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Accelerating residential PV expansion: demand analysis for competitive electricity markets

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Abstract

This article quantifies the potential market for grid-connected, residential photovoltaic (PV) electricity integrated into new homes built in the US. It complements an earlier supply-side analysis by the authors that demonstrates the potential to reduce PV module prices below $1.5/W_p$ by scaling up existing thin-film technology in 100 MW_p/yr manufacturing facilities. The present article demonstrates that, at that price, PV modules may be cost effective in 125,000 new home installations per year (0.5 GW_p/yr). While this market is large enough to support multiple scaled up thin-film PV factories, inefficient energy pricing and demand-side market failures will inhibit prospective PV consumers without strong public policy support. Net metering rules, already implemented in many states to encourage PV market launch, represent a crude but reasonable surrogate for efficient electricity pricing mechanisms that may ultimately emerge to internalize the externality benefits of PV. These public benefits include reduced air pollution damages (estimated costs of damage to human health from fossil fuel power plants are presented in Appendix A), deferral of transmission and distribution capital expenditures, reduced exposure to fossil fuel price risks, and increased electricity system reliability for end users. Thus, net metering for PV ought to be implemented as broadly as possible and sustained until efficient pricing is in place. Complementary PV "buydowns" (e.g., a renewable portfolio standard with a specific PV requirement) are needed to jumpstart regional PV markets.
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1. Introduction

The *demand analysis* presented here assesses the near-term potential for installing photovoltaic (PV) systems on rooftops of new US homes. It builds on an earlier *supply analysis* (Payne et al., 2001) that estimated the near-term (2007–2016) profitable selling price for thin-film PV [amorphous silicon (a-Si)] modules based on current technology scaled up for mass-production in large (100 MW_p/yr) factories. Assuming a fixed financial hurdle rate (20% internal rate of return), the supply analysis concluded that it would be profitable to manufacture such a-Si PV modules in 100 MW_p/yr factories if wholesale module prices were initially about $2.2/W_p$, falling by 5.5% annually until the tenth year of operation, when plants are retired. At these module prices, and given expected near-term reductions in "balance-of-system" costs, PV systems incorporated into new homes should become cost effective in significant US markets.

The focus of both the demand and supply analyses is US residential housing, which stands out as an especially attractive early market in establishing a worldwide PV industry for serving grid-connected applications[1] (Duke, 2002) because: (i) the after-tax cost of residential mortgage financing in the US is generally much less than the financing cost for commercial and industrial customers; (ii) average residential electricity prices are higher than commercial and industrial prices in the US;[2] and (iii) distributed PV systems scale down to the residential scale ($\sim$4 kW_p) without a substantial cost

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[1] Grid-connected systems (subsidized and mostly in industrialized countries) account for a majority of worldwide PV module sales—and this market segment has been growing at twice the rate of off-grid sales (Johnson, 2002).

[2] The average year-2000 electricity prices in the US were $0.082, $0.072, and $0.045/kWh for residential, commercial, and industrial customers, respectively (EIA, 2001).

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penalty relative to larger commercial installations (typically 10–100 kW_p).[3]

Although PV systems can be either incorporated into new homes or retrofitted onto existing homes, retrofitters face idiosyncratic installation challenges for each project and have difficulty realizing the scale economies available to homebuilders. A solar housing developer would benefit from the following advantages relative to a company that installs one-off retrofits:

- Low equipment prices can be negotiated by purchasing in quantity.
- Relationships can be developed with specialist architects, electricians, and roofers to optimize the design and installation of standard PV roofing packages.
- New homes can be sited and designed to ensure good solar access and easy installation.
- Interconnection costs can be mitigated by developing relationships and standard contracts with utilities and regulators.
- PV can be incorporated as a standard option in marketing materials for new homes.[4]

Thus, this analysis is further restricted to *new* homes, which represent the most cost-effective grid-connected residential PV applications (Payne et al., 2001).

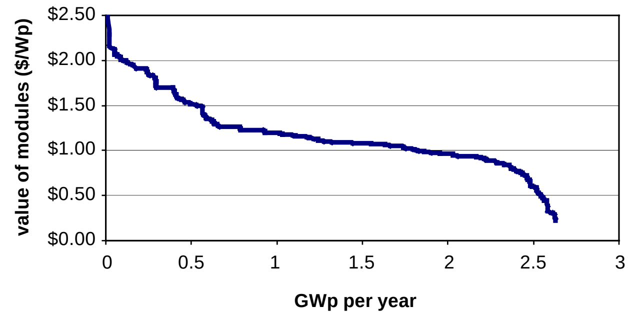

Fig. 1. Financial breakeven for PV in new US housing. A detailed bottom-up financial breakeven analysis shows the annual potential demand for PV modules installed in new single-family homes after 2005 assuming that 50% of new homes offer acceptable shading and orientation. (All housing data are taken from http://www.census.gov/const. Where available, this analysis uses average annual housing start data from 1999 to 2001 for the 160 high-value counties representing the first 0.3 GW_p/yr in residential PV demand. The rest of the graph estimates housing starts based on each county's population pro-rated share of projected year-2003 housing starts (~1.3 million/yr nationally) in each respective state.) A point on this curve indicates the PV quantity demanded in new single-family homes for a given wholesale PV module price. This financial breakeven curve was constructed based on a detailed lifecycle analysis that assumes net metering and accounts for variation in county-level insolation and state-level electricity prices. Homeowners finance their systems through tax-advantaged home mortgages and incremental homeowner insurance costs are assumed to be trivial. Finally, it is assumed that states and localities exempt the value of PV systems from property tax assessments to level the playing field in the competition with less capital-intensive conventional electricity technologies. No other existing or planned tax incentives are taken into account.

2. The breakeven schedule for new US residential PV

The demand analysis is based on a financial breakeven schedule for modules installed in new US homes. Based on county-level insolation and state-level retail electricity prices,[5] the present value of each W_p of PV module capacity (breakeven price) is calculated as[6]

$$\begin{aligned}\text{value } (\$/W_p) &= \sum[(\text{revenues} - \text{O\&M}) \text{ in } n\text{th year}]/(1+i)^n \\ &\quad - \text{installation costs } (\$/W_p) \\ &\quad - \text{inverter costs } (\$/W_p),\end{aligned}$$

where i is the discount rate, n the year after installation (1–25), revenues = (kWh of annual PV output per W_p installed) · (retail electricity price in \$/kWh), and O&M the annual PV system operations and maintenance costs per W_p installed.

Fig. 1 shows the resulting financial breakeven schedule for PV modules used in grid-tied PV systems for single-family housing in the US. This schedule indicates what the wholesale PV module price would have to be at any given annual sales volume in order to make consumers at least as well off financially by purchasing PV systems as by continuing to purchase conventional electricity. The graph shows that PV

[3] At present, per-system transaction costs are a major factor constraining residential markets such that some PV subsidy programs have done more to catalyze large-scale commercial projects rather than residential markets. This should change as markets mature and scalable equipment costs begin to dominate the economics of distributed PV.

[4] In contrast, retrofit companies must court each prospective PV system buyer separately, then develop a unique system design and negotiate an appropriate price for each case.

[5] County-level insolation data from Marnay et al. (1997) based on their GIS interpolation of data from 239 solar measurement sites (NREL, 1994) are used to construct "maximum possible" county-level insolation estimates assuming optimal tilt angle. This analysis reduces these estimates by 6% to bring them into agreement with city-level historical data from http://www.rredc.nrel.gov/solar/, and the system efficiency factor includes an additional 2% correction for sub-optimal tilt and orientation. Thus, each PV kW_p generates 3.75 kWh/day in Honolulu county vs. 4.34 kWh/day in sunnier Los Angeles county. The assumed state-level retail residential prices are average values for 2000 (EIA, 2001), because EIA (2003a) expects essentially stable residential retail rates through 2020.

[6] This methodology draws on the approach used by Marnay et al. (1997).

modules will be worth $\$2.5/W_p$ in new homes for counties with the best combination of high insolation and high electricity rates (in Hawaii) and $\$0.22/W_p$ in the lowest value areas (in Washington State).[7] Because PV modules currently cost $\sim\$4/W_p$, residential grid-tied PV is not yet cost-effective anywhere in the US. But the graph shows that by the time module prices have fallen to $\$1.50/W_p$, the annual US market for PV in new homes would be $0.5\,GW_p$/yr (125,000 homes)—a level comparable to the current *global* PV module sales for *all* applications (Johnson, 2002).

We use Fig. 1, which provides an estimate of the demand (willingness-to-pay) curve ($\$/W_p$ vs. GW_p/yr), to estimate prices endogenously and the return on investment for multiple $100\,MW_p$/yr scale PV factories. It is assumed that half of all new homes in every region (county) surveyed can be designed to accommodate $4\,kW_p$ systems[8] without prohibitive shading and orientation constraints. The potential PV module sales level (in GW_p/yr) at a given wholesale module price ($\$/W_p$) depends on the cost of financing, installing, and maintaining PV systems incorporated into new homes, as assessed in the previous supply analysis (see Box 1). Including the cost of a PV system in a home mortgage provides automatic low-cost financing, and, as noted earlier, homebuilders who routinely offer PV as an option for new homes can exploit cost-saving opportunities in PV equipment purchase, system design, and installation. The calculations in this section assume that these advantages apply.

3. Geographic concentration of residential PV markets

Fig. 1 indicates up to about $0.30\,GW_p$/yr of potential demand at module prices exceeding $\$1.75/W_p$. This initial market for residential PV is highly concentrated geographically. California dominates this market with a 71% share based on high overall insolation levels and an average electricity price of \$0.11/kWh (Table 1). Despite modest insolation levels, New York also represents an important early market due to its large population and high average electricity price of \$0.14/kWh—but its annual rate of new home construction is projected to be only 1.5 per thousand residents vs. 3.9 in California. As module prices fall to $\$1.50/W_p$, additional markets totaling up to $0.24\,GW_p$/yr would open up, including counties in Arizona, Vermont, New Jersey, Connecticut, Massachusetts, Rhode Island, Texas, and Nevada. These markets are substantially larger than the existing ones for residential PV. For comparison, the International Energy Agency found that the domestic US market for grid-connected distributed PV, lumping together commercial and residential applications, grew from $\sim 1\,MW_p$/yr in 1993 to $12.5\,MW_p$ in 2001.[9]

This geographic market concentration can facilitate PV market development. It gives key states, such as California and New York, the opportunity to make significant contributions in helping establish a viable PV industry even without coordinated federal action, e.g., by enacting measures aimed at developing local markets for system design and installation services and maximizing consumer awareness of PV.

4. Implications for $100\,MW_P$/yr scale a-Si PV production

Table 2 summarizes performance and cost characteristics of early $100\,MW_p$/yr a-Si PV module factories as estimated in the earlier supply analysis (Payne et al., 2001).[10] That analysis assumed that potential equity investors in the first few $100\,MW_p$/yr scale PV plants would require a 20% return to compensate for the risks associated with these early plants. In the present analysis, the internal rate of return for these plant parameters is calculated as a function of the number of $100\,MW_p$/yr plants built, using the financial breakeven analysis and considering only the US new housing market (see Fig. 1). Fig. 2 shows that—assuming that the hurdle rate drops from 20%/yr to 15%/yr once the process of bringing new $100\,MW_p$/yr plants on line becomes routine—this market could support five $100\,MW_p$/yr plants with a total salable module production level of $475\,MW_p$/yr[11] at a module price of $\$1.50/W_p$ (see Fig. 1).

In practice PV is a global commodity, so a complete market analysis would have to consider supply and demand from other factories and markets. Nonetheless, Fig. 2 suggests that it would be possible to profitably serve a large new residential PV market segment in the

[7] The divergence between the value of PV in the best (Honolulu County in Hawaii) and worst (San Juan County in Washington) counties results from a factor of 1.4 insolation range compounded by a factor of 2.8 electricity price range.

[8] Assuming 10% efficient modules, a $4\,kW_p$ system requires $40\,m^2$ of correctly oriented and un-shaded roof. This is readily accommodated on typical new US homes, particularly if the architect has PV in mind for the design, but empirical data are needed to confirm the 50% assumption if the design does not take PV into account.

[9] Further statistics are available at the IEA-PVPS website, http://www.iea-pvps.org.

[10] In June of 2002, Uni-Solar opened a $30\,MW_p$ facility for producing multi-junction a-Si thin-film PV (http://www.uni-solar.com) with grid-connected residential and commercial buildings as a primary market. The cost of capital equipment for this $30\,MW_p$ facility is roughly the same (in $\$/MW_p$/yr terms) as the estimated capital costs for the $100\,MW_p$/yr facility considered in the supply analysis, suggesting that the price projections from the latter may be conservative—particularly since the company projects that moving to a $100\,MW_p$/yr facility will yield significant additional scale economies.

[11] For the supply analysis a manufacturing yield of 95% is assumed, with the remaining product discarded as off-spec.

Box 1
Assumptions relating to rooftop PV systems adopted from the supply analysis[a]

As in the earlier supply analysis (Payne et al., 2001), it is assumed that residential rooftop PV systems last 25 years and are financed as part of the original new home mortgage at a real interest rate of 5%.[b] Home mortgages are the least costly borrowing option because interest rates are low for this well-developed and collateralized credit market, and the federal tax code allows an income tax deduction for interest on home mortgages—a subsidy that reduces lifecycle system cost by 15–20%.

The analysis further assumes *net metering* laws are in place so that a homeowner can run the meter backward when system output exceeds the home's need. Thus, PV electricity is valued at retail electricity prices (see *Net metering to address energy pricing failures* below).

The analysis also incorporates expected reductions in balance-of-system costs. Inverter costs have fallen by an order of magnitude since the early 1990s (Kurokawa and Ikki, 2001) and are assumed to fall 50% further to ~\$0.30/W_{ac} as PV markets expand. Similarly, the present value of maintenance costs should fall to ~\$0.20/W_p as the mean time between inverter failures reaches 20 years (Maish et al., 1997).

Installation costs include a fixed component of ~\$600 (roughly half labor with the remainder split between shipping and parts) plus a 10% contractor markup on wholesale module prices.[c] Shipping and field-installation are expected to be half as costly for flexible thin-film modules[d] as for rigid glass modules.[e] These estimates assume installers use innovative techniques in a competitive environment.

Three items left out of the cost calculations are home insurance coverage for PV systems, property taxes, and interconnection costs. Insurance costs are likely to be modest and can be neglected.[f] Property taxes, which are biased against capital-intensive energy systems, could adversely affect the economics of residential PV systems;[g] however, 18 states already offer property tax exemptions for solar facilities, and it is assumed that other states eventually adopt this policy. Scale economies should also facilitate standard contracts with local utilities such that interconnection costs can be covered by the contractor's PV installation fee.

[a] In this paper, costs are in constant year-2000 dollars and interest rates exclude inflation.

[b] Real average rate for 30-year fixed rate mortgages during 1990–1999 (data from the Bureau of Labor Statistics and http://www.hsh.com). High-quality PV systems might last 30 years or longer; in any case, new homebuyers routinely use 30-year mortgages to finance appliances (e.g., furnaces) that might need to be replaced before the mortgage is paid off.

[c] This translates into total installation costs of \$1600 (\$0.40/W_p for a 4 kW_p system) for \$2.50/W_p modules and \$1200 for \$1.50/W_p modules. Note that reported installation costs have already fallen to \$0.40/W_p in the German residential PV market (Krampitz and Schmela, 2003). Since it sets module prices exogenously, the earlier supply analysis assumed a fixed module price of \$2.50/W_p, translating into a fixed installation cost of \$1600 for all 4 kW_p systems, regardless of module price.

[d] One PV manufacturer (Uni-Solar) has developed field-applied PV for metal roofs and may modify this system to make it possible to bond flexible modules to plywood or other low-cost roofing laminates (Heckeroth, 2000).

[e] Direct bonding of flexible modules causes efficiency losses from high operating temperatures (77% system efficiency compared to 81% for framed rigid modules installed with airspaces and operated at lower temperatures).

[f] For module prices ranging from \$1.50 to 2.50/W_p the estimated cost for a 4 kW_p system is \$8400–13,000 installed. For the large new homes most likely to have such systems, this is such a small fraction of total insured home value that it probably would not affect premiums. However, at typical homeowner insurance rates (0.1–0.3%/yr of replacement value) the initial cost would be only \$8–40/yr, and the PV system replacement value should decline over time. Although some utilities have tried to impose large liability insurance premiums on PV system owners, industry advocates have generally been successful in striking these down as unreasonable interconnection barriers.

[g] Annual property tax rates average ~2% of assessed value. Such a tax could raise the lifecycle cost of residential PV electricity by as much as one-third, though this figure would be mitigated to the extent that PV roofing displaces expensive conventional roofing (e.g., tiles or high-end shingles).

Table 1
PV market potential in high PV-value (⩾\$1.75/W_p) counties

	Housing starts[a]	MW_p/yr[b]	Share (%)
California	105,000	211	71
New York	19,200	38	13
New Mexico	7410	15	5
New Hampshire	5980	12	4
Maine	5240	10	4
Hawaii	4270	9	3
Total	147,100	295	100

[a] Based on average housing starts from 1999 to 2001 from Census data.

[b] Calculated by assuming that half of new homes can accommodate a 4 kW_p PV system.

US based on the construction of several 100 MW_p/yr scale thin-film PV manufacturing facilities.

While a full analysis lies beyond the scope of this article, there is similar or better residential market potential in other industrialized countries (Duke, 2002). In particular, German and Japanese residential electricity prices are, respectively, roughly 50% and 300% higher than in the US (IEA, 2001). These higher electricity prices more than compensate for lower insolation levels in those countries. Also, at present, extremely low long-term interest rates in Japan provide more favorable system financing than in the US, even without the advantage of mortgage interest deductibility. The present analysis also ignores the large potential for residential retrofits as well as distributed PV installations on commercial buildings.

5. Market failures and the need for corrective public policy

The preceding analysis suggests the potential for a substantial near-term market for PV roofing in new US homes served by large (100 MW_p/yr) a-Si PV module

Table 2
Cost/performance parameters for early 100 MW_p/yr a-Si PV module factories

Construction time before production	2 years	Ramp-up to full production	2 years
Years at full output	8	Yield at full output	95% (95 MW_p/yr)
Initial wholesale module price	\$2.24/W_p	Module price decline rate	5.5%/yr
Real debt interest rate	6.5%/yr	Debt share of investment	35%
Debt investment	\$86 million	Equity investment	\$161 million
Operating costs	\$79 million/yr	Sales revenue	\$136 million/yr
Salvage value at end of life	\$7.5 million	Depreciation method	Double-declining
Corporate tax rate	35%	Module efficiency	10%

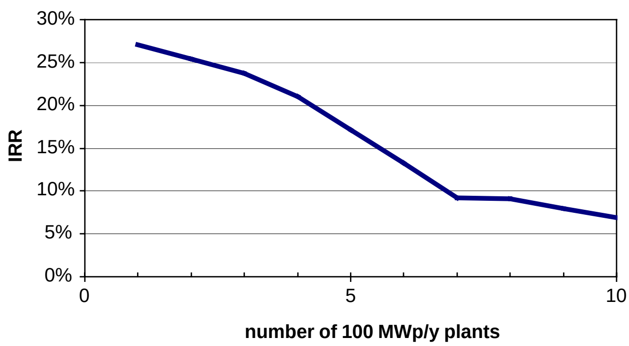

Fig. 2. IRR vs. number of large a-Si PV module factories serving US new home PV market. This figure shows the return on investment for 100 MW_p/yr thin-film PV factories as a function of the number of such plants dedicated to serving the market for PV in new US homes. These estimates are derived by combining the *supply analysis* of a-Si module factories presented in Table 2 with the demand (financial breakeven) analysis for PV in new homes shown in Fig. 1. The figure shows that the new US residential home market is sufficiently large to accommodate at least five such factories if the minimum acceptable rate of return is 15%/yr—at which cutoff the module price would be \$1.50/W_p (see Fig. 1). Note that the IRR does not change significantly from the 7th to the 8th plant because of the flattening of the demand curve around 700 MW_p/yr (see Fig. 1). The supply analysis summarized in Table 2 applies only to the first 100 MWp/yr factory, or possibly the first few. As the technology advances, production costs are likely to fall, making lower prices feasible. As module prices fall below ~\$1.50/W_p, markets for retrofitting existing homes and installing distributed PV on commercial buildings may become viable, ultimately opening up US markets large enough to sustain dozens of 100 MW_p/yr scale PV factories.

factories, without any government support other than the tax benefit implicit in home mortgage financing,[12] a property tax exemption for the incremental value of PV systems, and net metering. This theoretical potential is unlikely to be realized, however, without additional corrective governmental action to mitigate energy pricing distortions as well as demand- and supply-side market failures.

5.1. Pricing distortions

PV technology does not compete on a level playing field with conventional electric generating technologies. Distorted pricing affects supplier incentives to produce and deploy PV as well as consumer incentives to purchase PV systems. Pricing inefficiencies fall into two main groups: (i) failure to account for the environmental costs of conventional electricity and (ii) failure to account for the non-environmental benefits of PV electricity.

5.1.1. Failure to account for the environmental benefits of PV

PV's environmental characteristics provide much of the basis for public support for the technology. This technology enthusiasm and green consumerism put upward pressure on the demand curve for PV, but the impact is limited to small high-value markets, and Rader and Norgaard (1996) emphasize that *green pricing* electricity programs allow customers who opt for conventional electricity to *free ride* on the environmental improvements provided by those who pay extra for clean power. Similarly, Swezey and Bird (2001) report customer participation rates of less than 1% for most green pricing programs (under which utilities offer customers the option to pay a premium to support renewables). *Green marketing* programs (which give customers in competitive electricity markets the option to buy an environmental power blend) have had more success, but subsidies arranged as part of electric-sector restructuring have driven much of this green demand, and most customers have signed up for relatively cheap options that include little or no *new* renewables. Moreover, these programs favor relatively mature renewables over emerging technologies like PV that are most in need of market development support.[13]

The marginal support to PV technology offered by existing green pricing and marketing policies stands in sharp contrast to the substantial potential environmental

[12] The tax deduction for the interest cost component of home mortgages is an entrenched US subsidy. Including the cost of a rooftop PV system in home mortgage financing (and thereby qualifying the PV investment for the tax deduction) is no different from the standard practice of including the cost of major appliances in an initial mortgage.

[13] For example, Bird and Swezey (2001) report that wind accounts for 98% of the new renewables installed under green marketing programs thus far.

benefit offered by PV. Efforts to value the environmental damages from energy production and use have progressed significantly—e.g., the External Costs of Energy (ExternE) Project of the European Commission has supported for more than a decade research aimed at quantifying the economic value of environmental damages. Although there are considerable scientific uncertainties underlying such valuation analyses, state-of-the-art valuations make a compelling case for corrective policy actions, as discussed below.

5.1.2. Failure to account for non-environmental benefits of PV

In addition to its environmental advantages, PV technology offers important non-environmental benefits related to its attributes as a power source. In particular, distributed PV systems provide electricity where it is needed, PV electricity is coincident with electricity demand peaks in areas with substantial air-conditioning loads, and PV electricity is not subject to the considerable pricing uncertainty that characterizes natural gas-fired electricity.

The section below titled *net metering to address pricing failures* elucidates these issues, arguing that net metering can approximately correct for the failure of conventional electricity pricing to account for all of the environmental and non-environmental benefits of distributed PV. Beyond broad pricing considerations, there are also demand- and supply-side market failures that constrain PV sales. The next two sub-sections address each in turn.

5.2. Demand-side market failures

The financial breakeven schedule (Fig. 1) provides some indication of the actual demand curve for distributed residential PV, but the two concepts are not equivalent. The actual value of and demand for PV will be less than indicated because of real costs and risk-aversion factors not captured by the breakeven analysis and because of demand-side market failures that constrain willingness-to-pay below the socially optimal level.

PV roofing may have less aesthetic appeal than conventional roofing for some potential buyers, thus reducing their willingness-to-pay. Also, homebuyers may be reluctant to invest the effort necessary to become informed PV system owners and operators. In addition to these real costs, demand-side market failures may reduce the expressed willingness-to-pay for residential PV below the actual value to end-users. Even if systems are accurately rated and marketed,[14] their average output and longevity will vary—and this reduces the value of expected electricity bill savings for risk-averse homeowners. Markets for energy-efficient technologies illustrate some of the associated challenges. For example, Brown et al. (1998) cite multiple studies documenting the failure of individuals and firms to adopt cost-effective energy efficiency technologies. The underlying market failures may include bounded rationality and cognitive biases (Bazerman, 1994) that constrain the ability of individuals and firms to process available information about different energy alternatives.

5.3. Supply-side market failures

In principle, PV manufacturers and homebuilders should foresee the potential for residential PV and invest in the manufacturing and delivery mechanisms necessary to make it happen. There are, however, major supply-side market failures that constrain their efforts.

Bringing a 100 MW_p/yr thin-film PV facility on line involves far more than simply raising the necessary capital and mechanically realizing the potential scale economies. There are performance risks, and success depends on active investment in learning-by-doing. Efforts to scale up thin-film PV production have generally taken years longer than expected, and during these efforts "learning was literally all that was happening" according to the manager of the US thin-film PV program (Zweibel, 2002). Accordingly, Uni-Solar is moving from a 10 MW_p/yr facility to a 30 MW_p/yr facility even though the company feels that ultimately moving to 100 MW_p/yr would generate substantial further scale economies (see footnote 10).

Duke (2002) argues that much of the innovation resulting from learning-by-doing ultimately spills over among module manufacturers—thereby inhibiting the investments needed for such learning. The associated pathways include reverse engineering of competitors' products, poaching of employees, inter-firm communications (e.g., at conferences), shared benefits from learning-by-doing on the part of suppliers that serve multiple firms in the industry, and outright industrial espionage. Patents offer some protection, but outside of the pharmaceutical and, to a lesser extent chemical, industries most companies report that they are of limited use for protecting innovations (Mansfield et al., 1981; Mansfield, 1986; Levin et al., 1987; Cohen et al., 2000).

In a range of industries, technologies typically diffuse according to a logistic "s-shaped" curve, where Δt measures the time required to increase penetration levels from 10% to 90% of the long-term saturation level. A study of 265 technologies yielded an average Δt of 41

[14] Duke et al. (2002) illustrate serious problems with module overrating in the market for off-grid thin-film a-Si PV in Kenya, though the manufacturer with the most severely overrated modules has since gone out of business.

years,[15] but the average among energy technologies was 90–100 years (Grubler and Nakicenovic, 1991).[16] Thus, spillovers are likely to be particularly severe in the energy sector where technologies diffuse exceptionally slowly.

Like manufacturers, homebuilders face serious challenges in any effort to offer PV roofing as a mainstream option on new homes. They must develop effective marketing tools to convince homebuyers who may be skeptical of this novel technology with a long payback period; modify home designs to incorporate modules; find or train specialized roofers and electricians; and overcome regulatory red tape. For instance, early installers must educate the local grid operator as well as local zoning boards, but future installers will not incur this added expense. As with module manufacturing, these problems are expected to fade with experience, and the initial rate of learning may be steep.[17] However, the information generated via such learning-by-doing becomes readily available to all competitors: that is, homebuilders that invest in market conditioning suffer from *system spillovers* that are directly analogous to the *manufacturing spillovers* that threaten PV module manufacturers (Duke, 2002).

In sum, both module manufacturers and homebuilders face major near-term challenges if they attempt to scale up to serve this new potential market. In principle, they can overcome these challenges by forward pricing (selling at a short-term loss to gain market share and maximize long-term profit), but there is little incentive for individual firms to risk aggressive investments when manufacturing and system spillovers mean that most of the benefits will accrue to the industry as a whole rather than to pioneering PV investors.

Duke (2002) argues that the manufacturing and system spillovers described above represent positive externalities that justify public sector support for the technology commercialization process—optimally with support persisting until the ultimate floor price of the technology is reached. This situation is analogous to the private firm's tendency to under-invest in research and development (R&D) from the societal perspective, because spillovers among competitors make it difficult for any given firm to appropriate fully the benefits of such investments—and this is the positive externality that is used to justify public-sector support for R&D. Duke (2002) further argues that the highest priority for such commercialization subsidies should be for environmentally attractive energy technologies such as PV to the extent that the environmental costs of energy technologies displaced by PV are not fully internalized.

6. Policy options for transforming PV markets

The constraints described in the preceding section indicate that strong government support will be required to realize the full market potential for residential rooftop PV. The policy options to achieve PV market transformation fall into two broad categories: *market tuning* to address energy pricing distortions and demand-side market failures and *buydown subsidies* to address supply-side market failures, as delineated below.

6.1. Market tuning

Market tuning efforts further subdivide into: (i) efforts to refine price signals to better account for environmental externalities and other factors that market prices for electricity typically fail to capture and (ii) programs to mitigate the demand-side market failures described above. The next section argues that net metering legislation for PV (and possibly other distributed electricity technologies like fuel cells) is a reasonable surrogate for more direct measures that would ideally be enacted to address energy pricing failures.

6.1.1. Net metering to address energy pricing failures

Economists have long argued that energy prices should fully reflect both the direct and environmental costs of providing energy services. However, implementing efficient energy prices is a tedious process because of uncertainties relating to quantification of these externalities and the political battles that must be fought to implement any new pricing policies (which inevitably create new groups of winning and losing stakeholders). Net metering provides an elegant strategy for radically improving the efficiency of pricing incentives with respect to distributed PV electricity pending more precise social-cost pricing that may emerge over a period of decades.

In the US, as of early 2004, 38 states and the District of Columbia had enacted net metering legislation that allows PV system owners (and in most cases producers

[15] The mean Δt for a different set of 117 cases, all of which were constructed at the International Institute for Applied Systems Analysis (IIASA), is higher (58 years), but both distributions have long tails such that the majority of technologies show diffusion times between 15 and 30 years. Note also "the lists do not include only technological process, and product innovations, but also some social diffusion processes, such as the spread of literacy."

[16] On a broader scale, Nakicenovic (1996) shows that global carbon intensity (average carbon emissions per unit of energy consumed) has been declining at an average rate of 0.3%/yr since 1860, but estimates that it will take $\sim$300 years for this process to proceed from the 10% threshold to 90% decarbonization. The far faster rate of decarbonization attributable to France's nuclear program (2.2%/yr during the 70s and 80s) shows that policy decisions can dramatically accelerate this process.

[17] Consider that during 1993–2001, costs for components of residential PV systems in Japan fell by a factor of two for modules, a factor of five for installation, and a factor of eight for balance-of-system costs (Duke, 2002).

of clean distributed energy from other small-scale technologies like residential-scale fuel cells or wind) to run their meters backward when system output exceeds their electricity consumption rate.[18]

For typical US insolation (1800 kWh/m^2 yr) and a 77% system efficiency, the 4 kW$_p$ system considered above for residential rooftop applications produces 5500 kWh/yr[19]—about half the average annual electricity consumption rate for US households. Net metering is nonetheless an important catalyst for nurturing residential PV markets because, during periods of peak sunlight, a 4 kW$_p$ system will often produce more electricity than the household is consuming. Without net metering, PV system owners would be paid, at best, the wholesale rate[20] (typically about one-third of the retail residential rate) for electricity exported to the grid.

Net metering is generally regarded as a temporary subsidy for helping launch PV in the market. If the policy is not sustained for a period of decades, however, the adverse impact on PV market development could be significant—as has been the case when other important renewable energy promotional policies have been reversed.[21] PV sales volumes (in MW$_p$/yr) would drop both because homeowners would tend to install much smaller systems (less than $\sim$1 kW$_p$) that would rarely produce more than instantaneous household demand and because unit costs ($/kW$_p$) would increase to reflect the modest fixed costs associated with each system (e.g., the labor cost for installing the inverter).

However, as indicated above, a powerful case can be made that net metering policies should be both more widely adopted and kept in place until efficient energy pricing policies are implemented. Precise calculations are impossible, in part because the true value of PV electricity varies dramatically with local conditions, but distributed PV clearly offers public benefits by mitigating externality costs and supplying public goods including: (i) deferral of investments in new central-station peak generating capacity, (ii) reduced exposure to the risks associated with uncertain future prices for electricity derived from natural gas, (iii) greenhouse-gas (GHG) and air-quality benefits from avoidance of air emissions associated with displaced fossil fuel power generation, (iv) reductions in transmission and distribution (T&D) resistive power losses, (v) reduced reserve margin requirements for assuring the reliability of the electric generating system, (vi) reliability benefits associated with reductions in loss of electricity service associated with T&D outages, and (vii) avoidance or deferral of T&D investments that would otherwise be needed because of growing loads.

Table 3 presents estimates of the value of residential PV electricity for southern California and northern Illinois, including the first four of these benefits and assuming that the dispatch order reflects full social costs. California and Illinois were selected because these sites probably represent the polar extremes for prospective residential PV markets. PV added to the electric grid will displace the most costly alternative power sources on the electricity supply system. Outside of peak demand periods this will tend to be the fossil fuel with the highest short-run marginal cost per kWh. For California, the fuel displaced would be at existing relatively inefficient natural gas electricity generation facilities (accounting for 95% of fossil fuel power generation in 1999) for which the fuel price is high but the environmental damage cost is relatively low. For Illinois, it is assumed that the fuel displaced would be coal (accounting for 92% of fossil fuel power generation in 1999) used in steam-electric power plants (for which the fuel price is low but the environmental damage cost is high).[22] Because of the strong correlation between peak PV output and air-conditioning loads on the electric power system, PV also obviates the need to build new central-station peaking power plants. For both California and Illinois it is assumed that such plants are natural gas-fired gas turbines. The assumed fuel prices for this analysis are levelized prices for the period 2006–2025 based on projections by the Energy Information Administration.

The next four immediate sub-sections describe the benefits offered by PV that are explicitly evaluated in Table 3.

New peak fossil fuel generating capacity avoided. Even though PV is an intermittent power source it has substantial generating capacity value because, to the extent that air-conditioning shapes this demand, the peak output of PV systems is well correlated with peak demand for electric power. The correlation is not perfect (e.g., cloud cover might simultaneously reduce output from all PV systems in a given region); however, the worst air-conditioning days are rarely heavily overcast, and Herig (2000) notes that insolation levels ranged

[18] Updated data on net metering legislation are available at http://www.dsireusa.org.

[19] For a PV system, the installed capacity C_{pv} (in kW$_p$)$= \eta_{mod} \cdot A_{pv} \cdot \mathrm{SPD}_{peak}$, and the annual PV output O_{pv} (in kWh/yr) $= \eta_{sys} \cdot \eta_{mod} \cdot A_{pv} \cdot \mathrm{INS}$, where η_{mod} is the module efficiency, η_{sys} the system efficiency, INS the insolation (kWh/yr/m^2), SPD$_{peak}$ the peak solar power density at Earth's surface = 1 kW/m^2, and A_{pv} the area of the PV array. Thus, the annual output per unit of installed capacity is O_{pv}/C_{pv} (in kWh/kW$_p$) $= \eta_{sys} \cdot \mathrm{INS}$.

[20] Under US law, the utility is required to pay the homeowner only the avoided cost of the electricity, which in practice means the wholesale rate.

[21] For example, in the US the on-again, off-again status of the renewable energy production tax credit has had a disruptive impact on the embryonic wind energy industry.

[22] If there were no social dispatching policy (which is likely) and if new power plants built in Illinois were efficient combined-cycle natural gas electricity capacity (which is much less likely), PV would instead displace this new capacity because of its high fuel costs relative to existing dirty coal-fired capacity.

Table 3
PV electricity value in southern California and northern Illinois

	Southern California	Northern Illinois
Insolation ($kWh/m^2/yr$)	2044	1607
Electric energy generated annually by PV unit ($kWh/yr/kW_p$)[a]	1566	1231
NG peaking electric energy displaced ($kWh/yr/kW_p$)	200	200
Steam-electric energy displaced ($kWh/yr/kW_p$)	1366	1031
Fuel for steam-electric energy displaced	Natural gas	Coal
Levelized natural gas price for electric generators, 2006–2025 ($/GJ)[b]	5.04	4.31
Levelized coal price for electric generators, 2006–2025 ($/GJ)[b]	—	1.17
Value at PV site of natural gas *peak power* generation avoided—i.e., not consumed[c] (¢/kWh)		
Capital cost avoided[d]	12.26	12.26
Fixed O&M cost avoided[d]	1.99	1.99
Variable O&M cost avoided	0.01	0.01
Fuel cost avoided	5.89	5.04
Natural gas price risk premium[e]	0.72	0.72
GHG emissions avoided[f] (at $100/t C)	1.93	1.93
NO_x emissions avoided[f,g]	1.37	1.37
Resistive power losses avoided[h]	4.27	4.12
Total value of peak power avoided	28.44	27.44
Value at PV site of *off-peak power* generation avoided—i.e., not consumed[i] (¢/kWh)		
Fuel cost avoided[j]	5.38	1.37
Natural gas price risk premium[e]	0.66	—
GHG emissions avoided (at $100/t C)[f,k]	1.76	2.91
NO_x emissions avoided[g,l]	1.88	7.88
SO_2 emissions avoided[g,l]	—	8.24
PM_{10} emissions avoided[g,m]	—	0.28
Resistive power losses avoided[h]	0.73	1.56
Total value of off-peak power avoided	10.41	22.24
Total value of PV (¢/kWh of PV power produced)[n]	12.7	23.1
State-wide average residential electricity price, 2000 (¢/kWh)[o]	10.6	8.8

[a] For a-Si modules mounted on flexible stainless-steel substrates, the system efficiency [100 · (ac power output/dc power output)] is 76.6%, so that the annual output (in $kWh/yr/W_p$) is 0.766 · [insolation (in $kWh/m^2/yr$)].

[b] Fuel prices are levelized prices for 2006–2025, assuming a 5% discount rate, based on Energy Information Administration projections for power generators (EIA, 2003a): California prices are those projected for the Pacific Census Division (California, Oregon, Washington, Alaska, and Hawaii); Illinois prices are those projected for the East North Central Census Division (Illinois, Indiana, Michigan, Ohio, and Wisconsin).

[c] Assuming that natural gas-fired peaking turbines are used to meet peak power demands and operate at full capacity 200 h/yr (2.28% annual average capacity factor). Peaking turbine performance and cost are from EPRI (1993). The equipment cost for a 150 MW_e, 30.8%-efficient turbine and auxiliaries is $270/$kW_e$ but the total plant investment (including contingencies, general facilities, engineering fee, and allowance for funds used during construction) is $419/$kW_e$. The fixed O&M cost is $10.2/$kW_e$ yr, and the variable O&M cost is $0.0001/kWh.

[d] Assuming a 15%/yr annual capital charge rate and that 39% of the capital and fixed O&M costs are avoided by residential PV investments (Herig, 2000).

[e] Following Bolinger et al. (2002) and the discussion in the main text it is assumed that the value of a hedge against uncertain natural gas prices is $0.62/GJ, the average of the natural gas price risk premium estimated by these authors for 10-year natural gas contracts that would be struck in 2000 ($0.72/GJ) and 2001 ($0.52/GJ), respectively.

[f] Using Argonne National Laboratory's Transportation Fuel Cycle Model (GREET) (Wang, 1999, Wang and Huang, 1999)], the following emission rates were estimated: (i) CO_2 emissions from natural gas combustion = 13.950 kg C/GJ; (ii) GHG emissions upstream of natural gas power plants = 2.56 kg C of CO_2 equivalent/GJ natural gas; (iii) GHG emissions upstream of coal power plants = 0.96 kg C of CO_2 equivalent/GJ of coal; (iv) NO_x emissions from *new* natural gas-fired peaking turbines = 66.7 g of NO_2-equivalent/GJ of natural gas.

[g] For typical power plant sitings in Europe, Rabl and Spadaro (2000) estimate that environmental damage costs associated with SO_2, NO_x, and PM_{10} emissions from power plants are (in $/kg): $11.2 for SO_2, $17.6 for NO_x, and $16.9 for PM_{10} particles—values adopted for the present US analysis.

[h] The transmission and distribution efficiency for residential customers is estimated to be 93% during off-peak periods and 85% during peaking periods (private communication from David Moskovitz, March 2003).

[i] Zero capacity credit is assumed for PV produced outside the 200 h/yr peak demand period.

[j] In 2000, the average efficiencies of natural gas power generation in California and coal power generation in Illinois were 33.7% and 30.8%, respectively (EIA, 2001).

[k] The average CO_2 emission rate for the combustion of Illinois bituminous coal is 23.9 kg C/GJ (EIA, 2001)—the value assumed for all coal power plants in Illinois.

[l] In 1999, average emission rates (in g/kWh) were 1.07 and 4.48 for NO_x from natural gas in California and coal in Illinois, respectively, 7.36 for SO_2 from coal in Illinois (EIA, 2003b).

[m] The emission rate of PM_{10} particles is assumed to be 14.3 g/GJ the average for all coal steam-electric plants in the United States in 1990 (Williams, 2000).

[n] PV value = [(onpeak generation · value onpeak) + (off-peak generation · value off-peak)]/(total generation).

[o] *Source*: EIA (2001).

from 82% to 99% of peak potential insolation during seven recent power outages located in diverse regions of the US. Moreover, thermal generating reliability is reduced on peak air-conditioning days, due in part to the reduced output of thermal generating facilities at high ambient temperatures. Herig (2000) estimates an "effective PV load carrying capability" of 66% for installations in commercial settings and 39% for residential installations, according to a nationwide analysis from 1986 to 1995. The tendency for average residential air-conditioning loads to peak later in the day than commercial air-conditioning loads accounts for the difference between the two figures. But when considering the impact of PV electricity on central-station generating capacity (as opposed to strain on the local distribution network), the 39% figure underestimates the true value of PV in displacing generating capacity. In fact, Perez et al. (2003) argue that its high effective load carrying capacity makes residential PV electricity worth \$0.166/kWh on Long Island (relative to \$0.15/kWh rates), even without considering environmental benefits.

Conservatively assuming a 39% credit for residential PV in displacing gas turbine peaking capacity gives rise to a fixed cost value for PV per total kWh of PV electricity generated of 1.8 ¢/kWh in California and 2.3 ¢/kWh in Illinois[23]—accounting for 14% and 10% of the full estimated avoided cost, respectively.

Reduced exposure to natural gas price volatility risk. Investments aimed at meeting a substantial fraction of one's total electricity needs with PV lead to reduced natural gas price risk. Natural gas price risk is a growing concern because (i) the natural gas combined cycle is the central-station power generating technology of choice wherever natural gas is available; (ii) the increasing natural gas price volatility (e.g., in California the price of natural gas to electric utilities in late 2000 was briefly nearly 10 times the average value for the late 1990s); and (iii) uncertainty about long-term trends for natural gas prices.

Market energy prices should reflect the reduced natural gas price risk associated with PV investments. A variety of financial instruments are available to provide a hedge against natural gas price uncertainty. For example, natural gas swaps enable two parties to exchange floating spot market gas prices for fixed gas prices over a predefined period. Bolinger et al. (2002) present an analysis estimating the market value to electric generators of a fixed natural gas price over the spot market price for periods up to 10 years based on real market data for swaps made in November 2000 and November 2001 (and assuming that the natural gas price forecast made at those times in the *Annual Energy Outlook* forecast of the Energy Information Administration provides a reasonable estimate of prospective spot market prices for gas). The fixed-price premium for 10-year price swaps estimated from these data is \$0.72/GJ for November 2000 and \$0.52/GJ for November 2001. For the calculations presented in Table 3, the average of these natural gas price risk premiums (\$0.62/GJ) is assumed. This amounts to \$0.007/kWh in California (5.3% of the full avoided cost) and \$0.001/kWh in Illinois (0.5% of the full avoided cost). The value is much less in Illinois because it is assumed that natural gas consumption is avoided there only when PV displaces power generated during the annual peaking period for the electric system.

Environmental benefits. The quantified environmental values for PV considered here are for GHG and air pollutant emissions avoided.

The appropriate value to assign to GHG emissions is highly uncertain. The ExternE studies of the European Commission suggest that, at the 95% confidence level, the value of GHG emissions (\$/t C as CO_2 equivalent) is in the range \$14–510/t C and in an "illustrative restricted range" of \$66–170/t C if only discount rates in the range of 1–3% are considered (EC, 1997). Here it is assumed that GHG emissions are valued at \$100/t C, near the middle of the latter range.[24] Fuel cycle GHG emissions for PV are negligible,[25] so that the value of

[23] Table 3 indicates instead that fixed costs (capital plus fixed O&M) for peaking capacity amount to 14.25 ¢/kWh in either California or Illinois—but those valuations assign the credit only to the 200 kWh/yr of PV electricity generated during annual peak demand periods, which account for only 12.8% of total PV generation in California and 16.2% of total PV generation in Illinois. Allocating the costs instead to all PV generation yields the values indicated in the text—e.g., $0.128 \times 14.25 = 1.8$ ¢/kWh in California.

[24] This level of carbon valuation applied to the fuel cycle GHG emissions for coal delivered to Illinois power plants (24.9 kg C/GJ of CO_2 equivalent—see Table 3) is equivalent to a tax on coal that would increase its price to \$3.6/GJ, up from an average price of \$1.1/GJ for electric generators in 2000. For natural gas, the corresponding fuel cycle GHG emission rate in the US is about 16.5 kg C/GJ—see Table 3, so that the same carbon valuation is equivalent to a tax that would raise the natural gas price to \$5.7/GJ, up from a \$4.1/GJ US average in 2000 for electricity generators.

The \$100/t C valuation is consistent with the estimated cost of achieving deep reductions in GHG emissions via the least costly option for de-carbonizing new fossil fuel power plants: pre-combustion CO_2 capture from a coal gasifier combined-cycle power plant with underground storage of the separated CO_2. The carbon tax needed to induce CO_2 capture and storage has been estimated to be \$90–100/tC when the separated CO_2 is transported 100 km and stored in an aquifer 2 km underground (Williams, 2003).

[25] The lifecycle environmental externalities for PV electricity (mostly related to GHG emissions) have been valued at ~\$0.001/kWh in a study supported under the ExternE Project (Rabl and Spadaro, 1999). This finding is consistent with a detailed lifecycle analysis of PV technologies for residential rooftop applications, focusing on embedded energy requirements and associated CO_2 emissions (Alsema, 2000). For a-Si modules manufactured in 1999 and installed in rooftop grid-connected applications with moderate-to-low insolation (1700 kWh/m^2 yr) lifecycle energy content is paid back in 2–3 years, including the energy embodied in framing and balance-of-system equipment—a finding that translates into markedly lower lifecycle CO_2 emissions relative to fossil electric generation alternatives.

shifting to PV is approximately the cost of the GHG emission damages for the fossil fuels displaced: \$0.018/kWh for California (14% of the full avoided cost) and \$0.027/kWh for Illinois (12% of the full avoided cost).

Health impacts (mostly associated with small particle air pollution, including small sulfate and nitrate particles formed in the atmosphere from gaseous precursor emissions of SO_2 and NO_x) dominate environmental damage costs from air pollution.[26] Valuations of SO_2, NO_x, and PM_{10} emissions by Rabl and Spadaro (2000) are assumed,[27] and the impacts of other emissions are neglected. The air pollution benefit is \$0.018/kWh for California (14% of the full avoided cost) and \$0.140/kWh for Illinois (60% of the full avoided cost). Thus, in California the air pollution mitigation value of PV in displacing fossil fuel power generation (mostly natural gas) is comparable to its value in reducing GHG emissions, whereas in the coal-intensive Illinois power sector, the air pollutant mitigation value of PV is five times its GHG emission mitigation value. Moreover, the air pollutant mitigation benefit of PV is about seven times the direct generation cost for coal electricity.[28]

Reduced resistive power losses. Deployment of residential rooftop PV systems leads to reduced resistive power losses because the electricity generated does not have to be transmitted long distances to users over power lines.[29] Average T&D losses for residential customers served by the electric grid are typically 7–8% during off-peak periods and can be twice that during peaking periods (private communication from David Moskowitz, March 2003)—values assumed for the calculations presented in Table 3. The reduced resistive loss benefit is \$0.012/kWh for California (9.3% of the full avoided cost) and \$0.020/kWh for Illinois (8.5% of the full avoided cost).

The next three immediate sub-sections consider other potential residential benefits that are not taken into account in Table 3.

Reduced electric system reserve margin requirements. PV deployment also makes it possible to reduce the reserve margins needed to ensure power system reliability. US utilities must generally maintain sufficient generating capacity in reserve to hold "the probability of disconnecting non-interruptible customers due to [generation] resource deficiencies" to less than 1 day in 10 years (NPCC, 1995)—corresponding to an average loss rate of 2.4 h/yr. Grids with large generation facilities require a higher reserve margin since an unanticipated loss of output from even a single generating facility could affect service continuity. In contrast, a power system with a large number of distributed PV systems alleviates reserve requirements because individual systems are far smaller than central-station plants, and the risk of unexpected technical failure is uncorrelated across different PV systems (Kelly and Weinberg, 1993). Electricity rates reflect the *average* cost of maintaining reserve margins, but regulators are working to find ways to appropriately price reliability benefits in the context of electricity restructuring (SEAB, 1998). So PV system owners might eventually receive direct compensation for providing these public benefits.

Improved T&D reliability. T&D system failures cause the vast majority of service interruptions, and overall power outages experienced by typical consumers are more frequent than the design rate of 2.4 h/yr for generating capacity (SEAB, 1998; Short, 2002). For example, the power outage rate at the Kerman substation of the Pacific Gas and Electric (PG&E) Company in California's San Joachin Valley is in excess of 20 h/yr. Locating PV systems near consumers can alleviate strain on the electricity distribution system, thereby reducing the probability of a power failure in the area where the system is located and enhancing reliability of electric service. PG&E researchers carried out surveys to estimate their customer's willingness-to-pay to avoid loss of service and came up with values ranging from \$70/kWh for commercial and industrial customers to \$5/kWh for residential customers. If the number and duration of outages for typical residential customers were the same as at Kerman, and if outage electricity were valued at \$5/kWh, the T&D reliability benefit would be \$0.008/kWh for California and \$0.01/kWh for Illinois.[30] Distributed generators should be rewarded for their capacity to reduce outages in the T&D system, but

[26] Appendix A discusses recent research on air pollution impacts and assessments of the underlying health damages, as well as findings of Rabl and Spadaro (2000) as applied to US fossil fuel power plants.

[27] The average population densities of California and Illinois are 84 and 86 persons/km^2, respectively—approximately the same as the 80 persons/km^2 value assumed in Rabl and Spadaro (2000) for their European impact analysis. The pollution from Illinois power plants is likely to affect a population over a much larger area than the State of Illinois; however, in light of the fact that the average population density for the entire region east of the Mississippi River is 76 people/km^2, it is reasonable to apply these European findings to the entire Eastern US.

[28] Electricity from typical coal steam-electric plants sells for about \$0.02/kWh. Capital costs are largely written off for the older coal plants that dominate coal-based power generation.

[29] There will also be modest offsetting losses associated with delivering any excess PV power to neighboring households, but most PV electricity will be used on-site.

[30] The value of this distributed PV benefit can be estimated based on an analysis carried out by PG&E researchers for a 500 kW_e PV array installed at the Kerman substation (Shugar et al., 1992). The distributed benefit of increased service reliability (\$/kW_e yr) is $DB_{isr} = OF \cdot ADO \cdot AV_{pv} \cdot LF \cdot VSNL$, where (i) OF = outage frequency (5.25/yr—assumed to be the same as at Kerman), (ii) ADO = average duration of an outage (4.29 h—assumed to be same as at Kerman), (iii) AV_{pv} = availability of the PV system = 0.33, (iv) LF = load factor (ratio of average to peak demand) of house (0.33 assumed); (v) VSNL = value of service not lost (\$5/kWh assumed—based on consumer surveys carried out by PG&E). Thus, DB_{irs} = \$12.26/kW yr so that the benefit per kWh of PV electricity provided = (\$12.26/kW yr)/(1566 kWh/kW/yr) = \$0.0078/kWh for California and (\$12.26/kW yr)/(1231 kWh/kW/yr) = \$0.0100/kWh for Illinois.

there is currently no mechanism in place to do this. The improved T&D reliability benefit was not taken into account in Table 3 because of the paucity of data in the public domain relating to the frequency and duration of outages for residential customers.

Avoidance or deferral of T&D system investments. Distributed PV systems can also provide local voltage support that reduces reactive power losses and avoids the need to install shunt capacitors on the T&D system. And because PV reduces strain on the T&D system by providing local power at the time of the system peak demand, PV investments can also lead to avoided or deferred investments in T&D capacity and substation transformers and to reduced servicing requirements for voltage regulators. Such benefits can be substantial in some instances; for a 500 kW_e PV array installed at the Kerman substation such benefits have been estimated to be worth \$80/kW yr (Shugar et al., 1992; Williams and Terzian, 1993)—which would amount to almost \$0.04/kWh for a residential PV system in California. Such benefits are not taken into account in Table 3 because the benefits are very site specific.

The PV benefits presented in Table 3 indicate total values of \$0.127/kWh for California and \$0.231/kWh for Illinois. The indicated values in both cases are higher than the average retail electricity rates for residential customers: \$0.106/kWh in California and \$0.088/kWh in Illinois, even though the explicitly estimated benefits do not include all benefits. For comparison, if conventional wholesale electricity pricing rules were to prevail, the price offered for PV electricity would be approximately the average avoided fuel cost: \$0.054/kWh in California and \$0.020/kWh in Illinois.

This analysis suggests that net metering might be considered a reasonable surrogate for assigning a true value to distributed PV electricity, and may underestimate the benefits offered by PV in some areas. Of course, the specifics will vary: (i) as a function of PV penetration levels on the electric grid, (ii) regionally, according to the utility load profile (peak coincidence) and the conventional generation displaced (avoided emissions benefits), and (iii) locally depending on distribution capacity constraints. Note that in the Pacific Northwest, where hydroelectricity dominates power generation, the environmental benefits of PV electricity would be far lower than in Illinois or California, but retail electricity rates there are also very low, so net metering would still be a reasonable policy; in any case, residential PV is unlikely to penetrate this market very quickly.

There are considerable uncertainties regarding these valuations—especially for the environmental benefits, as noted earlier. But even if, for example, damage values per kg of NO_x, SO_2, and PM_{10} were reduced to the levels estimated in Rabl and Spadaro (2000) at 1 geometric standard deviation below the mean (14% of the mean values for NO_x and 16% of the mean values for SO_2 and PM_{10}), the value of PV power for only those benefits explicitly calculated in Table 3 would be \$0.110/kWh in California and \$0.103/kWh in Illinois,[31] in both cases still higher than the retail electricity price.

Further research could clarify the extent to which net metering over- or under-compensates PV system owners under varying conditions. However, establishment of net metering as a reasonable surrogate for efficient energy pricing for valuing residential PV (i.e., not just using net metering as a temporary PV market-launch strategy) need not await the results of such research, because any subsidy that might arise from net metering would have a trivial impact on electric utility rates for decades to come. Consider, for example, an extreme scenario for California, in which all environmental externalities are assigned zero value, so that the residential PV value for the non-environmental items listed in Table 3 would be \$0.088/kWh, which is 17% below the retail rate. Further, suppose that, starting in 2010, PV modules from five 100 MW_p/yr facilities are installed in the California market. By 2020, the output from the total installed PV base in the state (5 GW_p) would be 2.2% of projected total electricity demand. Moreover, a substantial share (25–50% depending on system size and household load profiles) of PV electricity simply offsets current household demand, and this portion of PV output will clearly be valued at retail electricity rates (just as energy savings from buying efficient air conditioners would be). Thus, even if the true value of PV electricity were only \$0.088/kWh, electricity service providers forced to allow PV net metering would suffer revenue losses of about \$83 million/yr in 2020—only 0.25% of their projected revenues.

6.1.2. Non-pricing programs to improve the efficiency of PV markets

In addition to adopting pricing reforms, governments can address the demand-side market failures that constrain consumers from making cost-effective investments in technologies like energy efficiency and PV. In particular, the demand-side failures that inhibit homeowners from making cost-effective PV investments justify public support for programs to better inform potential system buyers—just as programs such as

[31] The environmental benefits of avoiding emissions from existing coal power plants might also be dramatically reduced if stringent air pollutant control regulations were imposed on these plants. Relative to the indicated emission rates for Illinois coal plants in Table 3, it is feasible, with current technology, to reduce SO_2 emissions by about 90% using flue gas desulfurization technology and NO_x emissions by about 80% using selective catalytic reduction technology. With such levels of controls in place the overall PV value in northern Illinois (*conservatively neglecting the costs of emissions reduction*) would be \$0.107/kWh, which is still higher than the retail rate.

energy efficiency labeling and consumer education are justified and have been widely enacted to overcome barriers to investments in cost-effective energy-efficient end-use technologies.

Governments can also play a useful role by providing specific assistance for companies that are helping to pioneer new PV markets. The classic example is installer training. Given sufficient economic incentive, private companies will train their own personnel, but companies risk losing their investment if their employees move to competing firms or start independent PV installation businesses.

Governments can also catalyze new PV markets by bringing together and educating the relevant stakeholders. For example, the New Jersey Board of Public Utilities launched a program (http://www.njcleanenergy.com) under which the state's utilities are working with homebuilders, major retailers and installers to transform the residential PV market. Such programs might be funded by "wires" charges that are commonly implemented as part of electricity sector restructuring in order to support public benefits activities in the emerging more competitive industry structure—so-called system benefits charges (SBCs). SBCs mandated by regulators on all electricity sales can protect individual utilities that might otherwise be reluctant to back such broad efforts for fear that the benefits would spill over to competing electricity providers.

6.2. *PV buydown support*

Government intervention beyond market tuning measures is needed to address structural supply-side market failures. Some form of direct support for PV manufacturers is called for in order to give them the confidence to invest in learning how to build large (e.g., $100\,MW_p$/yr) factories despite the risks that the associated manufacturing innovations will spill over to competitors. Similarly, subsidies are essential to ensure that homebuilders have adequate incentive to pioneer new markets for PV homes despite the associated *system spillovers*, as defined above. In addition to addressing these supply-side market failures, buydown subsidies provide a blunt but potentially effective tool for overcoming any residual market tuning inadequacies.

The two alternative buydown strategies are: (i) fix unit subsidies and let the induced quantities vary; and (ii) fix quantities and let the implicit subsidies vary. Fixed subsidy options include tax credits, rebates, and electricity feed-laws. These have the virtue of administrative simplicity and well-defined program costs, but with this approach governments have difficulty (i) setting initial subsidies high enough to provide sufficient *activation energy* to launch regional markets; (ii) ensuring that the subsidies adjust as needed to compensate for demand-side market failures, phase out smoothly as prices fall, and persist until the price floor is reached.

Some states have devised relatively sophisticated subsidy programs in which technologies compete against each other for funding, and subsidy levels decline as a function of installed capacity—but these programs still require ad hoc administrative intervention to ensure that targeted technologies are not over-funded and that promising technologies with longer lead times are not left behind.[32] Moreover, this approach usually focuses on launching markets rather than providing the sustained demand-pull support that is consistent with the optimal buydown trajectory envisioned in Duke (2002). Finally, under the unit subsidy approach, manufacturers and system integrators contemplating risky investments to scale up their operations have no assurances that expected markets will materialize.

Maximum incentives offered per Watt for fuel cells, PV, small wind, and sustainable biomass in New Jersey
(*by the New Jersey Board of Public Utilities*)

	Incentive block			
	1 (2.0 MW)	2 (5.5 MW)	3 (12.5 MW)	4 (30 MW)
Small systems (<10 kW)	\$5.00	\$5.00	\$4.00	\$3.00
Medium systems (>10–100 kW)	\$4.00	\$4.00	\$3.00	\$2.00
Larger systems (>100 kW)	\$3.00	\$3.00	\$2.00	\$1.50
Maximum incentive as percent of eligible system costs	60%	50%	40%	30%

Quantity-based mandates offer a promising alternative that could provide for predictable and efficient market development absent detailed information about current and future demand schedules. Under a renew-

[32] In New Jersey, fuel cells, PV, small wind, and sustainable biomass are equally eligible for direct financial incentives that decrease over time as a function of total installed megawatts for all the eligible technologies. If factors other than resource availability (e.g., insolation or wind levels) impede competition among technologies, or if one technology appears likely to capture an overwhelmingly disproportionate amount of the funding, the Board of Public Utilities can modify the percent or \$/W caps for a particular technology or sub-category of technologies. The program also includes a protective measure for small systems in that it is not possible for more than 50% of the incentives available in any block to be used for systems greater than 10 kW in size without Board approval. In each block, total incentive value is capped according to both the percent of total installed cost and on a \$/W basis (http://www.njcleanenergy.com) (see table above).

able portfolio standard (RPS), for example, electricity suppliers must provide qualifying renewable electricity for a fixed and rising share of their total supplies, buying tradable renewable energy credits from other generators as needed to make up any shortfall from supplies they generate themselves.[33]

At present, most policymakers think of the RPS as a mechanism for acquiring renewable electricity at the lowest current cost—and it functions admirably to this end—but it is also possible to use the RPS to support emerging renewable technologies. The simplest strategy would require obligated parties to use PV or other promising but immature renewables to meet some minimum share of their overall RPS obligations. Alternatively, to skirt concerns about government picking technological winners, policymakers could cap the total share from the largest contributor, possibly adding a second higher cap for the top two contributors, and so on (Payne et al., 2001).

Also, the RPS is usually considered as an instrument for central-station power rather than distributed options such as residential PV. RPS mechanisms would have to be modified to accommodate small residential PV systems without incurring high transaction costs—e.g., by developing mechanisms that help PV homebuilders aggregate and sell the associated stream of renewable energy credits in order to use the present value of this income stream to reduce up-front prices for PV systems.

7. Policy recommendations

The preceding analysis suggests a number of specific policy recommendations to enhance the likelihood that markets for PV roofing in new US homes will fulfill their potential to provide cost-effective distributed electricity.

7.1. Implement and sustain effective net metering nation wide

The trend toward increasingly sophisticated electricity pricing [e.g., location-specific real-time pricing and dual metering (charging separately for electrons sold and electrons purchased)] along with policies that internalize environmental externalities may gradually reveal the true value of distributed PV. But it is not necessary to delay the advancement of PV technology until that uncertain future time when such reforms will be in place. As shown, net metering provides a reasonable and easily implementable surrogate for correct electricity pricing that can help to advance PV technology in distributed markets. Thus, net metering policies for PV should be extended to all states and sustained until efficient electricity pricing policies are in place. Also, unreasonable constraints on net metering for PV in existing states should be eliminated.

Fourteen of the states that had net metering laws as of 2002 impose caps on the total level of net metering allowed in the state. These are not restrictive at present but would become so over the coming decades. Businesses contemplating investments to serve grid PV markets may hold back for fear that existing or potential net metering caps could limit the long-term payoffs from scaling up operations now. Furthermore, as noted above, net metering should be in place for decades, absent other mechanisms to price accurately the societal benefits PV will produce relative to other forms of electricity generation.

7.2. Implement effective PV buydowns

In addition to net metering as a market tuning measure, buydown subsidies are needed to compensate for supply-side market failures. Among the available policy instruments for providing sustained PV buydown support, quantity-based approaches have important advantages over unit subsidies, as a way to reduce information requirements on the part of program managers and facilitate optimal sustained buydowns.

Quantity mandates automatically vary unit subsidies as needed to induce the targeted level of sales growth despite market activation energy requirements and demand-side market failures. Moreover, the modeling results in Duke (2002) suggest that the optimal global buydown for PV modules may extend for decades—far longer than the time horizon for most existing buydown programs based on fixed-price subsidies. It may prove easier to sustain optimal long-term demand-pull support under such mechanisms since the subsidy does not require direct government expenditures. In fact, most existing state-level RPS laws already have at least a 10-year horizon, and a few extend through 2020. A successful long-term RPS will ultimately drive per-unit subsidy levels down to low levels, but may nonetheless continue to generate substantial sales growth even in the late market development period by ensuring that key players (e.g., homebuilders and commercial building managers) continue to focus attention on PV.

Early experience in New Jersey suggests that PV support (in this case unit subsidies, but the principle applies equally to quantity mandates) must specifically target residential PV market development. Otherwise businesses will tend to take advantage of high initial subsidies to develop large-scale projects on commercial buildings and avoid the short-term barriers that must be overcome to launch the residential PV market. The NJ unit subsidies partially address this concern by reserving

[33] RPS credits are often called tradable renewable energy certificates in the US. In Europe the credits are called green certificates and the instrument a Green Certificate Mechanism. Note that the obligated parties can also be electricity generators or consumers.

a share of the funds for small systems, but thus far the fixed unit subsidies have proven insufficient to activate a major residential PV market, and regulators are under pressure to reallocate subsidy funds to the commercial sector.

The RPS concept is still under development and has attracted criticism in some cases.[34] There is room for concern, for example, that awkward credit markets or the uncertain value of future credits will limit investment. Regarding the former, regional buydowns should encourage experimentation that helps to identify quantity mandate mechanisms that work well in practice. Regarding the latter, quantity mandates at least give manufacturers a sense of the minimum future market size—though even a fixed demand schedule does not tell them their future revenue stream since the market clearing price will depend on the total manufacturing capacity built by the industry (including their competitors). Manufacturers face similar risks in all competitive markets, however, so they are accustomed to assessing and managing this revenue uncertainty. Moreover, the embryonic Texas RPS provides a basis for optimism that a well-structured RPS can be an attractive option for promoting the commercialization of renewables in a competitive electric industry (Langniss and Wiser, 2003).

7.3. Develop regional PV market transformation strategies

Although a nationwide net metering policy is desirable, Duke (2002) argues that regional PV market transformation programs that include both buydown initiatives and non-pricing programs to improve the efficiency of PV markets will often be preferable to more centralized efforts—particularly since the best markets will be concentrated regionally. Program designers in key regions will typically be better positioned than program designers in central bureaucracies (who are responsible for all regions) to tailor subsidy terms to fit the maturity of the markets in their region—thereby reducing the risk that subsidy levels will be too high in some areas (e.g., causing wasteful subsidy expenditures on free riders in relatively mature markets) and too low elsewhere (e.g., failing to provide adequate activation energy to new markets).

Such regional programs offer additional benefits by: (i) allowing individual states or even localities to take leadership roles in commercializing PV (e.g., to satisfy green constituents); (ii) reducing the risk to manufacturers that overall sales levels will plummet if any single program is prematurely eliminated; and (iii) facilitating learning about alternative implementation strategies.

8. Conclusion

This article argues that rooftop systems for new US homes can emerge as a major new market for PV once module prices fall below $\sim\$2/W_p$. The companion *supply analysis* argues that module costs at such levels will be readily achievable in the near term if manufacturers scale up to $100\,MW_p$/yr thin-film module manufacturing facilities and homebuilders offering PV construct thousands of PV homes annually. The demand analysis presented here indicates that by the time module prices fall to $\$1.5/W_p$ the annual US new home market would be up to $0.5\,GW_p$/yr (125,000/yr of new homes), which is comparable to current total global PV sales for all applications, and that these markets will be characterized by strong regional concentrations.

Despite these large potential markets, inefficient energy pricing and demand-side market failures inhibit prospective PV consumers, while manufacturing and system spillovers make it difficult for manufacturers and homebuilders to appropriate the benefits of the investments needed to foster learning-by-doing.

It is recommended that governments support residential PV markets with two distinct mechanisms: (i) net metering more widely implemented and sustained indefinitely as a surrogate for the true social value of PV electricity; and (ii) buydown subsidies. The latter should ideally come implicitly in the form of quantity mandates, but explicit unit subsidies can also work. Net metering should be implemented at the broadest possible level (e.g., federal legislation), but it is preferable for individual states and localities to champion separate PV buydown programs (as well as associated non-pricing programs to improve the efficiency of PV markets). This ensures that each program is tailored to local conditions and guards against the risk of a substantial drop in overall PV module demand if any single program is phased out unexpectedly.

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[34] For example, the Danish Wind Industry Association has opposed the use of an RPS (green certificate mechanism) primarily due to doubts about the long-term credibility of the renewables mandate (http://www.windpower.dk/articles/busiview.htm). Also, Rader (2000) identifies major implementation flaws in the Connecticut and Massachusetts RPS programs while suggesting that programs in Nevada, New Jersey, and especially Wisconsin programs require reforms.

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Appendix A. Valuation of health damage costs from fossil fuel power plant air pollution

In recent years health damages, especially from chronic exposure to small particle air pollutants has been a major focus of concern about air pollution. Recent epidemiological research indicates major mortality impacts from long-term, low-level exposure to particulates (Pope et al., 1995)—both particles that are emitted directly in combustion and sulfate and nitrate particles formed in the atmosphere from gaseous precursor emissions of SO_2 and NO_x. Lippmann and Schlesinger (2000) survey the recent literature and conclude that the correlation of ambient particulate exposure levels commonly found in US cities with increased human mortality and morbidity remains robust to all attempts to identify possible confounding variables. The available literature generally suggests a linear dose–response function for any given type of particulate, but Dockery et al. (1993) indicate that particulates smaller than 10 μm (PM_{10}) are more damaging than larger particles, while particles smaller than 2.5 μm ($PM_{2.5}$) show the strongest correlation with mortality by far.

It is estimated that those who have died from exposure to $PM_{2.5}$ air pollution particles in the US had their lives shortened, on average, by 14 years from this exposure (EPA, 1997). About 75% of those who have died prematurely have been age 65 and older, but this age group accounts for only about half of the average (14 yr) life shortening, because the years of life lost (YOLL) for this age group is modest relative to that for deaths among younger age groups.[35] Reducing small particle air pollution can substantially reduce mortality. The US Environmental Protection Agency has estimated (EPA, 1997) that the Clean Air Act of 1970 reduced premature deaths in 1990 by 184,000—i.e., if the Clean Air Act had not been in place, total US deaths in that year would have been 8.5% higher in 1990. Similarly, the EPA projects that enactment of the Clean Air Act Amendments of 1990 will reduce the US death rate in 2010 by 23,000/yr (EPA, 1999). But even with these laws in place, the premature death rate associated with residual small particle air pollution is significant. For example, Abt (2002) projects 6000 premature deaths from emissions from 80 US coal-fired power plants in the year 2007 (even accounting for new control technologies mandated by that year).

These recent findings translate into much higher costs for air pollution damages than was the case for studies carried out just a decade ago, before chronic mortality impacts were taken into account. The ExternE Project of the European Commission has supported for more than a decade research aimed at quantifying environmental damage costs associated with energy production—focusing on health impacts but considering other impacts (including climate impacts) as well. The ExternE assessment of air pollution damage costs for fossil fuel power plants involves: (i) quantifying air pollutant emissions from specified power plants (g/kWh), (ii) calculating the resulting increased air pollutant concentrations in all affected regions, taking into account both dispersion of pollutants and atmospheric chemistry as appropriate, (iii) calculating impacts of increased air pollutant concentrations (e.g., using dose–response functions in estimating health impacts), and (iv) making economic valuations of these impacts.[36] In assessing Europe-wide impacts a key parameter of these studies is the value of the YOLL per death due to pollution exposure—which the ExternE studies estimate to be 83,000 € (91,000 USD) for chronic mortality and 155,000 € (170,000 USD) for acute mortality.[37] Rabl and Spadaro (2000) illustrate the ExternE methodology by calculating, for "average" European conditions (including a population density of 80 persons/km^2), air pollution damage costs for: (i) new base load coal steam-electric power plants equipped with electrostatic precipitators, flue gas desulfurization equipment, and low-NO_x burners, and (ii) new natural gas-fired combined-cycle power plants.

They estimate air pollution damage costs to be 0.045 € ($0.05)/kWh for coal plants[38] ($\sim$1.25 times the cost of electricity from a new coal steam-electric plant without internalization of the externalities) and 0.011 € ($0.012)/kWh for natural gas plants equipped with low-NO_x burners ($\sim\frac{1}{3}$ the cost of electricity from a new combined-cycle plant without externalities internalization). Most of the estimated environmental damage cost is associated with chronic mortality arising from small particle air pollution, and most of that arises from nitrate and sulfate particles generated in the atmosphere from

[35] About 10 YOLL, on average, for those 65 and older, who account for 75% of those who have died prematurely, compared to 48 YOLL for those age 30–34 who make up 2% of those who have died prematurely.

[36] The economic impacts are estimated on the basis of estimates of "the willingness-to-pay", the amount of money a person is willing to pay to eliminate or reduce the adverse impact.

[37] Calculated from an assumed value of a statistical life (VSL) of 3.1 million € (3.4 million USD).

[38] For comparison, a 1994 study carried out by the Oak Ridge National Laboratory and Resources for the Future (ORNL and RfF, 1994) carried out in collaboration with ExternE researchers in Europe but *which did not take into account chronic mortality impacts*, estimated that the health damage cost for a new coal plant sited in the Southeast US would be $0.0003/kWh.

gaseous precursor emissions of NO_x and SO_2. There are considerable uncertainties underlying these estimates. The mechanisms of action for health damages are not well understood, some of the issues involved are controversial, and uncertainties underlying these air pollution damage cost estimates are high.[39] For example, Rabl and Spadaro (2000) estimates mean values of damage costs from NO_x and SO_2 (mostly via nitrate and sulfate particle formation in the atmosphere) to be 16.0 and 10.2 €/kg, whereas the damage values at 1 geometric standard deviation are, on the low side, 2.2 and 1.6 €/kg, respectively, and, on the high side, 36 and 26 €/kg, respectively. Nevertheless, the ExternE analysis represents the state-of-the-art in estimating costs of externalities for energy production systems.

To get rough estimates of air pollution damage costs for the US, applying the ExternE findings for Europe to regions of the US with comparable population densities [for example, the US region East of the Mississippi (76 persons/km^2 in 2000) and California (84 persons/km^2 in 2000)] is not unreasonable, in light of the fact that the crucial dose–response function for chronic mortality (which dominates ExternE air pollution damage cost estimates) is based on studies in the US (Pope et al., 1995) and per capita income is similar in Europe and the US.[40]

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[39] Following current ExternE practice, the Rabl and Spadaro (2000) analysis assumes that SO_2 and NO_x emissions generate secondary aerosols that can be treated as $PM_{2.5}$ and PM_{10}, respectively, although there is much uncertainty about this assumption. The authors caution that, although there are studies that report correlations of mortality with sulfates, there are no concentration–response functions for nitrates, because in the past nitrates have not been monitored as a separate component of air pollution.

[40] A key economic parameter is the VSL, which may well be higher for the US than the $3.4 million value assumed for Europe in the ExternE studies, because US incomes are somewhat higher. The US Environmental Protection Agency reviewed 26 studies estimating the VSL for the US and concluded that the estimates are distributed via a Weibull distribution characterized by a median estimate of $4.8 million and a standard deviation of $3.24 million (EPA, 1997).

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