al.*, 1997) well before the introduction of the CAPM and other modern finance principles that explain how to adjust project valuation for risk. By ignoring financial risk, lenders and investors understate the value of PV projects relative to fossil alternatives.

Modern finance theory would also counsel us to evaluate PV not on the basis of its *stand-alone* cost, but on the basis of its *portfolio cost* — i.e. its cost contribution relative to its risk contribution to a portfolio of generating resources.[3] Along these lines it can be shown

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[1] The Capital Asset Pricing Model (CAPM), one of the important foundations of modern finance, is a one-factor model that is remarkably robust in its ability to explain the relationship between risk and the investor-required return or discount rate for an asset. Using the CAPM, the required return or discount rate for asset j, R_j, can be expressed as $R_j = R_f + \beta(R_m - R_f)$ where R_f and are R_m respectively the risk-free rate of return and the return to a broadly diversified market portfolio, and β is a statistically derived covariance term relating the variability of asset j to the variability of the broadly diversified market portfolio. Most investors are familiar with β (beta), the CAPM risk measure, which is widely used in valuing stocks. The CAPM is generally attributed to Nobel Laureate William Sharpe (1964) see Varian, 1993, p. 165).

[2] For example, the International Energy Agency (IEA, 1999) recently held a conference whose "principal focus" was engineering-economic techniques for assessing energy and environmental issues. Similarly, recent EC energy valuations (see Nuñes, 1999) seem to use engineering models that ignore financial risk.

[3] Portfolio theory, another major development of modern finance, is generally attributed to Nobel Laureate Harry Markowitz (1952). The application of portfolio principles suggest that PV and other resource alternatives whose costs do not co-vary with the current fossil portfolio can reduce generating costs at any given level of risk.

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(Awerbuch, 2000, 1995b) that the inclusion of PV in a portfolio of generating assets serves to reduce overall portfolio cost and/or risk. This somewhat counter-intuitive result holds even though PV "costs more" on a stand-alone basis. The important implication of portfolio theory is that the true relative value of PV can be determined not by evaluating alternative resources, but by evaluating alternative resource *portfolios*.

Energy planners also ignore the special discounting procedures needed to produce appropriate *societal* valuations for environmental externalities produced by fossil technologies thereby significantly understating the relative value of PV.[4] A significant body of economic literature, beginning with Pigou (1932), and culminating more recently with the work of Lind et al. (1982), develops valuation principles for societal costs and benefits streams that, when applied to environmental externalities, yield significantly *higher* present values for these societal cost streams.[5] For example, Awerbuch (1993c) estimates present value externality costs for coal-fired electricity that are three times as large as those produced by standard engineering costing models. In order to develop reliable societal valuations of PV, which creates no emissions, it is essential to correctly value the environmental externality costs associated with fossil alternatives.

Finally, PV and other passive, modular technologies represent a *radical architectural* innovation (Henderson and Clark, 1990) in the electricity production/delivery process.[6] Such technologies create discontinuities: they dramatically alter production economics and present new risk and benefit–cost tradeoffs that are often not fully understood until the technologies are more fully exploited. Indeed this was the case when computer-integrated manufacturing (CIM) was first introduced in the 1970s. Although CIM *seemed* intuitively appealing, it failed traditional benefit–cost tests because it was difficult to imagine — let alone quantify — the full range of benefits it produced. The cost-benefit justification of CIM had to await the development of new valuation concepts such as "modularity/flexibility/reversibility"[7] and the idea of *strategic* options (Aggarwal, 1997) and *capability* options (Baldwin and Clark, 1992). These unique attributes make PV more attractive relative to traditional fossil alternatives; by ignoring them, energy planners and investors improperly understate the value of PV.

Like CIM, PV is intuitively appealing. Like CIM, it will probably not be fully understood or properly valued without a new, appropriate vocabulary of benefits. The exploitation of PV, like that of CIM, will undoubtedly require new electricity production and delivery paradigms. Existing techniques and accounting vocabulary do not yet allow us to definitively value many of the unique attributes of PV. We can, however, effectively capture its special risk properties using commonly used finance-oriented valuation tools that are not generally used for energy technologies.[8]

The next section of this paper surveys the analytic shortcomings of traditional energy costing models and offers specific recommendations as well as future research directions while the subsequent section discusses how our limited understanding of PV technology affects lending and investment practices. Finally, Appendix A provides an illustrative, risk-adjusted cost estimate for PV and gas-based generation.

2. The limitations of current energy valuation models

Energy planners, it seems, place less emphasis on *planning* and more on *engineering-economics*-oriented cost analysis. Although it ignores financial risk, engineering-economics has provided a practical, accounting-based means to help engineers value project alternatives. The evidence suggests (Awerbuch, 1993a) that engineering economics may work reasonably well[9] under the following general restrictive conditions:

> *Condition 1: It makes sense to model the asset or project on the basis of its cash flows*: The practice of representing assets by their cash flows is so widespread that we tend to forget about this basic assumption, which probably does not hold for many new, passive technologies. For example, it is virtually impossible to capture the benefits of a fax machine on the basis of its

[4] Based on published externality cost streams used for resource planning in the US, the understatement of PV's value relative to coal is in the range of \$0.02–0.05/kWh (Awerbuch, 1993c).

[5] Pigou observed that because it continues indefinitely, society's time-value of money differs from that of *finite-lived* individuals, who clearly prefer a dollar of benefits today over, say, next year. Market-based discount rates reflect the time preferences of such individuals and are therefore higher than societal rates. The "reverse telescopic" effect of market-based rates makes them inappropriate for valuing societal cost (or benefit) streams such as externalities. Lind–Arrow define the conditions under which societal discount rates are appropriate. Societal cost–benefit streams diversify risk over a large number of people so that each holds only a very small share. To be effective, such risk spreading requires that the costs and benefits be *uncorrelated* with income.

[6] For additional discussion of this idea see Awerbuch (1993b), Awerbuch *et al.* (1997), Awerbuch *et al.* (1996) and the literature cited therein.

[7] These attributes, developed in the late 1970s, helped explain the advent and ultimate supremacy of "lean" or flexible manufacturing. Flexibility (especially the option-to-wait) is discussed by Dixit and Pindyck (1994); other flexibility option values have been explored in the context of PV by Felder (1996), Hoff *et al.* (1996) and Hoff (1998).

[8] A brief illustration is given in Appendix A. For more detailed discussion see Awerbuch (1995b).

[9] Meaning that more sophisticated techniques will probably not change the decision outcomes.

cash flows, e.g. additional phone charges incurred as compared to savings in postage and clerical time (Awerbuch, 1993b) which illustrates the fundamental limitation of accounting-based valuation. Fax technology cuts costs by speeding up information transfer and decision-making, important attributes for which there exist no accounting entries.

Condition 2: It makes sense to assume homogeneous technological choices are coupled with an environment of static technology: This condition, which no longer holds in most parts of our economy including energy, has two important implications for valuing investments. Homogeneous technology implies that risk is not dependent on technological choice while technological stasis suggests a predictable future in which *strategic* and *managerial* options have little value.[10]

The assumption of technological homogeneity probably posed little difficulty 50 years ago, given the relatively limited choice of options — oil- and coal-fired central station steam — which are homogeneous in that:

(i) They use similar fuel inputs with highly correlated prices.
(ii) They have a similar mix of capital and operating outlays and direct and indirect costs.
(iii) They have similar operating cost structures — their operating leverage is similar.
(iv) Choosing a particular technology did not create different strategic and capability options that might alter the future technological path; future capabilities were not significantly enhanced by choosing, say coal over oil-fired steam generation.
(v) The technologies were all equally "lumpy" and irreversible.

These general conditions are not easily met in today's technological environment, which presents planners with a broad range of supply- and demand-side options, some of which. Like PV, have unique attributes that are ignored by engineering-cost models. To make matters worse, these models almost always favor expense-intensive technologies such as fossil-fired generators over capital-intensive renewables such as PV. In addition to the limitations imposed by the generally restrictive conditions described above, energy valuation models suffer from a number of specific limitations as discussed next.

2.1. Limitations of traditional engineering-oriented models for valuing PV[11]

For nearly a century, engineering-economics costing models have been the mainstay for estimating the kWh cost of electricity (COE)[12] although it is not generally recognized that the approaches are merely rule-of-thumb proxies that yield only rough approximations of true cost. If we are to develop efficient energy policies that properly value PV and other renewables, we will have to adopt more sophisticated finance-oriented valuation procedures. Surprisingly, national energy policy in the US, the UK and elsewhere has not focused on this important need. Everyone, it seems, is quite content to leave the arcane costing procedures to the green-visor types, which is a mistake: the complexity of choices available makes open discussion of how to value PV and other decentralized and conventional technologies even more crucial.

Improper investment analysis has had far-reaching national implications in other industries. For example, myopic capital budgeting contributed in part to the near collapse of the American steel industry in the 1970s when accounting-based analyses suggested that existing technology was less costly than innovative alternatives. And this is not an isolated example. Traditional, accounting-based cost analyses almost always suggest that the incumbent technology is a better bet and that the innovation is too costly (Kaplan, 1986). Flawed engineering-based analyses also kept American manufacturers from making timely investments in innovative technologies such as CIM and computer-aided design (CAD), which led to a loss of world preeminence for these manufacturers who spent the next two decades regaining their leadership. Given the dismal record engineering-based cost models have in identifying promising innovations in manufacturing, it is unreasonable to expect that they will help us understand the costs and benefits of PV.

Some might argue in the emerging competitive market, low-cost providers will prevail so that discussions about proper valuation become irrelevant. But power purchase decisions and public policies including renewables portfolio standards and set-asides involve the valuation of uncertain future cost streams, which requires sophisticated procedures. It is not possible to make efficient investment decisions or develop appropriate public policy in today's complex environment using rule-of-thumb approaches that were "close enough" in simpler times: policies that rely on them will be productive only by

[10] The, application of traditional engineering economics to the valuation of electric generating alternatives seems to originate with Paul Jeynes (Kahn, 1988, p. 23) who was rather careful to note the principal shortcomings of the approach, i.e. it works only where expected revenues and the firm's rate of return remain unaffected by the technology choice (Jeynes, 1951, 1956), thus implying that all resource options show the same degree of financial risk.

[11] An abbreviated version of this section appeared in *Energy Magazine* (September 1996, pp. 3–6) published by Business Communications Co., Inc. (www.buscom.com).

[12] In the US, these procedures were formalized by the Electric Power Research Institute (EPRI) where they are widely known as "EPRI-TAG" procedures (see EPRI, 1991). Although they are called "cost models", the COE these models produce is actually a *revenue requirement* or *price* that exceeds *cost* by about 50%. This crucial difference is not widely understood.

accident. There are a number of reasons why traditional, engineering-based valuation approaches do not correctly reflect the relative value of PV. These are discussed below along with modest recommendations in each case.

2.1.1. *Traditional approaches ignore financial risk*

Loosely defined, financial risk is the variability of annual fuel and other input costs. Under an engineering approach a *risky* cost stream has the same present value as an equivalent but *safe* cost stream. This violates fundamental finance theory. Dollar for dollar, a risky cost stream, such as future outlays for fuel, must have a *higher* present value since it is less desirable than a safe cost stream.[13] This intuition — that risky cost streams are less desirable — seems to be widely understood. For example, homebuyers in the US overwhelmingly choose fixed-rate mortgages even though adjustable-rate mortgages carry initially lower interest rates. These borrowers obviously conclude that the fixed payment stream is more desirable — it has a lower present value.

Engineering cost approaches (such as EPRI-TAG) do not differentiate for risk and will therefore always indicate that less costly but riskier fossil alternatives are more economic, which is equivalent to arguing that junk bonds are a better investment than US Treasury obligations because they promise a higher annual payment stream for each $1000 invested and are hence "cheaper".

Most of the financial risk of fossil technologies is associated with fuel price variability, which many think is eliminated by the use of long-term fixed-price contracts and other hedging strategies. This view is not correct (Awerbuch, 2000). While such strategies provide a means of dealing with this risk, they are not without cost. Neither are they themselves free of risk, as evidenced by the multi-billion dollar collapse of Long Term Capital Management, a firm whose principals included prominent Nobel Laureates that contributed to the valuation theories underlying the options and derivatives the firm employed (New York Times, 1999).

In efficient markets the firm will pay what it "should" for its hedging strategies by compensating another agent for undertaking the risk.[14] When many firms hedge against the same risk the cost of their strategies can be expected to rise (Awerbuch, 2000). Ultimately, if fossil prices rise sufficiently, it can be expected that long-term contracts will be abrogated, as were the fixed-price nuclear fuel contracts when the cost of "yellowcake" rose sharply in the 1970s. From a national policy perspective, therefore, incorporating riskless *physical* assets such as PV and wind[15] may be essential for long-term energy security and reliability.

2.1.2. *Traditional approaches produce "stand-alone" instead of portfolio costs*

Financial portfolios are widely used by investors to manage risk and to maximize performance under a variety of unpredictable economic outcomes. Similarly, it is important to conceive of electricity generation not in terms of the cost of a particular technology today, but in terms of its *portfolio cost*. At any given time some alternatives in the portfolio may have high costs while others have lower costs, yet over time, the astute combination of alternatives serves to minimize overall generation cost relative to the risk.

By contrast, traditional energy valuation approaches, at least in the US, focus on finding the single *least-cost* alternative — a questionable procedure that is roughly analogous to trying to identify yesterday's single best performing stock and investing in it exclusively. Rather than focusing on "least-cost" options, assuming this is even possible in today's dynamic environment, our energy policies must focus on developing efficient (i.e. optimal) generating portfolios. Now the traditional selection criterion, minimum stand-alone cost, is replaced by overall portfolio generating cost coupled with expected portfolio risk (year-to-year cost fluctuations). Using standard portfolio theory principles, it can be shown that PV, which "costs more", serves to *reduce* the cost of a fossil-generating portfolio at any given level of risk. Indeed on the basis of American fuel prices and costs, evidence in the US indicates (Awerbuch, 2000) that small additions of PV — on the order of 3–6% — can serve to reduce generating costs or risks as compared to the existing fossil portfolio. Properly evaluated, PV does not "cost more" as widely believed.

2.1.2.1. Implications for lenders and investors. Portfolio concepts also have important implications for the diversification of the private portfolios of lenders and investors. Fossil fuel price movements, which have historically co-varied *negatively* with the returns to other assets (Awerbuch, 1995b, 1993a), affect the value of all investments in the economy.[16] This means that, to the extent

[13] Note that the opposite intuition holds for a risky *benefit* stream, which would have a *lower* present value than a "safe" stream. The difference arises because risky costs systematically move against economic cycles (they are high when the economy is doing poorly). Of course such a stream — which is high when other income is low — is quite attractive to a recipient who would value it by discounting at a rate below the riskless rate of return. Given perfect information, both payer and recipient will use the same discount rate to value the payment stream (Awerbuch, 1995a).

[14] The idea is that this agent has lower costs by virtue of its ability to hedge or diversify the risk.

[15] These technologies are systematically riskless as further discussed in Section 3.

[16] This seems consistent with the results reported by Lind (1982, p. 63), who finds that renewable investments will be negatively correlated with GNP, i.e. they will provide a form of insurance that pays off when the economy is doing poorly. More recent evidence (Sadorsky, 1999) further suggests that fossil price movement affects the volatility, and hence value, of other assets.

fossil prices continue to co-vary negatively with other assets,[17] PV investments may provide a valuable form of insurance to diversified portfolios, i.e. their value will be greatest when the returns to other assets are low. Such defensive or counter-cyclical investments, however, will provide relatively lower yields consistent with their low systematic risk.[18]

2.1.3. *Traditional approaches rely exclusively on the direct (busbar) cost*

Reliance on the direct busbar cost means that overhead and indirect resources consumed by such activities as fuel purchasing or Clean Air Act compliance are ignored so that the comparison implicitly assumes that such costs represent a constant percentage of the total costs of each resource alternative. While this assumption probably held at one time, it no longer does. Overhead requirements for PV, for example, are significantly lower than for most fossil alternatives. Costs are therefore distorted even more in cases where overheads are applied to various technologies using arbitrary firm-wide overhead allocation rates. This underscores the need for more detailed activity-based cost analyses (see Atkinson *et al*., 1997, Chapter 6) to help us better understand how different technologies consume overhead costs. Without this we will not know the *total* costs of operating particular technologies and hence will persist in relying on the traditional but flawed busbar cost comparisons.

2.1.4. *Traditional approaches ignore managerial and strategic options that PV may create*

2.1.4.1. Radical architectural innovation. When first introduced to manufacturing, computer-integrated manufacturing (CIM) could not be justified on the basis of existing benefit–cost techniques,[19] partly because its full range of benefits had not yet been exploited and could therefore not be conceived and valued. Full exploitation of new cost-cutting technologies, particularly *broadly applicable technologies* (Porter, 1990) such as PV, might require years or even decades. During this period, early adopters are incrementally adjusting to the new technology by slowly rearranging production processes and re-conceptualizing their understanding of how production costs are driven.

The Bessemer steel process, developed in the mid-1800s, provides an excellent illustration.[20] Bessemer changed the way steel was made by reducing batch production time to 15 min, but existing British mills could not properly exploit this innovation because they were organized around the previous open-hearth technology, which had a production time of several days (Clark, 1987). Fully capturing Bessemer's cost advantages had to await new American factories that were laid out around the new process (Clark, 1987). This meant new floor plans, new job classifications and new logistics — new processes for moving raw materials and finished product. Using the identical Bessemer process, the new US factories produced almost four times as much steel as their European counterparts (Clark, 1987).

The Bessemer case suggests that we probably do not yet understand how to fully exploit PV and other passive distributed technologies or how to express their ultimate costs and benefits. Our electricity production and delivery processes are based on "active" 19th century central-station fossil technology (Awerbuch *et al*., 1996) that requires the support of complex organizations to manage the complicated logistics and maintenance functions needed to literally keep the wheels spinning. Such technologies exhibit considerable agglomeration (scale and scope) economies.

PV, on the other hand, does not fit well into this 19th century industrial model and may be more cost effective when deployed outside traditional hierarchical organizations. PV shows few scale economies. It requires little, and hence do not benefit from, traditional corporate overhead support (e.g. PV does not depend on a staff to negotiate fuel contracts). In a manner similar to manufacturing innovations, the ultimate benefits of PV may be largely *complementary* (Milgrom and Roberts, 1990), i.e. the cost-cutting benefits of PV may show up elsewhere in the production process. For example, PV and similar modular resources may reduce overheads and indirect costs by providing a means of reducing supply–demand imbalances that lead to excess capacity. Since it has no corresponding accounting entry, the wastefulness of this electricity production paradigm goes largely unrecognized, much as the wastefulness of manufacturing inventories, which were considered essential under the old mass-production paradigm, also went unrecognized until the emergence of "lean manufacturing" in the 1970s.

2.1.4.2. Managerial and strategic options. Experience in manufacturing suggests that new technologies often create valuable managerial or strategic options that can be "exercised" at a later time. While the existence of such options clearly increases the value of a particular project,

[17] Recent events seem to support the proposition. Oil prices have risen dramatically over the last 15 months, while at the same time, stock market performance (in the US at least) has weakened dramatically suggesting a *systematic* negative relationship between fossil prices and the value of other assets in the economy.

[18] Technically, a negative-beta assets will yield an expected CAPM return below the riskless rate.

[19] For a fascinating discussion and illustration of this problem see Kaplan (1986).

[20] This illustration is more fully described in Awerbuch *et al*. (1999, Chapter 4).

this value yields no immediate benefit in terms of reducing annual accounting costs. The literature divides options into several categories, although there can be overlap between them.

Flexibility options: PV technology is modular which creates valuable *flexibility* options since managers can install capacity slowly, over time, to match load increases. Recent work on the value of flexibility (cited previously) suggests that when valued in a traditional manner, inflexible projects are comparable to flexible ones only if their present value is considerably greater.

Strategic Options: The adoption of PV, even in small amounts, can create *strategic options* (Aggarwal, 1993, 1997) or capability options for managers by creating opportunities to serve new customers or provide different levels of quality and reliability as well as different types of services.

For example, manufacturers that adopted numerically controlled process technology in the 1970s were able to more readily adopt CIM a decade later (Kaplan, 1986). Numerically controlled production machinery was driven by coded paper tape which required workers to learn how to resolve product shapes and required machine movements into a series of numerical instructions based on a set of X–Y coordinates. This training and experience created a *capability* that enabled the firm to more easily transition to CIM, which requires similar skills.

Additional research will be required to better understand how to conceive and value such options in the case of PV. Indeed it is difficult to value strategic and capability options because it is hard to see the future. In the case of paper-tape technology, hindsight clearly implies that no matter what the initial cash-flow-based benefit–cost analyses may have indicated, the original adoption of numerically controlled equipment was ultimately cost effective, not necessarily because of direct cost savings (although these may have accrued as well) but because of the capabilities and strategic options it created.

2.1.5. Traditional approaches ignore cost-of-quality in electricity production/delivery

In manufacturing, *cost-of-quality* concepts are, by now, well understood (e.g. Kaplan, 1990; Kaplan and Atkinson, 1989, Chapter 10), and generally involve the elimination of wasteful activities such as assembly-line setups, the maintenance of parts inventories or the remanufacture of defective products. As of yet, there is no generally accepted definition of the cost-of-quality in electricity production and delivery, although it undoubtedly implies the reduction or elimination of inherently wasteful activities such as traditional reserve requirements and transactions such as meter-reading and the ordering, movement and storage of fuel and other materials, etc. Of course attaining such a result requires that we substantially re-conceptualize the entire generation/delivery process just as manufacturing was largely re-conceived from mass production to flexible production, (sometimes equated with "lean manufacturing") in the late 1970s. PV, which can easily be located close to loads (even as part of the roofing or as thin films on windows and architectural curtain walls) and, in principle, does not require metering, will no doubt help us re-conceptualize the process in such a fashion.

Traditional cost accounting does not identify wasteful activity. For example, there is no manufacturing cost category for "producing defective parts". Similarly, the costs of maintaining such essentially useless resources as idle or spinning generation reserves are not explicitly recorded so that managers have little incentive to focus on these activities in order to reduce cost. Instead, managers focus on line-item cost-accounting items such as fuel or maintenance. This is similar to the earlier focus of production managers, who equated cost reduction with, for example, substituting low-cost materials, a strategy that would be ridiculed in today's competitive global manufacturing. Moreover, traditional cost accounting does not properly categorize most transactions costs including the negotiation, purchase, movement and storage of fuel and other supplies or the activities associated with meter-reading and billing, which may be significant in the case of small accounts.

Finally, quality manufacturing implies the production of goods that deliver value through intelligent design, which meets customer needs and expectations. Drucker (1992) observes that manufactured products contain higher information content, coupled with lower energy, material and labor content. The idea applies to electricity production/distribution as well: the focus needs to shift from one of simple busbar cost minimization to one of delivering fewer, "smarter" kilowatt-hours that have a higher value to customers (Awerbuch *et al*., 1999, Chapter 4). In such an environment, the higher stand-alone cost of PV-based electricity may be more than offset by the greater value.

2.1.6. Engineering approaches focus on current technology costs

The relative costs of fossil versus PV-based generation will change drastically when a new need is imposed, such as a requirement for zero or low carbon emissions, or, when changing economic conditions alter the relative costs of input factors, e.g. labor costs might rise over time relative to capital costs without any offsetting productivity gains in operation and maintenance.

In spite of such obvious possibilities, energy valuation procedures tend to be almost exclusively based on costs as *currently conceived and constructed*, without reflecting underlying future changes in technology cost or operating conditions. This practice is quite astonishing given the long planning horizons — typically 20 years or more — used in most valuation exercises.

In addition, planners use the *currently conceived* accounting costs for resource alternatives even though energy policies often represent inter-temporal *investment strategies* that need to reflect *anticipated* costs. PV technologies, for example, are on a declining cost curve while fossil technologies are on the mature part of the technology curve — recent efficiency gains not withstanding. The real costs of fossil alternatives are likely to rise with real increases in labor and fuel, and with future attempts to adapt them to new needs.

Effective valuation procedures must therefore consider future changes in technology costs. This involves, among other things, (i) assessing and valuing contingencies such as future environmental requirements and, (ii) using learning (experience) curves and similar tools to develop assessments for relatively mature as well as emerging technologies.

2.1.6.1. The era of technological change: *the need for technology assessment.* Qualitative technology assessment can help properly capture the relative cost of *using* a particular technology such as PV as the world changes in the future. And although planners *project* O&M costs to the future, this does not properly capture the true costs that might be encountered when operating conditions, competitive pressures and the cost of alternatives may change. There is plenty of evidence to illustrate this point: we routinely discard computers, copiers and fax machines because they have gotten too costly to use, even though the original cost is sunk and we have made no unanticipated maintenance outlays! In other words, while the original cost projections materialized *precisely*, the technologies nonetheless obsolesced.

In these cases, although the engineering cost projections were on target, *relative* costs changed as a result of new operating requirements or new needs to which the technology could not be easily adapted. We might, for example, discard a paper copier because it does not reduce/enlarge, or a fax machine because it does not cut the paper. This capability may not have been important originally, but over time, operating conditions change, e.g. the volume of usage increases (or the cost of labor rises — see below). This alters the cost picture so that it now becomes too expensive to use copiers that cannot reduce or fax machines with continuous scrolls of paper. In each of these cases the technology has become too expensive even though its accounting costs materialized as originally projected. Such an outcome is especially true if competitors have all switched to newer technology.

Energy resource options are similarly subject to cost changes as they are adapted or redeployed to meet new market, regulatory and operating conditions so that it might also become too costly to operate a particular option even though costs have materialized as projected. The most obvious changing conditions are:

(i) *Environmental Regulation*: More stringent emissions requirements might require sizable retrofits to meet air quality standards. Such contingencies are frequently ignored even though they have significant present value costs,[21] which serves to bias the analysis against PV.

(ii) *The development of new, lower cost technologies*: Planning techniques need to evaluate the efficiencies — and hence costs — of future vintages of PV and gas turbines since these may differ from the costs used in today's screening analyses. Along these lines, S-shaped (logistic) curves coupled with engineering assessments can be used to help estimate efficiency increases (i.e. reduced heat rates, improved ramp-up, lower maintenance requirements) for gas turbines and other existing technologies. Experience curves can also be used to estimate manufacturing cost reductions as PV (and other emerging technologies) mature.[22]

(iii) *Changes in the relative cost of labor and other input factors*: Valuation procedures often project labor costs using arbitrary escalation rates that do not reflect the underlying economic changes in the relative costs of factor inputs. A more detailed analysis might reveal that, absent productivity gains, the substitution of capital for labor may become increasingly attractive in electricity generation just as it has in manufacturing. Such structural changes could easily swing the advantage away from expense-intensive fossil technologies, towards PV.

Clearly such forces can join to radically alter the currently conceived operating cost picture for a given technology. For instance, absent significant efficiency gains, a scenario of relatively undramatic annual operating cost increases for gas turbines coupled with more stringent emissions requirements could combine with experience-based cost reductions in PV to make the latter the low-cost stand-alone choice at some not too distant future time. Such relative cost changes are obscured when all technologies are evaluated using their currently constructed costs.

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[21] For example, consider the possibility of a $300 million outlay to meet new emissions requirements in the tenth year of a coal-fired project. Such an outlay has a present value of $100 million — *even if the likelihood of this contingency is only 50%.* This is significant relative to the $600 million or so cost of a 500 mW_e coal-fired plant.

[22] The results of such experience curve analysis can dramatically change estimated costs in a new technology such as PV if we conceive of the resource as being installed incrementally over the planning horizon. Using a set of projected experience curves for photovoltaics developed by Williams and Terzian (1993), we obtain a vintage-levelized cost for PV-based electricity that is nearly 50% lower than the currently installed cost (Awerbuch, 1995b).

3. Correcting financial misconceptions: lending and the risk properties of PV

Investment analysis tools used to evaluate energy alternatives were conceived around the time of the Model-T Ford. They were OK for comparing one central-station fossil alternative to another but they are not useful in today's dynamic environment with technologically and institutionally diverse resource options whose risk and benefit–cost tradeoffs have been significantly altered.[23] Lenders and investors, however, are slow to catch on to the new economics and altered risk structures. This is OK — it keeps them from making obvious mistakes, like investing in a technology that goes bust. But it does not keep them from making *less* obvious mistakes — like missing out on profit-making opportunities involving new technologies. Then again, opportunity losses, which are economically indistinguishable from cash losses, concern them much less since probably no one will ever know.

As a consequence, lenders and investors concoct various reasons to explain their reluctance to support PV projects. Some of these ideas sound astonishing given the financial properties of PV. The key ideas are that PV is free of fuel price risk, and, moreover, has virtually no operating expenses since almost all costs are in the form of up-front investment outlays. PV is therefore essentially riskless, i.e. it comes about as close as a real asset can to providing the systematically risk-free (zero-*beta*) characteristics of a US Treasury bill (Awerbuch, 1995b). This, of course, does not mean that PV is entirely free of risk, but the remaining risk, the random or so-called *technology risk*, is fully diversifiable (Interstate Renewable Energy Council, 1996). Moreover, these technologies, by virtue of their modularity and flexibility, reduce a number of risks such as the likelihood of creating costly excess capacity, a risk that is quite significant in the case of lumpy central-station resources. Obviously, there is some lack of communication or understanding; perhaps lenders and investors have lost sight of the finance fundamentals.

3.1. Capital intensity

Lenders apparently worry about the capital intensity of PV (Mendis, 1999). Loans for PV projects tie-up a high percentage of annual cash flow, which makes these seem riskier to bankers. It seems to them as if their loan includes the cost of, for example, the future fuel-stream (PV uses no fuel) whereas for a fossil technology, fuel is paid for out of annual revenues and is not part of the obligation to the lender. This idea reflects a fundamental misunderstanding of the risks and economics of a renewables investment. PV is a low-*beta* asset — it exhibits very low asset risk. Total risk is the sum of the underlying business or asset risk plus the financing risk. Any venture with low business risk (low asset beta) can take on more financing and still have an acceptable overall beta. It seems lenders would want as much of such a project as they could get. For the same amount of paperwork they can get a bigger loan than, say, on a gas turbine.

But bankers still worry: their loan ties up a much higher percentage of the project's cash flows than would a loan on a gas turbine, where the loan drains much less of the annual cash flow leaving more for other expenses. And that's the key — there are virtually no other expenses with capital-intensive PV. Where the asset is nearly systematically riskless, high loan-to-value makes a lot of sense. Everyone seems to understand that. For example, when you put up riskless Treasury bills against your margin loan, your broker might lend you 90% of their value. But you might only get 50 or 75% of value if you put up risky stocks.

This confusion, which one hears expressed often, has to do with a misunderstanding of operating leverage. Lenders think that PV resources have high operating leverage. Projects with high operating leverage are riskier because a high proportion of the cash flows is committed to fixed outlays, outlays that cannot easily be reduced when revenues fall. But PV actually creates very *low* operating leverage since there are virtually no fixed costs. The problem here is that lenders include the loan payment as part of the operating leverage calculation, which is incorrect — financing decisions are never part of the operating leverage calculation — check out any finance textbook.[24] In any event, the bottom line may be the same: in the case of highly leveraged (i.e. high financial leverage or loan-to-value) PV projects, a large proportion of the cash flows is indeed committed to covering debt service. But, again, why should this be problematic?

The high debt outlays associated with PV resources are offset by the low asset betas (just like high-margin loans on low-risk securities). Bankers should understand this idea — they have no trouble lending against shopping centers, office buildings and other real estate where very large proportions of operating cash flows are needed to service the mortgage. In such cases bankers worry more about the credit worthiness of the tenants. And perhaps this is what it comes down to in the case of PV projects — what is the credit worthiness of the power purchasers. Given purchasers with equal

[23] E.g. A central station plant may produce the cheapest electricity *on paper*, but this calculation is useless if you judge demand growth incorrectly so that your 500 MW plant produces at only half capacity. In any event, given the pace of technological progress, small turbines are no longer necessarily inferior to large-scale plant and may in fact soon be more efficient (Vesey, 1999).

[24] For example, Rao (1992, pp. 193–195), defines operating leverage as the commitment to fixed *production* costs (see also Brealey and Myers, 1991, pp. 199–200). Financing costs are never part of the operating leverage computation since they are a financing decision and a project can always be financed using more equity for which there is no periodic payment obligation.

creditworthiness, PV projects are considerably *less* risky than fossil-based projects. Any flexible, distributed project will be less risky than an equivalent central-station installation. The sunk costs for a distributed project are generally lower, which increases *reversibility*, an important determinant of project risk and flexibility.

3.2. Risk and project return

Investors are as confused as lenders are about renewables. Based on existing economics, they do not see how these technologies can produce the high rates of return to which they have become accustomed. The answer of course has to do with risk differentials. Establishing a distributed PV installation involves buying and erecting PV modules and attendant devices, entering into maintenance contracts, signing up power purchasers on firm contracts at a price that will cover the loan payments, the modicum of maintenance costs and the expected component replacements. This is not rocket science. Insolation values are widely available and can be readily measured at a given site. The year-to-year variability in insolation, it turns out, is very small (Awerbuch, 1992) so that revenues will remain quite constant year-to-year[25] — assuming the customers are as good as they say they are. And out of pocket expenses are also very small (operating leverage is low) so that with proper planning, they should not significantly alter the bottom line even in a bad year.

The production of PV-based electricity, it seems, is a reasonably simple, clean business with controllable costs and little risk. It does not require visionaries at the helm; it does not require extraordinary technical or managerial ability. It is unreasonable to expect PV investments, which can be made virtually riskless to generate the high returns that investors might expect from, say, a risky internet business that has unknown revenue streams and extremely short technology life cycles that could threaten to vaporize the value of the firm's technology or patents overnight.

More importantly, since fossil price movements have historically tended to be counter-cyclical (i.e. they covary *negatively* with the returns to other assets in the economy), the value of PV-based electricity and hence the value of a PV investment will also be counter-cyclical, i.e. it will have a negative beta — its value will rise precisely as the returns to other assets fall.[26] Based on the CAPM, the expected returns from assets with negative betas will be lower than the riskless rate obtained on US Treasury obligations. The beauty of a negative beta asset, however, is that its value will rise just as the rest of the portfolio is declining. This "insurance" value, therefore offsets the lower returns provided by PV.

[25] Weather variations can now also be hedged with weather futures that are beginning to trade in the US.

[26] This presumes the negative covariance between fossil prices and the economy continues. PV will be a zero-beta asset given long-term fixed-price contracts for its electric output. Spot electricity prices, however, will rise with rising fossil prices, which in turn will serve to increase the value of PV investments generally (except those that are, like housing under rent-control, encumbered by fixed-price contracts) since their costs are fixed.

3.3. Modularity, loan size and perceived lending risks

PV's modularity and reversibility reduces project risk, in part because sunk costs are relatively small as compared to traditional central-station generators.[27] This means that PV projects can easily be stopped and started at any time and even reversed by removing and selling the modules (as was the case at Carissa Plains). While all of this flexibility adds to PV's value, it seems to make bankers nervous about the safety of the PV assets that secure their loan. They worry that the modules may disappear, presumably through theft or fraud. While this concern seems legitimate, one must wonder why the industry has not figured out how to mitigate the problem. Are underwriters willing to provide casualty insurance on installed PV modules? In the US, bankers seem to gladly lend on all sorts of transportable assets including cars, computers and refrigerators. In the case of cars, they routinely require theft and other insurance.

A final concern about PV lending, frequently expressed by bankers, is the small size of PV loans, which raises costs. While this is no doubt accurate, it needs to be further examined. Again, one wonders why the industry has not figured out how to overcome this obstacle. In the US, banks routinely lend on consumer appliances, restaurant kitchen equipment (often in the form of leases) and a host of other specialized equipment. The key seems to be specialization — lenders have learned how to effectively promote loan packages in their area of expertise — whether it is lending on small airplanes or leasing the furniture and equipment in a dentist's office. To the extent that such financing is well established in the US, one wonders why such specialization has not emerged with regard to international lending for PV.

Loan size, and the security of chattel may present greater impediments in certain countries with less developed commercial practices. In the US, where such practices are well established, lenders are protected by the Federal *Uniform Commercial Code* (UCC) and by state statutes, which typically spell out the means of recording liens and perfecting claims, as well as the basic obligations of borrowers (and lessees) vis-à-vis chattel encumbered by liens. By standardizing the basic requirements, the UCC thus reduces the transactions costs involved in lending. To the extent that emerging nations may not have established commercial codes and

[27] This means that salvage values are relatively high.

practices, chattel mortgages may be riskier and more costly to administer.

So, we return to the opening idea: the technology is not the problem — it is the way we conceive it and the way we measure its attributes. And along these lines, as this paper has suggested, we have a lengthy history of using inappropriate engineering-oriented valuation and investment analysis tools that ignore risk differentials and a variety of other important technology attributes. These analysis tools have failed miserably in other industries. Why do we continue to use them to evaluate energy options? Because engineers and planners are almost always familiar with them, while knowing little about more appropriate finance-oriented valuation tools.

4. Policy prescriptions and implications

In Europe as well as the US it is essential for energy planning agencies to abandon outmoded concepts and adopt the state-of-the-art valuation and investment models described in this paper. The divergence between valuation theory and practice is perhaps nowhere greater than in energy planning, where outmoded accounting concepts and engineering approaches, long since discarded in manufacturing and other industries, still provide the *sole* basis for decision-making.

PV and similar passive renewables present a unique menu of risk, cost and quality choices. Traditional valuation models, conceived long before such choices became technologically feasible, cannot "see" the special attributes and values[28] because they are steeped in the vocabulary of a different technological era — one of *active, expense-intensive* production technology. The unfortunate outcome of using such models is that planners continue to undervalue PV, and worse, to ignore its unique properties. Properly understood and exploited, these attributes could undoubtedly form the basis for re-conceptualizing (reengineering) the electricity production and delivery process in ways that we can yet not imagine. The literature is rich with prescriptions for how to proceed.[29] Energy planners and policy makers have a responsibility to broaden the analytic horizons to include new valuation approaches that more properly reflect the unique attributes of PV and other renewables.

Appendix A. Illustrative risk-adjusted busbar cost comparison of PV and gas combined cycle

The general valuation or costing procedure involves two steps: first future annual operating costs for a particular resource alternative are estimated; these are then discounted to their present values. Using a cash flow approach,[30] the present value cost of a capacity addition can be written as

$$\text{present value cost} = \text{PVC} = (\text{IO} - \text{ITC}) - (\text{PVTD} \times \tau) + (\text{PVOC}(1-\tau)), \tag{A.1}$$

where IO is the initial capital outlay, ITC is the investment tax credit, if any, PVTD is the present value of the yearly tax depreciation allowances, τ is the firm's marginal tax rate and, PVOC is the present value of annual operating costs (fuel, O&M, property taxes and insurance).

In order for the PVC to have any economic interpretation, PVTD and PVOC must be obtained using the correct market-based discount rate. If this is done, then the PVC is the cost that would be incurred by any entity to produce the electricity. Now, if desired, a simple transformation can be made to convert costs to present value revenue requirement:

$$\text{PVRR} = \text{PVC}/(1-\tau), \tag{A.2}$$

where PVRR is the present value revenue requirement and PVC is the present value cost estimated in Eq. (A.1).

The PVRR is the *price* of the electricity produced. The distinction between cost and price is quite basic, but the two are frequently confused because planners do not understand whether their analysis produces a cost or a price.[31]

[28] As always, there are exceptions. Nobel Laureate George Stigler (1949, p. 129), while discussing "indivisible and unadaptable fixed plant", inadvertently illustrates an unimaginable (then) technology with zero marginal costs. PV may be the first production technology that approximates Stigler's remarkable insight.

[29] For example, a recent special issue of this journal devoted to the valuation of renewables (*Energy Policy* 24(2), 1996) presented models and procedures applicable to the valuation of diverse energy alternatives in a dynamic environment of institutional and technological change.

[30] Utility planners in the US, and perhaps elsewhere needlessly complicate matters by modeling revenue requirements, which include annual debt payments, depreciation recovery earnings and other accounting concepts that do not affect the asset's present value. For example, cash flows to equity and debt investors, discounted at the WACC, yield a present value equal to the initial project outlay. For the purpose of valuation, the stream of debt payments, depreciation recovery and earnings are irrelevant and can be replaced by a single value — the initial project outlay. A demonstration of the equivalence between the cash flow approach of Appendix A and the more complex revenue-requirements method is given in IREC (1996); see also EPRI (1990 Chapter 9); a rigorous proof is given by Tardiff and Bidwell (1990).

[31] For example, planners sometimes improperly compare a value derived using EPRI-TAG, which yields a *price* (i.e. revenue requirement) to an avoided cost.

Table 1
Input data: 200 mW combined cycle and 50 mW photovoltaic

Economic assumptions		
Marginal corporate tax rate	0.40	
Inflation rate	0.04	
Cost inputs		
	Combined cycle	Photovoltaic
Project useful life (years)	30	30
MACRS tax life (years)	15	5[a]
Cost per kW	\$500	\$2750
First year fuel cost per kWh	\$0.0248	—
Fixed O&M per kW	\$14.40	\$3.25
Variable O&M per kWh	\$0.0043	\$0.0021
Land lease per kW	—	\$0.88
Capacity factor	0.75	0.24
Heat rate (BTU/kWh)	7514	—
Federal tax credit	—	0.10
State tax credit	—	—

[a]Assumes a non-utility investor

A.1. An Illustration

Let us illustrate these ideas with two examples that contrast the engineering approach with the finance approach to valuation, with overhead costs and option values ignored. The first involves a 200 mW combined cycle unit recently proposed in the northeast US; the second, a 50 mW photovoltaic project in Lualualei, Hawaii.[32] Table 1 gives the estimated costs and economic assumptions for each project.[33] Table 2 shows the computations using WACC-based as well as market-based discounting.[34] The first block shows the capital costs beginning with the initial outlay and the tax credits (IO - ITC in Eq. (A.1)) followed by the present value of the depreciation shelter (PVTD τ).[35] The market-based approach, which values (discounts) depreciation tax shelters at the riskless rate, yields larger present values for these than the traditional approach which discounts all cash flows at the WACC.[36]

Subtracting the depreciation tax shelter from the net outlay yields the net post-tax qutlays. Note that the WACC-based approach overstates this post-tax outlay for both projects, although the bias is worse in the case of PV. This is one of the ways in which engineering-based cost models bias against *any* capital-intensive technology, whether a computer or a PV module. And since most new process innovations tend to be capital-intensive, the process invariably biases against *any* innovation.

Next the table shows the present values for the after-tax operating costs (PVOC$(1-\tau)$ in Eq. (A.1); present value computations are not shown). These are divided into two groups — the debt equivalent group and the cyclical group. Debt equivalents are those outlays that represent fixed, debt-like obligations such as property taxes, fixed O and M and land leases. Recipients of these obligations would value them much the same way they do the firm's debt with a required rate of return or discount rate equal to the after-tax cost of debt (Box 1).[37] Fuel costs are also included in the debt-equivalents group because projected fuel prices in the example are based on a long-term contract, which in essence is a fixed obligation. Different discounting might be appropriate for fuel purchased on the spot-market.

Box 1 Discount rate estimates for valuing PV and combined cycle.

I. Recent market rates		
Single-A utility bond yield	7.0%	
Long-term US government bond yield	6.0%	
II. *Nominal discount rates*		
	Pre-tax	Post-tax[b]
Riskless rate (for depreciation tax shelters)	4.5%[a]	2.7%
Cost of debt (for fuel and fixed O&M)	7.0%	4.2%
Cyclical discount rate (for variable O&M)	10.0%	6.0%
WACC		8.8%

[a]US government Bond yield less 1.5% term premium.
[b]Post-tax discount rate = pre-tax rate(1 − tax rate).

Note that the WACC-based present values for this group of operating costs understate the market-based present value costs by approximately half, with the most

[32] Hawaii offers a 40% investment tax credit for PV, the value of which does not approach the likely savings in societal environmental externality costs, which are in the range of \$7000/kW (Awerbuch, 1993c). To maintain generality, Appendix A reflects only the 10% US Federal tax credit.

[33] A more detailed discussion of the cost assumptions is given in IREC (1996). Capital costs for each alternative have been updated.

[34] A fuller discussion of discount rate estimation can be found in IREC (1996).

[35] Revenue requirements models do not compute the depreciation tax shelter explicitly. Rather, it is part of the yearly income tax computation.

[36] Depreciation tax shelters are riskless cash flows — almost like money in the bank — which will accrue to the firm as long as there is sufficient income to offset the deductions. They are therefore discounted at the (after-tax) riskless rate obtainable on US treasury obligations (see, for example, EPRI, 1990, Chapter 9).

[37] The valuation of debt equivalents is discussed in Brealey and Myers (1991, pp. 473–474). It is not possible here to fully discuss the theory relating to discount rate estimation for cash outflows. This is discussed in Awerbuch (1993a, 1995a, b), Copeland and Weston (1988, pp. 414–419) and Seitz (1990, Appendix 11-A).

Table 2
Estimated cost and revenue requirement per kWh combined cycle and photovoltaic generation

Present value post-tax costs per kW		Combined cycle		Photovoltaics	
		WACC	Market based	WACC	Market based
Capital costs					
	Initial outlay	$500	$500	$2750	$2750
	Less: Immediate tax credit	$0	$0	($275)	($275)
	Net outlay	$500	$500	$2475	$2475
	Present value depreciation shield	($107)	($165)	($832)	($1014)
	Net post-tax outlay	$393	$335	$1643	$1461
Debt-equivalent outflows					
	Property tax	$116	$210	$1	$3
	Fixed O&M	$134	$242	$26	$52
	Land lease	$0	$0	$7	$14
	Fuel costs (long-term contract) per kW	$1040	$2167	—	—
Cyclical outflows					
	Variable O&M	$259	$365	$37	$51
The present value cost per kW		$1942	$3319	$1714	$1581
	Levelization rate	*8.8%*	*8.8%*	*8.8%*	*8.8%*
	Levelized charge	$186	$317	$164	$151
	Hours per year	6570	6570	2102	2102
	Levelized cost per kWh	$0.028	$0.048	$0.078	$0.072
	Revenue requirements ($/kWh)	0.047	0.080	0.130	0.120

significant dollar error coming from the estimated present value of the fixed fuel contract. (In the case of the PV, the errors are not significant since the operating costs are small.) By understating operating costs in this manner, engineering cost estimates further bias the comparison in favor of existing, expense-intensive technologies and against new, capital-intensive ones.

The last block of Table 2 shows the kWh cost estimation. The total present value costs is annuitized or levelized using the WACC (8.8% in this case).[38] The WACC-based cost estimate for the combined-cycle unit is $0.03/k Wh, a 40% understatement of the market-based estimate of $0.05. In the case of PV, the WACC estimate *overstates* the correct market-based cost by about 10%.[39] Finally, the costs are transformed to a revenue requirement as per Eq. (A.2).

The analysis shows that while PV is still more "costly" on a stand-alone busbar basis, traditional approaches significantly magnify this result: the WACC result indicates that PV is more than twice as costly as the CC alternative; the more reliable market-based results show a differential that is considerably smaller. The fossil technology's seeming advantage could easily disappear with the inclusion of overheads, indirect costs and option values.

[38] The WACC is appropriate for levelization; for proof see EPRI (1990). This is the only appropriate use for the WACC in performing cost estimates.

[39] Using the actual Hawaii energy credits, the WACC-based PV cost overstates the market-based value by almost 30%.

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