CLEAN ENERGY TECHNOLOGY BUYDOWNS:

ECONOMIC THEORY, ANALYTIC TOOLS, AND

THE PHOTOVOLTAICS CASE

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Abstract

The conventional responses to the market failures that constrain energy innovation include *market tuning* (*e.g.* pollution taxes) as well as *supply-push* (*i.e.* public support for research, development, and demonstration). There is no similar consensus favoring *demand-pull* programs, but this dissertation develops an economic rationale for subsidies to pull emerging clean energy technologies down their respective experience curves. Even with optimal pollution taxes in place, such *buydowns* can improve welfare—primarily by correcting for *learning-by-doing* spillover that discourages firms from *forward pricing* (*i.e.* pricing below the short-term profit maximizing level to reduce costs through production experience). Learning spillover also occurs in other sectors, but the case for clean energy buydowns is unique.

Governments wisely seek a broad supply-push portfolio, but only the most promising clean energy options merit demand-pull support because individual buydowns are costly and generate scant spin-offs absent successful commercialization of the targeted technology. Moreover, governments have more information about technologies at the deployment stage and failure to screen out poor prospects can yield entrenched corporate welfare programs (*e.g.* grain ethanol).

The buydown selection criteria proposed herein favor support for photovoltaics (PV), and the recommended implementation strategy optimizes this support. Conventional analyses assume markets fully materialize as soon as the technology reaches financial breakeven, suggesting buydowns should be implemented as quickly as possible. The *optimal path method* introduced in this dissertation more accurately

models demand and defines the welfare-maximizing subsidy/output schedule. An optimal PV buydown would triple current demand subsidies and sustain declining per-unit support for over four decades. Such a buydown (initially targeting residential markets in industrialized countries) need never raise electricity rates by more than 0.5 percent while delivering roughly $50 billion in long-term net benefits (relative to a no-subsidy scenario) and allowing PV to provide over 5 percent of industrialized country electricity by 2030 (*vs.* less than 1 percent without subsidies).

Finally, implementing buydowns at the regional level bypasses the international collective action problem and reduces the disruption from the failure of any single program. A decentralized approach also facilitates program innovation and reduces free rider subsidy costs—a crucial determinant of buydown economics.

Table of Contents

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List of Figures

List of Boxes

List of Tables

List of Acronyms

a-Si	amorphous-silicon photovoltaic modules
BCG	Boston Consulting Group
BE	break even price
BCR	benefit-cost ratio
CAES	compressed air energy storage
CCGT	combined-cycle gas turbine
CdTe	cadmium telluride
CIS	copper indium diselenide
EIA	Energy Information Agency
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ExternE	Externalities of Energy (A Research Project of the European Commission)
FHWA	U.S. Federal Highway Administration
GAO	U.S. General Accounting Office
GWp	peak gigwatts
IPCC	Intergovernmental Panel on Climate Change
kWp	peak kilowatts
kWh	kilowatt-hour
MEB	marginal excess burden
MTBE	methyl tertiary butyl ether
MWp	peak megawatts

NPV	net present value
NSS	no-subsidy scenario
O&M	operations and maintenance
OECD	Organization for Economic Cooperation and Development
OTA	U.S. Office of Technology assessment
PCAST	President's Council of Advisors on Science and Technology
PV	photovoltaic
PVMaT	Photovoltaic Manufacturing Technology program
PVUSA	Photovoltaics for Utility Scale Applications
RD^2	research, development and demonstration
RD^3	research, development, demonstration and deployment
REL	German Renewable Energy Law
RPS	Renewable Portfolio Standard
SHS	solar home system
TMC	true marginal cost
tWh	tera-watt hours
UNDP	United Nations Development Program
USDA	U.S. Department of Agriculture
WBG	World Bank Group
Wp	watts produced by a photovoltaic module at standard test conditions
x-Si	crystalline silicon photovoltaic modules

Chapter 1: Introduction

Motivation

Market economies have an impressive track record of generating growth by efficiently allocating resources and fostering innovation by rewarding risk taking (Rosenberg, 1994). The competitive forces that channel $600-900 billion per year into global capital investments in the energy sector (UNDP, 2000) have successfully contained long-term energy costs despite finite fossil fuel supplies.[1] The energy system has been made more economically efficient by fuel switching as well as technological innovation related to fossil fuel extraction, electricity generation, and end-use appliances. Markets, however, are only as efficient as their price signals, and fossil fuel prices do not accurately reflect the burden of pollution.[2] Partly as a result of this socially sub-optimal pricing, externalities from energy production and use cause more damage to the

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[1] U.S. energy expenditures as a share of GDP rose from 8 percent in 1970 to 14 percent in 1981, primarily due to an eight-fold increase in the real price of oil driven by OPEC (BP, 2002; EIA, 2001). By the year 2000, exploration and innovation had raised the ratio of oil reserves to production by nearly one-third on a global basis, helping to disrupt OPEC and cut the price of oil by nearly a factor of 2.6 (from $75 to $29/barrel for Brent crude in constant 2000$). Similarly, the real price of internationally traded coal fell by nearly a factor of two from 1987 through 2000. In conjunction with the macroeconomic shift toward the service sector, these trends have steadily pulled the energy share of domestic GDP back down, reaching 7 percent by 2001 (EIA, 2001).

[2] Industrialized countries, and to a lesser but growing extent some developing countries, have imposed regulations that require pollution control equipment (*e.g.* SO_2 scrubbers for coal-fired electricity plants and catalytic converters for automobiles) as well as energy taxes (*e.g.* high gasoline taxes in Europe). Both approaches reduce pollution but not generally to the socially optimal level (*i.e.* to the point where the marginal cost of further abatement equals the marginal social benefit). Pollution controls, for example, generally fail to cover all pollutants (*e.g.* small particulates or CO_2) while energy taxes often bear little relation to the externality cost of the associated emissions and therefore provide poor incentives for pollution mitigation. For example, Newbery (2001) argues that, considering environmental damages and road usage costs, European nations tax oil and (to a lesser extent) natural gas far too heavily relative to coal (which is untaxed except in Denmark and Finland and was heavily subsidized in many countries until recently).

environment and public health than any other sector of the global economy (UNDP, 2000).

Direct policy remedies for environmental externalities are well understood but difficult to implement due to political constraints, particularly for transboundary or global pollutants like CO_2. Moreover, even if energy prices fully accounted for pollution costs, other important market failures would still constrain alternative energy—notably innovation spillovers that limit the incentive to invent, develop, and commercialize new technologies.

There are four components to the innovation chain: research, development, demonstration, and deployment (RD^3). The once-dominant linear model gave basic research a privileged position as the prime mover of the entire process and argued for unfettered funding of "curiosity-driven" basic research (Bush, 1945). Subsequent analysis suggested that "use-inspired" basic research plays an important role (Stokes, 1997) and underscored the role of learning-by-doing during the development, demonstration, and deployment of new technologies (Arrow, 1962; von Hippel, 1988).[3] Accordingly, revised innovation models incorporate learning-by-doing feedback loops among these stages of the innovation process (Kline and Rosenberg, 1986).

These innovation theories broaden the scope for potential government intervention. On the *supply-push* side, the importance of use-inspired investigation suggests that practical objectives should guide a portion of public funding for basic research, while learning-by-doing bolsters arguments for supporting technologies during the development and demonstration stages of the innovation process. More radically, learning-by-doing implies that governments can encourage innovation during the deployment phase with *demand-pull* measures. This dissertation focuses in particular, on *buydowns*, defined as demand-pull subsidies intended to launch long-term commercial markets for immature technologies that cannot yet compete.

That such measures have the potential to encourage innovation begs the question of whether governments *should* intervene and, if so, how, and to what extent. The question is controversial for supply-push measures and often not even asked for demand-pull measures.

On the supply-push side, empirical work suggests that private spending on research, development, and demonstration (RD^2) falls short of the social optimum.[4] In addition to spillovers among competitors within an industry (*e.g.* reverse-engineering), inter-industry spillovers (*e.g.* firms using improved inputs from suppliers) play a major role. Based on a survey of six empirical studies, Jones and Williams (1998) concludes that accounting for inter-industry spillovers raises the average annualized social return to RD^2 from 27 percent to nearly 100 percent. Thus, innovation spillovers (exacerbated by risk-aversion) constrain private RD^2 investment (Nadiri, 1993), and both problems are most severe at the basic research stage when the potential payoff from commercialization is most remote. Finally, Margolis and Kammen (1999) identifies particularly acute RD^2 under-investment in the energy sector.

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[3] Similarly, empirical econometric research has confirmed Schmookler's hypothesis that demand-pull factors substantially drive innovation (Schmookler, 1966; Scherer, 1982; Brouwer and Kleinknecht, 1999).
[4] This dissertation uses RD^2 interchangeably with research and development (R&D) on the assumption that the "development" component of the latter may be construed to incorporate demonstration efforts. RD^3 encompasses all four innovation stages.

Estimating the relative costs and benefits of public RD^2 support remains the subject of active debate. To fund RD^2, whether directly through appropriations or indirectly through the tax code, governments must raise revenue elsewhere in the economy. As with any public expenditure, this involves welfare losses attributable to under-provision of the taxed goods and services.[5] More radically, some theoretical "R&D-based growth models suggest that R&D should be taxed…" in order to prevent over-investment caused when private agents invest in duplicative "business-stealing" R&D (Li, 2001). In contrast, the empirical literature consistently supports strong public investment in RD^2, as has recent work integrating empirical and theoretical methods.[6]

Academic debate aside, most governments have concluded that appropriability problems justify public RD^2 support. The mechanisms range from funding government laboratories to bolstering private research by means of investment tax credits and grants. Patents are widely used as a combined supply-push and demand-pull measure[7], but researchers continue to actively debate whether the costs of current patent laws exceed their benefits (Mazzoleni and Nelson, 1998; Jaffe, 2000).

Strong patent laws encourage innovation by increasing appropriability (dynamic efficiency) but they grant temporary exclusive legal rights that allows patent holders to

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[5] Taxation need not cause welfare losses to the extent that governments raise marginal revenue by taxing negative externalities like pollution, but most taxes affect goods like income and conventional products.

[6] Li (2001) shows that the argument for taxing RD^2 in one prominent case (Grossman and Helpman, 1991) is an artifact of two simplifying assumptions: 1) unit elasticity of substitution of goods in consumption; and 2) failure to account for "interactions between industrial and patent policies." Similarly, without making any "particular assumptions regarding market structure, the patent system or distortionary taxes," a recent analysis that links new growth theory models with the empirical research and development productivity literature concludes that overall RD^2 investment should be increased by a factor of two to four (Jones and Williams, 1998). Jones and Williams (2000) bolsters this result based on an empirically calibrated growth model that incorporates spillovers as well as the potential for wasteful duplication of effort.

[7] Supply-push measures primarily induce additional investment in RD^2 while demand-pull support principally encourages learning-by-doing. By this definition patents are a supply-push mechanism, but

raise prices above the competitive level (market power inefficiency) and encourage wasteful investments by competitors working to bypass patents (duplication inefficiency). Government can tune the scope and duration of patents (Scherer, 1972) or explore creative modifications,[8] but patents may be ineffective even for their primary purpose of promoting dynamic efficiency. Mansfield, Schwartz, and Wagner (1981) surveyed 48 innovations from the chemical, electronics, machinery and pharmaceutical industries and concluded that, pharmaceuticals aside, patent protection had little impact on over three-quarters of the innovations in their sample. Follow-up work with a broader sample yielded similar results.[9] Subsequent research confirms that non-pharmaceutical firms continue to consider patents to be among the least significant mechanisms for appropriating the benefits of their investments, especially for process innovations that are easier to keep secret than product innovations (Levin *et al.*, 1987; Cohen, Nelson, and Walsh, 2000).[10]

The limited value of patents for protecting intellectual property does not make them irrelevant. Even in industries for which surveyed firms considered patents

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they also promote learning-by-doing to the extent that they encourage firms to commercialize patented innovations.

[8] Various modified patent schemes have the theoretical potential to preserve dynamic efficiency while reducing market power and duplication inefficiencies. Kremer (1998) would give companies the option of auctioning their patents, with the government stepping in to buy the patent at roughly double the clearing price from the auction. The factor of two multiple is intended to approximate the full social value of the innovation including *consumer surplus* (the integral of demand minus price from zero to the quantity demanded). To encourage accurate price revelation, the winning private bidder would occasionally be allowed to buy the patent. Lichtman (1997) worries about the welfare losses from the taxes required to pay for such buyouts and argues for leaving patents in place, using end-user subsidies to ameliorate market power inefficiency. This dissertation makes a related argument for demand subsidies to the extent that appropriable learning-by-doing results in market power (Chapter 2).

[9] A survey of one hundred firms from twelve industries indicates that they considered patents instrumental to the development of fewer than 20 percent of their patented inventions on average, except in the pharmaceuticals, chemicals, and petroleum industries, where the corresponding figures were 60, 38, and 25 percent, respectively (Mansfield, 1986).

relatively insignificant, Mansfield (1986) reports that firms patented 66 percent of "patentable" innovations. Subsequent research suggests a 50 percent increase in the annual number of U.S. patents from 1985-1996, possibly driven by a 40 percent increase in real RD^2 investments (Jaffe, 2000). Cohen, Nelson, and Walsh (2000) presents evidence that firms most often patent for reasons that have little to do with profiting directly from the protected innovation, such as preventing competitors from patenting related innovations, improving their negotiating position, and fending off possible patent infringement lawsuits. Jaffe (2000) argues that such strategic patenting may be a "zero- or negative-sum game."

In sum, to encourage innovation governments routinely resort to patenting despite its demonstrable flaws. The imperative to induce private innovation investments has generally trumped concerns about market power and duplication inefficiency. There is a similarly compelling need for demand-pull measures to mitigate the market failures that constrain the deployment of certain technologies, but governments have pursued demand-pull remedies only sporadically and with little theoretical guidance from academia. This is striking since demand-pull subsidies have certain advantages relative to patenting. Most importantly, demand-pull subsidies do not generally exacerbate market power and duplication inefficiencies. Nor can they be bypassed and thereby rendered ineffective like some patents.[11]

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[10] Levin *et al.* (1987) reports that firms consider 1) lead-time, 2) moving quickly down the learning curve, and 3) sales or service efforts (for product innovations) to be the three most important mechanisms for appropriating the value of their innovations.

[11] Of course, demand-pull mechanisms suffer from some of their own concerns as discussed throughout this dissertation.

Under the rubric of *induced technical change* there is active research focused on testing the demand-pull hypothesis (*i.e.* that changes in demand are a principal determinant of innovation patterns) and exploring how relative factor endowments and prices impact innovation trajectories (Newell, Jaffe, and Stavins, 1999; Ruttan, 2001). In an essential contribution, Spence (1981) explores the welfare implications of market structure under learning-by-doing. His modeling demonstrates that output falls short of the social optimum under learning-by-doing but he largely ignores the possibility for corrective subsidies. Dasgupta and Stiglitz (1988) explores the implications of learning-by-doing for market structure in a game theoretic model. Among other conclusions, the authors argue that learning effects may justify "infant industry" protection under certain conditions, but they do not explore the possibility of buydown subsidies. In sum, despite these important lines of research, the economics profession has yet to fully grapple with the concept of technology buydowns.[12]

Similarly, energy modelers have made important advances incorporating learning effects into forecasting work but have yet to explore the implications for technology buydowns. Much of the recent modeling work has focused instead on defining the optimal carbon abatement path. In an influential analysis that incorporates learning-by-doing and uncertainty, Grubb (1997) favors market incentives (such as early carbon taxes) and government R&D to stimulate "the development and diffusion of lower carbon technologies, practices and infrastructures" but he concludes that governments should avoid "large-scale deployment of technologies that are immature and costly." Yet it is

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[12] A search in Econlit for "buydown" and "buy down" reveals no relevant hits while "induced innovation" produces 81 hits and "demand pull" yields 38, but none has any clear connection to buydown economics. For comparison "research and development" yields over 19,000 citations.

precisely the set of immature, and therefore costly, technologies from which the most promising buydown opportunities can be drawn.

In another representative example[13], Mattson and Wene (1997) use a dynamic nonlinear optimization model that projects costs through 2050 for different electricity technologies based on their respective experience curves. Computational limitations due to the non-convexities introduced by experience curves prevent the authors from identifying a global optimum, but they illustrate two different paths with nearly identical present value costs[14] despite radically divergent technology mixes and carbon emissions. In the low-carbon case, early investments in clean energy technologies (before they are cost-effective in mass markets) pull down costs and start the gradual diffusion process such that alternative energy builds a large market share by the end of the analysis. The authors cite these examples to highlight path dependencies (Arthur, 1994) in the energy economy. For the low-carbon scenario, the authors assume that high-value niche markets will provide the necessary demand-pull or else “large grid-connected electricity systems will bear the costs of introducing the emerging technologies.” This phrasing suggests the possibility of an implicit buydown in which *quantity mandates* (such as the Renewable Portfolio Standard discussed in Chapters 4 and 5) drive utilities to invest in clean technologies, but the authors do not elaborate.

Grubler, Nakicenovic, and Victor (1999) criticize conventional linear programming models for relying on arbitrary maximum sales growth rates without which

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[13] Grubler and Messner (1998) as well as Barreto (2001) also highlight the importance of early investments in emerging clean energy technologies based on bottom-up linear programming models of the energy sector that incorporate learning-by-doing.

[14] The analysis assumes a real discount rate of 5 percent and excludes carbon and other environmental externalities.

"the model would instantly switch from one technology to another as soon as the latter is less costly." In these models the optimal solution shows early investments in pre-competitive technologies merely as an artifact of the need for private industry to meet assumed rate constraints on sales growth for new technologies. To improve realism, the authors develop an optimization model capable of making forward-looking investments. Based on uncertain learning-by-doing,[15] the model endogenously generates early deployment that leads to long-term commercialization of radical new technologies that initially cost many times as much as the incumbent options. The authors therefore conclude that it is possible that the economy will achieve widespread diffusion of radical low-carbon technologies without carbon regulations or other technology policy support—but they underscore that pollution regulations are no less necessary and caution that "in market societies, decisions are principally made by market agents rather than social optimizers," alluding to market failures such as innovation spillover that may prevent private markets from achieving dynamic technological efficiency without government support.

These studies usefully highlight path dependencies and the importance of early action to begin the long-term shift to a less polluting energy system—but they have yet to crystallize the economic rationale for adding a demand-pull component to technology policy. Grubler, Nakicenovic, and Victor (1999) comes close, suggesting "more costly investments that carry inventions through development and early demonstration in commercial niche markets" in order to complement traditional public support for research

[15] Early in the article the authors highlight a version of the learning curve that makes marginal cost a function of cumulative expenditures on both RD^2 and production experience, but here they revert to a simple learning curve that makes marginal cost a function of cumulative production experience alone.

and increase the probability that the market will select low-carbon technologies. Similarly, Barreto (2001) acknowledges that early carbon taxes are a good idea but may not prove sufficient "to trigger the necessary early technological learning."[16]

Still, none of this literature directly examines the market failures (Chapter 2) that may prevent the private sector from commercializing technologies characterized by strong learning-by-doing. The literature also skirts the issue of "technology picking" even though some form of screening mechanism is necessary for any efforts to develop and demonstrate particular technologies—and absolutely essential for efficient allocation of scarce resources among potential *buydown* candidates (Chapter 3).

In addition to the dangers inherent in technology picking (Cohen and Noll, 1991), one explanation for this collective reticence may be that energy modelers focus on identifying long-term "global optima" considering all possible technologies. They therefore use stylized functions to represent generic technology categories, whereas technology selection requires in-depth assessment of particular technologies in specific markets.

Beyond the energy modeling literature, there are increasingly clear calls for adding an activist demand-pull component to technology policy. PCAST (1997) "recommends that the nation adopt a commercialization strategy in specific areas complementing its public investments in R&D." Loiter and Norberg-Bohm (1999) argues for demand-pull measures to avoid "wasting the expenditure of public resources on research programs" and Margolis (2002) similarly argues for demand-pull policies to complement and protect conventional supply-push investments. Finally, Wene (2000)

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[16] This is a particularly serious concern given that low-cost but finite solutions such as afforestation and

suggests that "an efficient policy package should support the creation or exploitation of niche markets" for low carbon technologies to fight lock-in to conventional fossil fuel technologies. These are useful steps, but even this broader literature has yet to provide a clear definition or economic rationale for buydowns, let alone an implementation roadmap.

Approach

This thesis builds on the relevant economics literature to provide a rationale for considering buydown support for any emerging technology characterized by strong learning-by-doing. Given analytic uncertainties and implementation risks, however, governments should probably restrict buydown efforts to the clean energy sector, which appears to be uniquely promising (Chapter 2).

The efforts of energy modelers to generate globally optimal technology trajectories usefully addresses broad questions (*e.g.* estimating overall carbon abatement costs as a function of abatement timing) but they have yet to focus on the potential to improve economic efficiency using buydowns that target specific technologies. Though comprehensive optimization remains far out of reach, this dissertation argues that it is possible to improve social welfare by supporting promising clean energy options on a case-by-case basis. Accordingly, it develops technology selection criteria and implementation guidelines for buydowns (chapter 3). The dissertation then illustrates these methodologies for the case of solar photovoltaics (PV) taking into account the details of the relevant market segments (chapter 4) and integrating top-down and bottom-up technology assessments (chapter 5). Finally, it closes with a summary of the principal

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landfill methane recovery may dominate early compliance efforts.

findings and an agenda for further research—including application of the methods developed in this dissertation to additional clean energy technologies beyond PV (Chapter 6).

Chapter 2: The rationale for clean energy buydowns

Governments routinely promote innovation through activist supply-push mechanisms like patents and public support for RD^2, but they generally leave commercialization to market forces. By analogy to the supply-push response to RD^2 spillover, this chapter suggests that technology buydowns can alleviate learning-related market failures by subsidizing the deployment of certain new technologies. The theoretical case for considering buydowns applies to any technology characterized by strong learning but given the buydown implementation challenges and risks described in Chapter 3, governments should focus demand-pull support on the clean energy technology sector, which appears to hold unique promise as explained later in this chapter.

In addition to market failures that arise in connection with learning-by-doing, new technologies may impose other costs and benefits that are not reflected in market prices. Clean energy, for example, provides *non-learning public benefits* (*i.e.* non-rival and non-excludable benefits other than the price reductions from public buydowns that compensate for insufficient private investment in learning-by-doing) by reducing the pollution, price risk, and security costs associated with displaced fossil fuels. Governments can complement buydown efforts by making markets as efficient as possible with measures such as 1) incorporating externalities into prices; 2) providing reliable product quality information to consumers (Duke, Jacobson, and Kammen, 2002); and 3) reducing bureaucratic obstacles facing early adopters. *Market tuning* of this sort should be a technology policy priority but, in addition to ameliorating learning-related inefficiencies, buydowns offer an alternative remedy when political or other constraints rule out comprehensive market tuning. Piecemeal efforts to buy down clean energy technologies, for example, have the potential to speed the global decarbonization trend even if efforts to achieve meaningful international carbon regulations continue to falter.

Market failures attributable to learning-by-doing

This section argues that market failures constrain the diffusion of any emerging technology characterized by strong learning effects. There are three cases depending on the extent to which each firm is able to appropriate the cost-reducing benefits of its own production experience:

1. imperfect spillover;
2. perfect appropriability (zero spillover); and,
3. perfect spillover.

Each of these cases is consistent with a different level of competition but, as shown below, output always trails below the social optimum because of some combination of market power or insufficient investment in cost-cutting production experience.

This suggests a possible role for buydowns regardless of the level of spillover, but the impact of demand-pull subsidies is different in each case. In particular, buydowns permanently solve spillover problems once they bring the targeted technology to its long-term price floor, while subsidies to correct for market power caused by learning effects (or inadequate market tuning) may have to continue indefinitely.

Imperfect spillover

Incumbent firms that can capture a substantial share of the learning-by-doing benefits from their production gain widening cost advantages over potential entrants (Spence, 1981). This gives the incumbents *market power*, *i.e.* the ability to increase profits by withholding output in order to drive prices above the competitive level. As with patents that may help companies recover the cost of RD[2], when individual firms are better able to appropriate the benefits of learning-by-doing dynamic efficiency improves but market power and duplication inefficiencies worsen (Chapter 1). In particular, firms that can appropriate learning benefits will invest more aggressively in cost-reducing production experience, but they will also use their cost advantage to set prices above the competitive level.

Under incomplete spillover, the first-mover in a new industry may emerge as a monopoly or multiple firms may enter and survive in an oligopolistic market structure (Smiley and Ravid, 1983; Ross, 1986; Dasgupta and Stiglitz, 1988). General predictions about the impact of learning-by-doing on market structure are impossible without arbitrary assumptions regarding strategic interaction, initial conditions, and key parameters, but factors that tend to increase industry concentration include: 1) a high discount rate such that potential entrants weigh early losses more heavily than long-term profits and, 2) strong and highly appropriable learning effects.

The profit function for an industry with multiple firms with identical and constant production costs can be written as:

where the i[th] firm's profit function and . Total revenue equals the i^{th} firm's output, , times industry price as determined by the inverse demand function, *P(Q)*. Total cost is simply times the firms' marginal cost.

When there are few enough firms such that individual output choices affect market prices, taking the partial derivative with respect to the i[th] firm's output yields marginal revenue (MR) minus marginal cost (MC). Setting this result equal to zero generates the familiar first-order condition[17] for profit maximization:

Thus, marginal revenue equals price plus a negative second term such that the profit-maximizing condition $MR = MC$ implies $P > MC$, rather than $P = MC$ as for competitive markets.

The factor in the second term is always negative because, holding all else constant, an increase in output by the i[th] firm will always decrease the price as defined by the demand schedule. The factor in the second term is known as the *conjectural variation*. In the non-collusive case, marginal revenue is relatively flat because other firms tend to cut production when any given firm increases its production,

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[17] In principle, it is also necessary to show that the second derivative is negative at this point to confirm that the first order condition has identified a profit maximum rather than a minimum.

and this partially counteracts the negative factor. Under collusion the marginal revenue schedule is particularly steep (resulting in a high markup of price above the competitive level) because firms react to rivals' production cuts by curtailing their own production. Finally, when each firm profit maximizes taking all others' output level as fixed.

There is no general rule about each firm's reaction to the others' production decisions and consequently, "…there is no generally accepted theory of the type of equilibrium that is likely to emerge…" under oligopoly (Nicholson, 1995). Thus, the number of firms and degree of competition could vary widely depending upon initial conditions and strategic interactions. In any case, incomplete learning spillover may give incumbent firms market power, implying either monopoly or oligopoly market structure.

For expositional clarity it is useful to explore the monopoly scenario without discounting (r = 0). Figure 1 illustrates the concept using a typical learning curve that shows rapid initial cost reductions as a function of cumulative production, tapering off to a cost floor as the product reaches maturity. *Unit cost* in period *t* equals where *x(t)* is the rate of output at time *t*,

and *z* is a unit cost floor estimated by bottom-up technology assessment based on irreducible materials and production costs in a fully *learned-out* industry.

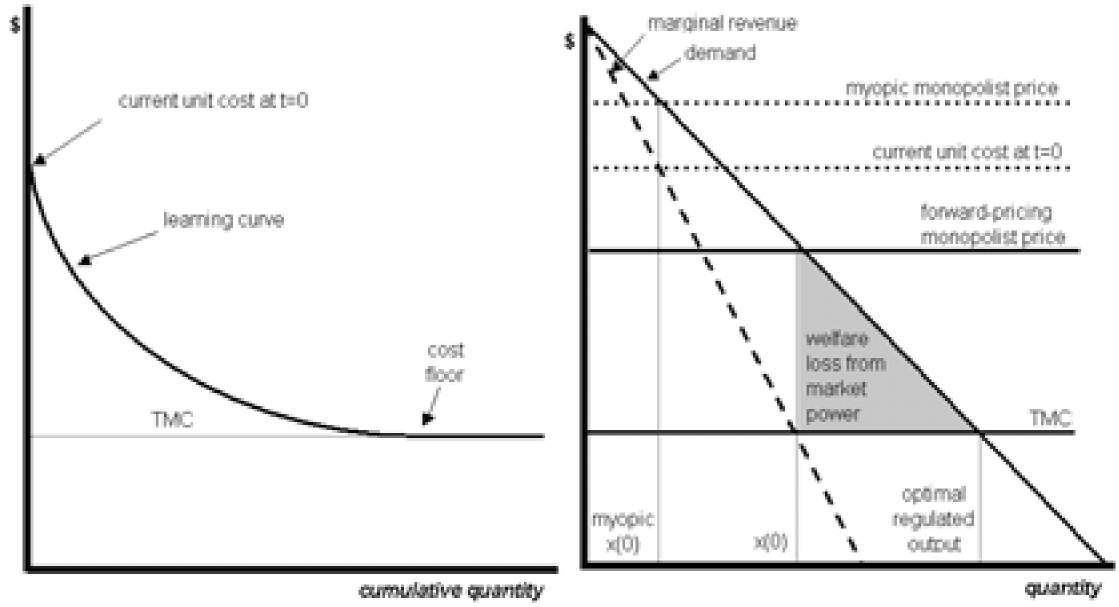

Figure 1. Optimal forward pricing and market power inefficiency under imperfect spillover

A myopic monopolist sets initial production at *myopic x(0)*, where marginal revenue equals current unit cost, *i.e.* long-run marginal cost including levelized capital costs. A forward-pricing monopolist that is indifferent about the timing of profits (r = 0) recognizes that, considering the entire production run, the true marginal cost (TMC) of producing an extra unit at time zero is its final "learned out" unit cost. Thus, the forward-pricing monopolist increases its output in each period to the level where *MR(t) = TMC, i.e. x(0),* thereby increasing market performance. Production nonetheless falls short of the social optimum (generating the welfare losses shown in the shaded triangle) because the monopolist does not set output such that price equals TMC. In this example the forward-pricing monopolist sets price below its current unit cost at $t = 0$ such that such that it incurs an initial loss in order to maximize its long-term profit. Note that the right side of the figure ignores intra-period learning effects for graphical clarity.

Conventional short-term marginal cost curves are upward-sloping because they assume fixed capital investment levels so the marginal cost of producing additional units increases as production scales up within any given period. In contrast, as defined in this dissertation, unit cost is a *long-term* marginal cost concept that incorporates "levelized" capital costs, *i.e.* firms anticipate output levels with reasonable accuracy and adjust their capital levels to minimize unit costs given the level of accumulated production knowledge in each period.[18]

To simplify presentation, the right side of Figure 1 further assumes that there is no intra-period learning and constant returns to scale such that the unit cost curve for any period is flat. The unit cost lines shift down along the learning curve as cumulative output increases. A myopic monopolist that ignores learning effects will set initial output in each period such that its marginal revenue equals its current unit cost for that period, . In contrast, a monopolist that is able to appropriate most or all of the benefits of learning-by-doing may *forward price*, defined as maximizing long-run profit by initially producing more than the short-run profit-maximizing quantity. Setting output in each period to maximize profit over the entire production cycle, the forward-pricing monopolist voluntarily accepts lower profits in early years in order to maximize long-term profitability. If the learning function has a long-term cost floor and r = 0, then equals which, in turn, equals the cost floor, *z*.

For r > 0, the monopolist will still forward price, but less aggressively. The Appendix derives the first order condition for monopoly profit maximization for continuous time and output. This yields:

(1)

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[18] Of course, unexpected shocks such as a sudden outward shift in the demand schedule would still increase short-run marginal cost within any given period even if there is a long-term trend towards lower unit costs as a result of learning-by-doing.

where , T = the final period in which the firm produces, and the instantaneous learning function is . By this first-order condition, in each period the firm must set output such that marginal revenue equals *current* true marginal cost (CTMC), defined as current unit cost plus a negative term equal to future cost savings (from the learning induced by current output) discounted back to the current time. Increasing r reduces the second term such that, in the limit as , CTMC(t) asymptotically approaches current unit cost because future learning benefits become irrelevant to current output decisions.

The Appendix also derives CTMC(t) using final unit cost plus an integration term, both discounted to the current time:

(2)

If $r = 0$, the monopolist sets output in each period such that marginal revenue equals final unit cost, as explained above for the discrete case. Regardless of the discount rate, the monopolist fully forward-prices to maximize the present value of net profits over the production period but output still falls short of the social optimum because of market power.

Turning to the oligopoly scenario, the analysis is similar to figure 1, but there are three distinct sources of welfare loss. First, as in the monopoly case, welfare is constrained by the *market power effect*. Second, unless learning is completely appropriable, the existence of multiple firms diminishes the incentive to forward price because some of the benefits spill over to competitors. Ghemawat and Spence (1985) refer to this as the *disincentive effect*. Finally, with imperfect spillover, learning is less effective when total production experience is divided among multiple firms. This creates a new source of inefficiency (the *divided learning effect*) that is discussed in the next section.

Perfect appropriability

Perfect appropriability is the extreme assumption that each firm is able to completely appropriate the innovation benefits of its production experience. This is unlikely in practice, but it provides a useful hypothetical for explaining the divided learning effect introduced above.

Under perfect appropriability, each firm follows a distinct learning curve based on its own production experience. The disincentive effect is neutralized because learning does not spill over, but incumbents may be able to generate strong market power because they can totally exclude rivals from the innovation achieved through forward pricing.

Even when learning is perfectly appropriable it is possible that multiple firms will remain in the industry due to a wide range of complicating factors including uncertainty, innovation from sources other than learning-by-doing, and branding effects. To the extent that multiple firms persist, market power will attenuate but the divided learning effect will be worse. The divided learning effect means that the rate of cost reduction progress will decline as the average market share of each firm decreases. This follows for perfectly appropriable learning because cost reductions along the learning curve are a function of each respective firm's cumulative output, and none of these learning benefits spill over.

Governments could, in principle, intentionally increase market concentration to ameliorate the divided learning effect, but this would be risky. To ensure that the benefits from reducing the divided learning problem outweigh increased market power costs, a policy that promotes greater market concentration would probably also require price regulation. Kahn (1988) discusses the inherent inefficiencies of such regulations in the case of public utilities regulated as natural monopolies. Combined with the complexity and political drama associated with selecting firms to favor, the obstacles to efficient price regulation suggest that intentional market concentration is not a viable policy option. Nonetheless, the desire to maintain innovation incentives may represent a legitimate rationale for reducing the intensity of government anti-trust action in some cases.

The perfect spillover assumption

In the extreme case of perfect spillover, there is no divided learning effect and perfect competition eliminates welfare losses from the market power effect (Dasgupta and Stiglitz, 1988) but firms will fail to forward-price, resulting in the welfare loss shown in Figure 2.[19]

To maximize social welfare rather than profit, the government would have to provide subsidies (or impose the equivalent output mandate) such that:

(3)

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[19] In principle, users could correct for this market failure by *forward purchasing*, *e.g.* buying as though the price of a new technology had already fallen along its learning curve. The benefits would, however, spill over among all buyers making forward pricing an unlikely strategy except in specialized markets with only one or a few primary buyers (*e.g.* military procurement) or as part of the motivation for green consumerism (chapter 3).

where $P(t) - S(t)$ is defined as *net price*, *i.e.* the price consumers pay net of subsidies. If $r = 0$ then $CTMC(t) = z$ and the government should set subsidies such that in each period the price to the consumer is equal to expected long-term unit cost, z, including a competitive return on invested capital.

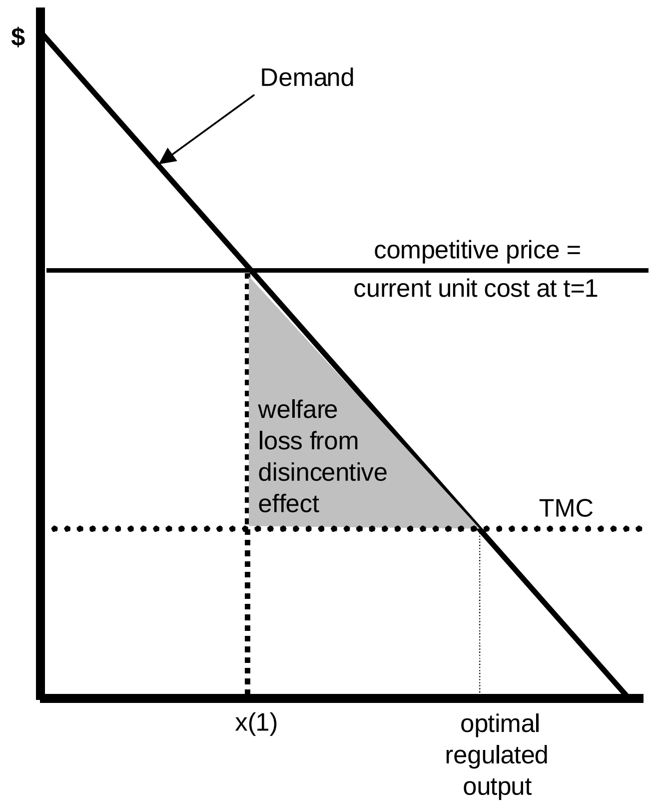

Figure 2. Insufficient forward pricing under perfect spillover and competition

Under perfect spillover incumbent firms do not gain any cost advantage over potential challengers, so perfect competition is possible and there is no welfare loss from market power. With N identical firms, however, each firm's final output accounts for only a 1/N share of cumulative industry output. Thus, firms forward price only marginally. This figure depicts the extreme case ($N = \infty$) where each firm's market share is trivial such that firms do not forward price at all. This causes the welfare loss shown in the shaded triangle. Note that the figure ignores intra-period learning effects for graphical clarity.

In practice, however, firms always have positive real discount rates such that the TMC falls somewhere between current unit cost and the long-term cost floor. For photovoltaic modules, for example, under base case assumptions, the TMC in the first year of the optimal buydown equals roughly half the initial unit cost—and quadruple the expected final unit cost (Chapter 5).

Note also that the empirical methods introduced in chapter 3 and applied to the PV case in chapter 5 use discrete time steps and assume that current period output has no effect on unit costs. This slight learning lag means that equations 2 and 3 hold only approximately, but the modeling results are qualitatively consistent with both equations.

Unless otherwise noted, this dissertation assumes perfect spillover as an approximation for markets characterized by high but imperfect spillover. By eliminating market power and divided learning inefficiencies, the perfect spillover assumption facilitates empirical analysis. It also makes it possible to assume competitive markets and stable profit margins such that unit price equals unit cost, where the latter is defined to include a competitive return on invested capital (Chapter 3). In the case of PV, spillover rates appear to be high since dozens of producers continue to compete and there is no single dominant firm even after decades of production (Chapter 4). Beyond the PV case, a significant economics literature argues (Arrow, 1962; Spence, 1981; Stokey, 1986) or empirically confirms (Levin *et al*., 1987; Irwin and Klenow, 1994) substantial learning-by-doing spillover among competitors.[20]

Learning spillover represents a market failure analogous to, and intertwined with, the RD^2 appropriability problem. Just as RD^2 spillover causes firms to under-invest in structured innovation efforts, learning-by-doing spillover discourages firms from forward pricing. Extending the analogy, RD^2 subsidies have proven to be a useful tool for overcoming appropriability problems on the supply-side, suggesting that buydowns can address production shortfalls attributable to learning-by-doing spillover on the demand side.

Direct spillover mechanisms include reverse engineering of competitors' products, communication among employees of different firms, worker movement among competing employers and even industrial espionage (Ross; 1986; Duke and Kammen, 1999). *System spillovers* may also play an important role. In addition to manufacturers, the individuals, firms, and agencies that use, deliver, and regulate a technology may "learn by doing" during the deployment phase—and these market conditioning benefits become accessible to all firms in the industry.

First, potential adopters often learn about new products by observing other consumers (Bass, 1980; Vettas, 1998). Companies can attempt to brand their products, but the broad public education benefits of their efforts to market the technology may spill over to the benefit of competitors. This form of system spillover is common to all new products but it is more severe for small-scale technologies that must be mass-marketed (*e.g.* energy-efficient appliances or distributed electricity technologies such as PV or small fuel cells) relative to large-scale technologies that can be sold to a small group of well-informed buyers (*e.g.* central-station electricity generation equipment).

Second, when the manufacturer of the core technology (*e.g.* PV modules) cuts prices and scales up production, the associated demand pull helps to bring down the cost of essential complementary equipment and services (*e.g.* installation and maintenance) provided by specialist companies. Manufacturers may be able to mitigate these spillovers by means of horizontal integration (*e.g.* some PV module manufacturers have begun to incorporate power conditioning inverters directly into their modules) and vertical

[20] Lieberman (1987) reviews the literature and offers empirical evidence of spillovers as high as 60-90 percent in some cases.

integration (*e.g.* designing, installing and maintaining entire systems). There are, however, also benefits to focusing on core competencies.

Third, manufacturers and users must induce regulatory reforms to accommodate certain new technologies but they cannot exclude other users or competing manufacturers from these benefits. For example, to add a new electricity source to a power grid, system integrators or end users themselves must work through considerable red tape. In the process, regulators learn about the technology and ultimately streamline the process to the benefit of all suppliers and customers.

Finally, positive network externalities play an important role for many technologies (Unruh, 2000). Telephones provide a classic example in that the benefit to each user of having a telephone line increases as a function of the total number of people that can be reached on the network. Pioneering manufacturers generally cannot prevent their competitors from sharing in the benefits of increased customer demand as the network matures and becomes more useful to all users. In the energy sector, the need for an extensive hydrogen infrastructure as a prerequisite for commercialization of fuel cell vehicles offers an important example.

Summary

The preceding discussion shows that, with strong learning effects, initial output always falls short of the social optimum regardless of the level of spillover. In principle, buydowns can address this output shortfall and thereby improve social welfare. Buydowns not only compensate for inadequate forward pricing (to the extent that learning-by-doing spills over) but also reduce the social cost of market power (if monopolies or oligopolies emerge because they are able to retain the benefits of learning-by-doing) by directly subsidizing demand so as to push sales levels towards the social optimum.

Even if the industry starts with only one or a few firms, demand-pull programs encourage competitors to emerge to take advantage of the larger markets and lower industry-wide production costs catalyzed by the subsidies.[21] It may also prove possible to design buydowns to actively promote spillover.[22] Such a strategy would reduce the dual costs of divided learning and market power,[23] ensuring that a competitive market structure emerges such that subsidies can be ultimately be phased out completely once the technology has become fully mature and has reached its long-term price floor.

The unique buydown potential of the clean energy sector

Chapter 3 argues that estimates of the net benefits of buydowns are inherently uncertain. Governments should therefore focus buydown support on technologies within the clean energy sector.

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[21] If one or a few firms starts with a large cost advantage (*e.g.* due to patented technologies resulting from their RD^2 investments) a buydown might initially fail to encourage entry. Nonetheless, a sufficiently strong demand-pull program should lower entry barriers by generating direct and system spillovers and increasing the incentive for potential competitors to enter the market.

[22] The government may, for example, encourage information exchange as part of an overall market transformation effort that includes a buydown. The U.S. PV Manufacturing Technologies (PVMaT) program provides an effective model for using supply-push programs to facilitate information flows among competing firms (Margolis, 2002).

[23] Ghemawat and Spence (1985) show that welfare improves as spillover increases since efficiency gains from alleviating the divided experience and market power effects usually outweigh losses from the disincentive effect.

The buydown advantages of clean energy technologies

First, as noted above clean energy technologies provide non-learning public benefits by reducing fossil fuel[24] pollution, mitigating fuel price risk, and improving security. These benefits are uncertain but substantial. For example, Holdren and Smith *et al.* (1999) concludes that "…at every scale the environmental impacts of human energy production and use account for a significant portion of human impacts on the environment." To the extent that market tuning is inadequate, demand-pull subsidies help to compensate for the inefficiently low *financial* payoff to consumers that invest in clean alternatives.

Second, energy technologies diffuse exceptionally slowly, giving governments time to design and implement buydowns before new developments eclipse their plans. Technologies typically follow an "s-shaped" diffusion path, spreading slowly until they reach roughly 10 percent of their maximum long-term saturation levels, then diffusing rapidly before tapering off after the 90 percent penetration level. Technologies vary widely in the time it takes them to diffuse from the 10 percent to the 90 percent levels, denoted Δt in the literature. A sample of 265 cases yielded an average Δt of 41 years[25]

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[24] Fossil fuel technologies are not necessarily inherently polluting. It may prove cost-effective to develop technologies that recover most of the energy content of fossil fuels as hydrogen for use in fuel cells and other devices, sequestering the CO_2 byproduct in suitable reservoirs that prevent its release to the atmosphere (Williams, 2002b). For the case of coal, concerns about mining pollution would remain, though regulators could mitigate these externalities by restricting mining to relatively benign sites and extraction techniques.

[25] The mean Δt for a subset of 117 cases all of which were constructed at the International Institute for Applied Systems Analysis (IIASA) was higher (58 years), but both distributions have long right 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."

but the average among energy technologies was more than twice as long at 90-100 years (Grubler and Nakicenovic, 1991).[26]

Third, spillovers are severe in the energy sector, implying correspondingly favorable opportunities for corrective buydowns. Slow diffusion times tend to exacerbate direct manufacturing spillovers, giving competitors time to borrow innovations from leading firms. More importantly, firms working to introduce innovative energy technologies face massive *system* spillovers that have caused the economy to *lock-in* to the existing fossil fuel infrastructure (Cowan, 1999; Unruh, 2000). To compete with low-cost mature energy systems, companies introducing a new energy technology must generate a critical mass of new adopters to persuade other manufacturers to develop necessary balance of systems equipment and ensure rapid regulatory transformation to accommodate the new technology. This is a tall order when most such benefits quickly become available to competing firms.

For example, direct hydrogen fuel cell vehicles may have more long-term promise than methanol or gasoline vehicles with expensive on-board reformers (Thomas *et al.*, 2000); however, firms attempting to market such vehicles would have to convince potential customers that an extensive hydrogen delivery system will quickly materialize. This, in turn, would require persuading energy companies to navigate regulatory hurdles and risk massive sunk cost investments to build such an infrastructure. Each early adopter increases the odds that all of this will come to pass, but the benefits spill over to

[26] 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 percent per year since 1860, but the article estimates that it will take ~300 years for this process to proceed from the 10 percent threshold to 90 percent decarbonization. The far faster rate of decarbonization attributable to France's nuclear program (2.2 percent during the 70s and 80s) shows that policy decisions can dramatically accelerate this process.

future users. Even if they believe that their manufacturing progress will remain proprietary (low direct spillovers), alternative energy firms may refuse to risk the scale of forward-pricing necessary to commercialize a new energy technology because they cannot appropriate the associated market conditioning benefits due to system spillovers.

Fourth, many energy technologies follow experience curves (Chapter 3), with price falling as a predictable function of cumulative production experience for years or decades (Wene, 2000; McDonald and Schrattenholzer, 2001). This is consistent with strong learning-by-doing, which is the most basic prerequisite for effective demand-pull efforts. It also gives analysts a tool for quantifying the impact of a buydown on the price of the targeted technology and forecasting prices for the incumbent and emerging alternatives with which it must compete.

Fifth, for a technology that reduces the cost of a homogenous commodity like kWhs of electricity or joules of heating or transport energy, welfare improvements are easier to measure than for new products that offer qualitatively distinct consumer benefits.[27] It is possible to approximate the prospective welfare gain from an energy technology buydown based on the present value of the stream of cost savings relative to the business as usual case (Chapter 3). This requires estimating the rate at which the demand schedule shifts out over time, but it does not require predicting a new demand schedule from scratch.[28]

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[27] All new energy technologies have unique attributes but they generally substitute for existing technologies that have clear cost structures rather than providing entirely new services. PV, for example, can be used in novel stand-alone applications including powering telecom repeater stations and off-grid homes, but gas or diesel generators provide a reasonable benchmark for the cost of providing these services without PV.

[28] For entirely novel products, the increase in welfare depends on the shape of the unknown and evolving demand curve. Hausman (1997) describes the *compensating variation* procedure for calculating the consumer surplus gain by estimating the decline in expenditure that would hold utility to the level that prevailed before the new product was available. While conceptually straightforward, to predict future

Finally, energy is a commodity product with thin profit margins and substantial risk of price collapses, making technological innovation difficult without public sector support (PCAST, 1997). New energy technologies are typically many times more expensive than incumbents, and since different energy sources are often close substitutes customers are unwilling to pay a premium for a new option except in niche markets that take advantage of particular attributes of the new technology (*e.g.* modularity).[29] Also, in the energy sector, learning-by-doing on the part of equipment manufacturers and system integrators drives incremental innovations that are difficult to protect with patents. Even after a new energy option starts to become cost-effective, achieving widespread deployment poses a major hurdle because manufacturers and system integrators must adapt existing physical and regulatory infrastructure to the new technology. Assuming $\Delta t = 50$ and a patent term of 17 years, for example, a new energy technology will have reached less than a third of its maximum long-term market penetration level before patent protection expires. This contrasts sharply with major new drugs that may reach most of their market potential soon after they are approved.

The buydown disadvantages of technologies from other sectors

Buydowns appear to be generally either unnecessary or perilous outside the clean energy sector, as illustrated by the following examples. The first three underscore that conventional supply-side mechanisms, including patents, may suffice in some cases. The next three suggest that buydown implementation is too risky and difficult to pursue in

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welfare gains for a new product requires, at a bare minimum, accurate estimates of future revenues from sales of the product as well as the price elasticity of demand. These are difficult to estimate without recourse to the bottom-up financial breakeven schedule estimation method described in Chapter 3.

many sectors. There is a possible role for transportation equipment buydowns, but only where there are clear non-learning public benefits at stake from improved energy efficiency. Finally, military procurement policy takes advantage of learning-by-doing effects, but government purchase plans alone do not constitute a buydown since the primary goal is not to engender a self-sustaining commercial market for the favored technologies.

Innovation is crucial to the pharmaceuticals industry, but there is little need for demand-pull support because RD^2 drives the industry and patents provide excellent incentives in this sector (Chapter 1). New drugs often have unique and even life-saving advantages, so patients who can benefit from a novel treatment have a high willingness to pay (either directly or through insurance premiums for policies that include good prescription drug coverage). This implies an inelastic demand schedule such that pharmaceutical companies can support their research programs with monopoly profits from occasional blockbuster drugs. Also, since the selling price on successful patented drugs far exceeds manufacturing costs, learning-by-doing during the drug production process is a relatively insignificant driver of pharmaceutical economics. Finally, pharmaceutical companies can market new drugs with relative ease by ensuring that doctors are aware of the new option and its benefits (though firms are also increasingly advertising certain drugs directly to the public). In sum, patenting is an ideal instrument

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[29] These constraints should also factor into government decisions about the viability of buydowns, but they nonetheless underscore that the energy sector is inertial.

for catalyzing pharmaceutical innovation such that buydowns are largely superfluous in this sector.[30]

Governments should steer clear of buying down new agricultural seed technologies for similar reasons. As with new drugs, traditional hybridization or genetic engineering could offer major non-learning public benefits such as developing crop strains that reduce pesticide requirements or provide essential nutrients (*e.g.* the so-called golden rice that contains vitamin A for the prevention of blindness in developing countries). The diffusion time scale will vary radically depending on context, with rapid uptake possible among large agribusinesses and much slower adoption among small or isolated farmers, particularly in rural areas of developing countries.[31] Nonetheless, this sector is otherwise analogous to the pharmaceuticals industry, suggesting that conventional RD^2 will be more important than learning-by-doing, and that patents should provide effective incentives for private investment, particularly if complemented by government supply-push support. As with pharmaceuticals, subsidies for low-income developing country customers may provide net public benefits, but these would come in the form of patent buyouts or other poverty alleviation programs rather than technology buydowns as such.

Considering a traditional manufacturing example, buydowns look only marginally more relevant for the chemicals industry. Lieberman (1984) identifies strong learning

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[30] Drug companies have little incentive to develop new treatments for diseases like malaria that primarily afflict impoverished developing countries. This may argue for public investment in low-cost therapies like vaccines—including direct research funding and demand-side subsidies (*e.g.* free vaccination programs). These subsidies are not, however, buydowns since they do not aim to generate self-sustaining commercial markets for particular technologies.

[31] Griliches (1960) documents diffusion rates for hybrid corn seed with Δt figures ranging from less than 5 years in grain-intensive Iowa to well over a decade in Kentucky. In areas like Alabama where corn was a

effects at the industry level—suggesting high spillover rates among competing firms. Nonetheless, patents are moderately effective for preventing direct spillovers in the chemicals industry (Mansfield, 1986), and manufacturers sell most chemicals directly to wholesale industrial buyers who then use them to produce other goods. Thus, as with pharmaceutical firms that can market drugs though well-informed doctors, user education is less of an obstacle than for goods marketed directly to diffuse consumers. Similarly, system spillovers should not impose serious barriers to new product commercialization. Most new chemicals will not require large-scale development of complementary technologies and positive network externalities should be modest.[32] There may be significant regulatory hurdles, but these often serve legitimate environmental goals rather than representing arbitrary bureaucratic obstacles. Finally, benign substitutes for dangerous chemicals provide non-learning public benefits, but regulating the polluting incumbent technology will likely prove more effective than subsidizing clean alternatives. For example, taxes on polluting chemicals provide incentives for the full range of possible adjustments, including manufacturing process redesigns and commercialization of clean substitutes. This market tuning approach works better for chemicals than for clean energy because new chemicals are typically only marginally more costly than incumbents and they may offer important performance advantages. Also, chemicals usually impose localized environmental and health impacts, making it

much less important crop, hybrid seed did not even reach the 10 percent threshold until 1948, more than a decade after Iowa.

[32] In fact, there may be substantial *negative* network externalities as in the case of pesticide resistance (Cowan and Gunby, 1996).

relatively easy to enact controls (relative to regulating global carbon emissions or transboundary air pollution from fossil fuels).[33]

There are also sectors for which patents may not ensure dynamic efficiency but buydowns are also of little use. Semiconductors, consumer electronics and communications technologies illustrate the point.

With the exception of national security concerns related to reliance on imported computer technology, semiconductor buydowns would not offer any clear non-learning public benefits. Moreover, new generations of semiconductors emerge and diffuse at breakneck pace (year), rapidly making incumbent technologies obsolete. Governments would be hard-pressed to identify and buy down promising new chip designs more successfully than private firms in this fast moving market. Also, there are substantial learning effects and direct spillovers in the industry (Irwin and Klenow, 1994; Gruber, 1994) but the rapid pace of innovation suggests that manufacturers have substantial (if not optimal) incentive to develop new chip generations, possibly because there are no serious *system* spillovers to overcome, *e.g.* successively faster central processing units fit seamlessly into standard desktop and laptop architecture (with continuously upgraded components and software).

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[33] Even for global chemical contaminants there is positive precedent in the Montreal Protocol that has begun to phase out the most egregious ozone-depleting substances. Major manufacturers of chlorofluorocarbons were able to develop, and quickly profit from, relatively benign substitute compounds. This greatly facilitated international negotiations by transforming the most focused and powerful opponents of increased regulation into advocates (Oye and Maxwell, 1995). An analogous scenario is possible for low-carbon energy technologies, as exemplified by the decisions of BP and Royal Dutch/Shell to stop actively opposing climate change regulations while ramping up investments in solar and carbon sequestration technologies. Still, the scale of sunk-cost investments in conventional fossil fuel technologies makes this a far more challenging case, as underscored by the efforts of other oil majors and energy-intensive industrials to lobby against carbon controls.

Buydowns for consumer electronics would be similarly ill advised as these products offer few non-learning public benefits and they diffuse rapidly through well-developed marketing and distribution channels. Innovation spillovers discourage firms from introducing certain new consumer electronics products, but system spillovers are low and patent laws may at least mitigate the problem of manufacturing innovation spillovers. In any case, it would be perilous for the government to favor particular consumer electronics products given fickle consumer tastes and short product lifecycles—particularly since the private sector has such an impressive record of commercializing new consumer electronics products.

The case for buying down communications technologies is little better despite some superficial factors that suggest a possible role for demand subsidies. In particular, traditional fixed line telephone networks benefit from positive network externalities. This could justify a "buydown" to ensure that the network grows quickly even though early adopters are not fully compensated for the public benefits they provide (by becoming accessible to all users on the phone network). In the industrialized world, telephone networks are largely in place, but network externalities provide a possible argument for subsidizing the installation of fixed line phone networks in developing countries. As with semiconductors and consumer electronics, however, the blistering pace of change suggests that demand-pull subsidies are unlikely to improve on market forces.[34] In particular, wireless and internet technologies have made rapid incursions into

[34] Of course, governments may play an essential regulatory role even when buydowns are inappropriate, *e.g.* auctioning bandwidth to wireless carriers.

the telecom market based on their unique attributes.[35] It appears that neither of these technologies requires any buydown support and their success increasingly obviates the need for traditional telephone networks.

There is a case for considering buydowns for transportation technologies but this mainly applies to innovations that save energy, reduce pollution, or both. The diffusion times for new transportation technologies are long (Grubler and Nakicenovic, 1991), giving governments an opportunity to intervene productively with buydowns before unexpected new technologies disrupt their plans. Moreover, there is evidence of predictable learning effects as exemplified by the genesis of the learning curve concept in a classic study of airplane manufacturing (Wright, 1936). In terms of estimating buydown benefits, most transportation equipment innovations offer incremental improvements to existing technologies that can be readily measured in terms of lower costs. It is also possible to envision transportation improvements that provide major non-learning public benefits other than energy efficiency. Certain, safety measures, for example, may primarily protect the occupants of other cars and therefore constitute a public benefit rather than an owner benefit. Rather than attempting a buydown, however, it is likely to be more effective to simply mandate such measures (or impose appropriate subsidy or tax incentives) since a buydown does not address the fundamental safety externality problem. More broadly, the industry has a successful track record of sustained commercialization of innovations as underscored by steady improvements in mass-marketed automobile and aviation technologies. This suggests that patents (plus

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[35] The internet and wireless examples demonstrate that radical new technologies can transform a formerly staid industry (conventional telecom) in unpredictable ways. Even in the uniquely inertial energy sector (as

public RD^2 investments) adequately compensate for manufacturing spillovers and system spillovers are not a serious constraint for most automotive innovations. There are, however, strong spillovers such as the positive network externalities that lock in the economy to gasoline automobiles, making it difficult for alternative vehicles (electric and fuel cell) to make headway in the market.

For military technologies the government routinely makes procurement decisions that trade off the goal of pushing the technological frontier *versus* attaining a lower unit cost by buying larger quantities of any given model of fighter jet or other equipment. This is not truly a buydown process, however, since the goal is not to catalyze self-sustaining commercial markets.[36]

In sum, there is a unique non-learning public benefits case for supporting clean energy technologies with buydowns. To the extent that political constraints preclude direct market tuning remedies, subsidizing clean energy helps to reduce welfare losses from pollution externalities. Beyond this familiar argument, clean energy buydowns also mitigate the market failures associated with learning-by-doing spillover. These externalities are particularly severe in this sector because new energy technologies typically cost much more than incumbent options and they generally require many decades to realize their long-term potential.

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indicate by exceptionally long Δt diffusion times) governments should consider the risk that unforeseen energy technologies will emerge and cut short the expected payoff from a buydown (Chapter 3).

[36] Governments may encourage arms exports to ensure a strong military industrial base (or simply because arms manufacturers have strong lobbying power), but the primary goal of military procurement should be to ensure a strong defense capability not to build markets for new arms technologies *per se*. In fact, arguable there are strong negative national security externalities from open market exports of advanced armaments.

Summary

Certain economists (notably Spence, 1981) have recognized that production of any new technology characterized by strong learning-by-doing will fall short of the social optimum, but they avoid the inference that governments may be able to improve economic efficiency by subsidizing demand. Lyons (1987) as well as Dasgupta and Stiglitz (1988) represent a partial exception. Both articles suggest that with strong learning-by-doing, national efforts to protect *infant industries* would increase global welfare under certain conditions. In particular, such tariffs could shelter immature domestic producers until they gain sufficient cost-reducing production experience to out-compete foreign producers that are assumed to have lower current costs but less favorable learned-out production costs.

This dissertation makes analogous arguments for protecting *infant technologies* that are projected to provide low cost energy services once they mature. There is a case for subsidizing early markets for any technology characterized by strong learning-by-doing (especially if spillovers are high), but given implementation risks governments should limit buydowns to clean energy technologies.

The next chapter builds on this theoretical base to develop implementation guidelines for selecting and supporting specific clean energy technologies. The chapter focuses on the question of how to maximize the benefits of scarce public funding.

Appendix

This appendix derives the first-order conditions for monopoly profit maximization under learning-by-doing. True marginal cost (TMC) is defined to account for the decline in future costs as a function of the permanent learning induced by a higher rate of current output. The monopolist sets output in each period such that marginal revenue equals TMC. By analogy, a welfare-maximizing social planner must set output such that *price* equals TMC.

No discounting case

The firm chooses an output rate at every point in time, , to maximize the undiscounted stream of profit considering the entire output trajectory, , from time zero to *T*:

where the cumulative production at any point in time, *t*, is given by and, revenue and cost functions are as follows:

where P(x) equals the inverse demand function, and

where unit cost (the learning function).

Profit maximization requires the familiar first order condition that the monopolist set output such that marginal revenue equals marginal cost, with the latter labeled *true marginal cost* (TMC) to emphasize that it accounts for the contribution of current output to future learning effects.

Marginal revenue is simply the derivative or instantaneous revenue with respect to output:

To derive TMC it is useful to consider a Dirac delta function, *i.e.* a "pulse" defined such that it yields a unit increase in output at a point in time:

if

if

for each and every .

This allows the Dirac delta to "sift" a function from the integral.

for .

It is possible to define TMC(t) as,

where *TC(t,h)* is the total cost of output trajectory , where is perturbed by *h* times a Dirac delta function at time *t* and *TC(t,0)* is the ordinary total cost function for . Thus, by the sifting property,

Thus,

since,

Bringing h inside the integral and taking the limit yields,

by the definition of the derivative. Thus, *TMC(t)* equals current unit cost plus the marginal decline in future costs from a marginal increase in output at time t.

It is also possible to show that *MC(t)* is equal to the instantaneous marginal cost at the time horizon, T. That is, . This can be shown as follows,

Discounting case

Discounting back to time zero, the present value of marginal revenue is and the present value expressions for TC and TMC are:

For comparison with the no-discounting case, it is possible to define an expression for TMC(t) that includes final instantaneous marginal cost, [illegible] . Taking the derivative of *TMC(t)* with respect to *t*:

[illegible]

It is now possible to redefine *TMC(t)* as an unknown constant plus the integral of [illegible] from 0 to *t*:

[illegible]

The present value of the instantaneous marginal cost in the final moment of production can be similarly defined:

[illegible]

Thus,

[illegible]

Substituting this result into the definition of *TMC(t)*:

[illegible]

As in the no discounting case, to maximize profits the firm must set the present value of marginal revenue equal to the present value of TMC in each period:

[illegible]

This yields the first definition of *current-period* true marginal cost, *i.e. CTMC(t)* defined as forward-looking true marginal cost discounted back to the current period *t*:

[definition #1]

This result is consistent with the Appendix from Spence (1981) after correcting for minor errors.

By the same method, it is possible to derive the second definition of *current* true marginal cost:

[definition #2]

The integration term in this definition of *CTMC(t)* is negative, and its absolute value declines as the discount rate increases. In the limit as $r \rightarrow \infty$ this term disappears and equals current unit cost, *i.e.* future learning effects become irrelevant to current profit decisions.

Chapter 3: Implementing clean energy buydowns

Chapter 2 presents a generic rationale for demand-pull support of any emerging technology characterized by strong learning effects but argues that governments should focus buydown efforts on clean energy technologies. This chapter offers policymakers guidance for selecting the best clean energy options for buydown support.

The chapter begins by introducing experience curves as a tool for quantifying and projecting learning effects. It then critiques the conventional approach to buydown cost-benefit analysis and presents an improved methodology. This approach suggests five criteria for selecting particular clean energy technologies to maximize the expected social return on buydown investments. Finally, the chapter underscores reasons for proceeding with caution, including analytic and implementation challenges.

Quantifying learning-by-doing

In order to assess a proposed buydown it is necessary to quantify the impact of increased sales on production costs. This section introduces the standard techniques used for quantifying and projecting learning-by-doing effects.

Learning curves

Learning curves describe the relationship between cumulative production and labor costs for a given product manufactured by a specific firm. T.P Wright introduced formal learning curve analysis in a 1936 study of airplane manufacturing, showing that manufacturing experience facilitates worker skill improvements, with benefits accruing in a regular manner with increased cumulative production (Argote and Epple, 1990). Thus, cumulative output serves as a proxy for the stock of worker skill improvements achieved through learning-by-doing. In a conventional formulation:

$$\qquad (4)$$

where equals labor cost per unit given cumulative production, , at time *t*, the parameter *a* equals the cost of a unit at *t* = 0, the parameter y_0 = cumulative production by the firm at *t* = 0, and *b* = the learning parameter.[37] The equation can be linearized for convenient graphing and coefficient estimation using ordinary least-squares regression:

The intuition for this power function relationship is that there are diminishing returns to learning. Progress is fast initially, but tapers off as workers become fully experienced.

The conventional measure of learning is the progress ratio (Dutton and Thomas 1984; Argote and Epple 1990). For each doubling of cumulative production the cost per unit decreases by the progress ratio (PR) factor. The derivation is straightforward:

$$PR = \frac{\quad}{\quad} = 2^{-b}$$

A typical learning parameter, b = 0.32, corresponds to PR = 0.80, which implies a 20 percent reduction per cumulative doubling of production. Note that, a lower PR implies faster progress; a more intuitive measure is the *learning rate* defined as LR = 1-PR.

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[37] See Hirschman (1964), Argote and Epple (1990), and Badiru (1992) for variants of equation 1. Also, Arrow (1962) summarizes the early learning curve literature and adapts the theory to a model that uses cumulative capital goods investment as the learning proxy.

Experience curves

During the 1970s, Boston Consulting Group (BCG) introduced experience curves to generalize the labor productivity learning curve to include all costs necessary to deliver a product to market (Boston Consulting Group, 1972). BCG presented evidence that its clients benefited from a predictable percentage reduction in *overall* costs associated with every doubling of cumulative production. That implies learning-by-doing not only in the narrow sense of labor productivity improvements, but also in associated RD^2, overhead, advertising, and sales expenses. These efficiency gains, in conjunction with the benefits from economies of scale, yield cost reductions characterized by the same functional form as equation 2 except that now accounts for all costs necessary to produce and deliver the product to the customer (rather than just labor costs). Dutton and Thomas (1984) compiled over 100 firm-level experience curve studies from a variety of manufacturing sectors that suggest a mean progress ratio of 0.8, *i.e.* a 20 percent learning rate.[38]

When innovations spill over among competing firms, it is possible to estimate an experience curve based on cumulative *industry* output. High spillover is also consistent with perfect competition (Chapter 2) and this, in turn, implies stable profit margins roughly equal to the market rate of return for similarly risky business ventures. Given these assumptions, the *industry-wide experience curve* reduces to:

(5)

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[38] The weighted average of the progress ratios for individual firms should be the same as the overall industry experience curve.

where *P* refers to price; equals unit cost (including a constant competitive profit margin) as a function of industry output; for *N* firms; production units are defined such that cumulative production equals one unit at $t = 0$; and *a* equals the price of the first unit produced. The price of emerging energy technologies typically falls by 5-25 percent with each doubling of cumulative industry output, *i.e.* according to industry progress ratios of 0.75 to 0.95, with most clustered around 0.80-0.85 (McDonald and Schrattenholzer, 2001).

Unless otherwise noted, the empirical analysis in this dissertation assumes perfect spillover and uses industry-wide experience curves, treating price data as a proxy for unit cost in competitive markets. The analysis also assumes that prices (*i.e.* unit costs) ultimately reach a floor estimated using bottom-up technology assessment to determine the minimum learned-out competitive price.

Cost-benefit analysis of buydowns

This section presents two distinct methodologies for evaluating the social net present value (NPV) of buydowns. Both approaches rely on an industry experience curve to project the price of the targeted technology, but they differ in their treatment of demand. The conventional breakeven line approach estimates demand based on the price below which the new technology becomes more cost-effective than the incumbent. This has the virtue of simplicity and graphical clarity, but suffers from substantial shortcomings. The second method uses annual demand schedules that shift outward over time. This refinement facilitates full consideration of niche markets, improves the accuracy of overall subsidy requirement estimates, and allows endogenous estimation of the optimal subsidy/output time path.

The conventional breakeven method

Figure 3 shows the conventional method of estimating buydown costs and benefits (Wene, 2000). A breakeven (BE) line indicates the price below which the technology becomes cost-effective; an experience curve shows a fixed percentage drop in the competitive price with each doubling of cumulative production; and finally, price equals unit cost defined to include a constant competitive profit margin based on the mutually consistent assumptions of perfect spillover and competition.[39]

Until the experience curve crosses beneath the breakeven line, no sales will occur without subsidies, except for niche market opportunities. After the crossover point, the economy begins to benefit from cost savings relative to using the incumbent technology that is assumed to be mature such that it has already reached its price floor. As shown by the dashed line in Figure 3, market tuning to account for the price of carbon or other externalities raises the BE price line to reflect social costs and thereby reduces buydown cost and increases the associated stream of benefits.

Assuming an industry experience curve with a one-year lag, the NPV of a buydown can be calculated under the breakeven approach as:

(6)

where the first and second terms in the right parentheses refer, respectively, to the buydown scenario and the no-subsidy scenario (NSS). For the buydown case, the initial sales level, X_0, and the assumed sales growth rate function under the buydown, *g(t)*, determine annual industry output in each period, X_t.[40] This, in turn, determines

where *a* equals the initial price, *b* is the industry-wide learning parameter, and Y_{t-1} is lagged cumulative industry production, *i.e.* $\sum_{i=1}^{t-1} X_i$. The setup for the second term is analogous, but follows the assumed sales growth rate excluding all subsidized sales, *h(t)*. This, in turn, determines the NSS price path, . *BE* equals the price at which the technology becomes cost-effective. Adding externalities (*e.g.* the value of displaced pollution) to *BE* yields the *social* NPV.

The analytic timeframe, *T*, extends to the point where the technology is projected to reach its price floor even under the NSS. Past this point in time the buydown cannot produce additional annual benefits. Note, however, that the analytic timeframe is still arbitrary under the conventional breakeven approach since the underlying sales growth rates for the NSS are *ad hoc*.

If niche market sales are zero or trivial then the technology never gets launched in the market under the NSS. In this case, there is no finite analytic timeframe and once a steady state flow of annual benefits is reached, say *X*, the present value from that point forward is simply *X/r* based on the standard perpetuity formula. In practice, however, conventional analyses typically neglect to model the NSS at all. Instead, analysts set *T* arbitrarily and ignore the baseline benefits under the NSS even if there are substantial niche markets—thereby substantially overstating buydown NPV.

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[39] Though these conditions are not always acknowledged by conventional analyses such as Wene (2000).

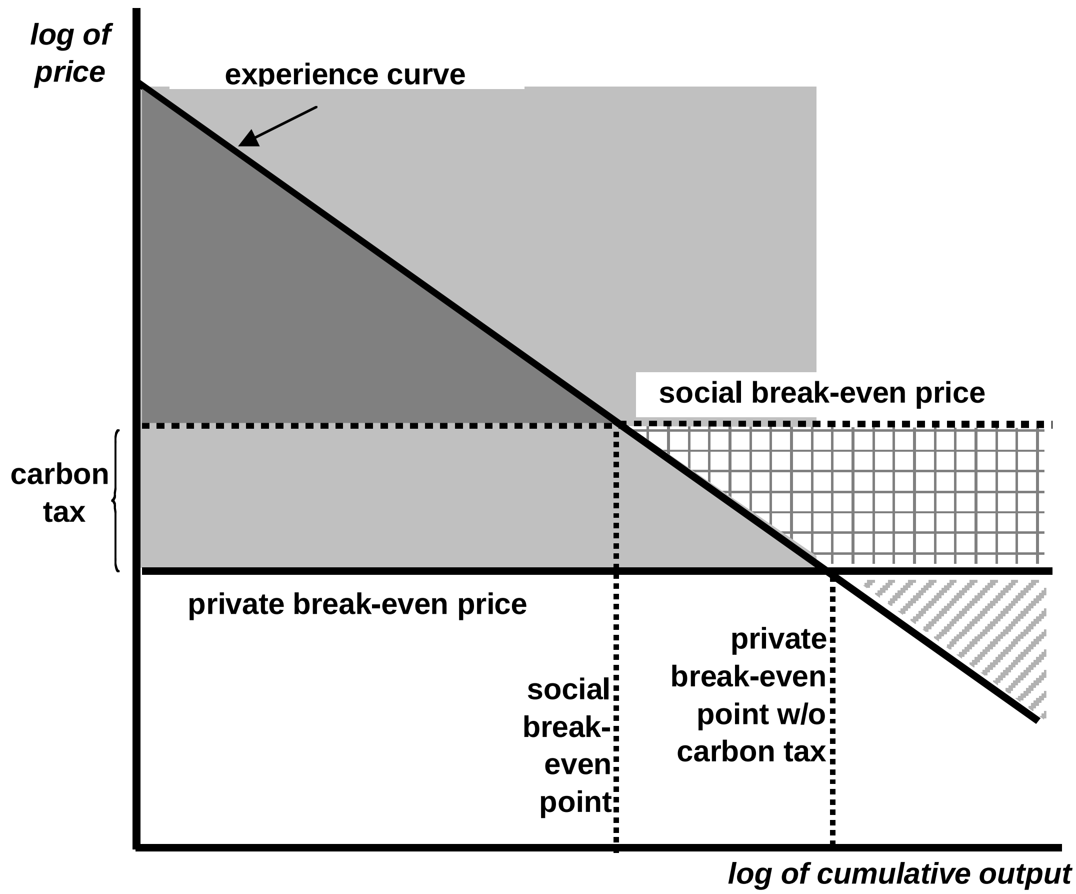

Figure 3. Buydown cost and benefits using the breakeven method

This figure shows the undiscounted costs and benefits for a buydown targeting an emerging clean energy technology. Both axes are in log scale to allow linear plotting of the experience curve with price declining by a fixed factor with every doubling of cumulative production (note that the relative areas of different sections of the chart therefore do not directly translate into relative magnitudes). The graph shows industry output and assumes perfect spillover of learning-by-doing and a competitive market structure such that price equals cost including a fixed competitive return on investment.

The undiscounted total buydown cost (combined light and dark shading) equals the area between price and demand up to the breakeven point. Payoff (hatched) begins once the price drops below breakeven such that the new technology begins to lower the cost of energy services in the economy.

Market tuning (e.g. a carbon tax) boosts the breakeven price to reflect its true social value, lowering the buydown cost to the darkly shaded area and increasing the payoff by the crosshatched shading.

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[40] Specifications for *g(t)* and *h(t)* are generally *ad hoc* and unsatisfactory under the conventional breakeven method (chapter 5). The optimal path method circumvents this issue by realistically modeling demand.

As shown in Figure 3, the breakeven approach assumes that there is a fixed total buydown cost that the government must plow through in order to start obtaining benefits in the form of lower energy costs. Assuming a positive discount rate, the inevitable recommendation is that the government should push the buydown as quickly as possible (Wene, 2000) but the breakeven method offers no guidance about the maximum achievable buydown pace.

Also, in practice there is never a single flat breakeven price. First, demand schedules tend to slope downward in practice. Even for a generation technology that captures the entire market for new capacity, sales would still depend on the price elasticity of demand for electricity itself. Combined-cycle gas turbines (CCGT), for example, have come to dominate markets for new generation capacity in many countries after two decades of sustained cost reductions.[41] Further reductions in the price of CCGT electricity would induce higher overall electricity sales and therefore higher sales for CCGTs. Similarly, even though electricity is a homogenous commodity, the conditions for generating and distributing it vary regionally. For example, coal continues to dominate in China because the indigenous natural gas supply is limited. Moreover, it took decades for natural gas to gain its dominant position in the U.S., and the process began with simple gas turbines for the peak power niche. For smaller-scale technologies such as photovoltaics (PV), there are multiple market segments with vastly different financial breakeven points (Chapter 4). This generates a downward-sloping demand

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[41] From 1981-1998, CCGT electricity costs in the U.S. and Europe declined 15 percent (PR=0.85) with every doubling of cumulative kWhs generated. Much of this was attributable to reductions in the cost of natural gas supply (though some of these gains arguably occurred due to the demand-pull from CCGT markets that induced new exploration and distribution infrastructure). Holding gas prices constant, each doubling yielded only a 6 percent drop (PR=0.94) in CCGT electricity costs (Colpier and Cornland, 2002).

schedule with willingness to pay ranging from hundreds of dollars per peak watt (Wp) in tiny markets in satellite applications to under $1/Wp for potentially massive central-station grid markets.

Second, demand schedules tend to shift outward over time[42] as prospective buyers learn about and gain confidence in a newly cost-effective technology—often by observing the experiences of early adopters in what Bass (1980) calls the "social contagion of the adoption process." Thus, in early years, willingness to pay falls short of the financial breakeven line until potential adopters become aware of the new option and gain confidence in its efficacy as well as knowledge of its proper application. This gap between potential and realized willingness to pay will be most severe for complex small-scale products requiring extensive advertisement and buyer education investments. Certain customers, such as large companies may have the capacity and incentive to inform themselves about the full range of energy options. This helps to accelerate the demand shift process, but less specialized users may take years to develop the knowledge and confidence required to take full advantage of an emerging technology.

Demand-side market failures may also artificially constrain willingness to pay. The government may be able to encourage faster outward shifting of demand through market tuning measures such as removing unnecessary bureaucratic barriers and providing reliable information about new product quality (Duke, Jacobson, and Kammen, 2002); however, other demand-side market failures may prove intractable. Chapter 5

[42] Ultimately, the demand schedule may shift back inward as markets saturate and the next generation of technologies emerges; however, the timing of market senescence does not affect buydown NPV as long as the market is expected to reach a mature steady-state sales level even under the NSS.

discusses this demand estimation challenge with reference to slow consumer adoption of certain highly cost-effective energy efficiency technologies.

The breakeven method can be modified to account for early niche markets that eventually saturate by making BE decline as a function of increasing cumulative output (Figure 20 in Chapter 4). This yields a type of long-term demand schedule covering the entire period being considered from 0 to *T*, but it still does not offer insight into the expected time path of price and output levels under the no-subsidy or buydown scenarios.

The next section presents a model that corrects for the deficiencies of the breakeven model. In particular, it accounts for time constraints on the technology diffusion process and uses realistic downward-sloping demand schedules for each year to allow analysts to estimate an optimal buydown subsidy/output path.

The optimal path method

The optimal path method employs downward-sloping demand schedules that shift out over time to assess the NPV of a proposed buydown. As shown in chapter 5, these can be estimated by combining typical diffusion times for energy technologies with bottom-up estimates of financial breakeven schedules in major market segments.

The left side of Figure 4 shows a snapshot of a single year, *t*, during an optimal buydown, while the right side shows the mature market once the price floor has been attained and demand has shifted out completely. Assuming a slight lag in learning effects, the market price in any year is indicated by the experience curve using cumulative production from the *previous* year. That is, from equation 5. Over time, prices fall along the experience curve until they reach a price floor, *z*.

For both the buydown and no-subsidy scenarios, the analysis assumes isoelastic demand, —, where l_t is the parameter that shifts demand outward every year according to a logistic function defined in chapter 5, _ is the price elasticity of demand, and *WTP* is consumer *willingness to pay* for the technology. This traces out the demand schedules shown in Figure 4.

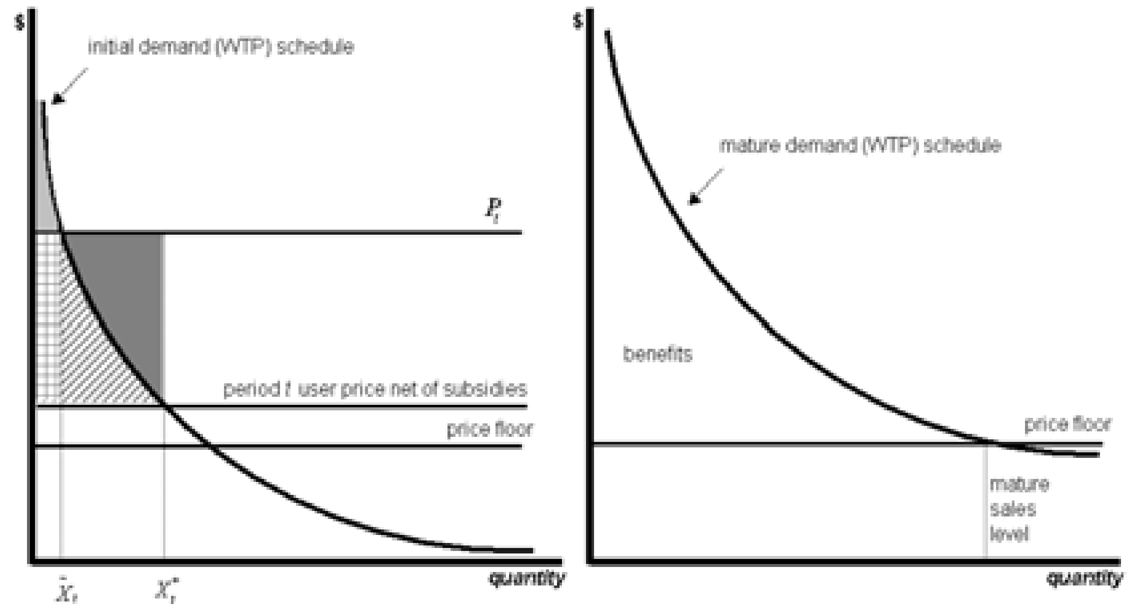

Figure 4. Buydown cost and benefits using the optimal path method

Under the no-subsidy scenario (NSS), the quantity demanded in year *t* is and consumer surplus is the lightly shaded region on the left side. With an optimal buydown, the quantity demanded increases and the minimum cost of the buydown during year *t* is the darkly shaded area. If the government cannot price discriminate, then subsidy costs rise to include the hatched region, and if it cannot exclude free riders then subsidies also include the crosshatched rectangle. As shown on the right, demand shifts outward as a function of time until it reaches the “mature demand schedule” (once all potential buyers are fully informed about the product and the market has been fully conditioned). Given sufficient niche markets, then even under the NSS cumulative output ultimately pulls the competitive price down to the price floor such that the quantity demanded rises to “mature sales level” and the total consumer benefit increases to the unshaded triangular area marked benefits. Under a buydown, these price reductions come more quickly and the higher present value of this accelerated stream of benefits more than offsets the initial buydown cost.

The figure assumes perfect spillover and competitive markets such that price equals unit cost including a fixed competitive profit margin, as determined by the experience curve using cumulative output in year *t-1*.

The consumer surplus in any period, t, equals — given that the quantity demanded is X_t. There is no producer surplus (or loss) since it is assumed that all producers earn a normal competitive profit margin on their invested capital.

For the NSS, the isoelastic demand and lagged experience curve determine while the optimal buydown path, , is calculated to maximize NPV defined as,

(7)

where the analytic timeframe, T, is explained below while P_t and are the competitive prices as determined by the experience curve with a one-period lag, under the optimal path and no-subsidy scenarios, respectively. Thus, the first and second of the bracketed terms in equation 7 calculate the stream of consumer surplus over the period from 0 to T under the buydown and no-subsidy scenarios, respectively. The second term (NSS) is always nonnegative since without subsidies there will be no sales for which WTP falls short of the competitive price. The no-subsidy constraint is relaxed for the first term (buydown scenario) and sales levels in each period are set consistent with the optimal path that maximizes NPV over the entire analytic timeframe from 0 to T. The buydown term can therefore be positive or negative in any given period because it estimates consumer surplus net of buydown costs (Figure 4). Until P_t falls to the price floor, the optimal buydown path always involves some subsidies that lower the net price paid by marginal consumers to the true marginal cost, as defined by the first order condition from equation 3 in Chapter 2. This accelerates progress along the experience curve and thereby increases consumer surplus in all subsequent years such that the overall welfare impact of the subsidies is positive.

There are two primary cases: 1) NSS sales are trivial because the initial price exceeds willingness to pay even in the best niche markets, *i.e.* such that the market never gets launched and, 2) NSS sales gradually pulls the technology down the experience curve until the price floor is reached.[43] Under the first case, NSS consumer surplus benefits are zero or trivial. Under the buydown scenario, if the market reaches a permanent steady state sales level (*i.e*. once the price floor is attained and the demand schedule has stopped shifting) a fixed quantity of consumer surplus, *X*, will be generated each year. As for the zero NSS sales case under the breakeven methodology, from that point forward the present value of this stream is simply *X/r*, by the perpetuity formula. In practice, however, it is likely that the technology will ultimately be displaced by a cheaper substitute at some unknown time. Thus, potential buydown benefits are large but uncertain in the event that there are insufficient niche markets to drive the technology to the price floor without subsidies. Under the second case, the economy ultimately reaches the same sales level under both the buydown and no-subsidy scenarios. Thus, *T* equals the time required for the economy to reach the price floor under the NSS.

There are also two principal cases to consider for estimating the total subsidies required in any given year of a buydown. If the government can exclude from subsidies those customers who would buy under the NSS (no free riders) and offer others the minimum marginal subsidy needed to induce them to buy (perfect price discrimination), then it can keep subsidy costs for any given year down to the darkly shaded area shown in Figure 4. This is defined formally as:

(8)

where is the quantity that would be demanded if there were no buydown subsidy in year t and is the sales level under the buydown. Note that this value is negative since P_t exceeds willingness to pay in this section of the demand schedule.

Assuming the government cannot exclude free riders or price discriminate, then its subsidy costs for any given year will be as shown in Figure 4 as the sum of the darkly shaded and crosshatched areas on the left side. Again, this value will be negative.

Technology selection criteria

Governments implementing a demand-pull component to energy policy must first decide which particular emerging technologies to support. By definition, buydowns only target technologies that have already been demonstrated. This forces the government to place bets on specific technologies rather than supporting broad scientific inquiry. Moreover, the high cost of the sustained subsidies necessary to open new market segments makes prioritization among competing clean energy options essential.

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[43] Technically, there is a third case in which NSS sales are significant but weak such that the price floor is never reached before the technology is displaced by some future option. In this case the analytic timeframe

All emerging energy technologies that have been successfully demonstrated are potential buydown candidates. The list includes 1) renewables such as PV, wind, advanced biomass, geothermal, and wave energy; 2) advanced fossil fuel technologies such as coal-derived hydrogen with carbon sequestration; 3) nuclear technologies such as pebble bed reactors; and 4) end-use technologies such as efficient vehicles, motors, and appliances. Among these options, technologies with the following characteristics will tend to generate the highest social NPV:

1. High learning-by-doing spillover (consistent with a competitive market structure and an industry-wide experience curve).
2. The technology has begun to sell in commercial niche markets and the emerging data suggest a reliably steep experience curve (low progress ratio) while technology assessment projects a low price floor.
3. Niche markets have proven insufficient to pull prices down rapidly (so the technology remains immature), but at lower prices demand is price elastic (flat) such that buydown subsidies can open up large markets (Figure 5).
4. Based on the preceding criteria, no other technology (including both incumbent and emerging substitutes) has better long-term prospects in the relevant market segments.
5. The targeted technology produces strong non-learning public benefits (*i.e.* public benefits not related to private under-investment in learning-by-doing).

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should extend only until NSS sales fall back to zero.

The first criterion ensures that buydown subsidies will accrue primarily to consumers rather than oligopolistic producers. It also means that demand-pull subsidies will no longer be needed once the price floor has been reached. In contrast, under low spillover, subsidies might help to further entrench the cost advantage of incumbent firms (Chapter 2), leading to on-going welfare losses from market power unless corrective subsidies are continued indefinitely. As an example, markets for PV appear to be highly competitive (Chapter 4) while markets for advanced nuclear technologies may tend to be oligopolistic because relatively few firms have the sophistication to compete in this sector and the industry is inherently secretive.

Figure 5. Conditions for a strong buydown NPV

This figure illustrates an example of conditions under which a buydown should yield a strong NPV. The demand schedule is inelastic in niche markets such that it would take many years to reach the mature sales level under the NSS. Assuming r = 0, the optimal subsidy would be set such that consumers a net price equal to the price floor in every period, dramatically accelerating the commercialization process. Note, however, the speed of the demand shift process plays a crucial role in determining the impact of the buydown since, as drawn, the most price elastic section of the demand schedule does not rise above the price floor until the market demand shifts out nearly to its mature level.

When the second and third criteria apply, a buydown can dramatically accelerate the positive feedback, or *virtuous cycle*, between increased demand (from price reductions) and price reductions (from increased sales), and thereby boost diffusion rates.[44] This introduces a tension in that strong niche market sales help to reveal the experience curve but they also obviate the need for a buydown. In particular, if there are sufficiently large high-value markets, NSS sales might bring the technology down its experience curve to the price floor relatively quickly. Nonetheless, even for technologies with strong niche markets, a buydown will substantially boost social NPV if unsubsidized sales levels are relatively low at high initial prices (*e.g.* the PV case developed in chapters 4 and 5).

Gauging these criteria requires data that are often proprietary and always uncertain—particularly early on when the potential return on a buydown investment is highest because marginal learning effects are strong. It is therefore impossible to evaluate the fourth criterion with complete confidence, making buydowns inherently risky. Note also that these information problems may be worse for large-scale technologies to the extent that there are fewer niche markets to reveal the demand and experience curve data. Nuclear technologies, for example, can only be sold to utilities or independent power producers and the electricity must prove competitive with wholesale rates that are relatively consistent within and even across different countries. In contrast, modular technologies like PV and high-efficiency consumer appliances may be able to gain a toehold based on sales to consumers with vastly different needs. Off-grid

[44] Duke and Kammen (1999) calls this "the indirect demand effect" and shows that accounting for this feedback substantially raises the benefit-cost ratio for buydown investments. Watanabe (1999) dubs the effect a virtuous cycle and explicitly incorporates the effect of increased sales volume on private RD^2.

consumers, for example, are often willing to pay an order of magnitude more than grid-connected consumers for PV or other distributed generation technologies. Similarly, the value of lighting technology is directly proportional to the annual hours of lighting required by different user groups.

These analytic uncertainties suggest focusing buydowns on clean energy technologies since they offer non-learning public benefits in addition to long-term cost savings. This provides a hedge against the risk of subsidizing a technology that does not provide the expected direct buydown benefits (*e.g.* because prices do not fall as fast as predicted by the historical experience curve). Super-clean technologies (*e.g.* fuel cell vehicles with onboard hydrogen storage) warrant particular buydown attention, but incrementally cleaner technologies may also deserve support as long as they fit the selection criteria outlined above and do not pose excessive lock-in risk. Internal combustion engine/hybrid electric vehicles, for example, though not nearly as clean as H_2 fuel cell vehicles, offer significantly lower emissions than conventional internal combustion vehicles, and their deployment in the near term would establish in the market the electric drive train technology that ultimately will be needed for fuel cell vehicles (Ogden, Williams, and Larson, 2002). Similarly, further buydown of wind power might make it marginally more difficult for grid PV to compete, but the risk is modest because these technologies excel in different niches. In particular, wind power works best in large-scale installations while grid PV has a comparative advantage in small-scale distributed applications (Chapter 4).

The criteria above help to identify promising buydown candidates, but the underlying parameters for the analysis are inherently uncertain and, even after successful technology selection, there remain substantial implementation risks. The chapter closes with a separate discussion of each of these challenges.

Analytic challenges

Experience curves provide valuable insight into future supply and demand trends for buydown candidates, but they are hardly laws of nature. Uncertainty about experience curves stems from many sources, including inadequate data, variations in RD^2 funding, and innovation breakthroughs or unanticipated periods of stagnation. This section considers the conceptual and practical concerns related to this technique.

Relation of experience curves to supply curves

Cumulative output, Y_t, can be redefined as current output, X_t, by treating the entire technology lifecycle as a single period. In this sense, experience curves define the *long-run marginal cost*, where the long run is the whole production period from 0 to T. As with conventional long-run supply, experience curves assume that producers anticipate output shifts and vary fixed-cost investments accordingly.

In case of unexpected demand shifts, however, firms cannot vary capital investments immediately. Thus, short-run marginal cost slopes upward because changing production given a fixed capital base is inefficient.[45] Also, the greater the share of market demand supported by buydowns, the higher the risk to manufacturers that the market will suddenly collapse because subsidies are discontinued, thereby stranding their investments. This may cause firms to withhold investments in private RD^2 and scale-up.

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[45] In response to rapid demand increases, producers may, for example, simply run overtime shifts on existing facilities, suffering productivity losses rather than achieving long-term cost reductions from

Governments can address these concerns by announcing credible buydown plans that ramp up slowly enough for manufacturers to anticipate higher sales and increase their capital investments accordingly. In principle, this strategy should avoid price spikes from unexpected production capacity constraints.

Experience curves and causality

For buydowns to work, cumulative production must largely determine prices, but other variables also may also play a causal role (Dutton and Thomas, 1984; Hall and Howell, 1985). There are three factors that stand out: 1) technological progress resulting from public RD^2 funding, 2) scale economies, and, 3) input prices. Analysts should thus consider the possibility that progress ratios may deteriorate (increase) if 1) increases in the combined total of public and private RD^2 lag behind increased sales levels; 2) the industry reaches its minimum efficient scale; or 3) technical progress in crucial inputs levels off. The latter two factors are only a concern, however, to the extent that scale effects and reduced input costs have partly driven historical experience curve trends.

Regarding the first factor, to the extent that technical progress occurs independently from production experience (the traditional linear model), declining costs from research progress will increase the quantity demanded in each period and, thus, boost cumulative output. There is, however, evidence that production experience and product use inspire a large proportion of technical innovation, particularly during deployment, which is the only innovation phase relevant to buydowns (Chapter 1).

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manufacturing scale-up. Opportunities to optimize production processes through learning-by-doing and use-inspired RD^2 may also suffer under these conditions.

Moreover, companies augment learning-by-doing with internal RD^2 that is often funded in rough proportion to sales revenue (Jelen and Black, 1983).

Regarding the second factor, to the extent that *current* production levels drive prices, analysis based solely on experience curve projections will be biased. In particular, it is likely that initial cost reductions will be relatively fast, until the minimum efficient production scale is reached, at which point progress ratios may increase (worsen). There are, however, sharp limits on the ability of any firm to reduce costs through dramatic scale-up without first working out the kinks in intermediate scale manufacturing facilities. Learning-by-doing is therefore an integral part of the process of ramping up production (Wene, 2000).[46]

Finally, input prices may vary. To the extent that this reflects exogenous shocks (*e.g.* oil price variation) it does not affect buydown NPV estimates except possibly by raising risk-adjusted discount rates. There may be cases in which growth in the industry directly raises input prices, such as the manufacture of crystalline PV modules that rely on a finite supply of low-grade silicon feedstock deemed insufficiently pure for the semiconductor industry. In general, however, buydowns may help to *reduce* the price of key inputs by providing demand-pull support that promotes learning-by-doing related to the manufacturing and efficient use of inputs. This phenomenon will be strongest when the inputs are new technologies developed primarily for the industry that is the target of the buydown, *e.g.* specialized manufacturing equipment. In the case of crystalline PV technology, for example, demand will eventually become large enough to justify

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[46] Efforts to scale up thin-film PV production, for example, have generally taken years longer than expected and during this period "learning was literally all that was happening" according to the manager of the U.S. thin-film PV program (Zweibel, 2002).

developing a dedicated supply chain of PV-grade silicon. Conversely, in the case of stand-alone PV systems (Chapter 4) lead-acid batteries are a major system input but the automobile industry dominates demand for this already mature technology, so there is little chance that PV markets will have any detectable impact on battery prices.

In principle, it would be useful to separate these factors. Isoard and Soria (1997) survey multiple empirical analyses showing that learning effects tend to dominate scale economies across multiple industries, including PV. Similarly, Watanabe (1999) performs an econometric analysis that suggests learning effects drive 70 percent of long-term price reductions in the Japanese PV industry.

It is also useful to determine whether time is a sufficient driver of cost reductions independent from cumulative production experience. Lieberman (1984) shows that a time trend independent variable becomes statistically insignificant as soon as a log of cumulative production is added to a regression model with log of price as the dependent variable. The same pattern applies to econometric analysis of the PV data used in this dissertation, *i.e.* adding a time trend variable to the basic univariate experience curve (equation 5) does not substantially affect the progress ratio estimate and the time trend becomes statistically insignificant. This suggests that autonomous technical progress (*e.g.* lab RD^2 that is independent from learning effects) has not been as important as cumulative learning-by-doing effects in driving cost reduction progress.

Grubler *et al.* (1999) employs a functional form that assumes costs decline as a function of cumulative combined expenditures on RD^2 and deployment. In principle this corrects for the failure of standard experience curves to account for RD^2 expenditures; however, this approach is constrained by the scarcity of technology specific data for private RD^2 expenditures. Similarly, Barreto (2001) explores various multivariate models including one that includes cumulative RD^2 expenditures and cumulative production experience as separate variables driving cost reductions—but he cautions that serious problems remain regarding data quality and complex interactions between these two factors.

Given these difficulties, the conventional experience curve is a reasonable and parsimonious model—providing a good empirical fit because the increasing sales volume required for each respective doubling simulates the slowing rate of cost reductions from scale economies, learning-by-doing, and reduced input costs as a technology matures. Nonetheless, it is important to examine the sensitivity of buydown NPV estimates to the progress ratio parameter as done for the PV case study in chapter 5.

Microstructure in experience curves

Wene (2000) usefully standardizes experience curve methodology, insisting, for example, that prices and cumulative production measure the same units;[47] however, it also suggests that buydown designers should consider structural technological shifts and variable profit margins that may produce "knees" in experience curves, as first argued by BCG (1972). Such *microstructures* no doubt occur, but they may be of limited forecasting value because available price data are often too imprecise to accurately identify them even retrospectively, let alone before or as they emerge.

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[47] The cost of wind electricity ($/kWh) should be compared to cumulative kWh generated rather than wind capacity (kW), for example. The latter comparison would produce spurious results because the $/kWh measure includes learning-by-doing not only in turbine manufacturing, but also in many other factors including site selection, installation, and maintenance. Progress in turbine production costs would be appropriately measured by comparing $/kW for turbines manufactured *versus* cumulative kW manufactured.

Consider first the question of technological shifts. Wene (2000) presents a PV experience curve based on European factory prices and cumulative global production of crystalline modules (Nitsch, 1998) and suggests that it may include a structural shift due to “changes in the production process” during 1984-1987. In fact, comparing these data with two other experience curves indicates that measurement error (*e.g.* exchange rate effects or shifts in the price sampling approach) or other anomalies may have determined the apparent microstructure (Figure 6). In any case, the long-term progress ratio for all three curves is identical (PR = 0.80).

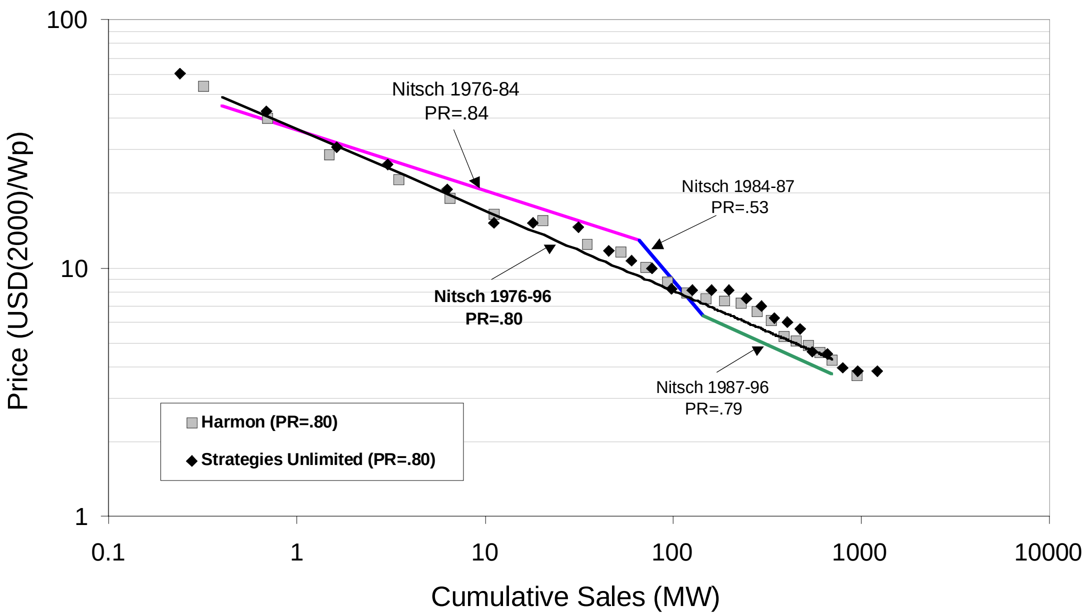

Figure 6. Spurious microstructure in PV experience curve

Comparing two all-PV experience curves (Johnson, 2002; Harmon, 2000) with the curve from Nitsch (1998) suggests that the apparent knee in the latter may be spurious. Nitsch (1998) uses European price data for crystalline modules, raising the possibility of an exchange rate anomaly or a shift in the price survey methods from retail to wholesale prices during 1984-1987. Despite apparent microstructure, the long-term experience curve for the Nitsch data has the same progress ratio (PR = 0.80) as the other two curves.

Turning to the question of profit margins, Wene (2000) shows Brazilian ethanol data (Goldemberg, 1996) divided into a flat initial period from 1978-1987 (PR = 0.90) followed by a steep section (PR = 0.47) from 1987-1990 and a resumption of more typical technical progress from 1990-1995 (PR = 0.78). Wene (2000) suggests that this may reflect initial forward pricing followed by profit taking that generated a *shakeout* after 1990 when new entry drove margins to a normal long-term level. Updated data reveal a similar microstructure with slightly shifted dates (Figure 7), but suggest that the apparent shakeout in the late 1980s was merely a wobble in an uncertain experience curve (R^2 = 0.83).

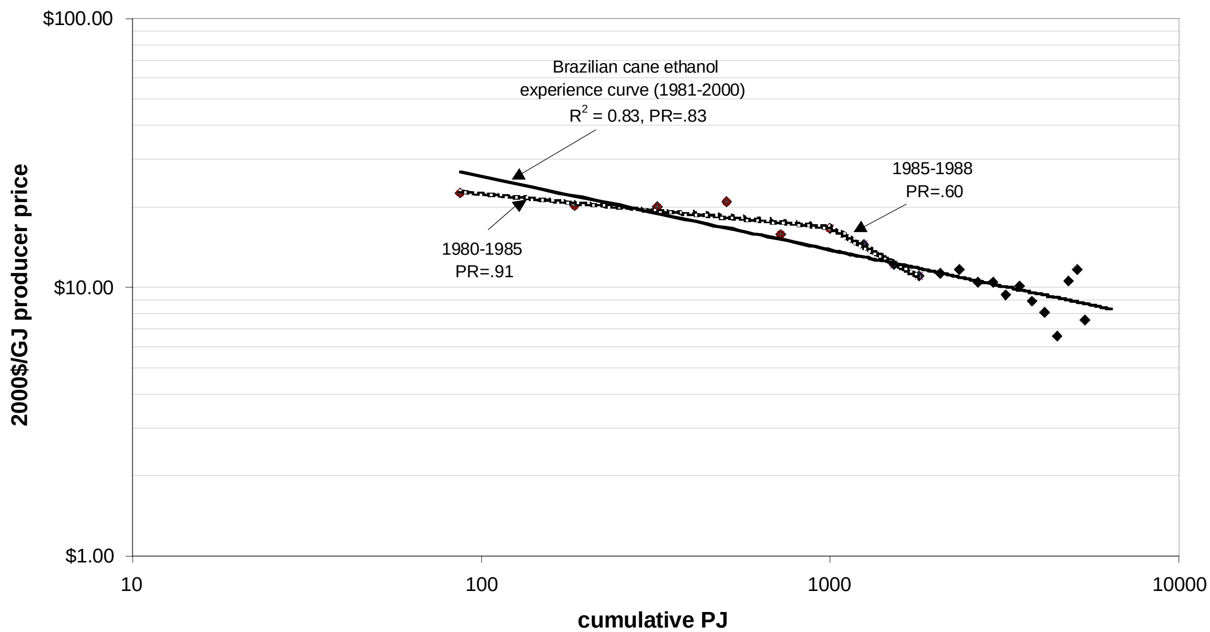

Figure 7. Brazilian Ethanol Program

This figure shows price data for the Brazilian cane ethanol program, highlighting the apparent 1985-1988 "shakeout" identified by Wene (2000). Subsequent data suggest that this was merely noise around an uncertain experience curve. Rask (1998) cautions that historical Brazilian ethanol data were distorted by government production quotas and price controls, though current and future data should be more reliable now that over 70 percent of production is unsubsidized (Walter, 2002). Source: ethanol data from Goldemberg (2002).

Since PV module manufacturing is a competitive industry characterized by substantial learning-by-doing spillover, profit margin variability is a relatively minor concern. It is, nonetheless, important to consider the impact of relaxing the perfect spillover assumption. In particular, to the extent that they can partially prevent innovation spillover, private companies may forward-price (Chapter 2). During the period of forward pricing and the subsequent transition to temporary extra-normal profits, the apparent progress ratio will be higher (worse) than the true progress ratio (Figure 8). During the subsequent shakeout, the apparent progress ratio will be abnormally low as new competition (brought by innovation spillovers or the development of cheaper technology variants) forces profit margins to normal levels, revealing the true progress ratio.

Estimates of the social cost of a buydown should ideally include producer losses attributable to forward pricing (plus public subsidies used to cover the gap between willingness to pay and price) while total benefits should include extra-normal producer profits (plus consumer surplus). Analysts cannot directly estimate producer losses or subsequent extra-normal profits using observed experience curve data, but this does not pose a major problem. First, if spillover levels are high, firms will not forward price aggressively. Second, under conditions of partial spillover and imperfect competition, the present value of any forward-pricing costs that incumbent firms incur should be roughly similar to subsequent extra-normal profits.[48] Analysts using observed prices would therefore underestimate buydown costs and benefits by a similar amount, leaving the buydown NPV estimate qualitatively unaffected (Figure 8). Finally, for a strong experience curve, changes in the price/cost margin should introduce only small deviations relative to the pronounced cost reduction trend.

Technological discontinuities may occur and bottom-up technology assessment gives analysts some ability to predict them. Similarly, profit margins may shift according

[48] If expected extra-normal profits exceed forward-pricing costs, new firms would enter the business until the profit opportunity evaporates. Under converse conditions, existing firms would either exit or forward price less aggressively until the expected net loss from forward pricing was eliminated.

to theoretically predictable patterns (Chapter 2). Nonetheless, top-down experience curves rarely provide sufficient precision to detect such shifts reliably. Rather, analysts can reduce uncertainty by using all available data points when estimating long-term progress ratios, while remaining cognizant of the potential for progress ratios to shift.[49] Again, this discussion underscores the importance of sensitivity analysis as well as cross checking experience curve projections with bottom-up technology assessments.

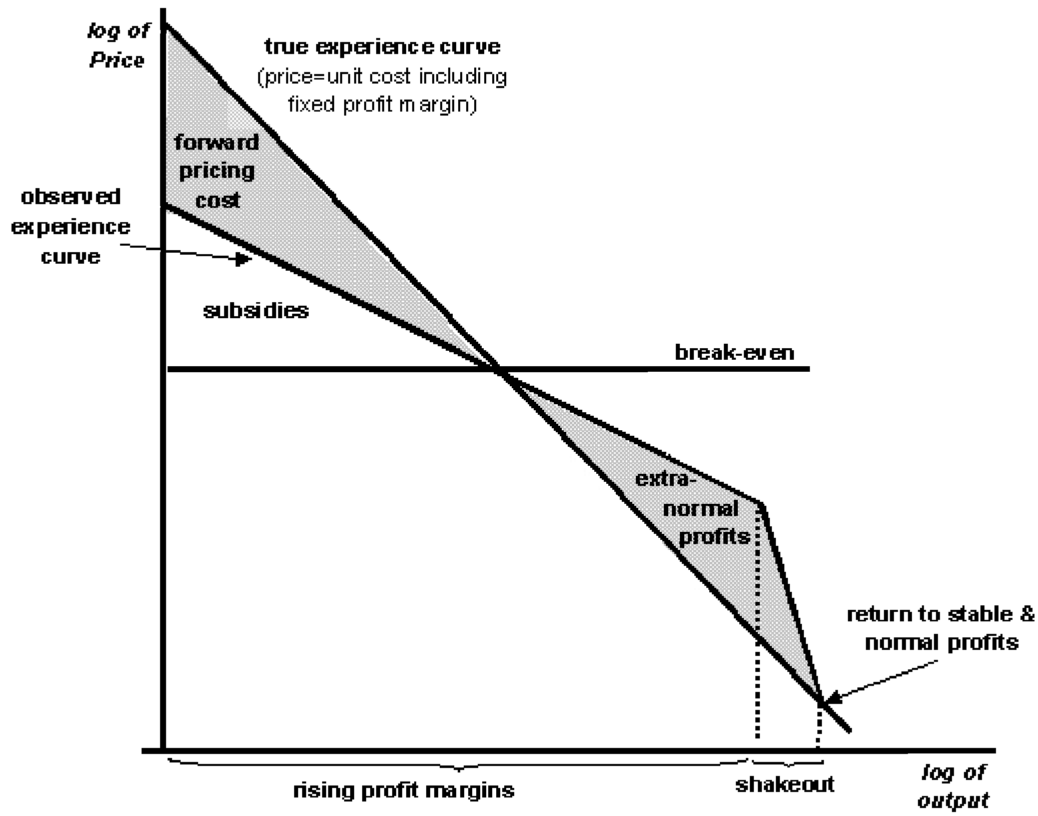

Figure 8. Using observed prices to estimate buydown NPV

For firms able to partially or fully retain experience benefits, the *observed experience curve* initially lies below the *true experience curve* (*i.e.* for a fixed competitive profit margin) due to forward-pricing. Firms subsequently gain market power and earn *extra-normal profits* that draw new entry during the *shakeout,* which eventually forces profits back to normal. Analysts can use observed prices to calculate buydown NPV despite shifting profit margins. First, experience benefits generally spill over, mitigating both

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[49] Obtaining historical data that use consistent protocols is also important, particularly given the uncertainties introduced by the large range between wholesale and retail prices.

forward-pricing and subsequent market power effects such that observed prices adhere closely to the *true experience curve*. Second, firms that can partially retain experience benefits will forward price to the point that expected *extra-normal profits* approximately equals *forward-pricing costs*. Thus, using observed prices should underestimate the discounted social costs and benefits of a buydown by a similar amount, yielding a roughly accurate NPV estimate.

Implementation challenges

Governments implementing buydowns face a range of challenges beyond analytic uncertainty—including concerns about subsidy efficiency and regressivity, decisions about timing, and the risk that lobbyists will determine technology selection rather than objective analysis.

Subsidy targeting, regressivity, and the marginal excess burden

In practice it is difficult to target subsidies accurately, and distributing buydown funds may involve transactions costs, so the total subsidy required may be substantially higher than the minimum possible expenditure (darkly-shaded area in Figure 4). Such *transfer subsidies* are transfer payments rather than direct economic costs. They do, however, require governments to raise revenue by taxing other sectors of the economy.

There is a substantial literature arguing that transfer payments impose welfare losses by constraining economic activity in the sectors taxed to fund the programs. Parry (1999) estimates the *marginal excess burden* (MEB) of taxation using Monte Carlo analysis of estimates from the literature to estimate a 68 percent probability that the MEB for funding any given transfer payment ranges from 0.31 to 0.48, with a central estimate of 0.39. For spending on public goods, the comparable range is from 0.21 to 0.35, with a central estimate of 0.27. The “minimum possible subsidy” component of buydown costs represents investment in a public good (clean energy commercialization), suggesting that the lower range would be most appropriate. Arguably, however, the higher range might apply for the transfer subsidy component of clean energy buydowns. On the other hand, the MEB could be far lower or even negative to the extent that governments fund buydowns by raising the price of conventional energy that does not already fully reflect pollution externalities costs. For simplicity and conservatism, this dissertation uses an average of the two central estimates from Parry (1999), *i.e.* 0.33, for the sensitivity analysis that incorporates possible MEB effects in chapter 5.

Kaplow (1996) presents an elegant and novel argument (not directly considered in Parry, 1996) that it is possible to finance public goods without incurring any net distortionary losses by adjusting the existing income tax to offset the benefits of the public good. He argues that governments often crudely approximate such adjustments over the long-term. Absent these compensatory measures, he convincingly argues that the net social cost of public funds is unclear because redistributive effects must be evaluated in addition to distortion costs. The base case PV analysis in chapter 5 therefore makes the assumption that the cost of public funds does not involve a distortion premium, *i.e.* the MEB is zero.

There are nonetheless concerns about the distributive implications of buydowns, particularly in monopolistic industries where producers may be able to capture some of the subsidies as extra profit. This suggests limiting buydowns to competitive industries or at least restricting support to industries characterized by high learning-by-doing spillover, such that the subsidies do not worsen market concentration.

Buydown advocates sometimes argue for targeting demand-pull benefits to low-income groups to alleviate poverty and commercialize clean technologies simultaneously (G8, 2001); however, it is important to keep program priorities straight. Higher income customers are generally the earliest adopters of emerging energy technologies and they often have specialized demands (*e.g.* a desire for backup electricity systems) and may even be willing to pay a "green premium." Thus, governments can often leverage scarce buydown funds most efficiently by targeting markets that favor wealthier consumers. Similarly, the case of solar home systems (SHS) in developing countries (Chapter 4) suggests that poverty alleviation and clean technology promotion may be most efficiently pursued with separate mechanisms, notwithstanding widespread rhetoric to the contrary. Realizable markets from SHS sales are simply too small to make a major contribution to global PV buydown efforts.

Careful program design can also mitigate regressivity. Targeting buydowns to appropriate market segments and using competitive subsidy mechanisms reduces the risk that program participants will receive windfall benefits (Chapter 5). Also, some governments may deem programs that increase the price of conventional polluting energy (*e.g.* the quantity mandates recommended in chapter 5) to have desirable equity implications to the extent that they help to ensure that "polluters pay." Finally, non-participants also benefit from any pollution reduction and energy diversification resulting from the buydown.

The politics of buydowns

Wilson (1989) highlights the political durability of programs that provide concentrated benefits funded with broad-based taxes. Concentrated benefits motivate active lobbying on the part of program beneficiaries while dispersed taxpayers may fail to organize any opposition because there are substantial transaction costs involved in such *collective action* and it is difficult to exclude political free riders (Olson, 1968).

Cohen and Noll (1991) highlight the concern that government RD^2 spending is too often distorted by such "pork barrel" politics,[50] noting that even programs that fail to meet their stated objectives rarely reach the level of political saliency necessary to penalize the politicians that supported them. Thus, there is a tendency for RD^2 programs to self-perpetuate—which is particularly problematic given that the conventional strategy entails winnowing under-performing investments from the broad portfolio of RD^2 projects that receive initial backing.

The political economy of buydowns is similar but arguably less worrisome. First, targeting buydown funding to only the most promising technologies is both necessary (buydowns are often far more expensive than RD^2) and feasible. Uncertainty about the long-term prospects of a technology declines as it moves from the laboratory to initial demonstration and deployment. This gives policy makers attempting to design demand-pull strategies opportunities to "pick winners" successfully. Second, the direct beneficiaries of RD^2 spending are obvious and highly focused: the laboratories and companies slated to receive government contracts. These groups have a strong incentive, and face relatively modest collective action challenges to lobby to get their piece of the pork. In contrast, for buydowns, some share of the benefits accrues to a customer base that may not even be aware of the technology before the buydown begins. The remainder will accrue to manufacturers and installers; however, unlike RD^2 spending which may be *de facto* or explicitly earmarked for specialized labs or companies, well-structured buydowns should never specify which companies are eligible suppliers (Chapter 5).

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[50] The authors limit their scope to federal *commercial* RD^2 projects, defined as RD^2 that could not be considered a success unless the technology ultimately achieves substantial commercial deployment. This is

Third, unlike RD^2, certain buydown implementation strategies impose large costs on small numbers of companies (*e.g.* the Renewable Portfolio Standard described in Chapters 4 and 5). Collectively, these factors suggest that *relative to RD^2* organized lobbying in favor of initiating new buydowns is likely to be weak while organized opposition will be strong. This moderates the risk that bad buydown programs will be launched.

As with RD^2, once a buydown has been launched the beneficiaries become clearer. Certain companies will emerge as the lead equipment and services providers, and some of these will undertake production capacity expansions that will prove a serious economic burden if the buydown is prematurely terminated. Moreover, by definition, a successful buydown will allow the industry to grow and thereby strengthen its lobbying ability. Similarly, on the customer side certain regions may emerge as lead niche markets for the technology, giving their political representatives incentive to lobby to continue the program.

In sum, it is both possible and essential to avoid launching mediocre buydowns because they are increasingly hard to kill once underway. The next section provides a vivid example of the risks of launching a misguided buydown.

Lessons from the U.S. Grain Ethanol Program

Starting with the Energy Tax Act of 1978, the U.S. initiated a subsidy program to promote corn-derived ethanol as a transportation fuel, used both for its fuel value and as an octane rating enhancer for lead-free gasoline in a 10 percent blend with gasoline,

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the type of RD^2 most relevant to demand-pull programs; however, the authors do not focus attention on demand-pull commercialization programs that target the deployment phase.

dubbed gasohol. The program exempted gasohol from a portion of the federal gasoline excise tax: a subsidy worth $0.40/gallon of the ethanol added to gasoline initially, $0.60/gallon during the late 80s, and $0.54/gallon since 1990. There have also been various state-level ethanol subsidies, while massive agricultural subsidies also support ethanol markets by keeping the price of corn artificially low. Multiple studies suggest that, even after two decades of massive support, gasohol production would cease if even just the federal tax subsidies were removed.[51]

The cumulative federal subsidy for ethanol from 1980-2001 is $13 billion in constant 2001 dollars.[52] Most of this represents a pure welfare cost rather than a transfer payment[53] or buydown investment. The ethanol experience curve[54] indicates a progress ratio of 0.93, with a 95 percent confidence interval ranging from 0.85 to 1.01 (Figure 9).[55]

Even with a universal mandate that all gasoline contain 20 percent ethanol, as of 2030 the projected price of corn ethanol would remain above its current breakeven price[56]

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[51] GAO (1997) estimates that "without the [federal excise tax exemption] incentives, ethanol fuel production would largely discontinue." Similarly, Crooks (1997) estimates that without the federal tax subsidy, ethanol could not compete even if corn were free unless crude oil prices were at least $25/barrel. Long *et al.* (1997) draws the same conclusion for Minnesota ethanol producers.

[52] The historical taxation rate chronology is from GAO (1997). Annual fuel ethanol use derived assuming 10 percent average gasohol blend during 1980-1992 and using Table MF-33E from FHWA (2000) and previous years of the annual report.

[53] Rask (1998) estimates that during winter months some Midwestern buyers would be willing to buy ethanol as an oxygenate for as little as $0.20/gallon in subsidy rather than $0.54/gallon. For these customers the $0.34/gallon "excess subsidy" could be considered a transfer rather than a welfare loss, but the essential point remains.

[54] Price data for 1989-1997 and for the year 2000 are from various issues of Oxy-Fuel News. Annual production numbers since 1980 are from FHWA (2000). Note that large volume production did not begin until 1982.

[55] Grain prices are volatile and determine nearly half the costs of producing ethanol, but adding a variable for historical corn prices to the model specification leaves the progress ratio estimate and confidence interval essentially unchanged and does not improve the model fit substantially. Note also that most producers in the industry had already approached their minimum efficient scale more than a decade ago, so there is little concern about the omitted scale effects distorting the results (USDA, 1986; Crooks, 1997).

[56] The breakeven method suffices in this case since demand for gasoline substitutes and additives is highly elastic (price-sensitive and well-informed corporations control the gasoline refining process and they will quickly switch to a cheaper option if it becomes available). Also, the point of this section is to provide a

as a fuel substitute despite additional subsidies totaling $150 billion in present value terms (r = 0.05). Thus, for any reasonable discount rate, the net present value of both the historical and current ethanol subsidies would be sharply negative.

Ethanol can also be used as a fuel *additive* to improve the environmental performance of lead-free gasoline, and its prospects are more promising in this market segment. The Clean Air Act Amendments of 1990 established the Federal Reformulated Gasoline (RFG) Program to reduce emissions of ozone precursors[57] in so-called “non-attainment” areas which account for about 30 percent of the gasoline consumed in the U.S. (EPA, 1999). These metropolitan zones use various oxygenates to comply, including methyl tertiary butyl ether (MTBE) which accounts for about 85 percent of the RFG market, ethanol which accounts for 8 percent, and two others[58] that account for the remainder (EPA, 1999).

Ethanol’s low market share suggests that it does not yet compete well even in the high-value markets for reformulated gasoline,[59] but recent regulatory developments may dramatically increase its use. MTBE contamination of ground water prompted California to announce plans to ban MTBE in December of 1999 (EIA, 2000a) and Congress has begun to contemplate a federal MTBE ban.

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crude estimate of the costs and potential benefits of the ethanol subsidy program rather than attempting to prescribe a detailed buydown subsidy time path. Finally, it is not possible to employ the optimal path approach without developing a detailed ethanol demand study, a project that lies beyond the scope of this analysis.

[57] The culprits are volatile organic compounds and oxides of nitrogen.

[58] These are ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME).

[59] In the Midwest where it is produced, subsidized ethanol is cheaper than MTBE; however, most of the non-attainment areas lie on the coasts and transport costs make ethanol less competitive in these markets because it is too corrosive to be sent through existing pipelines (Rask, 1998).

Given the federal ethanol subsidy, a national MTBE ban might more than double ethanol sales;[60] however, the environmental impacts of ethanol remain in dispute. When added to gasoline, ethanol raises the vapor pressure, which promotes evaporation of pollutants.[61] In terms of greenhouse gases, Wang *et al.*, (1997) concludes that grain ethanol use results in net greenhouse gas reductions, but the authors surveyed eight studies showing net greenhouse gas emissions ranging from negative 70 percent to positive 80 percent. This variance suggests that any net gains are likely to be marginal. There are also negative environmental externalities associated with growing grain, including pesticide and fertilizer runoff.

If the federal ethanol subsidy were removed, then other (possibly more benign and cost-effective) alternatives could compete on a level playing field. According to the EPA:

> In the event of an MTBE phase down with oxygenate flexibility, refiners have a number of blending options to meet RFG performance standards, including increased use of alkylates, aromatics, and perhaps other fuel blending streams derived from petroleum. (EPA, 1999)

Moreover, these options are new and may therefore benefit from relatively strong learning-by-doing effects (though they are similar to compounds already on the market so price reduction progress could prove modest). If the massive federal ethanol subsidy

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[60] This estimate is based on figures in EIA (2000a), and it incorporates the fact that ethanol's oxygen content is double that of MTBE on a volume basis and the oxygenate market accounts for less than half of current ethanol sales.

[61] This releases compounds that may increase atmospheric formation of ozone (Wyman, 1999) and certain other pollutants, including peroxyacetylnitrate (PAN) and acetaldehyde (Hathaway and Hawkins, 1999). Vapor pressure is not a concern during cold weather, and regions suffering from wintertime carbon monoxide problems primarily rely on ethanol rather than MTBE to comply with the relatively small Wintertime Oxyfuel Program designed to tackle that problem (USEPA, 1999).

remains in place, however, it is likely that such innovation will be limited and, at least in the near-term, ethanol will capture most of the MTBE replacement market.[62]

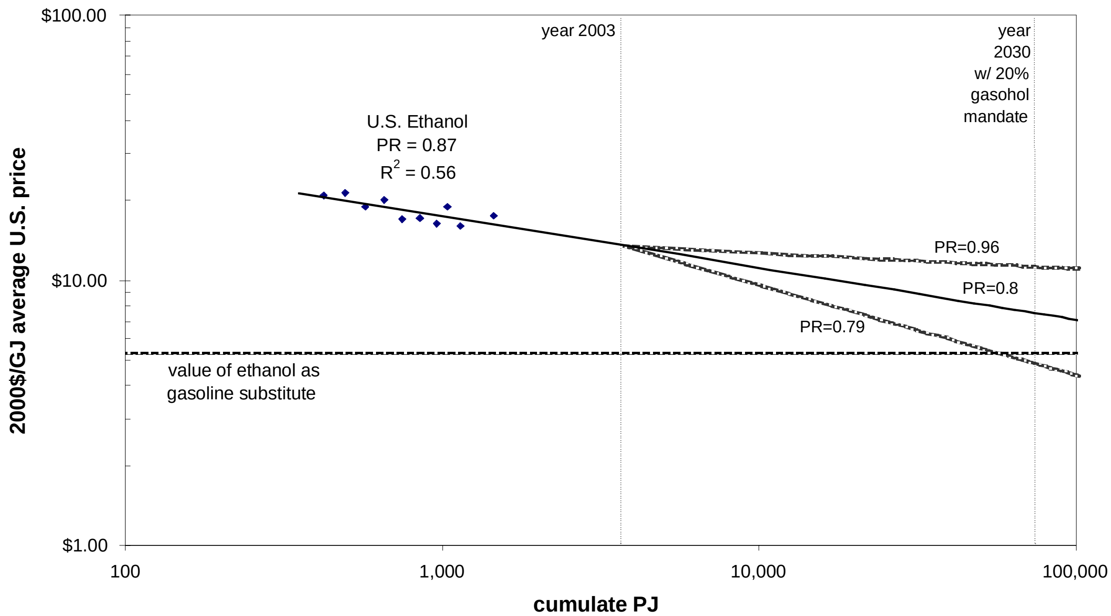

Figure 9. U.S. grain ethanol program

During the past two decades U.S. grain ethanol has received over $13 billion in federal subsidies plus substantial state-level funding. During the subsidy period 1989 to 2000 (excluding missing data points for 1998-1999), prices declined roughly in accordance with an experience curve (PR = 0.87) but the fit is poor such that the 95 percent confidence interval ranges from PR = 0.79 to PR = 0.96. Even requiring universal use of a 20 percent ethanol "gasohol" blend would leave ethanol costing more than gasoline (based on relative LHV energy content and average gasoline spot market prices from 1991-2001) after $150 billion in additional present value subsidies. Eliminating import barriers and using cheaper Brazilian ethanol would lower the NPV cost of a 20 percent gasohol mandate to $10 billion (r = .05). Source: Experience curve for 1989-2000 derived from EIA-819M and Oxy Fuel News.

The ethanol subsidy also distorts international trade. Brazil produces roughly three times as much (sugar cane derived) ethanol per year as the U.S. at about half the

[62] California Governor Gray Davis requested that the EPA exempt the state from gasoline oxygenation requirements to avoid the cost and possible environmental drawbacks of switching from MTBE to ethanol, which is considered the only viable alternative at present. In June 2001 the EPA denied their request, and the state of California responded with a lawsuit contesting the decision. The Natural Resources Defense Council (NRDC) backed the state's legal action, arguing that oxygenate mandates interfere with the state's ability to creatively reformulate gasoline in order to more effectively meet emissions performance standards while minimizing the risk of groundwater or other contamination.

unit price (Goldemberg, 2002). Imports face an effective tariff equal to the federal ethanol subsidy, however, making it difficult for them to compete in the U.S. market.

In sum, the U.S. ethanol subsidy program has proven extremely costly thus far and shows little sign of reducing ethanol's cost to the point that it becomes a cost effective gasoline substitute. Unanticipated additive markets may offer some consolation, but this cannot justify further subsidies, let alone the accumulated $13 billion in subsidies for ethanol to date, particularly since there is a range of promising reformulation alternatives that might flourish if the ethanol subsidy were removed.

Despite this dismal track record and uncertain future, the ethanol subsidy remains politically sacrosanct, largely because of the legendary lobbying machine of Archer Daniels Midland (Carney, 1995), the corporation that accounts for nearly half the domestic ethanol production capacity (GAO, 2002). Thus, this case underscores the perils of launching a "buydown" that generates its own constituency and perpetuates itself long after it should be shut down due to underperformance.[63]

Importantly, these problems were foreseeable and foreseen by many. Early bottom-up technology assessment suggested that the program's prospects were poor from the beginning (USDA, 1986) and, as it emerged, the ethanol experience curve confirmed that progress was likely to be disappointing (technology selection criterion 2). More fundamentally, grain ethanol was anything but an immature technology even in 1980 (technology selection criterion 3).[64] Consequently, the relevant experience curve for fuel

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[63] It may also indicate the need for complementary antitrust regulation. Note that in this case the market concentration probably cannot be attributed to proprietary learning-by-doing (Chapter 2) since learning effects have been so weak.

[64] Morris (1993) reports that total ethanol production in the late 1850s exceeded 90 million gallons (about 6 percent of current production levels), though production dropped after 1861 when ethanol became subject

ethanol may really have been one that reflected the long history and large cumulative production from these closely related industries. Taking this production experience into account should have indicated that future rapid cost reductions were unlikely.

The U.S. nonetheless turned to ethanol in the 1970s because of concerns about dependence on foreign oil in the wake of the 1973-74 oil embargo (USDA, 1986). Thus, the U.S. grain ethanol program was adopted in a crisis mode under the fear that oil prices would prove much higher and more volatile than they have in the past two decades. It was therefore less a buydown effort than an insurance policy against fossil fuel price increases. This was clearly a mistake given that short construction lead times meant that the government did not need a massive demand-pull subsidy to hedge against a sustained rise in the price of oil. Part of the appeal of ethanol, in fact, was that the "industrial and beverage ethanol industries had perfected the production process" and new distilleries could be brought on line in just 11-26 months (USDA, 1986). Moreover, since ethanol production did not produce net energy when the subsidy was initiated, the program required technical progress to succeed even as an insurance policy (technology selection criteria 4 and 5). As noted, the net energy contribution from ethanol production remains controversial twenty years later, further confirming the program's dismal record (Bovard, 1995; Wang *et al.*, 1997).

Finally, there is considerable interest in emerging technologies to produce cellulosic ethanol from much cheaper feedstocks like paper and agricultural wastes or fast-growing biomass (Hathaway and Hawkins, 1999). Bottom-up technology

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to a liquor tax which was not lifted until 1906. Ethanol production peaked again at ten million gallons per year in 1914 and was used widely both as a fuel and especially as a manufacturing input until Prohibition assessments suggest that there is potential for this new form of biomass to prove competitive with conventional fossil fuels (Lynd, 1996; Wyman, 1999). The failures of grain-derived ethanol should not tar the reputation of this technology, with its potential for rapid initial cost reductions because it is immature. At the same time, the existing generic ethanol subsidy is clearly misguided. Some form of support targeted exclusively to cellulosic ethanol would be dramatically less expensive and have the potential to pay large dividends. This might also free up funds for supply-push and demand-pull support of other emerging clean transportation fuel options such as hydrogen derived from fossil fuels with carbon sequestration. Meanwhile, reducing tariffs on imported ethanol (mainly from Brazil) would be the cheapest way to meet any short-term surge in demand attributable to the MTBE phase-outs.

Summary

The massive on-going subsidies for grain-derived ethanol underscore the potential for focused political interests to perpetuate technology subsidies once they are in place. At the same time, this example suggests that *ex ante* technology assessment can identify buydowns that are likely to fail. It was obvious at the ethanol program's inception that the technology was already relatively mature so that it failed to comply with multiple technology selection criteria. This suggests that it is possible to make effective demand-pull investments by using the technology selection criteria as an initial screen and conducting careful top-down and bottom-up analyses of promising candidates before initiating any buydown funding.

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began in 1919. Crooks (1997) reports that modern fuel ethanol production technology is essentially the same as the equipment and processes used by the beverage and industrial alcohol industries.

The next two chapters present the PV case study. Chapter 4 provides background on PV technology and argues that PV fits the buydown technology selection criteria. Chapter 5 then applies the modeling techniques developed in chapters 2 and 3 to quantify the net benefits from accelerated global efforts to commercialize PV and define an optimal buydown path.

Chapter 4: Background on PV technology and markets

The US government began powering satellites with PV starting in 1958 and various firms pioneered terrestrial markets for low-cost low-efficiency modules starting in the mid-1970s (Perlin, 1999). Off-grid users have taken advantage of the technology's unique modularity, portability, and reliability to power an expanding array of stand-alone applications; electronics manufacturers have developed a range of PV-powered consumer goods; and governments have sporadically (but with gathering force in the past five years) supported grid-connected PV.

Collectively, these commercial and government-supported markets have driven overall PV sales growth at a compound annual rate of 24 percent since 1980 (Johnson, 2002), with grid markets becoming increasingly dominant. Nonetheless, PV still provides only 0.02 percent of global electricity[65] relative to a potential grid-connected market of at least 10 percent, even without storage (EPRI/OUT, 1997). Absent continued and intensified government support, grid-connected markets will emerge slowly if at all—but accelerated buydowns targeting grid-connected markets have the potential to make PV a major source of global energy by mid-century. In addition to direct cost savings, this would yield tremendous non-learning public benefits, most notably by reducing reliance on fossil fuels that are either dirty (coal) or subject to price volatility (natural gas). Note that the public benefits value of the latter could be estimated by

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[65] 1.9 GWp installed capacity * 1700 kWh/m^2-yr insolation = 3.2 tWh/y, or 0.023 percent of the 14,000 tWh of global electricity consumption in 2002 (Johnson, 2002; EIA, 2002b).

considering the government's willingness to pay for insurance against economic disruptions induced by energy price shocks.

This chapter provides background on PV technology, details its conformance with the buydown criteria outlined in Chapter 3, and summarizes the state of international support programs.

PV Technology

Photovoltaic cells convert sunlight directly to electricity using semiconductor material doped with impurities such that one layer (n-type) has a surplus of mobile electrons while another (p-type) has a deficiency (Green, 2000). The energy from light creates a direct current flow through a circuit (p-n junction) formed by contacts on the top and bottom of the cell.

Under the general category of PV there are several competing *sub-technologies* relying on a range of different semiconductor materials and manufacturing processes, with varying costs ($/Wp) and solar conversion efficiencies. At present, module conversion efficiencies range from about 5 to 15 percent. High efficiency modules have an advantage in space-constrained applications, but in the most promising market segments low-efficiency modules are competitive if they offer a lower cost in $/Wp terms.

PV sub-technologies can be broadly classified into two groups: crystalline and thin-film. Crystalline cells launched the PV industry and continue to offer the highest technical efficiencies. Despite gradual inroads from other technologies, crystalline PV still has an 80 percent market share, of which 60 percent is multicrystalline and 40 percent monocrystalline (IEA, 2000). Both types of crystalline cells use techniques from the larger semiconductor industry and benefit from a low-cost supply of silicon that is off-spec for semiconductor applications but works well for PV manufacturing (Green, 2000). Monocrystalline cells are circular slices, less than half a millimeter thick, cut from a cylindrical ingot that has been pulled from a molten vat of silicon. Multicrystalline cells are cut from a block of silicon formed by cooling molten silicon within a rectangular mould. This process produces marginally less efficient cells but, because they are square, manufacturers can pack more of them onto each module.[66]

All crystalline cells go through a series of steps including: 1) chemical etching to leave a textured surface that captures light more effectively; 2) doping with phosphorous or other impurities to create the n-type impurity on the surface (the p-type dopant is usually boron that is added to the original molten silicon stock); and, 3) addition of top and bottom contacts (Green, 2000). Subsequently, multiple cells are soldered together in series and parallel to provide the desired voltage, and then encapsulated into a module.

The front-runner materials for thin-film modules include amorphous silicon (a-Si), copper indium diselenide (CIS), cadmium telluride (CdTe), and thin-film polycrystalline (Green, 2000). CdTe modules have achieved the highest technical efficiency levels in laboratory cells, but CIS has achieved the highest efficiency thus far (12.1 percent) in the large-area cells necessary to produce PV modules (Zweibel, 2002), and a-Si retains the largest market share among thin films. Thin-film modules involve deposition of fine active layers (under 1 micron) on glass or metal substrates. The most basic thin-film structure has a single p-n junction (or in the case of a-Si, a single p-i-n junction that includes an “intrinsic” layer) while more advanced modules stack two or

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[66] A third variant with a modest market share yields square cells by pulling a continuous ribbon out of the

more junctions on top of each other, each optimized to absorb a different range of light frequencies.

Manufacturers and independent labs rate PV modules according to their output under standard test conditions, defined as 1,000 watts/m^2 of solar insolation and a module temperature of 25 °C.[67] Field measurements suggest, however, that manufacturers routinely overrate their modules. Average performance levels for crystalline modules are also often just above the warranty level, which is typically about 90 percent of rated power (Hester and Hoff, 1985; Jennings, 1987, Lehman and Chamberlin, 1987, Chamberlin *et al.*, 1995). Similarly, the best quality single junction a-Si modules sold in Kenya stabilize at about 90 percent of rated power (Duke *et al.*, 2000). After a brief period of light-induced degradation, well-made a-Si modules exhibit long-term degradation that is roughly comparable to that for crystalline modules, *i.e.* 0-2.5 percent.[68]

PV market segments

PV first gained a commercial foothold by providing a lightweight and reliable electricity source for satellites. Starting with Vanguard I in 1958, PV modules had

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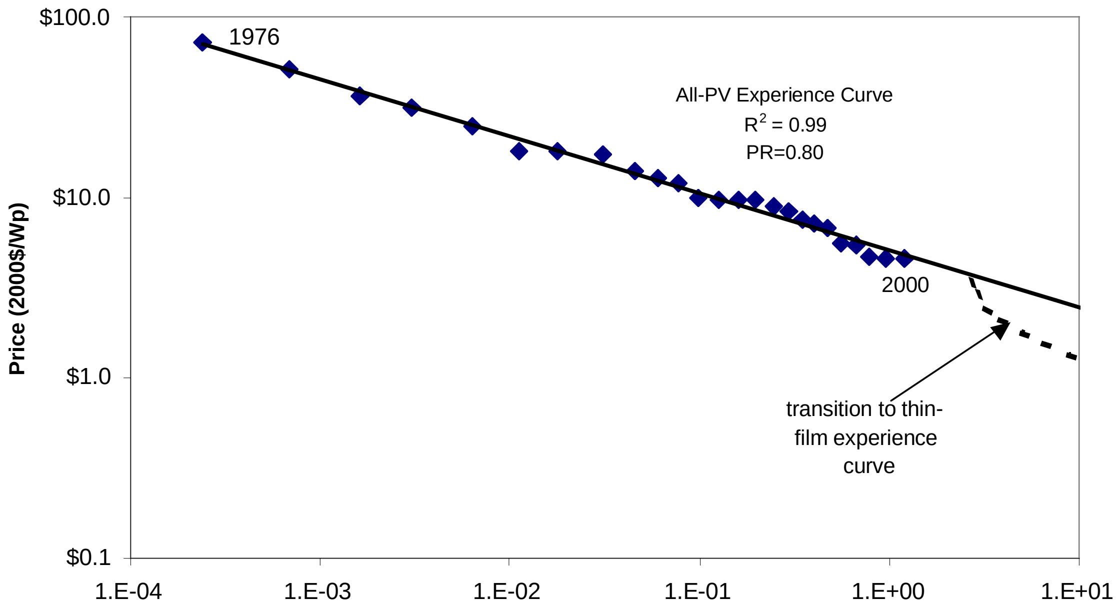
pool of molten silicon that is then cut into square cells (Green, 2000).

[67] Module power is approximately one-to-one proportional to insolation levels, while output voltage typically drops by ~0.3 percent per ˚C, yielding an approximately proportionate decrease in power output as module temperature increases (Green, 1982).

[68] The 2.5 percent figure should be considered an upper bound as it is derived from testing done on installations at the Photovoltaics for Utility Scale Applications (PVUSA) research facility in Davis, California, USA and much of this degradation may be due to *array level* effects such as corrosion in interconnections and degradation of power conversion equipment (PVUSA, 1998 and Townsend *et al*., 1998). Recent unpublished results from an 11-year old installation at Humboldt State University suggest far lower 0.4 percent annual degradation rates for certain crystalline modules. Moreover, some array-level degradation may be correctable by protecting circuitry from the elements, refining inverters, and improving encapsulation to more effectively limit PV module degradation attributable to corrosion. Other causes of long-term degradation in PV modules are complex and will vary according to the sub-technology in question.

powered about one thousand U.S. and Soviet satellites by 1972 (Perlin, 1999). This production experience, combined with 50 million dollars in U.S. research and development funding, brought prices down dramatically, but by 1971 PV still cost over \$400/Wp in 2001 dollar terms (Perlin, 1999).



Source: Johnson (2002)

Figure 10. PV experience curve

This figure shows the historical experience curve for crystalline and thin-film power modules (excluding small consumer cells and modules for space applications) based on average global wholesale prices plus a 20 percent retail markup. The experience curve indicates a tight fit and a 20 percent decline in price with every doubling of cumulative production (PR = 0.80). The 95 percent confidence interval ranges from PR = 0.79 to PR = 0.81 and the spread around the curve for PR = 0.80 is so tight that it is almost visually imperceptible and therefore not depicted. The figure also depicts the possible emergence of a new thin-film experience curve, with rapid progress during the transition due to the low initial cumulative experience with thin-film technologies (see discussion in main text, Chapter 4).

In the early 1970s, an Exxon affiliate, Solar Power Corporation, quickly dropped prices by a factor of five by prioritizing economic efficiency (\$/Wp) over technical efficiency (Wp/m^2), setting the stage for the first substantial terrestrial markets—using PV to power navigation aids and cathodic anti-corrosion systems in the oil industry (Perlin, 1999). Since 1976, annual sales have jumped 1,000-fold as real PV prices have fallen to about $4/Wp along a tight experience curve with a progress ratio of 0.80 (Figure 10).

Terrestrial photovoltaic markets subdivide into two broad categories: off-grid and grid-connected.[69] The former refers to stand-alone PV systems that use batteries for storage or operate during daytime only (*e.g.* water pumping). The latter category takes advantage of the grid to absorb excess PV electricity during the day and uses conventional dispatchable electricity generation capacity to back up intermittent PV electricity. The next section describes the off-grid market segments that fueled most sales growth through the mid 1990s before proceeding to consider the increasingly dominant grid markets (Figure 11).[70]

Off-grid markets

In addition to navigational lighting and cathodic protection, starting in the late 1970s, unsubsidized off-grid markets expanded to include remote power for various industrial niches, such as telecom repeater stations and transportation signaling. As prices fell, broader off-grid markets began to open up in the mid-1980s, including remote

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[69] Isolated mini-grids are a hybrid option. Mini-grids using a combination of PV and fossil fuel based engine-generator sets or fuel cells may prove useful for lowering the cost of electricity service for homes on ageing rural grids (Hoff and Cheney, forthcoming). The potential virtues of this approach include avoiding grid connection costs and providing cogeneration savings (*e.g.* heating water with waste heat) for new housing developments (Hoff and Herig, 2000). In principle, PV has a high value in these markets; however, there has been relatively little development of PV mini-grids thus far. It has generally proven cheaper to install stand-alone systems where necessary and to connect PV systems to the grid where possible rather than incurring the expense of installing, maintaining, and *administering* an isolated local distribution infrastructure.

[70] Super-high efficiency PV cells (*e.g.* Gallium arsenide) for space applications remain a small and highly specialized niche market that is only peripherally relevant to terrestrial PV (Perlin, 1999). Sales of small cells to power consumer devices like calculators peaked at a one-third share in 1986 but quickly saturated such that this market segment now accounts for less than 3 percent of global PV sales and their share is rapidly declining (estimates derived from IEA, 2000 and OITDA, 2002).

vacation cottages in industrialized countries and subsidized development projects such as water pumping for rural villages.

At the same time, a number of social entrepreneurs, many of them former Peace Corps volunteers, established non-profits dedicated to providing PV electricity to off-grid homes in developing countries (Perlin, 1999). There are approximately 2 billion people in the world that lack access to grid electricity (WBG, 1996). For this population, a small PV system provides sufficient electricity for prized applications like lights, television, and radio without the need for expensive transmission and distribution networks—and at lower cost than available non-grid alternatives like kerosene lamps, dry cells, and battery charging (Duke *et al.*, 2000). A typical solar home system (SHS) in a developing country context uses 10-100 Wp of PV modules to deliver from 50-500 wH/day stored in a lead-acid battery. While tiny by industrialized country standards, even a 10 Wp module is sufficient to provide an hour per day of black and white television and 3 hours of fluorescent light—dramatically affecting rural quality of life.

Off-grid markets have made critical contributions to the early PV commercialization process, and they should continue to expand gradually as a function of declining module prices, diffusion of information about existing applications, development of ideas for new niche markets, and global economic growth. However, sales growth rates in off-grid markets have tapered from 34 percent in the 1980s to 12 percent since 1990. Poverty and other market barriers limit the potential for future growth in SHS markets (see Box 1). Moreover, in off-grid applications like telecom, companies have long been willing to pay very high prices for the reliability and simplicity of PV relative to alternatives like diesel generators—suggesting that further marginal price reductions from current module prices are unlikely to induce dramatic sales increases. In short, the future of PV increasingly lies in grid-connected applications.

Box 1. A buydown role for solar home systems?

Since the late 1990s, various multilateral and non-governmental organizations have called for rapid scale-up of SHS markets, in part as a mechanism for displacing carbon emissions and buying down the cost of PV modules (WBG, 1996b; G8, 2001; Greenpeace, 2001). Approximately 1.3 million SHSs have been installed throughout the developing world during the past two decades through a combination of subsidized and unsubsidized sales (Ybema *et al.*, 2000). This represents only about 0.4 percent of the long-term market potential.

Small investments in market tuning can provide social benefits and gradually increase SHS sales, but more aggressive deployment would require complex delivery models (to overcome system maintenance and credit access barriers) plus heavy subsidies to compensate for rural poverty (Duke, Jacobson, and Kammen, 2002).

In 1999, as part of its universal rural electrification plan, the government of South Africa announced plans to provide large subsidies (roughly covering all up-front equipment costs) to private companies offering SHS on a *fee-for-service* basis to hundreds of thousands of households (Banks, 2000). This approach appears promising but political disputes have held up implementation and the prospects for rapid scale-up remain unclear (Anderson and Duke, 2001).

In any case, individual SHS are simply too small for this market to play a major role in the PV buydown process. A typical SHS uses about 1 percent the PV capacity of a typical grid-tied PV home; consequently, SHS represent only about 4 percent of cumulative module sales through 2000 and the long-term market for SHS is less than 1 percent of the potential distributed grid market.[71] Moreover, poverty alleviation is an overriding public objective in developing countries and SHS must compete for scarce public funds perhaps better spent on clean water, education, and modern cooking fuels.[72] SHS have assisted in the early commercialization of PV technology and remain a useful tool for rural development, but they are unlikely to play a major role in future PV module buydown efforts.

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[71] Providing a 50 Wp system to half the 350-400 million unelectrified homes yields a total SHS market of ~10 GWp relative to a potential long-term distributed grid PV market of at least 100 GWp/y (as described later in the next section of this chapter).

[72] South Africa is relatively wealthy so it has already met some of the most pressing rural development needs and it intends to use the fee-for-service model to deliver multiple services, including clean cooking fuels.

Grid-connected markets

Grid-connected PV does not require expensive battery storage because conventional dispatchable capacity can back up its intermittent output. Moreover, because PV output is often coincident with periods of high demand, it can be added to the grid without a significant cost penalty until penetration rates reach 10-30 percent of total energy generation (Metz, 1978; Kelly and Weinberg, 1993; EPRI/OUT, 1997). The higher end of this range assumes a grid with afternoon air conditioning peaks and substantial hydro or natural gas peaking and cycling capacity that can be used to back up intermittent PV output.

Grid-connected PV markets subdivide into large *central-station* facilities sited in desert climates and *distributed* applications located near the point of use. The advantages of central-station installations include the ability to select high insolation sites plus modest scale economies in installation, balance of systems equipment, and maintenance. On the other hand, central-station PV generally requires new transmission capacity while distributed PV *lowers* transmission and distribution infrastructure costs. Distributed PV also reduces technical line losses, and does not involve any land costs or associated "not in my backyard" issues[73] if it is integrated into buildings or underutilized property such as highway medians. Thus, central-station PV competes with wholesale power while distributed PV competes with retail electricity costing 2-3 times as much.

[73] In industrialized countries, power companies are increasingly having difficulty extending transmission lines and siting even the cleanest natural gas fired generation facilities due to local opposition.

Despite this value gap, the vast technical potential of PV still encourages visions of powering the planet with large installations in the desert.[74] In principle, central-station facilities on just 0.3 percent of the U.S. land mass could meet current U.S. electricity needs,[75] but the prospects for realizing this goal remain unclear. After aggressive buydown in distributed markets (as proposed below) the price of PV modules could fall as low as $0.30/Wp by 2030 if the PV experience curve were to accelerate substantially during a transformation to thin-film technologies (Figure 10). Given projected balance of systems costs for 2030 and module prices of $0.30/Wp, the busbar cost of central-station PV would be roughly $0.045/kWh (EPRI/OUT, 1997).[76] At these prices, and with low-cost storage, central-station PV might prove competitive in some regions. In particular, large scale compressed air energy storage (CAES) would allow PV to be transported to distant markets via fully utilized high-voltage transmission lines.[77]

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[74] Some have even envisioned a PV hydrogen economy powered by large central-station PV facilities (Ogden and Williams, 1989). Even if hydrogen production (from electrolysis of water) were done in a distributed fashion it is likely that the required electricity would be transmitted to the grid from large-scale desert sites able to achieve the lowest possible cost per kWh based on optimal insolation levels. Hydrogen derived from fossil fuels with sequestration of the separated CO_2 will likely prove more cost-effective for decades, however, unless it turns out that there are fundamental flaws in the CO_2 sequestration concept that would prevent its being deployed at large scales (Williams, 2002b).

[75] U.S. electricity consumption in 1999 was 3,700 billion kWhs (EIA, 2000c). Assuming average insolation of 1,850 kWh/m^2-year, each Wp of PV capacity yields,

0.75 technical loss factor * 1850 kWh/m^2-year * 0.1 module efficiency = 140 kWh/m^2-year

The space requirements for this much PV can be estimated as,

3,700 billion kWhs / 140 kWh/m^2-year = 26,000 km^2,

or just 0.3 percent of the 9 million km^2 in the U.S.

[76] A real commercial discount rate of 8.1 percent in accordance with EPRI/OUT (1997) yields an NPV multiplier of 11 years for a 25-year system. Assuming *system* costs of $0.70/Wp and negligible O&M costs then, for any module efficiency _,

[_*(1,000 W/m^2)($0.70/Wp)]/[_*(0.75 loss factor)(11 yr)(2,000 kWh/m^2-yr)] = $0.044/kWh.

[77] Appropriate geologic formations to support underground CAES are available throughout 85 percent of the U.S. (EPRI/OUT, 1997) and currently available technology allows ~1 day of storage for less than $0.40/watt of installed PV capacity (Table 2). If learning effects reduced this cost by a factor of two, adding storage to central-station PV might increase costs by ~25 percent, yielding baseload PV for under $0.06/kWh under the assumptions in footnote 76.

In any case, for the foreseeable future buydown efforts are likely to concentrate on cost-effective distributed grid markets—and there is plenty of growing room in such applications. Even if central-station markets never emerge, annual electricity demand growth could plausibly support a global market on the order of 100 GWp/y for distributed PV[78] without significant decline in the marginal value of PV due to saturation effects. Note also that intermediate scale above ground CAES located on distribution feeders could improve load management for high levels of distributed grid PV. While more costly than underground CAES, smaller above ground air storage systems can be sited where needed to provide highly cost effective short-term storage (*e.g.* extra power to cover periods of localized cloud cover during otherwise sunny days with high air conditioning demand).

A typical distributed residential PV system involves a 1-6 kWp array placed on a South-facing roof in the Northern hemisphere (and vice-versa). The direct current PV electricity feeds into an inverter that creates alternating current to power the household. When PV output exceeds domestic demand the excess electricity feeds back into the grid and powers the neighbors' homes.[79] When electricity demand exceeds PV supply, the home draws power from the grid. With *net metering* laws, system owners can physically run their meter backward when exporting power to the grid. This gives them full retail value for the excess power they generate while also allowing them to use the grid as a

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[78] Total global capacity was 3,200 GW in 2000 and it is projected to grow at 2.7 percent through 2020 (EIA, 2001b; EIA, 2002b). Assuming 2 percent annual growth thereafter implies 6,600 GW by 2030 with 130 GW added annually at the end of this period. More than half of this will be new daytime demand that PV could directly offset. There should also be a substantial stock of conventional peak capacity retired each year, implying a sustainable high-value PV market of well over 100 GWp/y by 2030.

[79] For a solar subdivision, collective PV output might exceed demand, in which case the power would feed back through the grid to neighboring commercial or residential customers, incurring modest technical line losses.

kind of virtual battery. Some homeowners also choose to add physical batteries to their systems to provide backup in the event of a grid power outage.

Table 1: Capital Costs for Electrical Storage (*1997 dollars*)				
Technology	Component cost		Total cost (*$/kW*)	
	Discharge capacity (*$/kW*)	Storage (*$/kWh*)	2 hours	20 hours
Compressed Air				
Large (*350 MW*)	350	1	350	370
Small (*50 MW*)	450	2	450	490
Above ground (*16 MW*)	500	20	540	900
Conventional pumped hydro	900	10	920	1,100
Battery (*10 MW*)				
Lead acid	120	170	460	3,500
Advanced (target)	120	100	320	2,100
Flywheel target (*100 MW*)	150	300	750	6,200
Superconducting magnetic storage target (*100 MW*)	120	300	720	6,100
Supercapacitor target	120	3,600	7,300	72,000

Source: Based on a presentation by Robert B. Schainker (of the Electric Power Research Institute) to the PCAST Energy Research and Development Panel, July 14, 1997; reproduced from PCAST (1999).

Summary

Grid markets account for 55 percent of PV sales—a share that is growing and is expected to continue to expand. Accordingly, this dissertation focuses on the market for distributed PV in residential rooftop applications (Payne, Duke, and Williams, 2001), though the modeling herein also considers potential markets in the facades and rooftops of commercial buildings as well as other distributed sites. Industrialized countries will drive initial sales because they can afford the necessary buydown support. Distributed grid PV also has potential in developing countries, but these markets will flourish only after industrialized countries have reduced equipment prices and developing countries have tuned their markets to reduce widespread electricity subsidies and other barriers.

PV and the buydown technology selection criteria

PV technologies conform exceptionally well to the buydown criteria outlined in chapter 3. This section considers each in turn.

Criterion 1: Competitive market structure

There appears to be considerable competition in the PV industry. In 1999 there were four manufacturers with market shares of 10-15 percent and five with 5-10 percent shares, with dozens of smaller manufacturers dividing the remaining 20 percent of the market (EIA, 2000b). Given that high levels of competition have persisted for more than four decades, it is reasonable to assume that there is a high level of technological spillovers in the industry.[80] Moreover, inflation-adjusted average manufacturing *cost* data gathered as part of the US Department of Energy's PVMaT program show a 40 percent decline over the period from 1992-1998 (www.nrel.gov/pvmat); this is consistent with the 40 percent *price* decline for the same period (Harmon, 2000), suggesting stable profit margins.[81] This competitive market structure improves the efficiency and equity of buydowns by making it possible to prevent dominant firms from reaping a windfall profit from the subsidies. It also justifies the use of industry-wide experience curves.

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[80] Under zero or low spillover, dominant incumbent firms can gain increasing production cost advantages over small incumbent firms or potential entrants. This may ultimately allow a monopoly or even oligopoly market structure to emerge (Chapter 2).

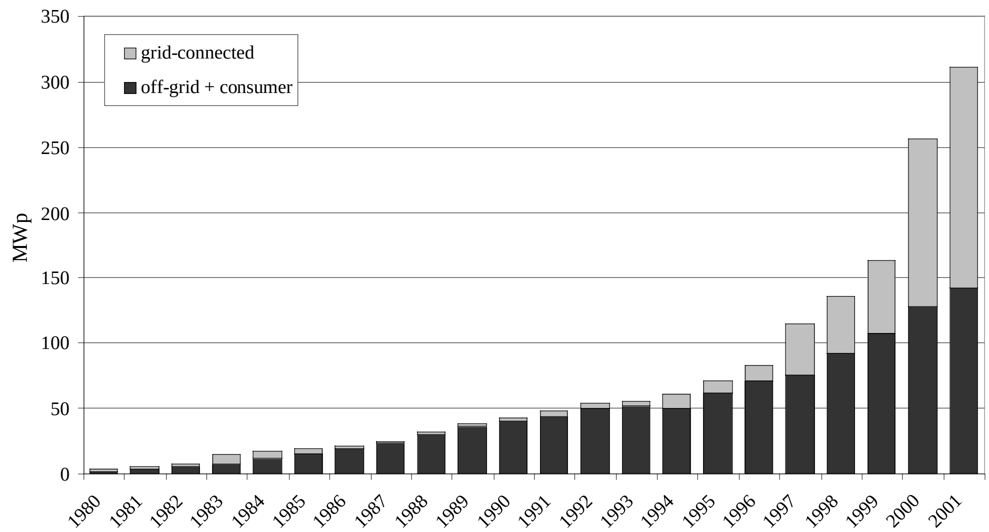
[81] There is evidence that some PV manufacturers have operated at a loss historically (Margolis, 2002). There are at least two companies that focus exclusively on producing PV and are publicly traded such that their financial information is available: one of them (Astropower) reports strong earnings and rapid earnings growth from 1997-2001 while (Evergreen) reports negative net income from 1996-2000. As discussed in Chapter 3, this raises the possibility that Evergreen is intentionally forward pricing, but more probably the losses simply reflect short-term startup costs, anomalous divergence between accounting profits and actual cash flows (*e.g.* high depreciation levels may depress accounting profits even if the business is generating positive cash flow), poor management, or simple misfortune.

Criterion 2: Strong experience curve with a low price floor

PV now has a substantial history of moderate sales growth in off-grid niche markets, augmented by sporadic subsidies primarily for grid-connected markets (Figure 11). This production experience has revealed a tight empirical experience curve (Figure 10) based on both crystalline and thin-film PV. Moreover, the curve is sufficiently steep to make a cost-effective buydown possible if the progress ratio (PR = 0.80) holds up and prices for balance of system and *delivery mechanism*[82] costs fall as expected. These data are in agreement with other studies showing progress ratios in the range from 0.78 to 0.82 (Williams and Terzian, 1993; Cody and Tiedje, 1997). The PV progress ratio is also consistent with the median progress ratio for many other technologies (Dutton and Thomas, 1984).

Bottom-up technology assessment corroborates these top-down projections. Zweibel (1999) suggests that PV module prices may not approach a floor until they have fallen by more than a factor of 10 from the 2000 price level of about $4/Wp. Similarly, the EPRI/OUT (1997) technology assessment projects year-2030 prices of $0.67/Wp for crystalline modules and $0.31/Wp for thin-film technologies (adjusted to constant year 2000 dollars). Extrapolating from the historical sales growth rate of 24 percent per year (see Figure 11), the all-PV experience curve projects that module prices would not fall below $0.70/Wp until nearly 2030, suggesting that irreducible technical constraints pose no imminent barrier to continued steady cost reduction progress as the industry matures.

Similarly, Payne, Duke, and Williams (2001) suggests a potential transition to a thin-film experience curve that will yield faster cost reductions from a smaller initial base of cumulative production. There is no clear experience curve available for any of the thin-film PV technologies, but the authors show that scaling up amorphous-silicon PV manufacturing facilities by an order of magnitude (to a production capacity of 100 MWp/y) could reduce a-Si module prices to \$2/Wp by 2007, with prices dropping to just over \$1/Wp by 2017.[83] For comparison, the historical experience curve (Figure 10) projects a market price of \$1.50/Wp for 2017 if the historical PV sales growth rate of 24 percent per year persists.



Source: Demeo *et al.*, 1999; Johnson, 2002

Figure 11. Global PV markets

Overall terrestrial PV markets grew at an average compounded rate of 24 percent from 1980 through 2001. Off-grid markets dominated through the mid-1990s except for a brief period in the early 1980s when heavily subsidized central-station grid projects gained prominence. Since 1990 off-grid sales have grown at a steady compound rate of 12 percent per year but buydown programs have fueled a 45 percent annual growth rate in grid-connected markets. Small cells used in consumer products briefly accounted for a significant share of sales in the mid-1980s but sales stabilized such that consumer cells are now a trivial

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[82] Defined as the cost of marketing, financing, installing, and maintaining clean energy systems.
[83] These prices are conservatively set such that the factory is able to cover all of its costs (including servicing 35 percent debt financing at a real interest rate of 6.5 percent with tax-deductible interest payments) while earning sufficient profit over a 10-year life cycle to provide a 20 percent annual return to shareholders. This corresponds to an after-tax weighted average cost of capital of:

(0.2 equity return)(0.65) + (0.065 debt return)(0.35)(1-0.35 tax rate) = 14.5 percent.

This is considerably higher than the 8.1 percent real average cost of capital used by EPRI/OUT (1997) to estimate the cost of central-station PV, but the performance risks for a novel PV manufacturing facility are far higher than for a power generation site using established technology.

and declining component of the global market.

Criterion 3: Low current sales but strong market acceleration with subsidies

Thus far, the price elasticity of demand in high-value PV niche markets has proven insufficient to generate enough sales growth to pull prices far enough down the experience curve in order to open up large distributed grid-connected markets. PV is already cost-effective in off-grid markets but, as noted, sales growth in these applications has tapered from roughly 20 percent per year to an average rate of less than 14 percent per year since 1996 (Johnson, 2002). At the current 12 percent sales growth rate, off-grid markets alone (excluding subsidized grid sales) would not pull down module prices far enough to begin opening up substantial distributed grid markets until after 2020—and module prices would not fall below $0.70/Wp until almost 2050.

Current cumulative production (~1.5 GWp) is a small fraction of the possible *annual* market once the demand schedule has shifted out to its mature level. Under the PV buydown scenarios in Chapter 5, sales in mature distributed grid-connected markets supported by fair valuation (*e.g.* net metering) would reach at least 100 GWp/y. This would generate 9 doublings of cumulative production experience by 2030, with an associated drop in the PV module prices from $4/Wp to $0.60/Wp along the all-PV experience curve.

Criterion 4: Low market risk from substitutes

Based on the first four criteria, no other known incumbent or emerging technology has better long-term prospects in the distributed generation markets that are most promising for PV buydowns. Distributed PV competes with retail electricity from the conventional electricity system as well as other emerging distributed generation technologies. The main components of the conventional electricity system are mature, making dramatic reductions in the retail price of electricity unlikely for the foreseeable future. Marginal improvements may occur and restructuring may lead to increased efficiency, but EIA (2002) predicts that real U.S. electricity prices will decline by only 6 percent through 2020.

Fuel cells represent the most serious competition from a distributed generation source but thus far companies have struggled to get past the demonstration phase, so there are no reliable experience curve data available (Lipman, 2002). Small fuel cell systems for single-family residences (<10 kW) will likely prove considerably more expensive than PV for the foreseeable future (Kreutz and Ogden, 2000). Large (>50 kW) stationary fuel cells show promise in commercial, industrial, and multi-home residential settings (Kreutz and Ogden, 2000; Lipman *et al.*, 2002) but distributed PV should remain valuable for shaving peak loads in these settings since fuel cells are most cost-effective if operated in a continuous baseload mode. Fuel cell vehicles plugged into the grid in office parking lots (Lipman *et al.*, 2002) could reduce the value of distributed PV in commercial and industrial settings, but these applications remain speculative and, again, successful development of this strategy would not threaten the residential PV market that is the main focus of this dissertation.

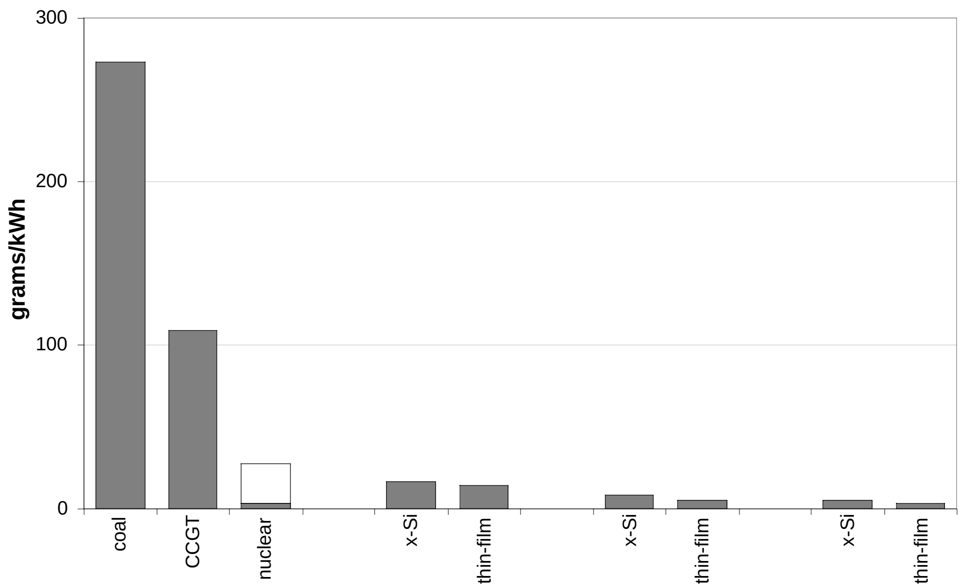
Small wind-turbines have the potential to be cost-effective, but they are difficult to site in urban or suburban settings due to noise and aesthetic issues. Gas turbines also suffer from noise constraints. Thus, efforts are underway to market “microturbines” at scales of the order of 50 kW for commercial, apartment, and small industrial building applications (where the competition it would pose for PV would be similar to that posed by fuel cells) but not for applications in single-family dwellings. In sum, the long-term prospects for distributed PV appear to be at least as good as for existing and emerging substitutes.

Criterion 5: Public benefits

In addition to direct long-term cost savings related to learning-by-doing, distributed PV offers major non-learning public benefits by mitigating externalities costs and supplying public goods including: 1) environmental benefits from displaced pollution; 2) system-wide cost savings and reliability benefits attributable to the coincidence of PV output with summer air-conditioning peaks and the fact that distributed PV alleviates strain on the transmission and distribution system; and, 3) reduced fuel price and security risk.

Environmental considerations are the strongest driver of public support for PV, and recent analyses have carefully monetized these benefits. The lifecycle externalities associated with PV electricity are trivial at approximately $0.001/kWh (Rabl and Spadaro, 1999). Similarly, Alsema (2000) presents a detailed technology assessment that shows that thin-film (a-Si) modules manufactured in 1999 and installed in rooftop grid-connected applications with moderate to low insolation (1,700 kWh/m^2-year) pay back their lifecycle energy content in just over a year, or 2-3 years including the emissions embodied in framing and balance of systems equipment. This translates into dramatically lower lifecycle carbon emissions relative to conventional alternatives (Figure 12), and the embodied emissions should fall further given projected innovation in PV manufacturing and installation (*e.g.* frameless modules for roofing).

Externalities of Energy (ExternE) research project by the European Commission, updates the climate change damage estimates from the Intergovernmental Panel on Climate Change (IPCC). Working Group III of the IPCC reported economic carbon damage estimates in the literature ranging from $5-125/tC but it refused to endorse this range, citing excessive uncertainty, and ExternE offers similar caveats. Nonetheless, its bottom-up model suggests a 95 percent confidence interval of $14-510/tC and an "illustrative restricted range" of $66-170/tC if real discount rates are restricted to a narrow range of 1-3 percent (EC, 1997).



Source: Alsema (2000)

Figure 12. Carbon emissions of PV relative to conventional electricity

Assuming low to moderate insolation, distributed PV systems produce far less carbon on a lifecycle basis than conventional fossil fuel electricity (based on 1999 technology). Estimates of lifecycle carbon emissions from nuclear electricity vary by an order of magnitude (as indicated by the hatched portion of the stacked bar) but the range suggests carbon emissions from this source may be similar in magnitude to current PV technology. Finally, lifecycle emissions for PV should decline more rapidly than emissions from conventional technologies because the latter are relatively mature.

PV also displaces regional pollution that causes substantial damage to human health. Various studies have monetized climate change damage estimates and the public health costs of local pollution in the European context (Box 2).

The environmental value of PV varies substantially by region. For example, just one percent of total electricity generated in California comes from coal-fired facilities (EIA, 2000c). Thus, in California PV primarily displaces natural gas and hydro electricity and, aside from carbon abatement, the associated environmental benefits are modest. In contrast, for the Midwest[84] coal accounts for 86 percent of current generation and 73 percent of projected 2020 generation, while natural gas generation is projected to grow from 3 percent to 20 percent by 2020 (EIA, 2002). Thus, grid PV may displace electricity from coal-fired cycling plants as well as natural gas facilities. This could raise the environmental benefits of PV in densely populated areas of the Midwest to $0.05-$0.10/kWh (excluding carbon emissions) depending on the share of highly polluting incumbent coal capacity displaced (Box 2).

Turning to the second major non-learning public benefit, because PV is peak-coincident and located at the point of use, it reduces service costs and increase reliability for all electricity users on the grid. The tendency for high PV availability to coincide with low conventional capacity availability on peak air-conditioning days (in part because higher ambient temperatures reduce the output of thermal generation facilities) translates into "effective load carrying capability" values of 66 percent for PV installations in commercial settings and 39 percent for residential installations, according to a nationwide analysis from 1986-1995 (Herig, 2000). Thus, even though PV is an intermittent power source it provides substantial effective capacity. Moreover,

[84] As defined by the East Central Reliability Coordination group that includes Michigan, Ohio, Indiana, Kentucky, and West Virginia.

correlating PV output with hourly wholesale electricity rates increases the *energy* value of PV electricity by 2-3 times relative to average wholesale rates.[85]

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[85] Based on an analysis by the author of 1999 hourly wholesale electricity price data from the Pennsylvania, New Jersey, and Maryland Interconnection (www.pjm.com).

Box 2. Monetizing local pollution costs

ExternE traces the dispersal pattern of local pollutants to estimate exposure levels and the associated impacts on human health, ecological systems, and physical infrastructure. ExternE uses a *years of life lost* approach that adjusts for the fact that most of the victims of air pollution mortality are relatively elderly (Rabl and Spadaro, 1999). The project emphasizes recent epidemiological research that indicates major mortality impacts from low-level exposure to particulates (Pope *et al.* 1995).[86]

Rabl and Spadaro (2000) draws on the ExternE results to estimate the externality cost of energy generation from a range of sources. As in the ExternE project, human health effects dominate their numbers, with the majority of the impact stemming from increased mortality associated with fine particulate emissions.[87] Based on an assumed average population density of 80 persons/km^2, a statistical life value of $3 million, and a carbon value of $120/tC, the study estimates typical externalities costs of $0.065/kWh and $0.021/kWh, respectively, for electricity from *new* coal-fired and natural gas combined cycle plants in Europe.[88] For the coal-fired case, carbon emissions account for 38 percent of the total costs *versus* just over half for natural gas.

Similarly, Levy *et al.* (2000) estimates externalities costs of $0.078/kWh and $0.09/kWh for two largely coal-fired plants in Massachusetts, excluding carbon mitigation benefits. Their damage estimates drop to $0.018/kWh assuming best available control technology. The authors use a statistical life value of $6 million and do not adjust for years of life lost. Using the $3 million value from ExternE and the years of life lost approach might cut these figures by a factor of two to four, but even excluding carbon emissions, the externalities costs would remain substantial for existing coal-fired facilities in densely populated areas. Finally, Abt (2002) estimates 6,000 premature deaths from emissions from 80 U.S. coal-fired power plants in the year 2007 (even accounting for new control technologies mandated by that year).

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[86] Lippman and Schlesinger (2000) survey the recent literature, concluding that the correlation of ambient particulate exposure levels commonly found in U.S. 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) indicates that particulates smaller than 10 microns (PM10) are more damaging than larger particles, while particles smaller than 2.5 microns (PM2.5) show the strongest correlation with mortality by far.

[87] Rabl and Spadaro (2000) follows ExternE in assuming that SO_2 and NO_x emissions generate secondary aerosols that can be treated as PM2.5 and PM10, respectively. The authors caution however, that there are no studies yet available correlating nitrates with mortality, and the toxicological causality underlying all particulate toxicity remains unclear. Major costs associated with carbon emissions include mortality from heat stress and the spread of malaria to formerly temperate zones (Rabl and Spadaro, 1999).

[88] Some carbon mitigation options cost little, or even offer a positive financial return (*e.g.* cost-effective energy efficiency constrained by correctable market failures), but abatement costs are a dubious guide for estimating pollution taxes. First, some of the easy abatement options available in the short term reflect the historical failure to internalize pollution costs. Second, there may be a substantial gap between engineering estimates and actual willingness to pay for clean energy options (Chapter 5).

Distributed PV also increases service reliability. U.S. utilities must generally maintain sufficient reserve margins to hold "the probability of disconnecting non-interruptible customers due to [generation] resource deficiencies" to less than one day in ten years (NPCC, 1995). Grids with large generation facilities require a higher reserve margin since an unanticipated loss of output from even a single facility could affect service continuity. In contrast, distributed PV alleviates reserve requirements because individual systems are far smaller than central station plants and the risk of unexpected technical failure is uncorrelated across different systems (Kelly and Weinberg, 1993). Of course, cloud cover may simultaneously reduce output from all PV systems in a given region, but the worst air conditioning days are rarely heavily overcast and Herig (2000) notes that insolation levels ranged from 82-99 percent of peak insolation potential during seven recent power outages located in diverse regions of the U.S. Electricity rates reflect the *average* cost of maintaining reserve margins, but regulators are still working to find ways to appropriately price reliability benefits in the context of electricity restructuring (SEAB, 1998). Thus, PV system owners do not yet receive direct compensation for providing these public benefits.

Peak-coincident *distributed* PV is particularly valuable because it does not have to be transmitted to users over power lines. This reduces the need for distribution infrastructure upgrades and lowers technical line losses that may approach 20 percent during peak periods.[89] Moskovitz (2001) reports average U.S. distribution costs of $0.025/kWh, with marginal rates ranging from zero to $0.20/kWh during peak periods, depending on congestion levels. Thus the average distribution value of PV exceeds

$0.025/kWh, though benefits vary dramatically depending on whether the local distribution system is nearing capacity.

Moreover, transmission and distribution system failures cause the vast majority of service interruptions (SEAB, 1998) and there is currently no mechanism in place to reward distributed generation (or energy efficiency) for alleviating these risks. All distributed PV systems alleviate strain on the electricity distribution system, thereby reducing the probability of a power failure in the area where the system is located. These unpriced reliability benefits spill over to neighboring homes or businesses, again without any mechanism in place at present to compensate the PV system owner.

In sum, PV offers the ultimate "soft energy" path (Lovins, 1979) alternative in that it reduces fuel price risk (Chapter 6) and makes the electrical system less vulnerable to physical attack by reducing reliance on centralized facilities and transmission lines that make potential targets. PV system owners benefit directly from reduced fuel price risk to the extent that they consume the power they generate; however, the exported share also alleviates fuel price risk for all customers on the grid. Similarly, PV system owners who purchase battery backup capability directly benefit from their relative invulnerability to power outages, but they also provide unpriced public benefits by making the overall system more resilient.

Synthesis

The five selection criteria suggest that PV makes an excellent buydown candidate—and the underlying data are unusually strong. On the supply side, the PV

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[89] 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.

module experience curve has proven reliable for over two decades, providing a relatively solid basis for extrapolation. Moreover, bottom-up technology assessments corroborate experience curve projections and suggest a low price floor. Demand assessments are also relatively convincing because, as described later in the chapter, available insolation data and the trend toward net metering facilitate estimation of the financial breakeven value of distributed residential PV. This provides a useful starting point for estimating actual willingness to pay (chapter 5).

Public sector support for PV technology development and deployment

Terrestrial PV modules have received substantial public support since their initial commercialization in the mid-1970s. Margolis (2002) details the history of supply-push and demand-pull programs and estimates that the U.S. spent $1.6 billion (in constant 1999 dollars) on PV technologies through 1999, with roughly 50 percent allocated to basic research and development, 30 percent to applied research and development, and 20 percent to demonstration and commercialization.[90] Japan and Europe have also provided substantial support, and their respective annual RD^2 expenditures substantially exceeded U.S. PV budgets by the year 2000 (Figure 13).

Historically, all grid-connected installations have been heavily subsidized, and sales in this sector have proven erratic, with disruptive consequences for manufacturers trying to predict future demand and manage the process of scaling up production levels (Demeo *et al.*, 1999). Public support for central station grid-connected applications

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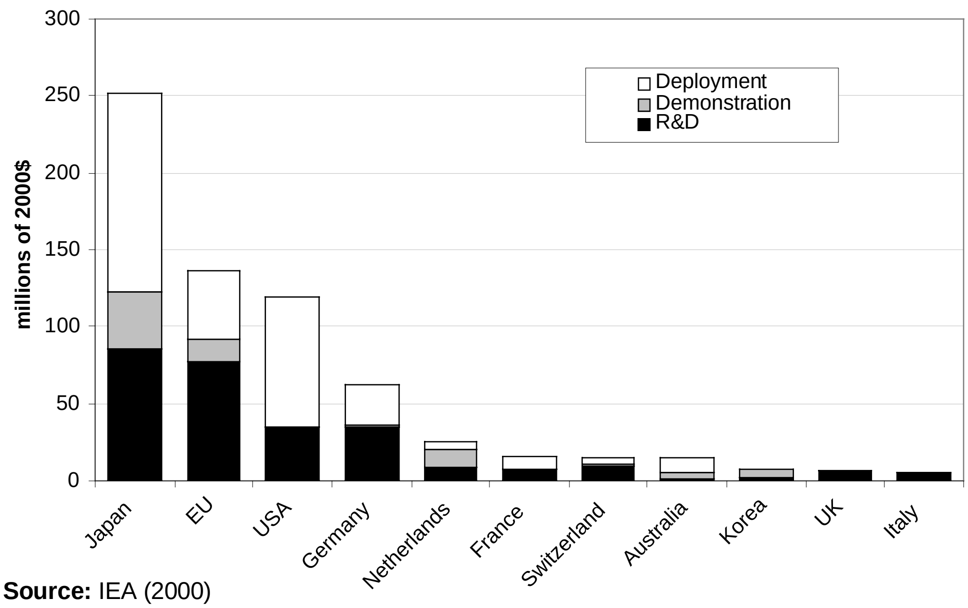
[90] Goldberg (2000) argues that, scaled by early market penetration levels, federal investment in solar RD^2 has been small relative to investments in commercializing nuclear power. Including solar thermal and photovoltaics, federal subsidies for solar power cost $7/kWh during the first 15 years of support. The

peaked in the early 1980s when federal and state subsidies briefly drove grid installations up to a 50 percent share of global PV sales (Figure 11). This market dried up completely after the Reagan administration cut back federal subsidies.



Source: IEA (2000)

Figure 13. Current PV support allocations by leading IEA countries

The figure shows a break down of PV funding allocations by leading IEA countries for the year 2000. The totals include federal, state, and local support programs and they highlight strong investment by Japan and rapidly growing support by Germany, which spends nearly twice as much as the U.S. on a per capita basis.

Despite this cautionary experience, global support for PV has increasingly shifted toward deployment, with increases in buydown expenditures outpacing public support for RD^2 (Figure 14). As noted, this has driven subsidized grid sales to account for over half of global demand by 2001 (Figure 11), with Germany and Japan leading the way.

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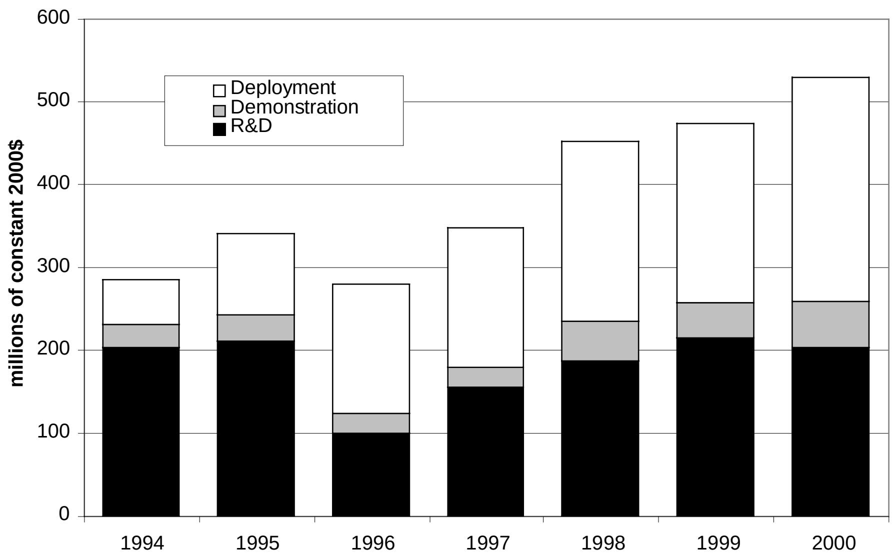
analogous figure for nuclear electricity is $15/kWh. Comparing the first 25 years of subsidies, the respective values are $0.51/kWh for solar and $0.66/kWh for nuclear.

To avoid the market disruptions caused by stop-and-go subsidies, this new wave of buydown programs aims to generate self-sustaining markets for distributed PV before subsidies are phased out. In that sense they are true market transformation programs as opposed to one-shot demonstration programs. Nonetheless, these large-scale buydowns are proceeding without a clear theoretical basis or implementation guidelines.



Source: IEA (2000)

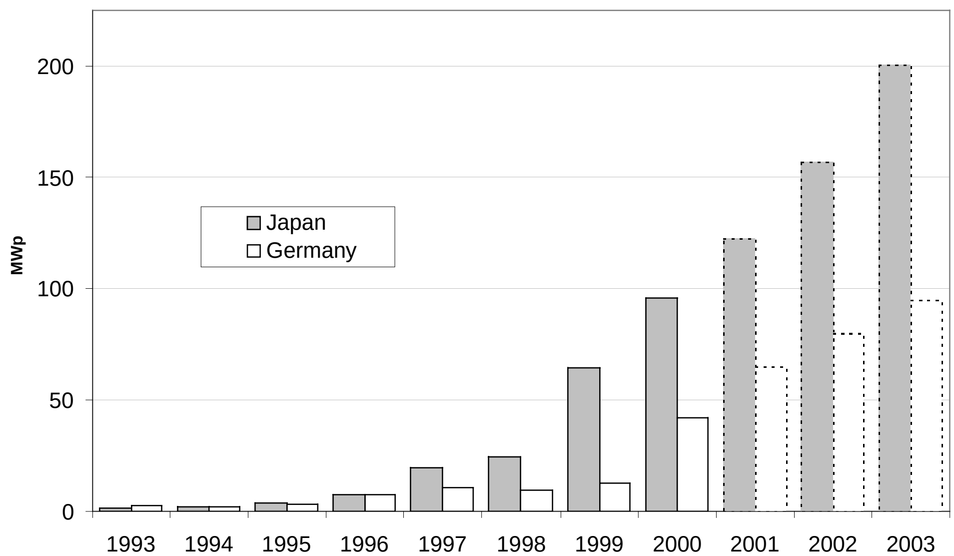
Figure 14. Trends in PV support among IEA countries

These figures reflect total funding at the federal, state, and local level by seventeen major industrialized countries in the International Energy Agency. Funding for R&D and demonstration programs has been relatively stable (aside from a dip in 1996) but buydown funding increased sharply over the seven-year period shown.

The Japanese PV buydown

Japan initiated an aggressive PV buydown in 1993 that grew to account for nearly 40 percent of *global* module sales by the year 2000 (Figure 15). The program primarily targets residential distributed grid PV, and subsidies initially covered up to half of installed system costs. The government gradually lowered the subsidy cap to $1/Wp by 2001, and the latest available figures suggest that strong sales growth continues nonetheless—with residential sales jumping from 64 MWp in 1999 to 96 MWp in 2000 (NEF, 2001).

Japan plans to end the residential PV subsidy after 2003, with cumulative installations of distributed PV approaching 700 MWp by that year and on-going sales projected to generate cumulative installations of 5,000 MWp by 2010 (NEF, 2001). This is achievable with 25-30 percent annual growth in residential sales (which currently account for 75 percent of the Japanese PV market) through 2010, but it remains to be seen if such sustained market expansion is possible once buydown support ends.



Source: Berger (2001); Weiss and Sprau (2001); Kurokawa and Ikki (2001); NEF(2001)

Figure 15. PV buydown sales trends in Germany and Japan

Germany and Japan have scaled up large buydown programs primarily targeting grid-connected residential customers. By 2000, these combined programs accounted for more than half of global module sales and were expected to drive global PV sales growth through at least 2003.

As shown in Figure 16, the price paid by Japanese residential PV consumers, net of subsidies, has been about \$5.50/Wp since 1995 while the *average* breakeven price is roughly \$4.50/Wp (IEA, 2001).[91] Possible explanations for strong sales despite this

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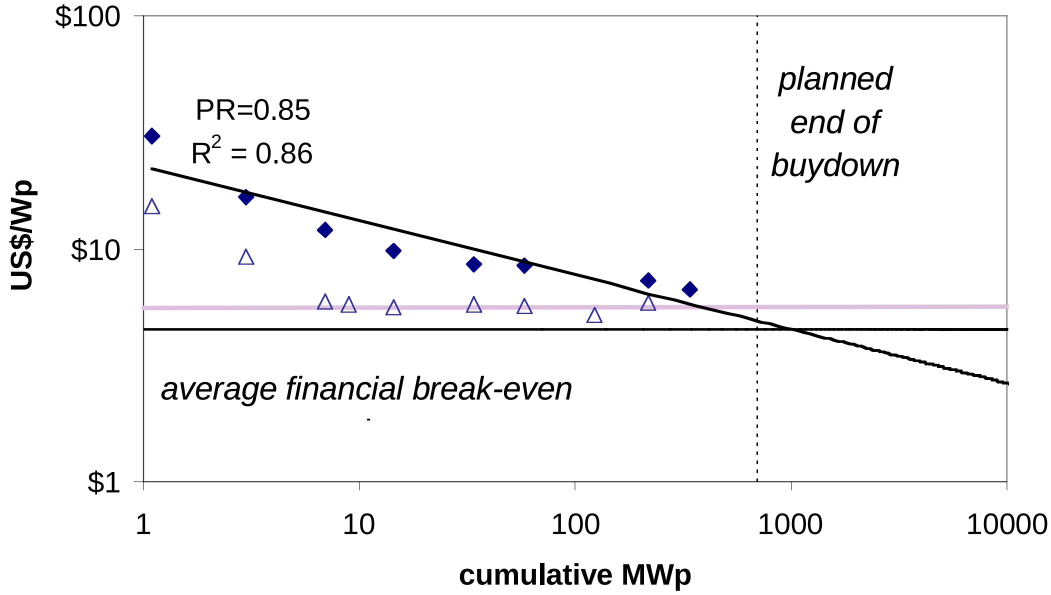
[91] These figures assume net metering. One percent deflation plus a long-term nominal interest rate of 1.4 percent yields a real mortgage rate of 2.4 percent, implying a net present value multiplier of 19 years for a

divergence include: 1) green consumerism, 2) regional niches with high retail electricity rates and/or strong insolation; or 3) additional assistance from other sources such as local governments.



Source: Derived using data from Kurokawa and Ikki (2001); NEF (2001)

Figure 16. Japanese residential PV buydown

The solid diamonds show installed prices for residential PV systems following a progress ratio of 0.85 in Japan. The open triangles show the price to the end user net of buydown subsidies during 1993-2000. Since 1995, the net price paid by users has hovered at about $5.50/Wp, or 40 percent higher than the average financial breakeven price of $4/Wp (based on $0.20/kWh retail rates, real mortgage rates of 2.4 percent, and average insolation of 1,400 kWh/m^2-year). The differential may reflect installations in areas with relatively strong insolation and/or expensive electricity, green pricing, or additional subsidies provided by localities. The government plans to end national subsidies after 2003, by which time the system price should be about $5/Wp.

Figure 16 suggests that after subsidies end in 2004 system prices should still be about $5/Wp, or 11 percent higher than the average breakeven price. This raises concerns that premature phaseout of the subsidies will cause sales growth to lag, particularly since supporting factors like green consumerism and regional niches with favorable insolation and electricity rates may saturate. Moreover, since the real discount

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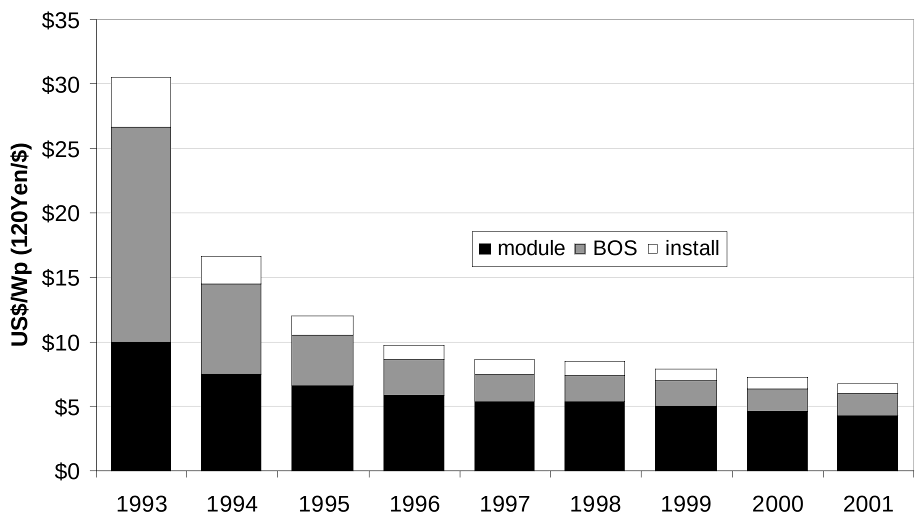
25-year system. For installed costs of $4.50/Wp and assuming negligible annual O&M costs as well as a module efficiency factor of _:

[_*(1,000 W/m^2)($4.50/Wp)]/[_*(0.75 loss factor)(19 yr)(1,400 kWh/m^2-yr)] = $0.23/kWh.

rate is nearly zero in Japan, the optimal subsidy in Japan would lower the net price to consumers nearly to the price floor (Chapter 2). This argues for continued subsidies beyond 2004 since the expected price floor for PV systems is far lower than $5/Wp.

Figure 17 shows a historical breakdown of average prices in Japan for system components. In accordance with experience curve theory, balance of system (BOS) and installation costs have fallen quickly because the cumulative experience base for each was minimal when the program began.[92] BOS prices have declined by nearly an order of magnitude along an experience curve with a progress ratio of 0.78 while installation costs have fallen by a factor of five in accordance with a progress ratio of 0.84. Thus this case illustrates the local benefits from regional buydowns even though PV *module* prices follow a global experience curve.



Source: Derived from Kurokawa and Ikki (2001); NEF (2001)

Figure 17. Japanese residential PV system price trends

Installed residential PV systems have dropped from over $30/Wp in 1993 when the Japanese buydown began to under $7/Wp by 2001 (in constant 2000$). System prices can be broken down into modules, balance of systems (BOS) equipment, and installation costs. The associated progress ratios are roughly

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This is roughly equivalent to retail residential electricity rates in Japan (IEA, 2001).

[92] Inverters for converting direct current PV output to grid-compatible alternating current are, in principle, global commodities, but Japanese manufacturers had to develop lower cost models that did not include the battery backup charging capacity that was a standard feature of most inverters for the PV market before large-scale residential buydowns began.

similar for all three (PR = 0.80 for modules, PR = 0.78 for BOS, and PR = 0.84 for installations) but installation costs have fallen by a factor of five (while module prices dropped by just over a factor of two) because the local experience base for installations was minimal when the program began. BOS prices have fallen even faster (by a factor of 8) because the associated progress ratio is better than for modules. Note that some balance of systems equipment such as inverters are international commodities—but manufacturers still had to design new models tailored to the specialized needs of the Japanese residential grid PV market (*e.g.* eliminating battery backup charging capability).

The German PV buydown

Germany has been aggressively scaling up support for PV deployment (Figure 15). The German PV buydown effort began with the national "1,000 Roofs Programme" that subsidized the installation of over 2,000 grid-connected systems totaling 5 MWp from 1991 to 1994. From 1995 to 1999 various states and cities provided incentives, including 10-20 year contracts to buy the output from residential PV systems for rates ranging above $1/kWh (Berger, 2001). These programs had some success but may also have disrupted markets by creating expectations for subsidies that were not met once small program quotas were filled (Berger, 2001).

Germany's PV buydown began in earnest in January of 1999 with its _500 million "100,000 Roofs Programme" that aimed to catalyze 300 MWp by the end of 2004 using heavily subsidized credit (including a 4.5 percent interest rate subsidy and forgiving of all payments for the 10^{th} year of a 10-year loan). The Law for the Priority of Renewable Energy (REL) followed in April of 2000, providing distributed PV system owners a guaranteed buyback rate of about $0.50/kWh[93] for a period of 20 years after installation, with the fixed buyback tariff for new installations to decline by 5 percent per year after 2001 (Berger, 2001).

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[93] This is more than four times the average residential retail rate of $0.12/kWh (IEA, 2001).

Recognizing that these two programs in conjunction provided excessive incentives,[94] the government indicated that it would review and probably reduce the credit subsidies after April of 2000. This produced a surge in applicants during the first quarter of 2000, causing the minister of the economy to exclaim “the decision to guarantee the old conditions until the end of March was the root of evil” and refuse to honor the old loan conditions for 15,000 applications that had been received by the deadline (Kreutzman, 2000). The government revised the REL in May of 2000 to eliminate the 10th year payment exemption and impose a cap of about $6/Wp on the amount eligible for subsidized financing, with a provision for the cap to decline by 5 percent annually. Moreover, it announced that the full 300 MWp target would be achieved (and financing subsidies under the “100,000 Roofs Programme” would end) a year earlier than planned.

The unexpected surge in demand under the German programs interrupted a decade of steady price declines, causing installed system prices to increase 6.5 percent in the year 2000 (to ~$6/Wp) due to short-term shortages of labor and equipment in Germany (Weiss and Sprau, 2001). It has also clearly required total subsidy expenditures in excess of the ideal minimum shown in Figure 4 from Chapter 3.

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[94] The subsidies effectively made for zero-interest loans (Kreutzman, 2000), implying a net present value multiplier of 25 years for a 25-year system. Given installed costs of $6/Wp in 2000 (Erge *et al.*, 2001), average insolation of 1,000 kWh/m^2-year (Berger, 2001) and negligible annual O&M costs, then for any module efficiency _ the breakeven value for residential PV in Germany was,

[_*(1,000 W/m^2)($6/Wp)]/[_*(0.75 loss factor)(25 yr)(1,000 kWh/m^2-yr)] = $0.32/kWh.

If the interest rate subsidy were eliminated the breakeven value would rise to $0.50/kWh such that, even with a guaranteed buyback rate of $0.50/kWh, PV would only remain competitive in areas with relatively favorable insolation.

The U.S. context

Distributed grid PV is not yet cost-effective in the United States[95] and the overall PV market is small and immature, with total installed capacity of 20-25 MWp (Maycock, 2001). Within the U.S., California has relatively high sales due to a favorable combination of expensive grid electricity and high insolation levels. Other positive factors include subsidies at the state, local, and utility level as well as a recent surge of consumer interest due to concerns about power outages from the year 2000 (Y2K) computer glitch and the electricity crisis of 2000-2001. Figure 18 shows the pre-subsidy cost ($/Wp) of 350 residential PV systems installed in California, all of which received a $3/Wp subsidy from the state (Payne, Duke, and Williams, 2001). Few if any of the systems shown represent a solid investment in strictly financial terms, suggesting that green consumers, technology enthusiasts, and consumers seeking backup power are driving the market.[96]

As regional markets like California develop, prices for residential PV should drop and converge due to learning-by-doing on the part of users, regulators, equipment manufacturers, and installers. Users will acquire better information about what systems should cost and seek out the most cost-effective applications such as new homes with PV built in from the start. Regulators will systematize interconnection standards, *i.e.* the

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[95] Assuming a real interest rate of 5 percent on mortgages, adjusted down to 3 percent to account for the value of the federal tax deduction on mortgage interest payments, yields a net present value multiplier of 17 years for a 25-year system. Assuming installed costs of $6/Wp, average insolation of 2,000 kWh/m^2-year in the Southwest, and negligible annual O&M costs, then for any module efficiency, _:

$$[\_*(1{,}000\ W/m^2)(\$6/Wp)]/[\_*(0.75\ \text{loss factor})(17\ yr)(2{,}000\ kWh/m^2\text{-}yr)] = \$0.23/kWh.$$

This leaves residential PV costing more than twice as much as average retail electricity rates of $0.11/kWh in California (EIA, 2002).

[96] There are 10 systems in the $4-6 Wp range. After a $3/Wp rebate, these systems should be viable on purely financial terms (footnote 95) but the other 97 percent of purchasers appear to have had other motivations.

technical specifications and legal liability requirements governing distributed power (Alderfer, 2000). PV module and balance of systems equipment manufacturers will continue their slide down respective experience cures. PV retailers and installers will streamline their approach and develop skilled teams of specialists. Finally, once the most enthusiastic green consumers have acquired systems, there will be fewer customers willing to pay an unusually high price for their system, further reducing price scatter.

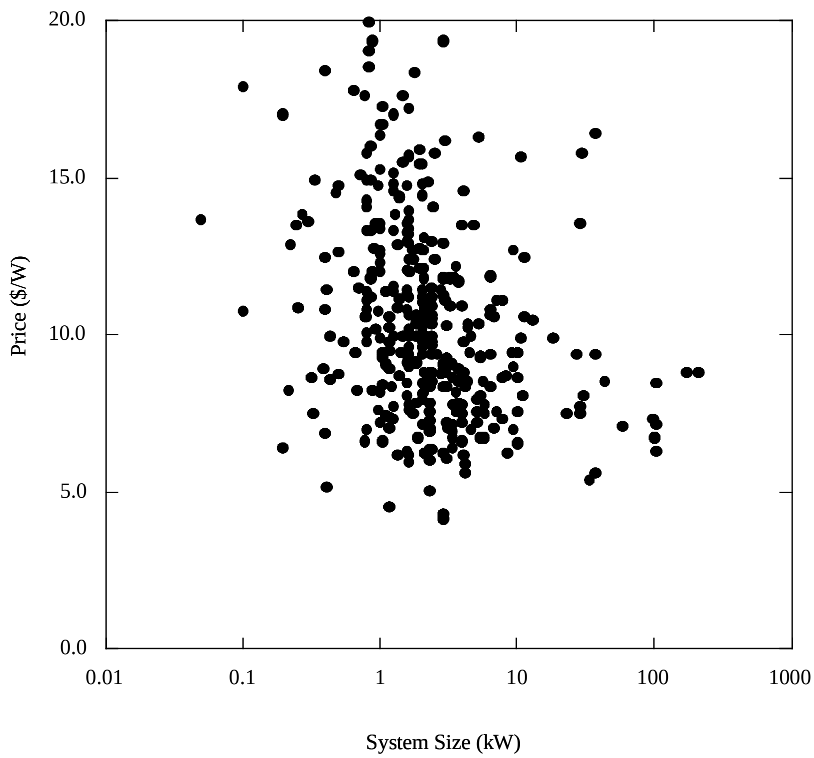

Figure 18. California Emerging Renewables Buydown Program

The figure shows the pre-subsidy price paid for 351 systems supported by the California Emerging Renewables Buydown Program as a function of system size. The data are for the first two years of the program from March of 1998 through June of 2000 and the wide scatter of prices for any given system size suggests an immature market.
Source: Payne, Duke, and Williams (2002)

The next two subsections outline the status of the domestic market tuning and buydown efforts intended to catalyze this market maturation process. This sets the stage for a discussion of the long-term market potential for distributed PV in the U.S.

Market tuning

Ensuring that PV system owners receive a fair price for all the electricity they produce is the single most important market tuning measure available to policymakers. Retail electricity rates are typically 2-3 times average rates for bulk power at the central-station busbar[97] and, to the extent that it directly offsets consumption, each kWh of electricity from a distributed PV system is automatically worth the retail electricity rate to the system owner. For most applications in commercial and industrial settings, baseload demand continuously exceeds PV system output so all the PV electricity is automatically valued at retail rates. For residential systems, however, output even from relatively modest systems may regularly exceed instantaneous demand, *e.g.* when the air conditioner and refrigerator happen to cycle off simultaneously. Until recently most utilities would only buy this excess power from distributed generators at low wholesale rates, if at all.

Net metering laws allow distributed PV system owners to sell excess generation back to the grid at full retail electricity rates, substantially improving their return on investment. As of 2002, 40 states and the District of Columbia had enacted net metering legislation that allows PV system owners (and in most cases producers of clean distributed energy from other small-scale technologies like wind) to run their meters backwards when their system output rates exceeds their electricity consumption rate.[98]

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[97] In 2000, average US retail rates were \$0.082/kWh and \$0.067/kWh for residential and commercial customers respectively (EIA, 2000) while in 1999 average hourly wholesale power rates were \$0.03/kWh in the PJM Interconnect and ISO New England spot markets as well as the California Power Exchange day ahead market (EIA, 2000c).

[98] Updated data on net metering legislation are available at www.dsireusa.org.

Net metering is arguably not a subsidy (or at most a modest subsidy) if it is considered a crude proxy for the non-learning public benefits of distributed PV (see *Public benefits* above).[99] Note, also, that all the kWhs generated by a PV system provide pollution abatement benefits, including the substantial portion[100] that reduces net electricity demand during the day. Thus, even if there is some subsidy to the system owner for the kWhs they sell back to the grid, all of the energy they generate provides compensatory environmental benefits.

In the long run net metering may still become a subsidy if PV penetration levels rise high enough to eliminate midday demand peaks (*e.g.* ~2030 in some regions under an accelerated buydown). By then, however, real-time pricing may be ubiquitous, allowing precise accounting for the value of PV electricity based on instantaneous location-specific supply and demand conditions.[101] In addition, the electricity pricing system may ultimately incorporate taxes to account for the full environmental costs of generating and distributing electricity. These pricing reforms would improve overall economic efficiency and directly encourage investment in clean distributed electricity sources. They would also provide incentives for efficient system design, *e.g.* encouraging the installation of PV on West-facing building facades in areas with late afternoon demand peaks.

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[99] Electricity service providers may argue that the public benefits from distributed generation are no reason to force them to pay any net financial costs that net metering *may* impose on them, but this argument has little merit. For utilities, regulators will generally allow them to pass through any associated costs (or savings) to consumers. Similarly, for competitive suppliers any net costs (or savings) from net metering will pass through to consumers as long as all service providers competing in a given region are subject to the same rules.

[100] A household with a small 1 kWp system will use nearly all of the PV output to meet its baseload demand—but roughly half of the output from a 4 kWp system may be exported (Wenger *et al.*, 1996).

[101] For example, Moskovitz (2001) proposes a scheme for "de-averaging" distribution costs to give appropriate incentives to locate PV where it is most valuable.

A range of other market tuning measures would catalyze grid-connected PV markets. For example, utilities reluctant to accommodate new competition from distributed generation have imposed unnecessary interconnection barriers such as permitting delays and exorbitant liability insurance requirements for residential PV systems (Alderfer *et al.*, 2000). Nationally standardized technical requirements and regulatory pressure to encourage utility cooperation could reduce such barriers.

Public information campaigns are also important complements to buydown programs. Well-designed programs can inform customers about the technology and give them credible information about the different technical equipment and design options to choose from. In addition to problems with overrated PV modules (see *PV Technology* above), PV manufacturers do not always adequately inform consumers about the divergence between rated *system* output under standard test conditions and actual performance. Even with accurately rated modules, PV systems usually deliver only about 75-80 percent of their rated power due to a range of factors including inverter efficiency losses, occasional system outages, temperature effects, shading, and soiling (Payne, Duke, and Williams, 2001; Wenger *et al.*, 1996). Moreover, an array that starts off producing 75 percent of rated power and degrades at 2 percent annually (see *PV technology* above) will produce only half its rated power after two decades. High quality modules already have achieved degradation rates of less than 0.5 percent. Reducing array-level degradation to this level should be achievable with refined inverters and installation techniques. Accordingly, this dissertation assumes a stable PV system efficiency of 75 percent of rated power—implying that annual degradation has been reduced to negligible levels and chronic module overrating problems have largely been solved.

Unlike many developing country markets (Duke *et al.*, 2002), minimum equipment standards are already in place for domestic PV markets, and homeowners are well positioned to demand quality. Nonetheless, clarifying module labels and strengthening the accelerated aging components of equipment tests (*e.g.* increasing the required number of thermal cycles) might help to improve performance. The government may also be able to encourage manufacturers and installers to compete based on quality by supporting credible long-term testing projects and publicizing the results.

Buydowns

Efforts within the U.S. to encourage distributed grid PV fall far short of the programs in Japan and Germany (Figures 13 and 15). The support that has been made available comes mainly in two formats. First, 14 states have established Public Benefits Funds, also known as Systems Benefits Charges, that impose a fixed "non-bypassable" surcharge on all electricity sales and use the revenue to fund a range of programs including market tuning (*e.g.* public information campaigns) and buydowns for PV and other clean technologies. New Jersey has a program designed to catalyze up to 50 MWp over the next 5 years[102] and California has plans for another 100 MWp over the same period, catalyzed by its Emerging Renewables buydown along with various other state, local, and utility programs.

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[102] March 9, 2001 NJ Board of Public Utilities Final Order of the Comprehensive Resource Analysis Proceeding. See www.njcleanenergy.com for details.

In addition to PBF funds, 15 states have enacted Renewable Portfolio Standards (RPS).[103] An RPS requires electricity service providers to produce or purchase sufficient renewable energy or, if trading is permitted, to purchase enough renewable energy credits to guarantee that the mandated share of total electricity production comes from renewable sources. This imposes compliance costs on the private sector and, indirectly, consumers. The unit cost of tradable RPS credits represents the implicit unit subsidy given to renewables by the mandate. Chapter 5 assesses the potential advantages and risks of this approach relative to alternative buydown mechanisms that fix the unit subsidy level and let the quantity demanded vary.

Residential PV market potential

The most cost effective grid-connected residential PV application will be in new homes (Payne, Duke, and Williams, 2002). Including the cost of PV in the mortgage provides automatic low-cost financing.[104] The installer can integrate wiring and modules into the original construction process and in some cases the modules can displace conventional roofing materials. A solar subdivision developer would also benefit from the following comparative advantages relative to a company that installs one-off retrofits:

- Negotiating low equipment prices by purchasing in quantity;
- Developing relationships with PV architects and training specialized crews of electricians and roofers to optimize the design and installation of standard PV roofing packages;

[103] See www.dsireusa.org for updated totals and program details.
[104] Although it is possible to arrange mortgage financing for retrofits, it is not automatic and may involve transaction costs unless the homeowner is already refinancing for other reasons.

- Siting and designing homes to ensure good solar access and easy installation;
- Mitigating interconnection costs by developing relationships and standard contracts with utilities and regulatory agencies;
- Reducing costs by incorporating PV as an option in standard marketing materials for new homes.[105]

The calculations in this section assume that these advantages apply.

Figure 19 shows the financial breakeven schedule for PV modules used in grid-tied PV systems for single-family housing in the U.S.[106] Based on county-level insolation and state-level retail electricity prices, the present value of each Wp of PV capacity can be calculated as:

PV Value = present value [*R* – *O*] – PV system installation costs – inverter costs;

where,

R = annual PV output (kWh/Wp-year) * retail electricity price ($/kWh)

O = annual PV system operations and maintenance costs

For each value (on the y-axis), Figure 19 shows the quantity demanded considering potential residential PV sales in all the counties for which the breakeven value is greater than or equal to *PV Value*. To estimate the size of the market in each county, the analysis assumes that at most half of annual new home completions[107] could carry 4 kWp

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[105] In contrast, retrofit companies that must court each prospective PV system buyer separately, develop a unique system design and negotiate a price in each case.

[106] Payne, Duke, and Williams (2001) develops this methodology drawing on aspects of the approach used by Marnay *et al.* (1997).

[107] Census figures estimate an annual average of 1.1 million single-family housing completions nationwide over the course of the last business cycle from 1991 to 2000. The average long-term trend-line growth rate since 1968 is negligible (0.5 percent per year) and future housing completion rates for each county are

systems.[108] The analysis further assumes: 1) projected lifecycle costs starting after 2005 for systems with a 25-year lifetime integrated into the roofs of new homes using mortgage financing; 2) county-level insolation data; and, 3) net metering laws such that PV electricity competes with state-level retail electricity prices.[109] Aside from net metering, public support is assumed to be limited to the existing tax deduction for mortgage interest, and a property tax exemption for PV systems, as explained below.[110]

PV modules currently cost about $4/Wp and the breakeven schedule does not begin until prices drop to $2.30/Wp, so residential grid-tied PV is not yet cost-effective anywhere in the United States. Nonetheless, Figure 19 illustrates that a 0.6 GWp annual market for PV could open up in the US if module prices were brought down to $1.50/Wp. This annual domestic market potential is roughly 25 times *cumulative* PV installations in the US market (Maycock, 2001) and it is double the global PV sales level in 2000 (Johnson, 2002).

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based on their respective shares of national population. This is conservative in that housing growth has been particularly strong in most of the states with the highest PV valuations.

[108] Assuming 10 percent efficient modules, a 4 kWp system requires 40 m^2 of correctly oriented and unshaded roof area. This is readily accommodated on typical new homes in the U.S., particularly if the architect designs the home with PV in mind (Payne, Duke, and Williams, 2001). For typical U.S. insolation (1,850 kWh/m^2-year) a 4 kWp flexible module system (efficiency factor = 0.75) would generate 5,550 kWh/y—somewhat more than half the average US household electricity consumption rate in 1997. As noted, however, net metering is important because systems will often produce more electricity than the household is consuming during periods of peak sunlight.

[109] County-level insolation data are from Marnay *et al.* (1997) based on their analysis using data from 239 solar measurement sites (rredc.nrel.gov/solar/) to construct county-level insolation estimates assuming optimal tilt angle. Projected state-level retail residential rates for 2005 are derived from data in Marnay *et al.* (1997) scaled by the projected change in real retail rates through 2005 from EIA (1999). Note that EIA (2002) expects residential retail rates to be essentially stable for the next two decades—declining by only 0.4 percent during the period from 2002 to 2020. Thus, using year 2000 retail electricity prices from EIA (2000) yields virtually identical results, though the price data used in this dissertation are marginally more conservative and the relative ranking of individual counties varies somewhat in each case.

[110] The divergence between the value of PV in the best (San Bernadino county in California) and worst (San Juan county in Washington) counties results from a factor of 1.8 insolation difference compounded by a factor of 2.5 electricity price difference. Note that installation and maintenance costs are assumed to be constant across all counties.

Because PV systems are capital-intensive, financing has a powerful effect on electricity generating cost. Home mortgages are the least-costly option for financing PV systems—both because of the low cost of money and the benefits of deducting mortgage interest from income taxes. Mortgage interest rates are typically of the order of half the hurdle rate used for business investments and a real mortgage interest rate of 5 percent is assumed here.[111] Moreover, deducting mortgage interest from income for tax purposes can reduce lifecycle costs by 15-20 percent.[112]

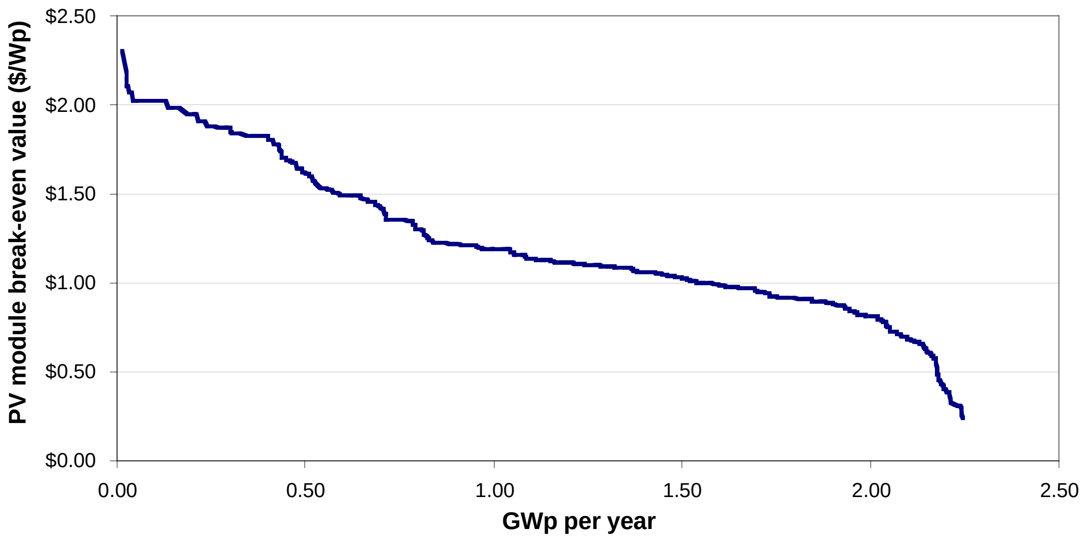

Figure 19. Financial breakeven for PV in new US single-family housing

A detailed bottom-up market analysis shows the annual demand potential for PV modules installed in new single-family homes after 2005. The y-axis represents the financial breakeven value of PV modules in new single-family homes based on a detailed lifecycle analysis that assumes net metering and accounts for variation in county-level insolation and state-level electricity prices. It further assumes learned-out costs for balance of systems equipment and delivery mechanisms (based on aggressive buydowns in the most active regions). Homeowners finance their systems through tax-advantaged home mortgages and incremental homeowner insurance costs are assumed to be trivial. Finally, states and localities exempt the

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[111] Based on real average rates for 30-year fixed rate mortgages during the period 1990 through 1999 using data from the Bureau of Labor Statistics and www.hsh.com. This assumes that the homeowner will finance their systems over the standard 30-year long-term mortgage period even though the system lifetime is conservatively assumed to be only 25-years.

[112] For a real mortgage rate of 5 percent, the NPV multiplier for a 25-year system is 14 years, or 16.5 years considering tax benefits *versus* just 11 years for central-station installations. The mortgage interest deduction is unlikely to be phased out in the foreseeable future, and including the cost of a rooftop PV system in mortgage financing is qualitatively no different from the standard practice of including the cost of major appliances in the initial mortgage or using a home equity loan or refinancing to fund major repairs.

value of PV systems from property tax assessments to level the playing field with less capital-intensive conventional electricity technologies. All other existing or planned tax incentives are excluded.

Based on these assumptions, PV modules will be worth \$2.30/Wp in new homes for counties with the best combination of high insolation and expensive electricity rates and \$0.25/Wp in the lowest value areas. Further, assuming that at most 50 percent of the new homes in any given county could be designed to have acceptable shading and orientation, the maximum annual quantity demanded for module prices above \$1.50/Wp is 0.6 GWp, or 150,000 homes per year. Absent buydown support, actual demand will be lower due to various factors including aesthetic concerns, information constraints, and risk-aversion.

Improvements to the inverters required to convert DC module output into AC power should substantially reduce PV electricity costs. This analysis assumes that inverter costs, which have already fallen by an order of magnitude since the early 1990s (Kurokawa and Ikki, 2001), fall by a further 50 percent to about \$0.30/W_{ac}. Inverter improvements are also expected to reduce operation and maintenance (O&M) costs. Finally, it is assumed that power conditioning units become sufficiently reliable to reduce O&M costs to ~\$0.01/kWh.[113]

The assumed installation costs are for established PV system installers using innovative techniques in a competitive environment. For example, it is estimated that shipping and installing thin-film modules on a flexible steel substrate would cost about half as much as for systems using conventional rigid glass modules (Payne, Duke, and Williams, 2001) because the latter are bulkier, heavier, and more fragile. Moreover,

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[113] Jennings *et al.* (1994 and 1996) measured O&M costs to be \$0.006 to \$0.05/kWh at a large-scale testing facility (PVUSA) and \$0.036/kWh on a 10 kWp rooftop system. Excluding inverter failures, however, other O&M costs were only \$0.001 to \$0.005/kWh. Maish *et al.* (1997) estimates that if the mean time between failures for power conditioning units can be increased to more than 20 years, O&M costs would be less than \$0.01/kWh. Similarly, an independent test site operator has suggested that an O&M cost of \$0.005 to \$0.01/kWh would be a realistic projection for the 2005 timeframe (Whittaker, 1999).

flexible modules can be rolled down over and fixed to an existing base[114] by means of an appropriate adhesive, resulting in a modest credit for the cost of avoided shingles.[115]

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 safely be neglected.[116] Property taxes could have a substantial impact on the economics of residential PV systems[117] but, in part because such taxes are biased against capital-intensive energy systems, eighteen states already exempt solar facilities from local property taxes.[118] It is assumed that other states will ultimately follow suit and therefore property taxes are not accounted for here. Finally, scale economies should facilitate standard contracts with local utilities such that interconnection costs become negligible and are covered by the contractor PV installation fee (assumed to be $1,000 per system plus labor costs of $400) already included in the calculations.

In addition to the new home market, PV systems can be installed on existing homes, but such retrofits are more costly. Retrofitters face idiosyncratic installation

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

[115] Direct bonding of flexible modules causes efficiency losses attributable to higher operating temperatures (relative to framed rigid modules installed with airspaces underneath) that are taken into account in the 75 percent system efficiency assumed in this dissertation.

[116] Payne, Duke, and Williams (2001) projects installed costs of ~$10,000 for a 4 kWp system integrated into a new home after 2010. For the large new homes most likely to carry systems, this is a small enough fraction of total insured home value that it may not affect premiums at all. In any case, typical annual homeowner insurance rates range from ~0.1-0.3 percent of replacement value, or just $10-$30/y initially, and the PV system replacement value should decline over time. As noted above, utilities have also attempted to impose large liability insurance premiums on PV system owners, but industry advocates have generally been successful in striking them down as unreasonable interconnection barriers.

[117] Typical annual property tax rates average ~2 percent of assessed value. Taking into account a property tax at such a rate could raise the present value 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).

[118] The property tax would have a far greater impact on the cost of PV electricity (for which capital costs dominate) compared to natural gas electricity (for which tax-expensed fuel costs dominate). The exemption statistics are from www.dsireusa.org.

challenges for each project, and they have difficulty realizing the scale economies available for builders that include PV as an option on new homes. To cover higher marketing costs and general hassle factor, retrofit contractors would charge higher markups than would new homebuilders. Collectively, these factors suggest a 20 percent premium on the total installed cost of retrofits as compared to new PV housing.

The financial breakeven schedule provides some indication of the actual demand schedule for distributed residential PV, but the two concepts are not equivalent. In particular, the demand schedule will tend to fall short of the financial breakeven schedule because of various constraints, including inadequate information and risk-aversion on the part of potential customers. Certain factors may also tend to boost demand beyond the financial breakeven line, including technology enthusiasm and green consumerism. These are modest effects, however, that will likely saturate quickly. Rader and Norgaard (1996) emphasize the free-rider problem: that green electricity programs allow customers that opt for conventional electricity to benefit from the environmental improvements provided by those who pay extra for clean power. Similarly, Swezey and Bird (2001) reports customer participation rates of less than 1 percent for most *green pricing* programs (under which utilities offer customers the option to pay a premium to support renewables).[119]

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[119] *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 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 technology like PV that are most in need of buydown support. For example, Bird and Swezey (2002) reports that wind accounts for 98 percent of the new renewables installed under green marketing programs thus far.

Summary

This chapter argues that PV fits the buydown technology selection criteria outlined in Chapter 3. Among a range of sub-technologies and markets, thin-film PV installed in distributed grid-connected applications holds particular promise. Major buydowns are underway in Japan and Germany, but the U.S. and other industrialized countries have yet to scale up demand-pull efforts. The next chapter uses the models from Chapter 3 to define an optimal global PV buydown—concluding that current collective efforts fall substantially short of the societal optimum.

Chapter 5: Buydown analysis for distributed grid-connected PV

This chapter applies the breakeven and optimal path methodologies introduced in chapter 3 to the PV case. The analysis takes a global scope, but focuses on the use of PV modules in distributed grid-connected applications, particularly in the residential sector. The chapter starts with a review of the relevant literature, proceeds to assess the economics of an accelerated global PV buydown, and concludes with a discussion of the relative efficiency of different subsidy mechanisms.

PV buydown literature review

As prices have come down and markets have grown, governments and independent researchers have taken an increasingly active interest in assessing the long-term prospects of PV. This has produced a literature that can be broadly grouped into 1) engineering cost projections; 2) cost-benefit assessments using the conventional breakeven model; and 3) microeconomic models.

Cody and Tiedje (1992) provides an important example of the bottom-up engineering approach. The authors use experience curves to forecast future PV electricity prices, concluding that 20 percent sales growth would reduce the year-2010 cost of central-station PV electricity to \$0.18-0.23/kWh (adjusted to year-2001 dollars).[120] The corresponding range assuming 40 percent sales growth was \$0.10-

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[120] This calculation seems to be roughly plausible. A real commercial discount rate of 8.1 percent (EPRI/OUT, 1997) yields an NPV multiplier of 11 years for a 25-year system. Assuming current installed *system* costs of \$5.50/Wp and negligible O&M costs, the current generation cost for any module efficiency, _, is:

$$[\_*(1{,}000\ W/m^2)(\$5.50/Wp)]/[\_*(0.75\ \text{loss factor})(11\ yr)(2{,}000\ kWh/m^2\text{-}yr)] = \$0.33/kWh.$$

0.17/kWh, but the authors do not directly address the potential for demand-pull support to accelerate the commercialization process.

Williams and Terzian (1993) also employs experience curves[121] to analyze the costs and benefits of a U.S. effort to accelerate PV commercialization by means of increasing RD^2 funding and subsidizing sales in distributed grid-connected applications. Using the breakeven method (Chapter 3) the authors estimate strongly positive NPV values under a range of parameters and accordingly advocate increased public investment in both supply-push and demand-pull support. Wene (2000) provides another more recent recent example of this approach.

Microeconomic models of PV development are scarce in the published literature but there are at least two relevant contributions in the form of unpublished manuscripts. Freeman (1981) introduces a continuous time model for a generic industry to explore the theoretical market structure implications of learning-by-doing using Nash equilibrium theory. This draft manuscript also presents a brief argument that an "optimal program of solar cell purchases by the government might cause…a 10 year advance down the development path…at the cost of several hundreds of millions of dollars." This analysis does not make any effort to develop an empirically realistic model of the PV commercialization process and, in particular, the demand schedule is highly stylized and static.

Assuming 20 percent sales growth from 2003-2010, the all-PV experience curve projects module prices will fall by 37 percent to \$2.60/Wp. If balance of system costs follow suit, central-station PV would cost ~\$0.21/kWh by 2010.

[121] The analysis also draws on the SUTIL (for Sustainable UTILity) electric utility planning model (Kelly and Weinberg, 1993) for estimating the value of PV as a declining function of increasing PV penetration levels on the electricity grid.

Richards (1993) develops a model that incorporates both the impact of learning-by-doing on area-related module prices ($\$/m^2$ rather than \$/Wp) and the impact of RD^2 expenditures on projected module efficiency. This manuscript uses optimal control theory to show, for a continuous time model, that the welfare-maximizing level of RD^2 funding may change over time but the optimal demand-pull subsidy (in \$/Wp terms) is non-zero and decreasing. To define the welfare-maximizing output and subsidy paths, the paper develops a discrete time numerical model that indicates "even under relatively pessimistic assumptions" that RD^2 should be increased by a factor of 6 and output by a factor of 17 during the first year of a buydown starting in 1993.

Richards (1993) makes an important contribution but it has not received attention in the subsequent literature and has a number of limitations. First, as the author notes, "specification and estimation of the research function suffers from a lack of useful data."[122] Second, the demand schedule is "based on conjecture" and does not incorporate outward shifting over time. This failure to account for the time required for market diffusion generates an unrealistically abrupt increase in first-year output under the optimal path. The demand schedule in Richards (1993) also ignores the potential for PV to reduce distribution costs and displace expensive peak generation capacity. Third, the author notes that "substantial intra-industry learning curve spillovers [may justify] government intervention in the marketplace" and he alludes to the debate over whether monopolies or competitive industries have greater incentive to innovate; however, he does not make explicit the role of market power or the perfect spillover assumption that is

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[122] In contrast, the models in this dissertation use empirical experience curves measured in \$/Wp rather than $\$/m^2$ and therefore do not require arbitrary assumptions about the payoff from RD^2 investments. Also, as

implicit in his specification of learning-by-doing. Fourth, the paper considers only the domestic PV market while acknowledging that the analysis may be "better suited to a global rather than a national planning effort." Finally, the paper does not provide an estimate of the net financial benefit from its policy prescriptions.

The chapter now assesses the PV case using both an improved breakeven method and the optimal path method developed in chapter 3. Unlike most conventional breakeven analyses, the next section subtracts from buydown NPV the benefits that niche market sales generate under the NSS. The subsequent optimal path method further refines the analysis to address the most important limitations to the PV buydown analyses reviewed above.

Assessing a global PV buydown: the improved breakeven method

This section uses the conventional breakeven method (Chapter 3) to estimate the relative benefits and costs of a global campaign to buy down PV modules. For example, assuming a fixed breakeven price of \$0.50/Wp for PV in central-station applications,[123] Wene (2000) indicates total future "learning costs" ranging from \$60-150 billion for progress ratios ranging from 0.78 to 0.82. This well-known analytic approach has the virtue of simplicity, but it suffers from serious shortcomings. The most obvious is the need to consider niche markets, as stressed by Wene (2000) in its treatment of the Japanese PV case and incorporated into the modified breakeven analysis below.

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illustrated by thin-film technologies (Chapter 4), higher efficiency is not the sole path to reducing module costs in \$/Wp terms.

[123] Wene (2000) suggests that PV will prove broadly competitive in central-station markets at \$0.50/Wp. Absent faster than expected progress in balance of systems costs, this is optimistic by at least a factor of two (see *Grid-connected markets* in Chapter 4).

Base case

Conventional breakeven analyses generally assume zero NSS benefits, a flat breakeven schedule, and an arbitrary analytic timeframe. This section applies the improved breakeven method defined by equation 6 from chapter 3 in order to assess a buydown targeting “niche markets” made up of distributed residential applications in the U.S., Western Europe, and Japan (hereafter OECD). This approach incorporates niche markets, accurately estimates NPV net of NSS benefits, and endogenizes the analytic timeframe. The approach remains flawed, however, because it uses arbitrary sales growth rate estimates rather than accurately modeling demand (as done in the subsequent treatment using the optimal path method).

For the base case it is assumed that the historical PV experience curve (Figure 10) persists, with a module price of $4/Wp in 2003. On the demand side, the analysis assumes that broad distributed markets (including installations in commercial buildings and developing country markets) open up at a module price of $1/Wp. To construct a breakeven schedule that covers the entire buydown period, the analysis multiplies the *annual* U.S. breakeven schedule for PV in new single-family housing (Figure 19) times the number of years until the $1/Wp threshold is reached.[124] The overall breakeven schedule also includes a retrofit market (for which PV module value is assumed to be 20 percent less than for new homes due to higher installation costs) equal to one-third of the 70 million single-family homes in the U.S.[125] Finally, to allow analysis at the global

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[124] Under the base case, it takes 20 years for module prices to reach $1/Wp under the buydown scenario and 38 years under the NSS.

[125] It is assumed that only 2/3 of existing single-family homes have acceptable roof orientations (Wenger, 1996) and half of those have sufficient unshaded area to accommodate a 4 kWp system. In contrast, up to half of new homes may be appropriate for PV because builders can design and site homes with PV in mind.

scale, overall OECD residential markets are assumed to be twice as large as the U.S. market.[126]

The NSS assumes that subsidized grid sales are eliminated completely after 2003 so that the only remaining market is for off-grid sales, which start at 160 MWp in 2002 and continue growing at the current rate of 12 percent per year. This off-grid market would be adequate to pull prices down to $1.80/Wp by 2027, which would begin to open up substantial distributed residential markets (Figure 19). Assuming that the sales growth rate accelerates to 25 percent per year at this point, then by 2030 sales reach 6 GWp/y and module prices would have fallen to $1.60/Wp based on cumulative sales of 40 GWp.

The "buydown" scenario assumes that subsidies cause PV module sales growth to increase to 30 percent per year until 2014. At that point, PV begins to break even in distributed residential applications and it is assumed that subsidies are removed and on-going sales growth falls to 20 percent per year until sales reach an assumed cap of 100 GWp/y in 2028. The PV experience curve projects that this growth would pull real module prices down to $0.60/Wp by 2030 when PV would contribute 11 percent of industrialized country electricity generation.[127]

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[126] The U.S. accounted for 43 percent of total electricity consumption in industrialized countries for the year 1999 (EIA, 2002b) and the residential sector accounts for roughly one-third of total electricity use in the U.S. and a similar share in other industrialized countries. For industrialized countries other than the U.S., it is assumed that higher electricity rates, *e.g.* ~50 percent higher in Germany and nearly triple in Japan (EIA, 2001) roughly compensate for lower insolation in determining the value of distributed PV electricity.

[127] EIA (2002b) projects total industrialized country electricity consumption of 11,000 tWh in 2020. Assuming 2 percent annual growth thereafter, sales would reach 14,000 tWh by 2030. The base case buydown scenario projects 900 GWp of PV installed in industrialized countries by 2030. At average insolation levels of 1,700 kWh/m^2-year (for any module efficiency, _) each Wp of PV capacity yields,

0.75 technical loss factor * 1,700 [(_*kWh)/m^2-yea]r * 1 [m^2/ (_*kWp)] = 1,300 kWh/kWp-year.

Thus, 900 GWp yields,

1,300 kWh/kWp-year * 900 GWp * 10^6 kWp/GWp = 1,200 tWh/y,

or 11 percent of projected industrialized country electricity consumption.

The base case buydown (Figure 20) generates gross benefits through 2030 of $228 billion based on costs of $9.1 billion, but $63 billion of these benefits would occur under the NSS, so the NPV (r = 0.05) attributable to the buydown is $156 billion. This analysis assumes that the government can hold subsidies down to the minimum possible level (dark shading in Figure 4). The ratio of benefits to this minimum required public outlay yields a type of benefit-cost ratio (BCR). In this scenario, the BCR equals 19.

In practice, however, governments will be unable to perfectly price discriminate based on the minimum unit subsidy necessary to induce each marginal PV buyer, so subsidies might have to be increased by the hatched region in Figure 4. Governments may also be unable to avoid subsidizing some free riders that would have purchased PV without any subsidy at all—further increasing the required subsidies by the crosshatched region in Figure 4. These *transfer subsidies* are not direct economic costs, but they raise equity concerns and generally impose efficiency costs (the marginal excess burden of taxation defined in chapter 4) because some sector of the economy must be taxed to finance them.[128] Once crucial disadvantage of the breakeven method is that it offers no way to estimate the likely magnitude of transfer subsidies.

Another important issue is whether the distributed PV market targeted for the buydown is sufficiently large, though consideration of the area requirements for distributed PV systems suggests that it is. The base case buydown would involve

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[128] The secondary welfare impacts of clean energy buydowns depend on how the subsidies are financed. Raising energy prices to finance buydown could *improve* social welfare as long as the price increases do not exceed the value of fully internalized environmental and security externalities. Recent studies suggest that the external costs of conventional electricity (Rabl and Spadaro, 2000) and transport fuels (Spadaro *et al.*, 1998) are comparable to retail rates. Thus, a gasoline tax to buy down cellulosic ethanol (Chapter 3) might have beneficial secondary price implications in the U.S, while in Europe the secondary price impacts might be welfare-reducing if gasoline prices already fully reflect or even exceed externalities costs, as suggested by Newbery (2001).

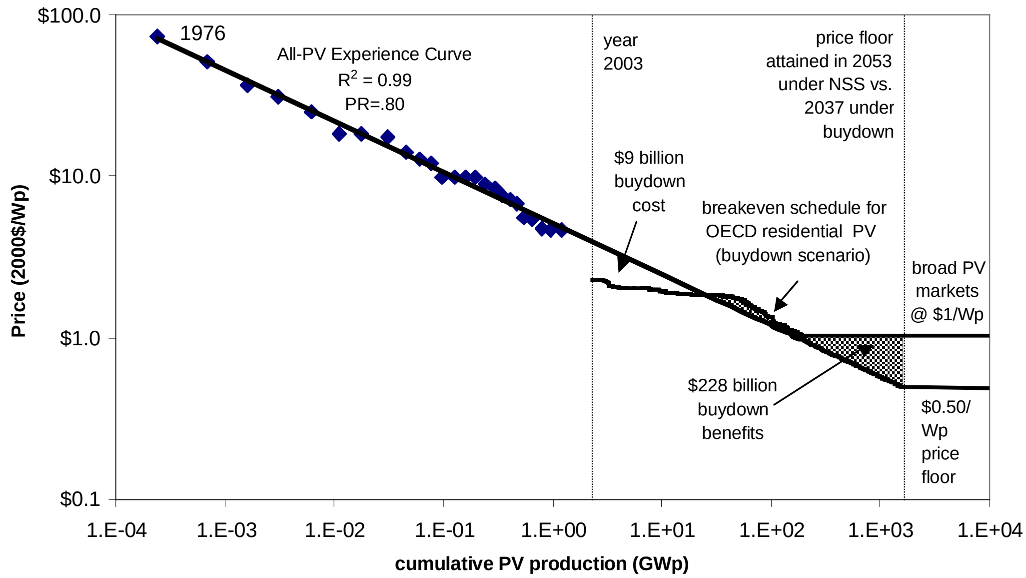

Figure 20. Distributed PV buydown for the OECD residential market

Using the breakeven method (see Table 2 for a comparison with the optimal path method), this figure shows a $9 billion buydown (unshaded) targeting distributed residential PV in OECD countries starting in 2003. The buydown scenario assumes a fixed sales growth rate of 30 percent per year through 2014 when PV breakeven is reached, after which the subsidy is zero and it is assumed that the sales growth rate is reduced to 20 percent per year. Under the NSS, the annual sales growth rate is 12 percent until distributed residential markets begin to open, at which point the sales growth rate jumps to 25 percent per year. The buydown brings PV modules to the assumed $0.50/Wp price floor in 2037 *versus* 2053 under the NSS. The analytic time period is therefore 50 years (2053-2003) since once the price floor is attained under the NSS there is no further difference between the annual benefits generated by the two scenarios.

The buydown and NSS scenarios yield total discounted ($r = 0.05$) benefits of $228 billion and $63 billion, respectively. Thus the buydown NPV is $228 - $63 - $9 = $156 billion. The total OECD electricity market is more than twice the size of the U.S. market and it is assumed that higher electricity rates (*e.g.* about double in Germany and nearly triple in Japan) roughly compensate for lower average insolation outside the U.S.

For the buydown scenario (depicted), the OECD residential PV breakeven schedule is defined as twice the US market which, in turn, is defined as 20 times the annual new home PV market shown in Figure 19 plus a retrofit market (for which PV's value is 20 percent less than for PV in new homes) equal to one-third of existing single-family homes. This follows since, under the buydown it takes 20 years to reach the $1/Wp threshold at which point broad distributed PV markets are assumed to open up (including commercial buildings and developing country markets). Under the NSS (not depicted), the breakeven schedule is shifted to the right because it takes 38 years to reach the $1/Wp threshold.

installing approximately 7 m^2 per capita by 2030, which could easily be accommodated on residential and commercial buildings in the OECD alone.[129] Beyond the indicated market penetration level for 2030, the value of distributed PV in OECD markets might decline if further grid penetration carved out dips in midday demand, making it harder to find additional high-value distributed PV sites. By 2030, however, lower prices would open developing country markets for distributed grid-connected PV. With further price reductions driven by sustained buydown support, distributed PV could provide as much as 20 percent of *global* electricity needs by mid-century without running into significant storage[130] or space[131] constraints.

Sensitivity analysis

The uncertainties underlying this analysis include expectations about progress ratios, improvements in balance of systems equipment and delivery mechanisms, and the rate of price reductions for substitute technologies.

The results are sensitive to the slope of the experience curve. Increasing the progress ratio to 0.83 from 0.80 forces the base case buydown NPV down by 27 percent. Raising the discount rate also cuts NPV since it drives down the present value of long-term benefits more than the present value of near-term subsidy costs. Discount rate choice remains an area of active academic debate (Portney and Weyant, 1999), but a real social rate of time preference of 4-6 percent is consistent with standard practice for

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[129] Conservatively assuming 10 percent average module efficiency, the total space requirement can be estimated as, 900 GWp * 1 m^2 / 100 Wp = 9 billion m^2. The OECD projects that the total population of its members will be 1.2 billion in 2030. Dividing the latter into the former yields roughly 7 m^2/capita.

[130] Total world electricity demand in 2050 will be roughly 41,000 tWh based on projected year-2020 demand of 22,000 tWh (EIA, 2002b) and an assumed annual growth rate of 2 percent thereafter. The base case buydown scenario projects annual sales of 150 GWp/y by 2030, growing at 2 percent annually to reach 230 GWp/y by 2050. At these levels, annual PV installations could be completely absorbed by *new* annual daytime electricity demand such that the value of PV electricity would not deteriorate over time.

[131] Given year-2050 world electricity demand of 41,000 tWh (footnote 130), a 20 percent share requires 8,200 tWh of PV output. At 1,300 kWh/kWp-year (footnote 127) this would require 6,100 GWp of installed PV capacity. Assuming 15 percent average module efficiency by 2050, the space requirement can be estimated as,

6,100 GWp * 1 m^2 /150 Wp = 41 billion m^2.

appraising public investments in the European Union and, in the view of the IPCC, appropriate for analyses of carbon mitigation investments funded by industrialized countries (IPCC, 2001b). Thus, r = 0.05 is a reasonable base case assumption for an OECD-funded PV module buydown, though the r = 0.10 case illustrates the importance of this parameter.

	A present value of benefits under buydown *$ billions*	**B** present value of benefits under NSS *$ billions*	**C** present value of minimum possible subsidy *$ billions*	**A-(B+C)** NPV *$ billions*	**(A-B)/C** BCR	buydown duration *years*	analytic time frame *years*
breakeven method *base case*	$228	$63	$9.1	**$156**	19	11	2003-2053
PR = 0.83	$215	$61	$40	**$114**	4.0	22	2003-2103
r = 0.1	$51	$9	$7.5	**$34**	5.6	11	2003-2053
Thin-film	$374	$198	$0.5	**$176**	318	4	2003-2043
optimal path method base case	$235	$144	$37	**$54**	2.5	43	2003-2066
optimal path method base case *33% MEB*	$220	$144	$32	**$44**	2.4	45	2003-2066

Table 2: Summary of PV buydown assessments

It is also possible that NPV will prove higher than the base case estimate. Payne, Duke, and Williams (2001) indicates that costs for thin-film PV modules may decline to about $1.70/Wp by 2010, which is less than the $2.30/Wp predicted by the all-PV

The U.S. census projects global population of 9 billion by mid-century, implying modest space requirements of 4.5 m^2 per capita.

experience curve under the buydown scenario. Thin-films benefit from both inherently low materials costs and opportunities for efficient continuous-process manufacturing (Zweibel, 1999). Payne, Duke, and Williams (2001) also demonstrates that manufacturers could achieve substantial cost savings by increasing the scale of a-Si thin-film PV module factories to 100 MWp/y.[132] This suggests the possibility that thin-film PV will establish its own experience curve lying below the all-PV curve.

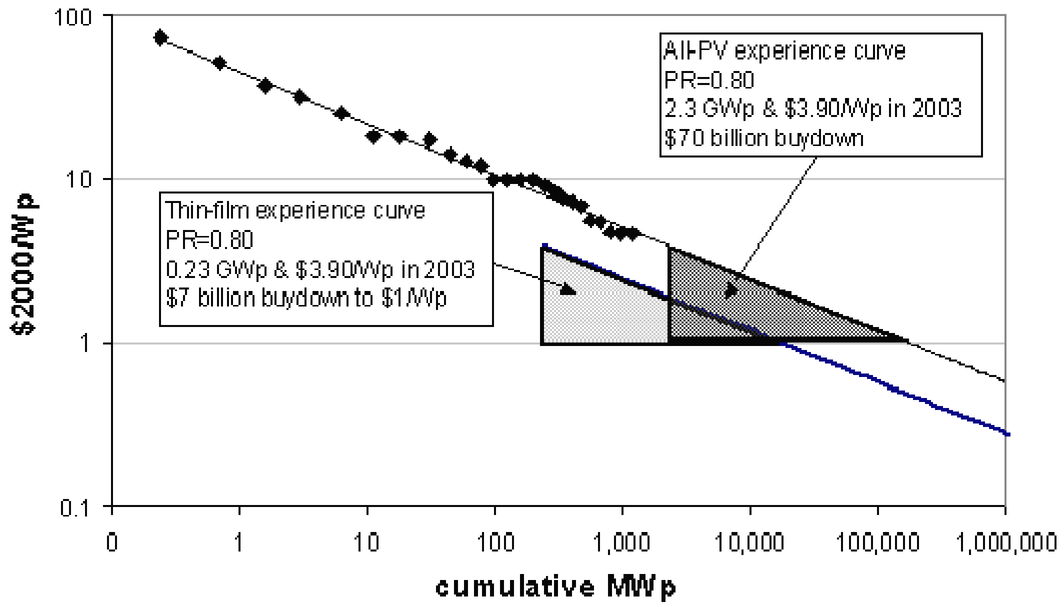

Figure 21: Buydown costs for all-PV and thin-film PV experience curves

This figure shows projections of retail PV module prices based on both the historical PV experience curve for all PV technologies (dominated by crystalline PV technologies) and a postulated thin-film curve assumed to have the same progress ratio and initial module price in 2003, but starting with an order of magnitude less cumulative production experience. Buydown is defined here as the incremental expenditure to reduce module prices from their initial values to a $1/Wp target price, without taking niche market opportunities into account.
Source: Updated from Payne, Duke, and Williams (2002)

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[132] In June of 2002, Uni-Solar opened a 30 MWp facility for producing multi-junction a-Si thin-film PV (www.uni-solar.com) with residential and commercial buildings as their primary intended market. The company projects that moving to a 100 MWp/y facility will yield substantial additional scale economies. The cost of capital equipment for this 30 MWp facility is roughly the same (in $/MWp terms) as the estimated capital costs for the 100 MWp/y facility considered in Payne, Duke, and Williams (2001), suggesting that the price projections from the latter may be conservative.

The shape of a potential thin-film experience curve remains unknown because crystalline technologies continue to dominate overall sales, but one possibility (Figure 21) is that thin-films will follow the same progress ratio as crystalline PV but starting from a base of cumulative production experience roughly one-tenth as large as for the all-PV experience curve—a construction that is consistent with the bottom-up technology assessment in Payne, Duke, and Williams (2001). If thin-films follow this path to eventual market dominance then the all-PV experience curve would show a transition similar to Figure 22.[133]

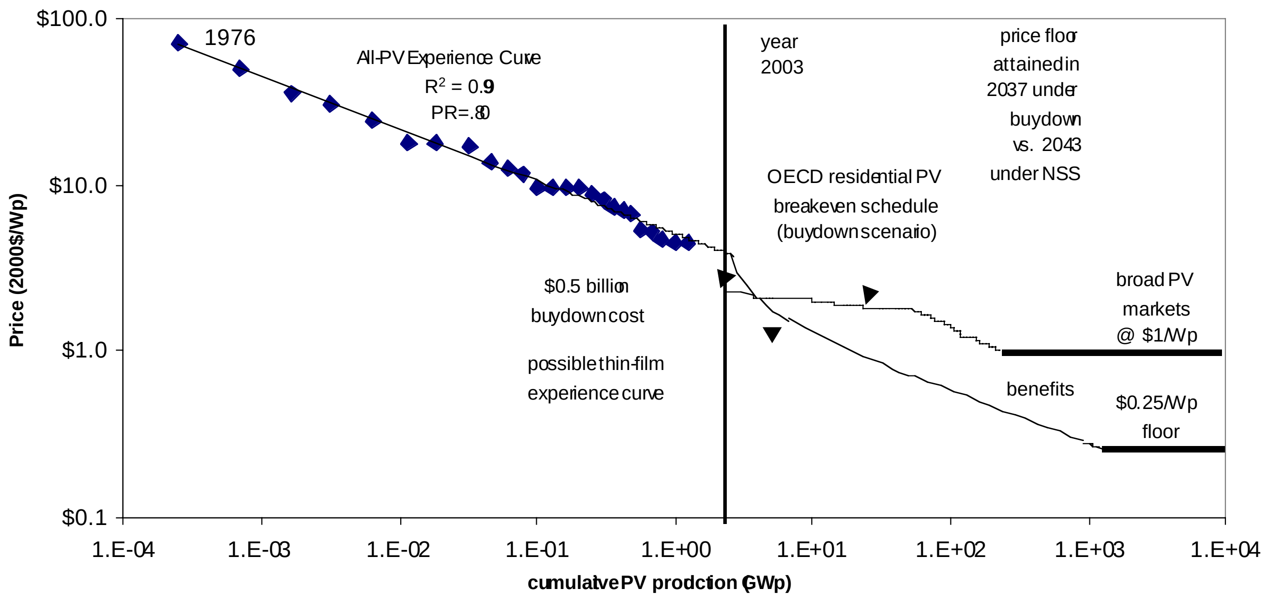

Figure 22. Distributed PV buydown (Thin-film Case)

Using the breakeven method for estimating buydown costs (see Table 2), this figure shows a buydown costing $0.5 billion (unshaded) targeting distributed residential PV in OECD countries. The buydown brings PV modules to the price floor in 2037 *versus* 2043 under the NSS, yielding total discounted (r = 0.05) benefits (unshaded region where the break-even schedule exceeds the experience curve and to the left of the price floor attained in 2037) of $374 billion and $198 billion, respectively. Thus the buydown NPV is $374 - $198 - $0.5 = $176 billion. The analysis uses the same assumptions as Figure 20 except that the

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[133] It is assumed that thin-films account for 10 percent of cumulative and current PV sales as of 2003, rising to 100 percent by 2013, with prices falling according to a progress ratio of 0.80 (as for the all-PV experience curve). The thin-film market share is based on historical data for U.S. and Japanese production as derived from IEA (1999) and OITDA (2002), respectively.

OECD residential PV breakeven schedule for the NSS scenario (not depicted) includes only 28 years of new home demand before the $1/Wp threshold is reached (*versus* 38 years for the all-PV experience curve). Also, the experience curve is assumed to transition to a thin-film curve (Payne, Duke, and Williams, 2001) with the same slope (PR = 0.80) but an order of magnitude less cumulative production. Finally, the price floor is also assumed to drop from $0.50/Wp to $0.25/Wp for this thin-film case.

Under these thin-film assumptions, the buydown case described above costs just $0.5 billion and yields gross benefits of $374 billion. With a thin-film experience curve, the assumed 12 percent annual growth rate for the unsubsidized scenario in off-grid markets would pull prices down far enough to begin opening distributed grid PV markets by 2010, accelerating the sales growth rate to 25 percent per year as under the all-PV case and yielding NSS benefits of $198 billion. Thus, the buydown NPV for the thin-film case is $374 - $198 - $0.5 = $176 billion.

As noted, all of these results are highly sensitive to the assumed sales growth rate in both the no subsidy and buydown scenarios. The optimal path method in the next section avoids these arbitrary assumptions.

Assessing a global PV buydown: the optimal path method

This section uses the optimal path method (based on Equation 7 developed in Chapter 3) to address some of the limitations of the breakeven method and endogenously estimate the optimal subsidy and output paths for a global PV module buydown. Under the base case, this approach recommends tripling the level of subsidized PV sales as quickly as possible, followed by moderate further increases over a period of decades. Such a buydown would allow PV to provide over 5 percent of industrialized country electricity by 2030 *versus* less than 1 percent in the NSS.

Base case

This analysis assumes an isoelastic demand schedule that shifts outward over time according to a logistic function:

such that,

The optimal buydown path, , starting in 2003 is completely determined by: 1) specification of these four demand-side parameters (α, β, _, and m) plus, on the supply-side, the learning parameter $b = -ln(PR)/ln(2)$, and the initial price and cumulative output (which are linked by from equation 5 in chapter 3); and (ii) specification of the initial sales for the NSS as X_{2002} = 160 MWp/y (the market for off-grid sales—which is assumed to be the same for all cases considered); and (iii) the optimizing condition that the NPV is maximized. For the sensitivity analysis below, the parameters vary across different cases, but within each case the same parameters are used for both the no subsidy and buydown scenarios.

For the base case: (*i*) the four demand-side parameters are assumed to be α = 0.088, β = 2.0, _ = 2.0, and m = 25, and (*ii*) on the supply-side, Y_{2002} = 1.9 GWp, P_{2002} = $4.20/Wp (the average world wholesale PV module price including a 20 percent retail markup), and b = -0.32 (PR = 0.80). In what follows the motivation for each of these base case choices is discussed.

For the base case, the price elasticity of demand is estimated based on historical data for unsubsidized PV markets combined with the projected breakeven schedule for distributed residential PV in the OECD (Figure 23). This curve indicates ; however, the true elasticity may be lower because, in addition to declining prices, nonprice diffusion effects (*e.g.* potential customers learning about the new option over time) partially explain historical sales increases. Accordingly, for the base case the model assumes .

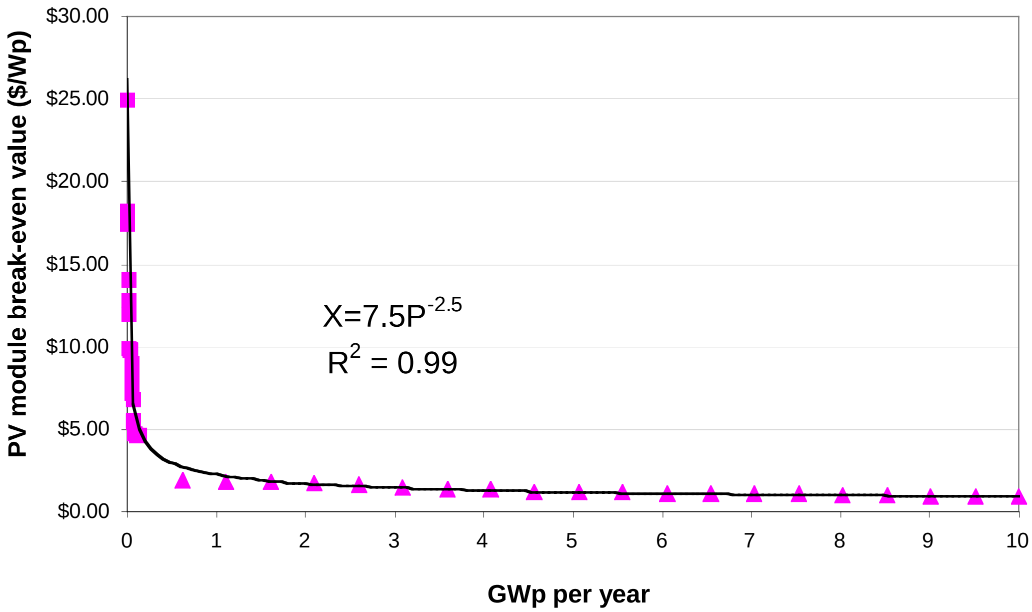

Figure 23. PV demand elasticity estimation

The square data points plot historical PV prices *versus* unsubsidized off-grid sales levels for 20 years from 1980-2000 (Johnson, 2002). The triangles represent 20 points from Figure 19 at evenly spaced quantity intervals. The best-fit isoelastic demand schedule consistent with these data has an elasticity of 2.5; however, some of this historical demand growth reflects diffusion effects rather than price effects, so the true elasticity may be lower.

Also on the demand-side, the scale parameter is set (m = 25) such that the annual quantity demanded is 100 GWp/y[134] in a mature market, *i.e.* once the demand schedule has fully shifted out and modules prices have reached the assumed floor of $0.50/Wp (Figure 24).[135] Given this scale parameter and P_{2002} = $4.20/Wp, the model sets the

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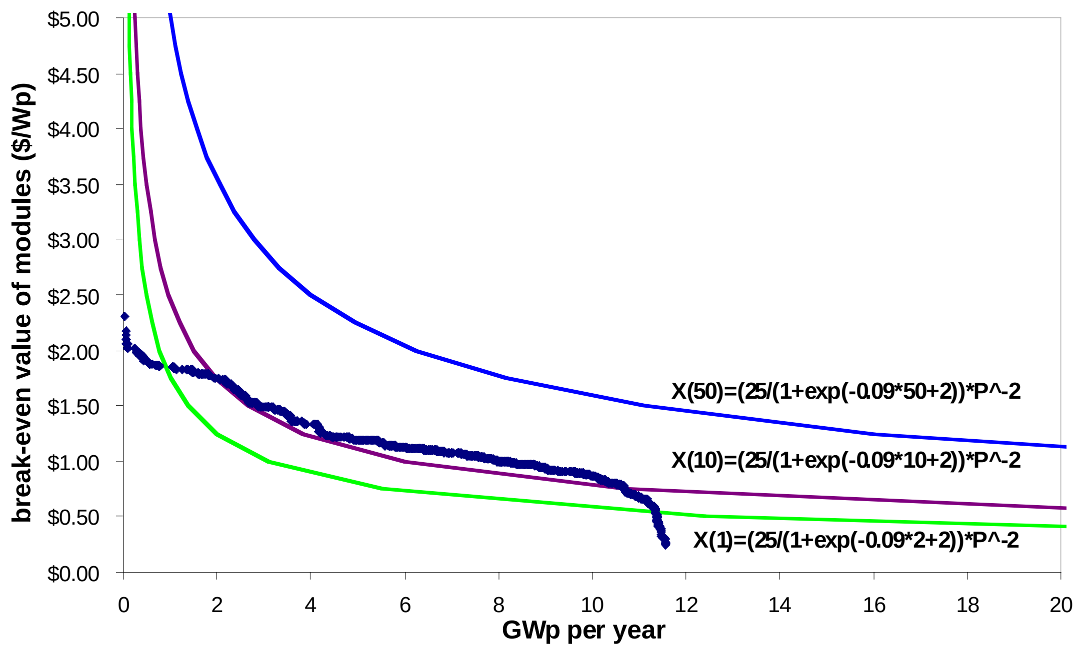
[134] This level of PV capacity additions is consistent with lower-bound estimates of global annual markets for new peak electricity generating capacity (footnote 133).

[135] This follows directly from the demand schedule, *i.e.* GWp/y.

location parameter, β, such that the average sales growth rate under the NSS is 12 percent per year during the first 5 years of the model run (2003-2008).

The base case parameter choice β = 2.0 leads to a plausible initial NSS sales trajectory, with the annual growth rate increasing to 15 percent per year by 2010 then gradually tapering off after 2025 as the demand schedule approaches the maximum NSS production rate (100 GWp/y), which is reached by the middle of the century. Sales level



off completely once the price floor is reached in the NSS.

Figure 24. Logistic demand shift for the optimal path method

This figure compares the logistically shifting all-market PV demand schedule used in the optimal path method analysis with the annual OECD residential PV breakeven schedule, where the latter is based on Figure 19 (*i.e.* the breakeven schedule for PV in new U.S. homes) increased by roughly a factor of 4 to account for retrofits as well as markets in Europe and Japan. In the first year of the analysis (2003) annual demand falls short of the breakeven schedule, but the two schedules overlap by year 10 after markets have matured (*i.e.* after a doubling of the coefficient on the isoelastic demand). After 50 years, demand shifts out by another factor of four due to growth in commercial buildings and developing country markets. At the price floor of $0.50/Wp, this yields a mature sales rate of 100 GWp/y.

Even in the first year, the all-market demand schedule exceeds the OECD residential PV schedule sales levels below 1 GWp/y because it includes off-grid PV markets for which the willingness to pay is much greater than for distributed grid-connected PV (although the potential non-grid market is small). Similarly, the all-PV demand schedule extends beyond the 10 GWp/y level at which the residential PV market in

OCED countries begins to saturate because other markets open up at these low prices, including commercial buildings and a full range of grid-connected applications in developing countries.

The base case location parameter setting (β = 2.0) implies that the demand schedule has reached 10 percent of its maximum extent by 2000 and 13 percent of its maximum by the start of the buydown in 2003, *i.e. X(1)* in Figure 24. The rate parameter is then set (α = 0.088) such that it takes 50 years for the demand schedule to shift from 10 percent to 90 percent of its eventual mature level, *i.e. X(50)* in Figure 24. These specifications are plausible given that PV has already had 30 years of niche market diffusion and Grubler and Nakicenovic (1991) show that for energy technologies

years (see *Prioritizing Clean Energy Buydowns* in Chapter 2).

These demand shift parameters yield a classic logistic diffusion curve under the buydown scenario, but the diffusion curve under the NSS looks more like an exponential function that levels off at 100 MWp/y (Figure 25). This reflects the fact that the logistic demand shift schedule, *l(t)*, should ideally be treated as a function of cumulative sales (in addition to time) because of the social contagion of the adoption process (Bass, 1980) and learning-by-using (Vettas, 1998). For example, under the NSS sales levels are lower than under the buydown so fewer potential PV buyers see the technology in use on other homes. This means that the quantity demanded at any given module price will be lower under the NSS—and, of course, the module price in any given year will be higher because cumulative production experience accrues more slowly under the NSS. Since *l(t)* should ideally be a function of cumulative output (as well as time), the true demand-shift rate under the NSS is slower than indicated in this simplified model that omits learning-by-using. Thus, assuming a constant demand shift rate for both the NSS and buydown scenarios is a crucial conservative assumption that substantially understates the net gain in sales levels (and consumer surplus) from providing buydown subsidies.

Given these parameters and assumptions it is possible to computationally determine the output path that maximizes buydown NPV. Solver add-in software for Excel iteratively tests different sales trajectories until it converges to the best path it is able to identify. In principle, the software can converge to the wrong solution, but the

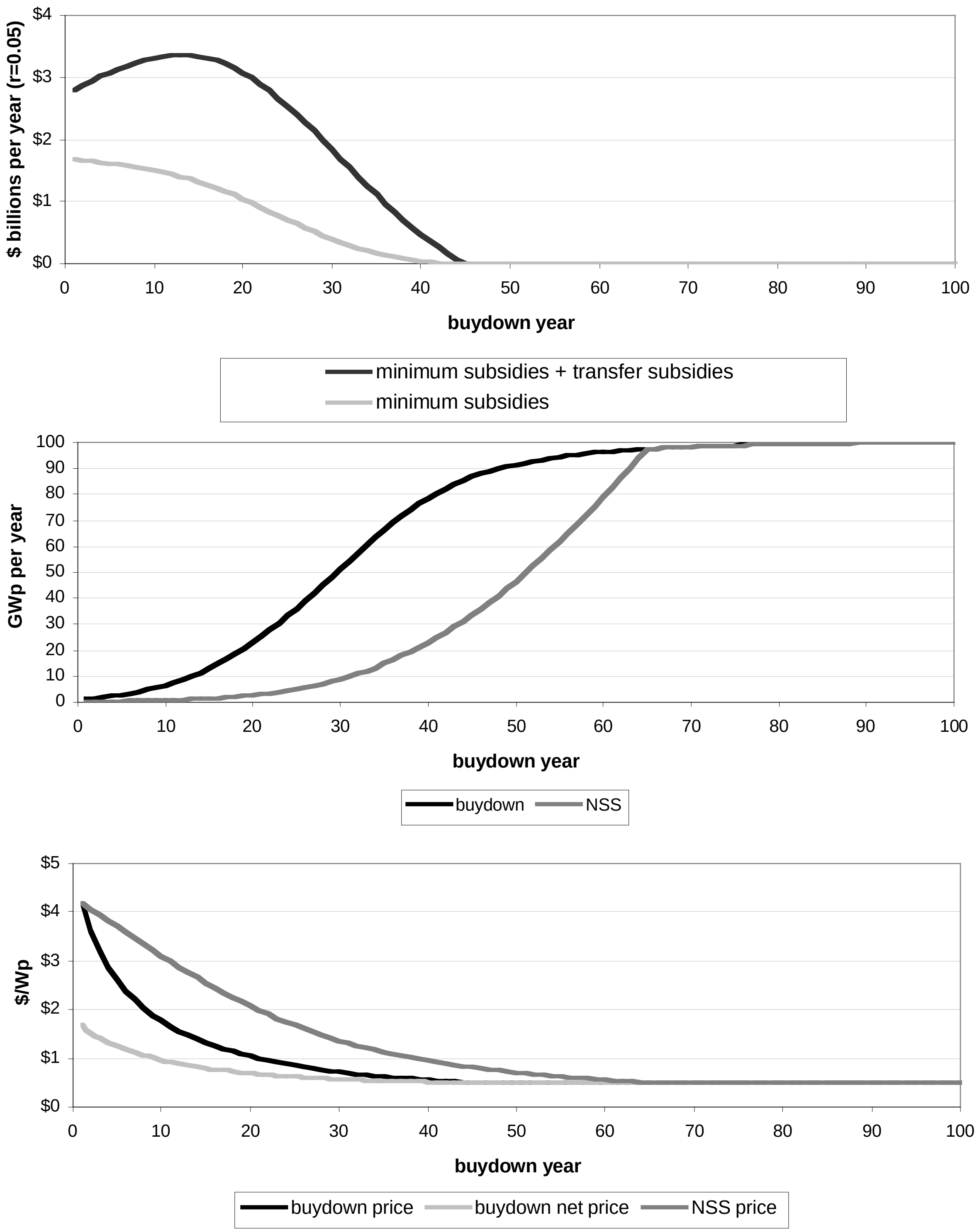
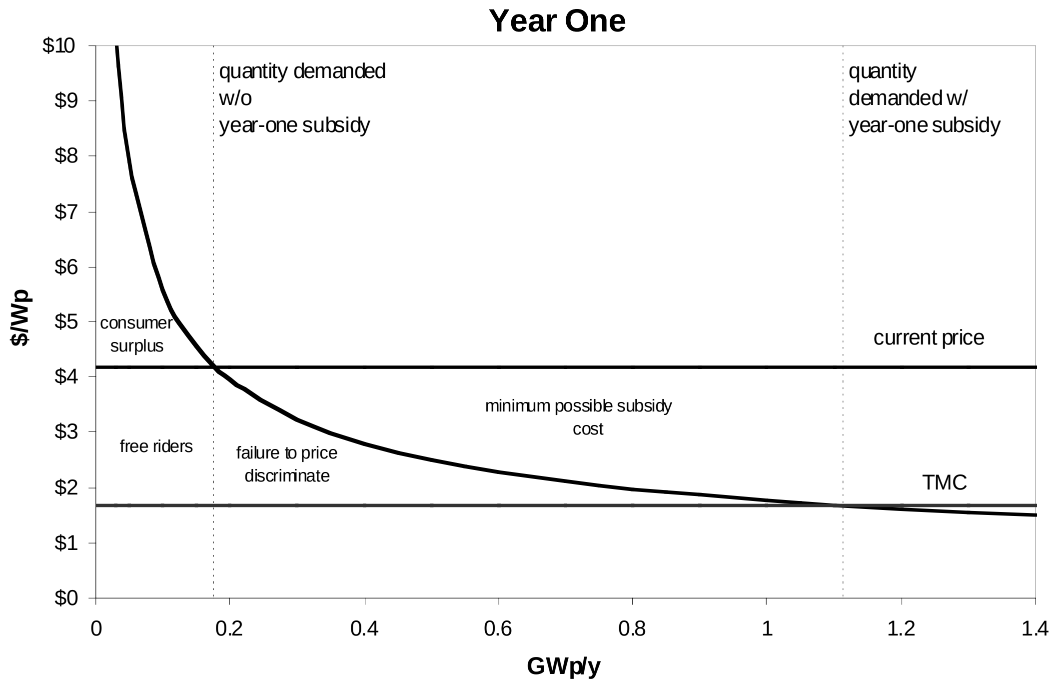


Figure 25. Optimal path method base case scenario (no MEB)

quantitative results under a wide-ranging sensitivity analysis are consistent with both theory and intuition, suggesting that the solver generally identifies the global maximum.

Figure 25 summarizes the base case scenario assuming no marginal excess burden of taxation. The top panel shows the minimum possible subsidy cost in each year as well as the annual subsidy cost including possible transfer subsidies. The middle panel shows the annual output path under both the NSS and the optimal buydown. The bottom panel shows the decline in both price and *net price* over time; where the latter equals price net of subsidies, *i.e.* the price the consumer actually pays for PV. Notably, net price declines much more slowly than the buydown price and is equal to 0.4, 0.6, 0.8 times the buydown price in years 1, 10, and 20, respectively, and eventually (after 45 years) the subsidy is completely phased out. Since the analysis assumes perfect spillover and competition, net price is also equal to the true marginal cost as defined by equation 3 in chapter 2. In accordance with this theory, Figure 25 shows that the optimal net price lies below price at the start of the buydown and both decline asymptotically toward the price floor over time. The bottom panel also includes the NSS price trajectory for reference.

Figure 26 shows the first and twentieth years of the buydown. In the first year (2003), output is six times as high as under the no subsidy scenario—and more than twice as high as under current sales trends for which demand would be 0.46 GWp/y in 2002 accounting for currently available subsidies. By the 20^{th} year, the optimal output level achievable with subsidies is 2.3 times the quantity that would be demanded if buydown support were discontinued starting that year (and nine times as high as under the NSS). The figure also shows the extra transfer subsidies that must be paid if the buydown programs are unable to price discriminate or exclude free riders.



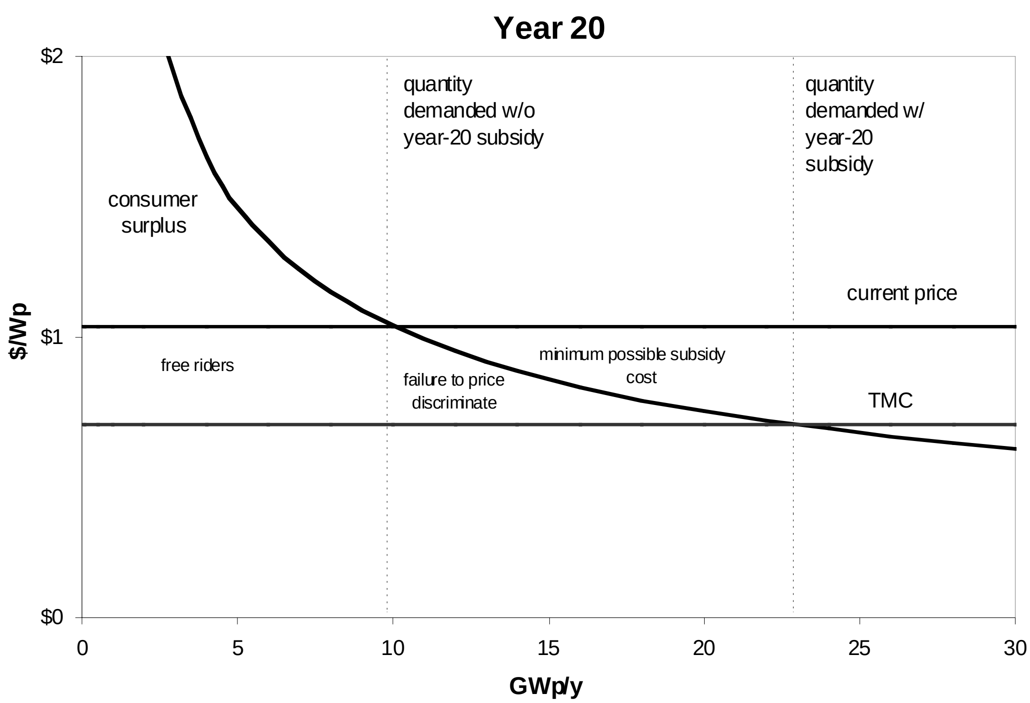


Figure 26. Base case snapshots for t = 1 and t = 20

The dark shading represents the minimum possible subsidy in each period under the optimal buydown as well as possible transfer subsidies including 1) if the buydown is unable to price discriminate and, 2) if the buydown cannot exclude free riders. In later years, transfer subsidy costs may account for an increased proportion of total subsidies because the potential base of free riders is higher. Note that the 10 GWp/y *quantity demanded without year-20 subsidy* implies that subsidies are discontinued only after the 19th year of the buydown.

The base case yields a NPV of $54 billion. This is lower than the breakeven method result because the optimal path method realistically models outward-shifting annual demand schedules, with on-going subsidies needed to drive the buydown until the price floor is reached. In contrast, the breakeven method optimistically assumes that no further subsidies are needed after prices fall low enough to *begin* opening up large distributed grid market segments. The breakeven method also underestimates total benefits in the NSS since it does not consider consumer surplus from high value off-grid markets and the assumed annual sales growth rates do not adequately account for unsubsidized sales levels as the price falls over time.

Sensitivity analysis assuming a 33 percent MEB

Figure 27 shows the base case modified to assume a 33 percent MEB for all subsidies in accordance with Parry (1999) which was described in chapter 4 (see the appendix at the end of this chapter for Figures 27-35). This reduces the NPV from $54 billion to $44 billion. Under these assumptions, the base case calls for immediately increasing the level of subsidized sales by a factor of 2.3. In the likely event that such rapid growth is unachievable, however, the buydown NPV need not suffer seriously. For example, imposing a constraint that total subsidized sales can never grow by more than 50% in any given year only reduces NPV imperceptibly (Table 2). The changes to the graphs in Figure 27 are trivial and therefore not shown.

If the buydown completely fails to exclude free riders or price discriminate, and these transfer subsidies are also valued assuming a MEB factor of 0.33, then the NPV would fall to $27 billion. This underscores the importance of identifying policy instruments that make it possible to avoid or at least minimize such transfers.

Table 3: Optimal path method sensitivity analysis using 33 percent MEB

	A present value of benefits under buydown *$ billions*	**B** present value of benefits under NSS *$ billions*	**C** present value of minimum possible subsidy *$ billions*	**A-(B+C)** NPV *$ billions*	**D** Present value of transfer subsidies *$ billions*	**A-(B+C+D)** NPV minus transfer subsidies *$ billions*	buydown duration *years*	analytic time frame *years*
Optimal path method *base case*	$220	$144	$32	**$44**	$17	**$27**	45	2003-2066
50% per year maximum sales growth constraint	$219	$144	$31	**$44**	$16	**$27**	45	2003-2066
PR = 0.83	$180	$136	$21	**$24**	$15	**$8.7**	101	2003-2138
undetected PR = 0.83	$186	$136	$29	**$22**	$16	**$5.6**	101	2003-2138
R = 0.1	$45	$34	$5.3	**$5.6**	$4.0	**$1.7**	50	2003-2066
M = 12.5	$135	$90	$21	**$24**	$12	**$12**	65	2003-2096
= 1.5	$271	$250	$15	**$18**	$12	**$5.7**	61	2003-2075
thin-film w/ $0.25/Wp floor	$240	$148	$31	**$61**	$13	**$48**	26	2003-2038
_t = 25	$320	$204	$47	**$69**	$22	**$47**	37	2003-2056
10-year buydown	$181	$144	$13	**$24**	$3.6	**$20**	10	2003-2066
Maximize (NPV - transfer subsidies)	$208	$144	$22	**$42**	$12	**$30**	50	2003-2066

Raising the progress ratio (from PR = 0.80 to PR = 0.83) and re-optimizing reduces NPV from $44 billion to $24 billion, or $8.7 billion for NPV net of transfer subsidies (Table 2). Initial output under the optimal path also diminishes relative to the base case (compare Figures 28 and 27). Similarly, slowing technical progress causes both the *buydown duration* and the *analytic timeframe* to more than double (to 101 years and 135 years, respectively) where the former term is defined by the time it takes to reach the assumed $0.50/Wp price floor under the buydown scenario and the latter is the time necessary to reach the price floor without any subsidies. Importantly, the NPV is only marginally lower if it takes the government a full decade to realize that the true progress ratio is worse than the historical rate of 0.80. Table 1 lists this scenario as "undetected PR = 0.83." Relative to the anticipated PR = 0.80 case, the NPV falls less than 10 percent in this scenario since the government can substantially cut back on subsidy levels as soon as it becomes clear that the rate of technical progress is lagging behind initial expectations.

More aggressive discounting has qualitatively similar but more severe deleterious impact on buydown economics (Figure 29). Doubling the real discount rate from r = 0.05 to r = 0.10 reduces the NPV from $44 billion to $5.6 billion.[136] The analytic timeframe is unaffected by the higher discount rate, but the buydown takes longer because the optimal subsidy path is back-loaded (delayed subsidies are less costly in discounted terms). Raising the discount rate also pulls the net price path closer to the actual price path and, accordingly, reduces output along the optimal path. This conforms to the theory in Chapter 2. Specifically, equation 3 indicates that the government maximizes welfare by setting output such that net price equals CTMC(t), and the Appendix demonstrates that CTMC(t) approaches current unit cost (*i.e.* current price assuming constant profit margins in competitive markets) as the discount rate approaches infinity.

Similarly, reducing the magnitude of the outward demand shift (Figure 30) by a factor of two (*m* = 12.5 instead of *m* = 25) or reducing the demand elasticity from _ = 2 to _ = 1.5 (Figure 31) makes the optimal buydown both less aggressive and less cost-effective relative to the base case. Reducing either parameter also extends the buydown duration and analytic timeframe by lowering sales levels in every year such that it takes longer to reach the price floor.

There are also a number of scenarios that increase buydown NPV. As in the breakeven method, it is possible to simulate the thin-film PV case by reducing the assumed initial cumulative output level by an order of magnitude and reducing the price floor from $0.50/Wp to $0.25/Wp (Figure 32).[137] These changes increase NPV by 40 percent relative to the base case and raise NPV net of transfer subsidies from $27 billion to $48 billion. Lowering the price floor tends to extend the buydown, but lowering the initial cumulative output more than offsets this effect such that the buydown duration decreases from 45 to 26 years in the thin-film case. Note that using thin-film PV parameters substantially increases *annual* consumer surplus under both the no subsidy and buydown scenarios, but the present value *totals* do not increase much (*e.g.* from $220 billion to $240 billion under the buydown as shown in column A of Table 2) because the analytic timeframe is shortened by nearly 30 years under thin-film assumptions.

Cutting the diffusion time in half (from _t = 50 to _t = 25 years) also increases NPV substantially (Figure 33). This parameter change shortens both the buydown duration and the analytic timeframe since the price floor is reached more quickly in both

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[136] NPV net of transfer subsidies is almost unchanged relative to the base case because higher *r* substantially reduces the present value of late-period transfer subsidies.

the buydown and no subsidy scenarios. Assuming an extremely fast global diffusion time for an energy technology (_t = 10 years) accentuates these effects, but the buydown period is shortened by only seven years because the slight lag in price declines (from using discrete time steps without intra-period learning) emerges as an increasingly important constraint.

It is also possible to model the consequences of interrupting a buydown prematurely. Figure 34 shows a scenario in which the buydown proceeds according to the base case optimal strategy through the tenth year, but then all subsidies are abruptly cut out. This reduces NPV by 45 percent.

Finally, the output path that maximizes NPV net of transfer subsidies (Figure 35) substantially scales back the intensity of support in each year. Note that buydown subsidies end thirty years before the price floor is reached under this scenario, as shown in the bottom panel of Figure 35.

Strategies for effective PV buydown implementation

Analysis of global PV module markets using both the breakeven and optimal path models suggests that industrialized countries should intensify and extend their PV buydown efforts—especially outside Japan, which has been spending more than twice as much on PV deployment as any other country on a per capita basis (IEA, 2000). In particular, the optimal path method suggests that worldwide PV module buydown efforts

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[137] This accords with the bottom-up technology assessment from EPRI/OUT (1997) that suggests a year-2030 module price of \$0.67/Wp for crystalline PV and \$0.31/Wp for thin-films.

should be tripled as soon as possible, then gradually expanded over a period of decades.[138]

These results are sensitive to parameter choice, but the analysis conservatively omits environmental benefits (except to the extent that they may be implicit in net metering rules). Moreover, as noted above, learning-by-doing on the part of users means that in practice the demand schedule would shift out more quickly under the buydown than under the NSS, feeding the virtuous cycle described in the *Technology Selection Criteria* section of Chapter 3. By omitting this nuance, the optimal path method underestimates the net welfare gain obtained by moving from NSS sales projections to the buydown scenario—thereby yielding a conservative buydown NPV estimate that is akin to using a high (pessimistic) progress ratio.

Results from the optimal path method also highlight the difference between subsidies that are necessary to cover high near-term unit costs *versus* transfer subsidies that give windfalls to 1) people who could be motivated to buy the technology for less and, 2) free riders who would have been willing to buy without any support. Although transfer subsidies are not direct economic costs they nonetheless impose welfare losses on the economy (the marginal excess burden of taxation defined in chapter 4) by impeding commerce in the sectors taxed to fund the buydown.[139] It is therefore crucial

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[138] For 2003, subsidized sales under the base case optimal buydown are over 900 MWp relative to projected subsidized sales under business as usual of ~300 MWp. Thereafter, the optimal level of subsidized PV module sales would steadily increase for 30 years (with the annual growth rate for subsidized module sales declining from 27 percent to 1 percent over that period). The share of unsubsidized sales exceeds 50 percent by the 25th year and subsidies are completely phased out after 43 years.

[139] Even if the buydown uses welfare-enhancing pollution taxes, it can still be argued that the opportunity cost of these funds equals the marginal inefficiency of the most disruptive taxes that these funds could displace.

that program designers minimize transfer subsidies to ensure that buydowns provide net economic benefits.

This section explores optimal buydown duration before considering the prospects for reducing transfer subsidies by segmenting markets according to both application and geography. It then discusses the relative merits of unit subsidies *versus* quantity mandates. The final subsection argues against targeting buydown funds to particular PV sub-technologies such as thin-film modules.

Extending buydowns to maximize social welfare

Analysts using the breakeven method tend to argue for implementing buydowns as aggressively as possible.[140] If a fixed breakeven schedule is used (and the progress ratio is also assumed to be constant) then stretching out a buydown lowers the present value of subsidy costs—but it necessarily lowers even more the discounted value of benefits that accrue subsequent to break even.

In contrast, the optimal path method illustrates that buydown pace is constrained by the time it takes for demand to shift outward plus any lags in learning-by-doing. Moreover, buydowns that ramp up too quickly may create temporary supply constraints that drive short-term prices up—and this may cause the long-term progress ratio to deteriorate as firms resort to stopgap measures rather than learning how to scale up production permanently and efficiently.

Results from the optimal path method analysis also suggest that subsidies should be sustained, albeit at a steadily declining per-unit level, for a period of decades until the

[140] For example, using this analytic framework, Wene (2000) suggests that governments may want to focus limited demand-pull funding on commercializing the most promising technologies as quickly as possible.

PV module price floor is reached. This holds under a wide range of parameters and it contrasts sharply with conventional thinking that aims to eliminate support as soon as unsubsidized sales begin to become viable in the targeted market segment. This conventional "breakeven" threshold is, in fact, an arbitrary criterion for eliminating support, and it runs contrary to the optimal path theory outlined in Chapter 3 as well as the modeling results presented above.

This calls into question Japan's plans to eliminate its residential grid PV subsidies by 2004 and it suggests that the alternative of a gradual phaseout over a much longer period would increase social welfare. The German program suffers from similar concerns in that the mandated buyback program may be discontinued as early as 2004, well before it pulls residential PV system prices down anywhere near to the long-term price floor.[141]

Market segmentation to reduce transfer subsidies

The ratio of transfer subsidies to minimum possible subsidies tends to increase as markets mature—primarily because the potential number of free riders increases as demand shifts out and the technology approaches its price floor (Figure 25). Shortening and front-loading the buydown may help to keep transfer subsidy expenditures in check (Figure 36); however, the economic costs of transfer subsidies aside, this approach reduces buydown NPV relative to an optimal path estimated without time constraints. A

[141] The program automatically runs until January after the year in which the total capacity installed with buydown support exceeds 350 MWp (REL, 2001). Given current sales projections this should occur by 2004. The law also specifies that, prior to discontinuing support, the Bundestag must "…adopt a follow-up compensation scheme which shall enable installation operators to manage their installations cost-effectively, taking into consideration the decline of marginal unit cost achieved by then in the field of system engineering" (REL, 2001). This may result in an extension of buydown support, but the legislative

better strategy is to segment the market in order to exclude free riders from subsidies and, to the extent possible, price discriminate when distributing funds to buydown participants who may require varying subsidy levels to induce their purchase.[142]

Reducing transfer subsidies using market segmentation by PV application

The most obvious market segmentation strategy is to exclude off-grid markets from subsidies. The optimal path model analysis incorporates both off-grid and grid-connected markets—but the latter drive the vast majority of sales after the first few years of buydown and, in any case, buydown subsidies would not be very effective in off-grid markets. SHS markets are too small and complex to play a major role in future efforts to pull PV modules down the global experience curve (see Box 1 in Chapter 4). Similarly, subsidies for off-grid commercial and industrial markets would have relatively poor leverage and could disrupt existing healthy markets if they are not sustained. There is also little need to invest in market tuning for off-grid commercial and industrial markets since, relative to individual consumers, businesses are better equipped to overcome certain market barriers such as capital and information constraints.

Targeting support to promising distributed grid market segments also ensures rapid progress in non-module costs that may be unique to each market (*e.g.* by improving balance of systems equipment, delivery mechanisms, and regulatory structures). In some cases, buydowns should even target specific types of distributed PV markets. There was,

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language suggests that subsidies will be set with an engineering breakeven price in mind rather than an optimal buydown path.

[142] It may also be possible to achieve limited price discrimination through other means besides market segmentation. For example, green pricing programs help to reveal and capitalize on the high willingness to

for example, no market for residential PV in New Jersey when the state initiated its renewables buydown in 2001, and results from the first year suggest that the nascent PV industry in the state has initially targeted large-scale installations on commercial facilities rather than developing the more complicated, but ultimately more cost effective, residential market (NJCEC, 2002). The New Jersey program appropriately reserves half of the funding in each declining subsidy block for small systems (<10 kW), but it remains to be seen how quickly this approach will activate the residential market.

In sum, governments can increase the potential benefits from scarce subsidy funding by restricting buydown support to distributed grid-connected markets and in some cases further specifying eligibility according to different types of distributed markets. Geographic market segmentation offers similar advantages.

Reducing transfer subsidies through regional market segmentation

Regional buydowns can be calibrated to local conditions and they allow more careful market segmentation to reduce free riders. For example, once delivery mechanisms mature in one region it should be possible to support on-going market development with lower unit subsidies than are required to launch distributed PV markets from scratch in another region. International buydowns would have difficulty detecting and calibrating to these subtleties.

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pay for renewables among certain consumers—but available evidence suggests that this market is limited to a small subset of the population (Chapter 4).

Global versus regional buydown strategies

Besides the advantages they offer in controlling transfer subsidies, there are many other reasons for giving careful consideration to regional rather than global buydown strategies.

Public support for clean energy technologies yields important global benefits in the form of carbon mitigation as well as price reductions for internationally traded system components. Thus, it is useful to apply the optimal path method at the global scale and, in the case of PV, this analysis shows that collective international buydown investments fall short of the optimum by a factor of three. Nonetheless, most buydowns are implemented at the national or even local level (hereafter referred to as *regional buydowns*).

One of the crucial advantages of demand-pull programs (and broader technology policy) is that they do not require global collective action because many of the benefits accrue nationally or even locally. First, buydown programs may help an individual nation to develop *technological leadership* in the clean energy sector. Baumol (1995) presents a rationale for temporary subsidies to support "retainable" environmental industries characterized by high start-up costs as well as scale economies and learning effects. Collectively, these factors give first movers an advantage over subsequent challengers. Clean energy technology manufacturing fits these criteria, giving governments a possible incentive to pursue competitive advantage in this sector—though to the extent that innovations from learning-by-doing spill over *internationally*, manufacturing cost advantages in this sector may not prove retainable.[143] Second, clean energy technologies reduce *local emissions* and "green" constituents may press the government to take a leadership role in global efforts to develop clean technologies. Third, buydowns reduce delivery mechanism costs and these benefits tend to accrue locally.[144] Evidence from the Japanese residential PV program confirms the prospect for rapid reductions in the immature local components of overall system costs (Figure 17). During the first three years of the Japanese program, installation costs fell by 64 percent, balance of systems costs (including new inverter designs optimized for this market) fell by 77 percent, and the retail price paid for modules fell by 33 percent relative to a 10 percent drop in the global wholesale module prices (Kurokawa and Ikki, 2001; Johnson, 2002).[145]

Decentralized buydown implementation also has several important virtues aside from facilitating transfer subsidy reduction. First, regional buydowns bypass the international collective action problem and the bureaucratic inertia of multilateral institutions,[146] allowing activist regions to lead even if other nations or localities would be unwilling to participate in a broader buydown effort. California, for example, has consistently pushed the envelope on air pollution regulations, most recently in the form of

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[143] Renewables advocacy literature often points to job creation benefits (*e.g.* Greenpeace, 2001), but other forces (*i.e.* monetary and fiscal policy as well as rules and norms that affect wage rigidity and labor mobility) largely determine employment levels. Nonetheless, leadership in advanced technology sectors has the potential to boost average wages incrementally.

[144] Firms can transfer some delivery mechanism learning benefits from the buydown jurisdiction to other regions and countries, but only imperfectly. Local firms have an advantage in marketing their services and navigating through regulatory requirements. Moreover, governments may purposefully structure buydowns to favor local businesses (though this would violate World Trade Organization precepts).

[145] Of course, Japan's buydown costs would be lower to the extent that other nations contribute to the global PV module buydown effort (Wene, 2000). This suggests a role for loose international coordination of regional buydown efforts as discussed in chapter 6.

legislation passed in 2002 to limit carbon emissions from automobiles. It remains to be seen how the state will implement this law, but it may involve measures that amount to buydown programs for advanced fuel-efficient vehicles (*e.g.* battery electric, hybrid, or fuel cell vehicles). Moreover, this law far outpaces action to address climate change at the national level.

Second, regional buydowns reduce the risk that global sales of PV modules and inverters will suddenly plummet if any given program is prematurely discontinued. This should encourage manufacturers of globally traded system components to invest in learning how to scale up production.

Finally, regional buydowns facilitate learning about diverse implementation modalities. Nations and localities can draw upon these experiences to identify the most effective subsidy format for their local conditions.

In sum, most buydowns are implemented at the regional rather than international level, and this approach has important virtues. Nonetheless, defining the optimal subsidy and output path at the regional level poses analytic challenges.

On the supply-side, analyzing a regional buydown requires consideration of installed *system* prices. Analysts should therefore base price projections for PV modules on the international experience curve (using exogenous international sales growth rates plus the incremental demand from the buydown in question). For non-module components of system cost, analysts can use data from relatively advanced regional

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[146] As an example, the Global Environment Facility approved support for the Photovoltaic Market Transformation Initiative in 1996, but it took five years for the World Bank Group to begin disbursing funds in Kenya (Duke, Jacobson, and Kammen, 2002).

buydowns to estimate progress ratios (*e.g.* PR = 0.84 for installation costs in Japan) and price floors.

For a regional buydown there may be no local demand data before a buydown is launched because the market does not exist. As with the global PV analysis in this chapter, bottom-up demand estimates based on financial breakeven calculations provide a starting point, but each respective regional buydown may require high *activation subsidies* to compensate the first few customers for the cost of 1) educating themselves about the new technology; 2) taking on perceived or actual performance risks; and 3) dealing with immature delivery mechanisms and regulatory systems. Also, even after a buydown has successfully launched its targeted market, willingness to pay will continue to lag behind the financial value of PV due to *demand-side market failures* similar to those that constrain even highly cost-effective energy efficient technologies.[147] Thus, precisely quantifying the optimal buydown path at the regional level would be challenging.

The next subsection introduces quantity mandates as an efficient buydown mechanism that reduces the information burden on program designers and adjusts automatically to 1) provide necessary market activation energy and, 2) compensate for demand-side market failures.

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[147] Brown et al. (1998) cites multiple studies documenting the failure of individuals and firms to adopt cost-effective energy efficiency technologies. The underlying market failures include principal-agent conflicts that arise when the individual or firm making decisions about energy options does not pay the utility bills. More broadly, bounded rationality problems and cognitive biases (Bazerman, 1994) constrain the ability of individuals and firms to process available information about different energy alternatives. Certain hidden, but nonetheless real costs (*e.g.* information gathering effort) may partially explain the apparent energy efficiency paradox. Some of these costs could diminish as a function of learning-by-doing on the part of users; however, firms attempting to encourage this process by means of aggressive forward pricing cannot capture all the resulting benefits.

Quantity mandates versus unit subsidies

Buydowns follow one of two broad strategies: 1) fix unit subsidies and let the induced quantities vary; and 2) fix quantities and let the implicit subsidies vary. Fixed subsidy options include tax credits, rebates, and electricity feed-laws. These approaches are easy to administer, but governments may have difficulty 1) setting initial subsidies high enough to provide sufficient activation energy to launch regional markets; 2) 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 buydown 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 1) targeted technologies are not over-funded and, 2) promising technologies with longer lead times are not left behind.[148] Moreover, this approach usually focuses on launching markets rather than providing sustained demand-pull support that maintains the optimal sales growth trajectory until the price floor is reached.

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.

Designing quantity mandates

Quantity-based mandates offer a promising alternative buydown mechanism that could provide for predictable and efficient market development absent detailed information about current and future demand schedules. Under a Renewable Portfolio Standard (RPS), for example, electricity service providers must purchase a fixed and rising share of their electricity from qualifying renewables, buying tradable credits to make up any shortfall.[149] 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 a modified RPS as a buydown mechanism by limiting the contribution of relatively mature renewables. The

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[148] 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 $/watt 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 percent 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 $/watt basis (www.njcleanenergy.com).

	Incentive Block			
Maximum incentive per watt	**1** **(2.0 MW)**	**2** **(5.5 MW)**	**3** **(12.5 MW)**	**4** **(30 MW)**
Small Systems (<10kW)	$5.00	$5.00	$4.00	$3.00
Medium Systems (>10-100kW)	$4.00	$4.00	$3.00	$2.00
Larger Systems (>100 kW)	$3.00	$3.00	$2.00	$1.50
Max incentive as % of eligible system costs	60%	50%	40%	30%

simplest strategy would require obligated parties to use PV or other promising but immature renewables to meet some minimum share of their overall RPS requirements.[150] Alternatively, to skirt the taboo against technology picking, 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, Duke, and Williams, 2001). Under either approach, credits for *bulk renewables* (*e.g.* wind, landfill methane, and waste-to-energy biomass) would trade at a lower value than credits for *buydown renewables* such as PV. In both tiers, competitive pressure would minimize credit prices, and the associated implicit subsidies. Nonetheless, credit prices would rise as high as needed to provide the activation energy necessary to launch the buydown.

To implement an RPS, program designers would ideally apply the optimal path method using demand and experience curve estimates for local installed system prices. Data to formally evaluate the optimal local buydown path for installed system are scarce, however, so one alternative is to estimate the local share of the optimal global PV module buydown effort, then set an RPS schedule to ramp up to this contribution along the fastest sales growth trajectory possible without inducing price spikes from capacity constraints. For example, the population of New Jersey is 0.8 percent of the total OECD population, suggesting that it should contribute 60 MWp to an optimal global PV module buydown

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[149] RPS credits are often called tradable renewable energy certificates in the U.S. Europe generally calls the credits green certificates and the RPS a Green Certificate Mechanism. Note that the obligated parties can also be electricity generators or consumers.

[150] The state of Nevada passed an aggressive RPS law in 2001 that requires that 15 percent of all electricity come from new renewables by 2013. It further specifies that 5 percent of this total come from solar technologies, including PV, solar thermal electricity, and solar thermal systems that displace electric heating or cooling loads. The solar set-aside concept has promise, though Sterzinger (2001) identifies implementation concerns in the case of the Nevada law, including the possibility of arbitrary exemptions under a vague clause requiring that the compliance cost be "just and reasonable."

over the next 5 years.[151] This is roughly consistent with the current NJ buydown that aims to catalyze as much as 50 MWp over a 5-year period (chapter 4), though better than average insolation levels and retail electricity rates suggest that more aggressive local support would also be reasonable. Of course, states will also set quantitative targets based on estimated direct local benefits from PV (*e.g.* reductions in fuel price risk and local pollution) but in the near-term PV can only contribute minimally to these objectives. The real payoff potential comes from the major self-sustaining markets that collective global buydown efforts promise to unleash in the long-term.

Under an RPS with a PV tranche, eligibility should be defined broadly to unleash the creativity of a range of players. Electricity service providers could, for example, cull PV credits using fixed rebates or leasing systems to homeowners (as the Sacramento Metropolitan Utility District has done). Builders might also be eligible to generate and sell credits. For example, homebuilders might design sales contracts to retain ownership of the expected stream of credits from PV generation in each solar home they sell. This would give a large well-informed player (capable of appreciating the full value of expected credits and minimizing transaction costs) strong incentive to roll out "solar subdivisions."

To ensure that individual homeowners also have an incentive to install systems on self-built new homes or retrofits, it would also be useful to structure the verification rules to facilitate up-front cash-outs of the stream of expected credits over the system lifetime. Regulators would use straightforward models to estimate system output depending on equipment, location, tilt angle, and orientation. All systems would be subject to spot-

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[151] The optimal global buydown would subsidize 7.5 GWp during the period from 2003-2008 (while an

checks to ensure that they were in place and functional, with possible revisions for substantial performance variation and penalties for fraudulent claims.[152]

Quantity mandates reduce information requirements and improve efficiency

As noted, the modeling results in this chapter suggest that the optimal global buydown for PV modules may extend for more than two decades—far longer than the time horizon for most existing buydown programs based on fixed-price subsidies. Also, 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, it may prove easier to sustain optimal long-term demand-pull support under such mechanisms since the subsidy is implicit. In fact, most existing state level RPS laws already have at least a ten 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 it may nonetheless continue to generate substantial sales growth in the late market development period by ensuring that key players (*e.g.* homebuilders and commercial building managers) continue to focus attention on PV.

In addition to their virtues as a way to reduce information requirements and facilitate sustained buydowns, quantity based buydowns may also reduce the economic costs imposed by transfer subsidies. For example, an RPS that raises overall electricity prices may impose secondary welfare *benefits* rather than costs if pollution taxes are not

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additional 1.9 GWp would be sold in unsubsidized off-grid markets).

[152] Domestic tax credits for solar thermal and wind gave buydowns a bad reputation because they were so large that they prompted shoddy installations in pursuit of the tax credit alone. Defining an RPS based on technical models of system output raises this specter but, given current module prices, subsidies should quickly drop to less than half of initial system cost—providing system owners with a strong incentive to

yet fully incorporated into electricity prices. Note, however, that the total rate impact of an optimal PV portfolio standard should never exceed 0.5 percent of total OECD retail electricity expenditures.[153]

Subsidy caps further improve quantity mandates

To improve political viability and enforceability, buydowns could include a *subsidy cap* that allows obligated parties to purchase tradable RPS credits from the government at a fixed price.[154] The initial cap should be set high enough to accommodate market activation costs, then decline along the expected trajectory for installed system costs (based on projected sales levels combined with learning curve estimates). This will not deter aggressive scale up by manufacturers and system integrators who are confident in their ability to reduce costs. It will, however, reassure skeptics and obligated parties by limiting the maximum possible compliance cost. Appropriate subsidy caps also reduce the risk that short-term demand constraints will drive up transfer subsidy costs if the RPS proves excessively aggressive.[155]

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ensure long-term technical performance in order to recover their investments. Moreover, PV systems are less vulnerable to failure than solar thermal systems which have mechanical components.

[153] Conservatively assuming it is impossible to price discriminate or exclude free riders, under base case parameters, the total undiscounted subsidies required for an optimal global PV module buydown start at $3 billion per year in 2003, peaking at just over $8 billion by 2030 and declining to zero by 2050. In comparison, OECD electricity consumption in 2002 was 7,500 tWh, rising to 14,000 tWh by 2030 (EIA, 2002b). Assuming an average retail rate of ~$0.10/kWh, this translates into $750 billion per year in 2002 rising to $1.4 trillion per year by 2030. This implies that a PV buydown funded exclusively by the OECD would raise average rates by 0.4 percent initially and 0.6 percent in 2030—but 70 percent of these costs represent transfers subsidies to free rider system owners rather than a real increase in the overall cost of electricity service. Also, this analysis ignores the reduced electricity costs enjoyed by PV users in regions where high insolation and/or electricity prices make PV fully economic without subsidies.

[154] Texas included this design feature with excellent early success in the wind electricity market (Wiser and Langniss, 2001).

[155] If demand schedules are highly inelastic past a certain point then excessive unit subsidies can cause short-run capacity constraints (see *The German PV buydown* in Chapter 4) that increase transfer subsidies without achieving a substantial increase in sales.

Potential pitfalls

The RPS concept is still under development and has attracted criticism in some cases.[156] 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.

Disadvantages of targeting support to specific PV sub-technologies

The strong NPV in the modeling runs using thin-film parameters raises the question of whether buydown efforts should focus on thin-films only (Table 2). The potential pay-off would be faster and cheaper PV commercialization if a distinct thin-film experience curve emerges. There are, however, arguments against this aggressive form of technology picking.

The value of any sub-technology restrictions would be contingent on the accuracy of current technology assessments. From the top-down vantage point, the fact that

[156] For example, the Danish Wind Industry Association opposes the use of an RPS (green certificate mechanism) primarily due to doubts about the long-term credibility of the renewables mandate (www.windpower.dk/articles/busiview.htm). Also, Rader (2000) identifies major implementation flaws in

emerging sub-technologies like a-Si are relatively new means that their experience curve track record is particularly uncertain. Bottom-up technology assessments suggest a long-term cost edge for thin-films (EPRI/OUT, 1997; BPA, 1999; Payne, Duke, and Williams 2001); however, multiple thin-film technologies are emerging and it is unclear which will prove most competitive in the long run. It is also possible that crystalline technologies will keep up with or even dominate thin-film technologies, particularly if high cell efficiency proves to be more important than cost per Wp in important market segments. For example, tracking solar concentrators using high-efficiency crystalline modules could become cost effective based on low-cost plastic lenses currently under active development (Schmela, 2001).

Restricting buydowns to particular sub-technologies would also be politically divisive—pitting manufacturers against one another and encouraging buydowns that favor certain sub-technologies only because local manufacturers have an edge in that category of PV. Restrictions of this sort would also protect local manufacturers from competitive pressures and inhibit the emergence of fully scaled-up manufacturing facilities. Such biased buydowns would be analogous to "tied-aid" technology transfer programs in that the favored manufacturer is protected from competition and consumers are discouraged from using the sub-technology that best suits their needs.

Given these risks, buydowns should avoid targeting support to particular PV sub-technologies. Instead, governments should structure quantity mandates (or unit subsidies) such that all PV technologies are equally eligible for support. This avoids a type of technology picking for which the government is uniquely ill-suited, leaving the

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the Connecticut and Massachusetts RPS programs while suggesting that programs in Nevada, New Jersey, decision instead to the private firms that are best able to assess the relative prospects of their respective manufacturing strategies. In the context of strongly growing global PV markets supported by credible buydown programs, firms with the most promising sub-technologies should have the confidence to forward price sufficiently to scale up production and compete successfully.[157]

PV buydowns in the context of comprehensive PV innovation policy

Buydowns are a necessary component of technology policy but governments must also pursue complementary supply-push and market tuning efforts. This section places demand-pull policy in the context of a comprehensive innovation policy before closing with a discussion of the benefits of (and limits to) diversification.

To encourage innovation in the energy sector, governments should use the full power of the *technology policy triad* including: 1) market tuning, 2) supply-push, and 3) demand-pull measures (Figure 36). First, governments should ideally impose indefinite market tuning measures to set the context for supply-push and demand-pull measures. Net metering laws are a crucial market tuning measure in that they provide a proxy for the non-learning public benefits of distributed electricity—and the analysis in this chapter assumes that both residential and commercial PV system owners are able to use net metering without restriction. Moreover, in contrast to buydowns, which are best done at the regional level, market tuning should be done as broadly as possible. In particular, Congress should pass national net metering legislation in the U.S. with ample caps in

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and especially Wisconsin programs require reforms.

[157] Of course, if learning spillovers for PV manufacturing are sufficiently severe this may not occur, but broad PV buydown efforts will at least overcome the system spillovers problem by reducing barriers and opening up PV markets for all sub-technologies.

order to standardize rules and give industry confidence that this mechanism will remain available as markets for distributed generation expand.[158] Such legislation could be modified if net metering begins to impose substantial costs on the electricity sector and, in any case, in the long-term net metering should be abandoned if real-time location-specific electricity pricing (with full pricing of environmental externalities) becomes a viable alternative.

Supply-push efforts help to bring emerging clean energy technologies past the demonstration phase, at which point buydowns become possible. Once the government implements a buydown, supply-push efforts should continue during the entire commercialization process, albeit with an evolving emphasis. In particular, larger markets will encourage companies to invest their own funds[159] to improve the technology. This may allow the government to taper off funding for applied development and demonstration of PV technologies while also giving the government a clearer sense of use-inspired priorities for fundamental research.

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[158] Forty states and the District of Columbia had net metering laws by 2002, but fourteen of these impose caps on the total level of net metering allowed in the state. These are not restrictive at present but may become so. In the case of New Jersey, for example, state-sponsored PV buydown programs aim to catalyze 50 MWp of PV installations by the end of 2004 (www.njcleanenergy.com). Assuming 3 percent annual demand growth and pro rating New Jersey's share of peak demand in the Mid-Atlantic Area Council based on population (EIA, 2002), 50 MWp represents 0.23 percent of projected New Jersey demand, or double the net metering cap of 0.1 percent. Unless the caps are increased or removed, 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.

[159] The U.S. PVMaT program has successfully facilitated specific manufacturing improvements (Margolis, 2002) but such support should be less critical as revenues for the PV module industry grow from roughly $1 billion in 2000 to $8 billion in 2010 and $20 billion by 2020 (based on sales levels and prices under the base case optimal buydown path).

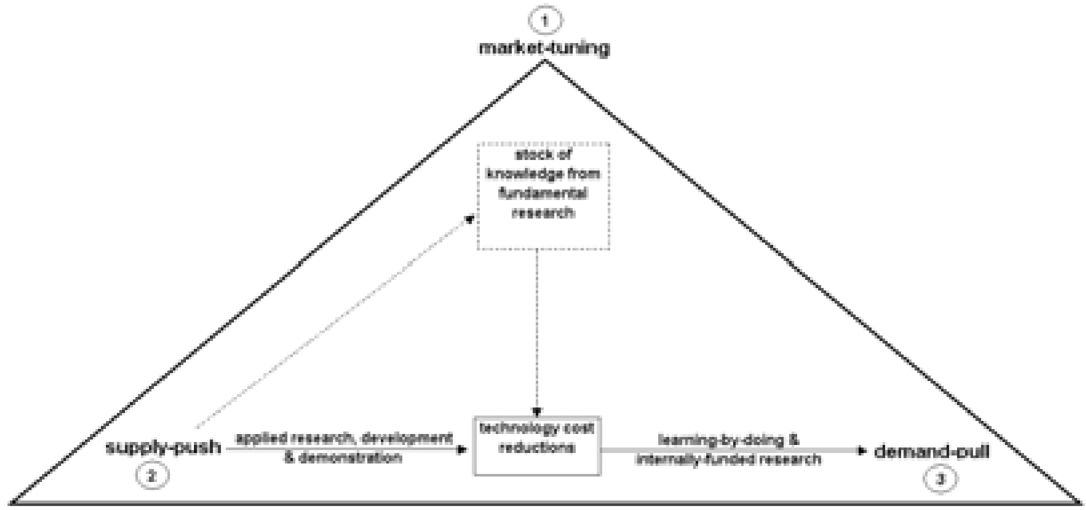

Figure 36. The technology triad

Market tuning efforts are the highest priority for technology policy since they optimize the entire innovation process. Pollution taxes, for example, provide a demand-pull for existing clean alternative energy while providing incentives for research and development to develop novel clean technologies. Government can then provide a supply-push by supporting fundamental research that increases the stock of fundamental knowledge or by funding applied research, development, and demonstration efforts (usually best implemented by the manufacturers themselves). Finally, for the most promising demonstrated technologies, government can provide a demand pull by subsidizing sales of the emerging technology, thereby increasing cumulative production experience that drives learning-by-doing and provides firms with the revenues necessary to finance internal RD2 efforts.

There is a large literature regarding optimal supply-push policy (Chapter 1) and specific recommendations for this component of the technology policy triad lie beyond the scope of this analysis. Nonetheless, governments must account for the interdependencies between supply-push and demand-pull support since sustained RD^2 funding may help to maintain strong progress ratios while buydowns help to ensure that RD^2 investments ultimately pay off (see, for example, Johnson and Jacobson, 2000).

An inadequate understanding of the scientific fundamentals could become a significant constraint on the development of some of the most promising energy technologies, including PV.[160] To remedy this, government RD^2 programs should

[160] Zunger *et al.* (1993) notes that nearly all semiconductors, including solar cells, rely on about ten materials relative to "10^3-10^5 species used in metallurgy, polymer technologies, biotech, and the

overcome taboos (Bush, 1945) and provide support for use-inspired fundamental research as a complement to support for curiosity-driven fundamental research—with support for such "Pasteur's Quadrant" (Stokes, 1997) research expanded as fundamental questions needing attention become clarified through production and field experience gained during the PV buydown process. Such support would increase the likelihood of accelerated learning, *e.g.* by shifting to the thin-film experience curve illustrated in Figure 21. These programs may perform best if governments develop use-inspired categories of inquiry through a transparent process and allocate funds to specific projects based on peer review (PCAST, 1997).

Recent scholarship supports guiding a portion of basic research according to use-inspired priorities (Stokes, 1997) but attempting to "pick winners" during the development and demonstration phases remains taboo. A diversified, blind, and provisional approach to supply-push policy makes sense to the extent that: 1) research and development projects are relatively cheap and uncertain and, 2) private companies have the best information about the prospects for developing and demonstrating their own technologies. Technology selection becomes increasingly necessary, however, if governments choose to support the development and demonstration stages of the innovation process—and it is an indispensable prerequisite for buydowns.

Summary

This chapter has applied the buydown assessment tools developed in Chapter 3 to the PV case, emphasizing the virtues of the optimal path method relative to the

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pharmaceutical industry." Use-inspired fundamental research could improve "solid state theory" in order to better guide the development of new semiconductor materials.

conventional breakeven approach. In particular, the optimal path method does not require arbitrary assumptions about sales growth rates and it gives policy makers guidance about the level and timing of buydown subsidies (or, equivalently, a buydown quantity mandate schedule) and an indication of the possible magnitude of transfer subsidies.

It is possible to apply the optimal path method with relative confidence in the PV case because there is a well developed experience curve and it is possible to estimate demand in the crucial distributed grid-connected residential market segment based on variation in retail electricity rates and insolation levels. In contrast, some other clean energy technologies such as automotive fuel cells and cellulosic ethanol are not yet sufficiently well developed to allow a similar analysis.

The results from the optimal path method suggest that global demand-pull support for PV falls far short of the optimal buydown in both intensity and planned duration. Despite their economic efficiency, extended buydowns may prove more difficult to sell politically relative to the conventional notion of a short buydown that gets an emerging technology to “breakeven” and then lets it stand on its own. Quantity mandates like the RPS may help, however, because they are perceived as long-term measures to increase the share of renewables in the energy mix.

Appendix: Sensitivity analysis (assumes 33% MEB of taxation throughout)

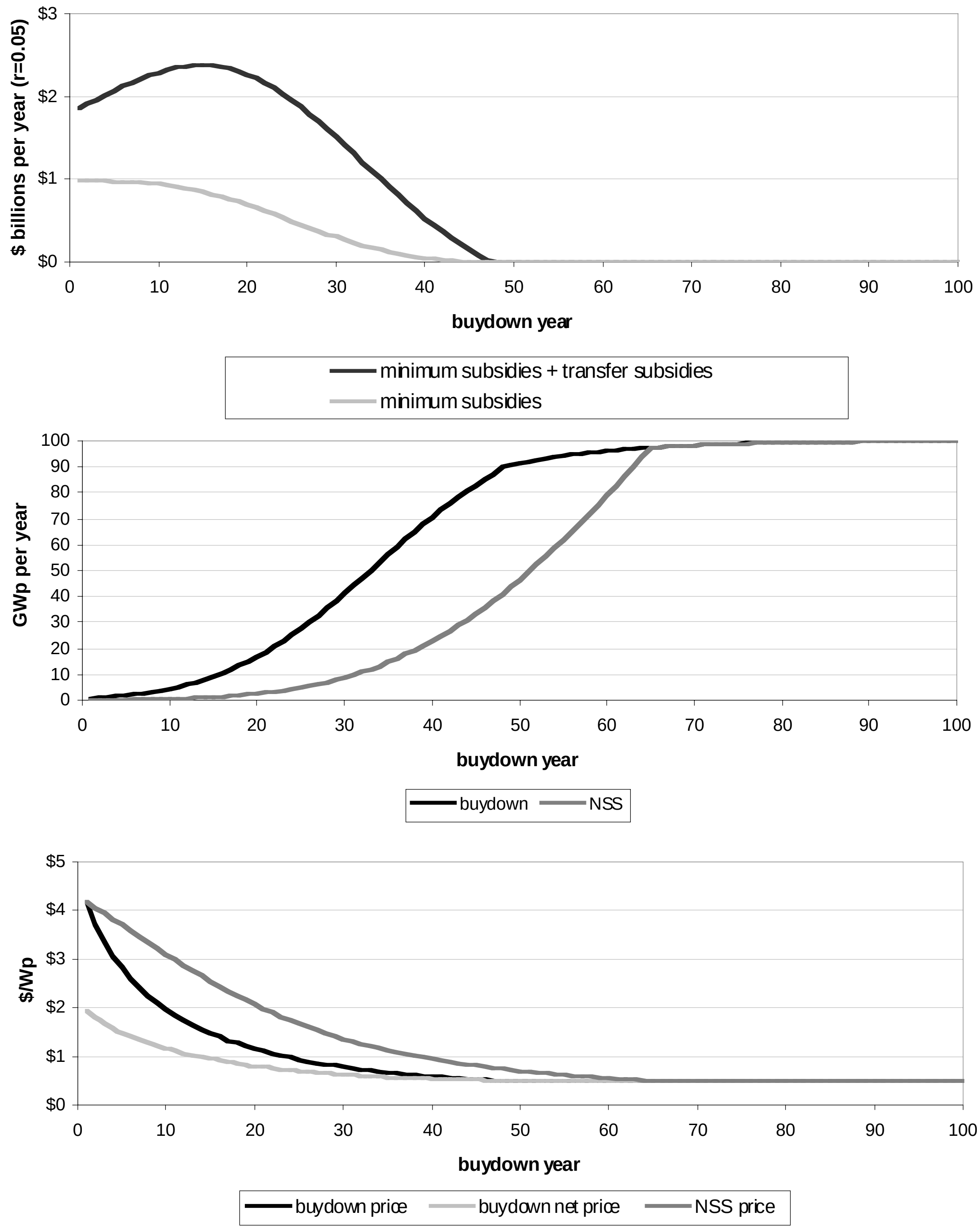

Figure 27. Optimal path method base case scenario

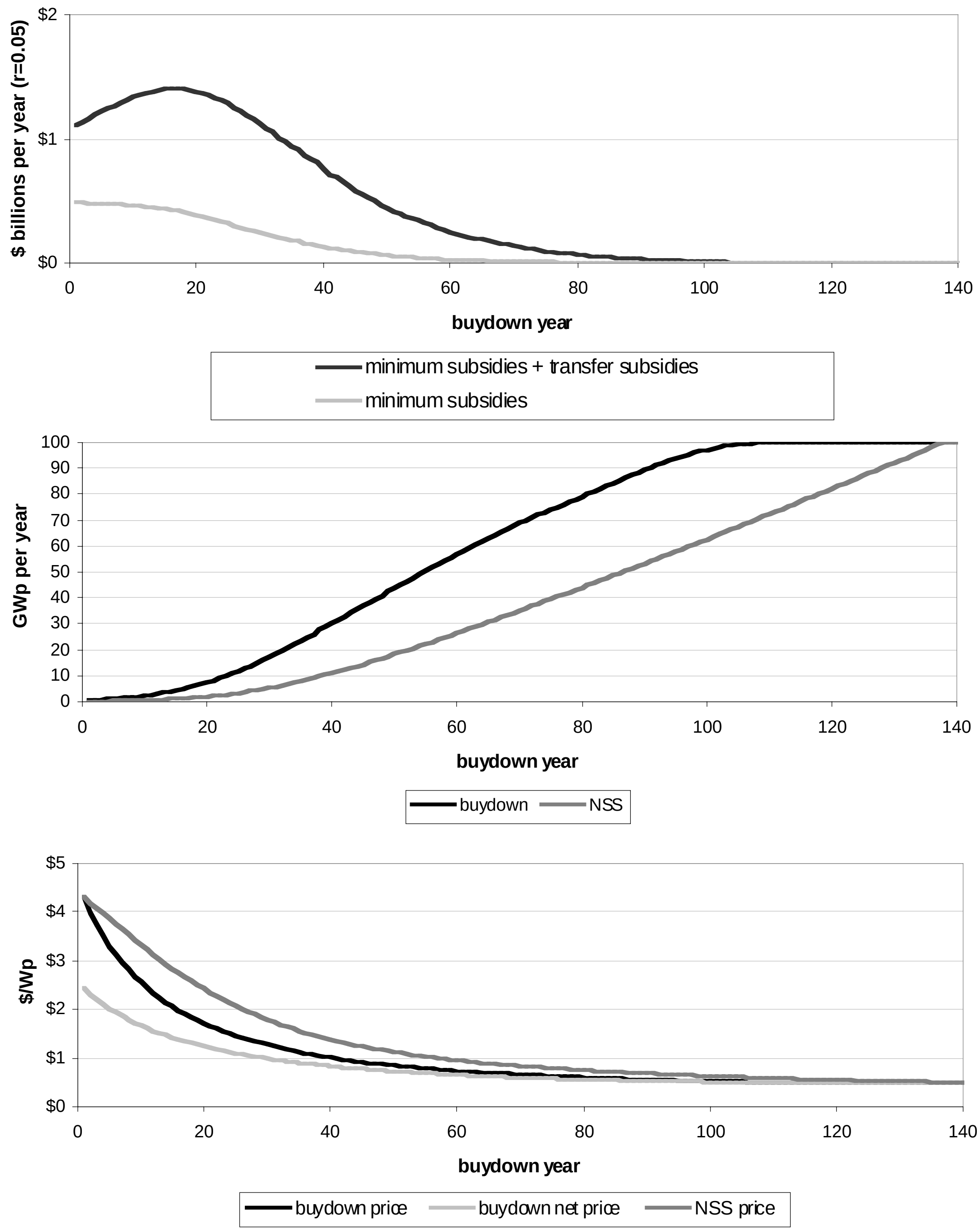

Figure 28. Slow progress scenario (PR = 0.83)

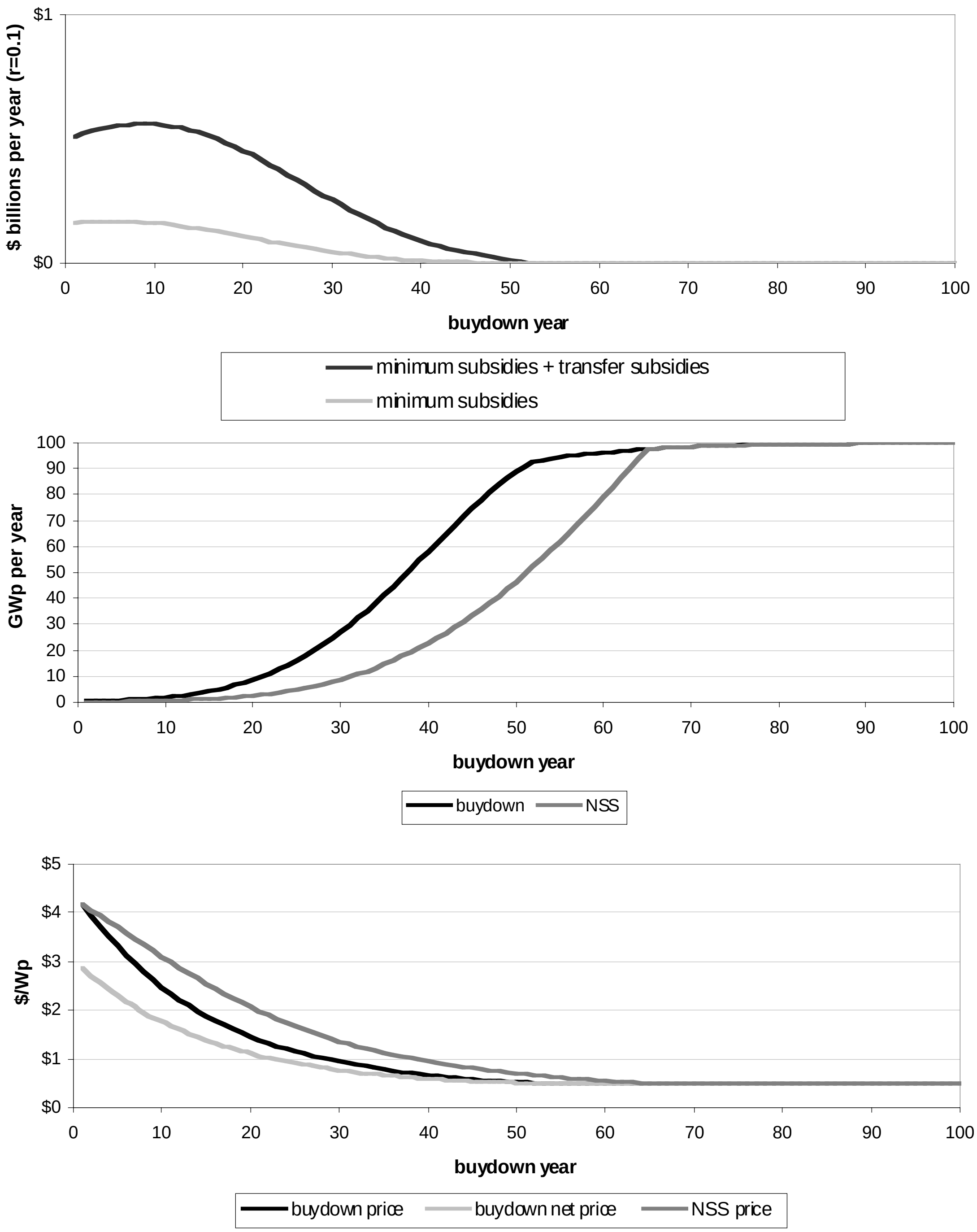

Figure 29. High discount rate (r = 0.10)

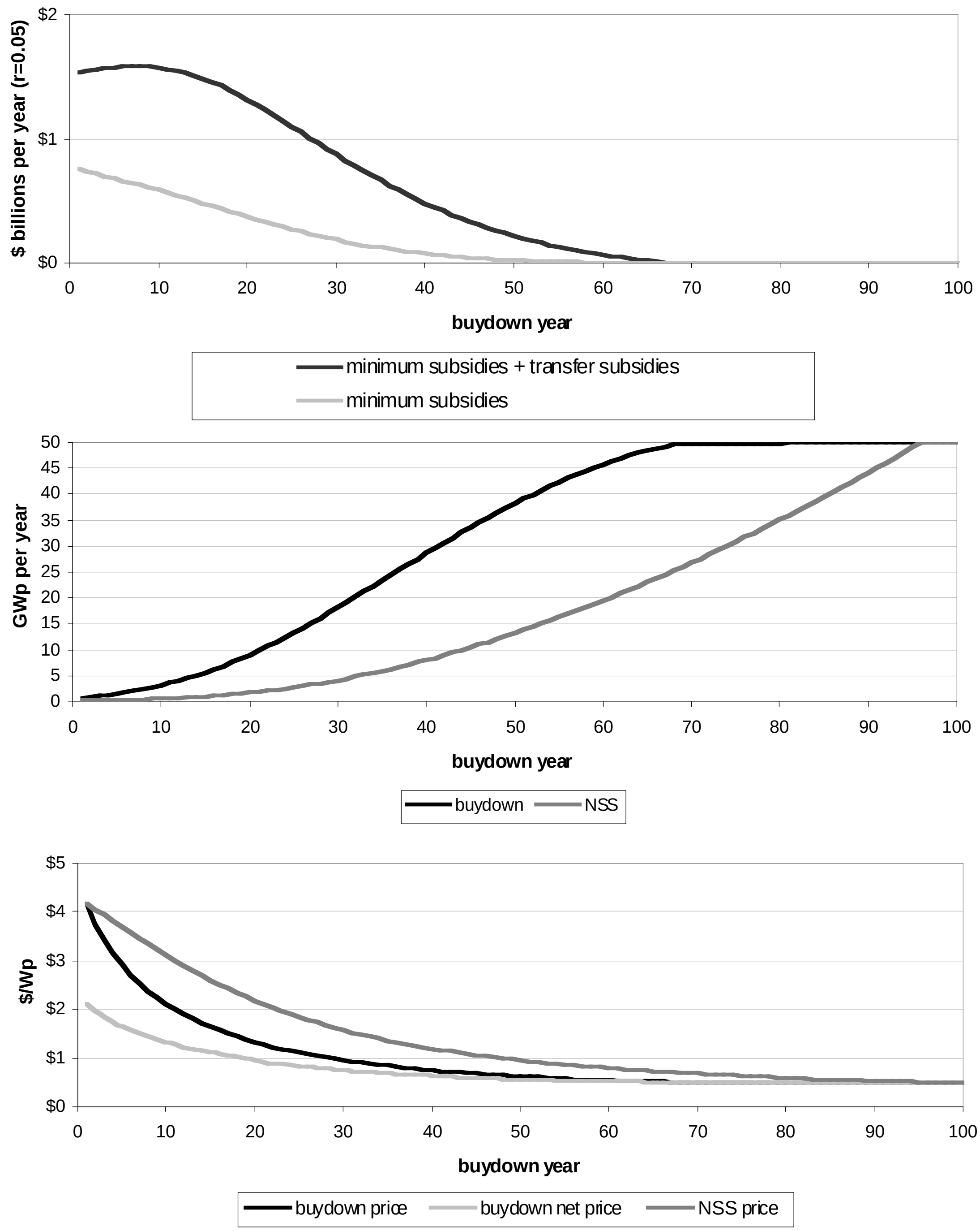

Figure 30. Reduced demand (m = 12.5 → X_t → 50 GWp/y in long term)

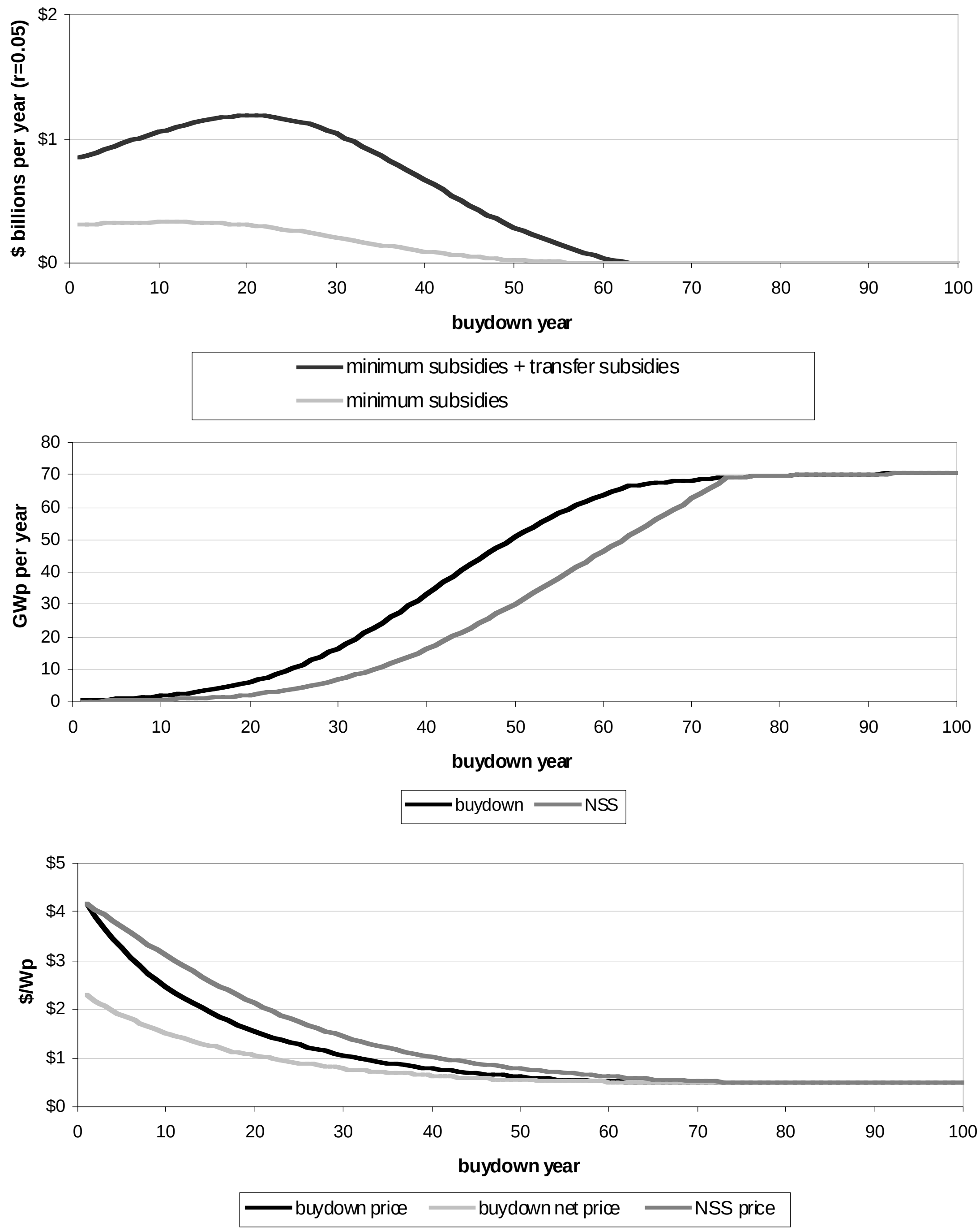

Figure 31. Reduced elasticity (_ = 1.5)

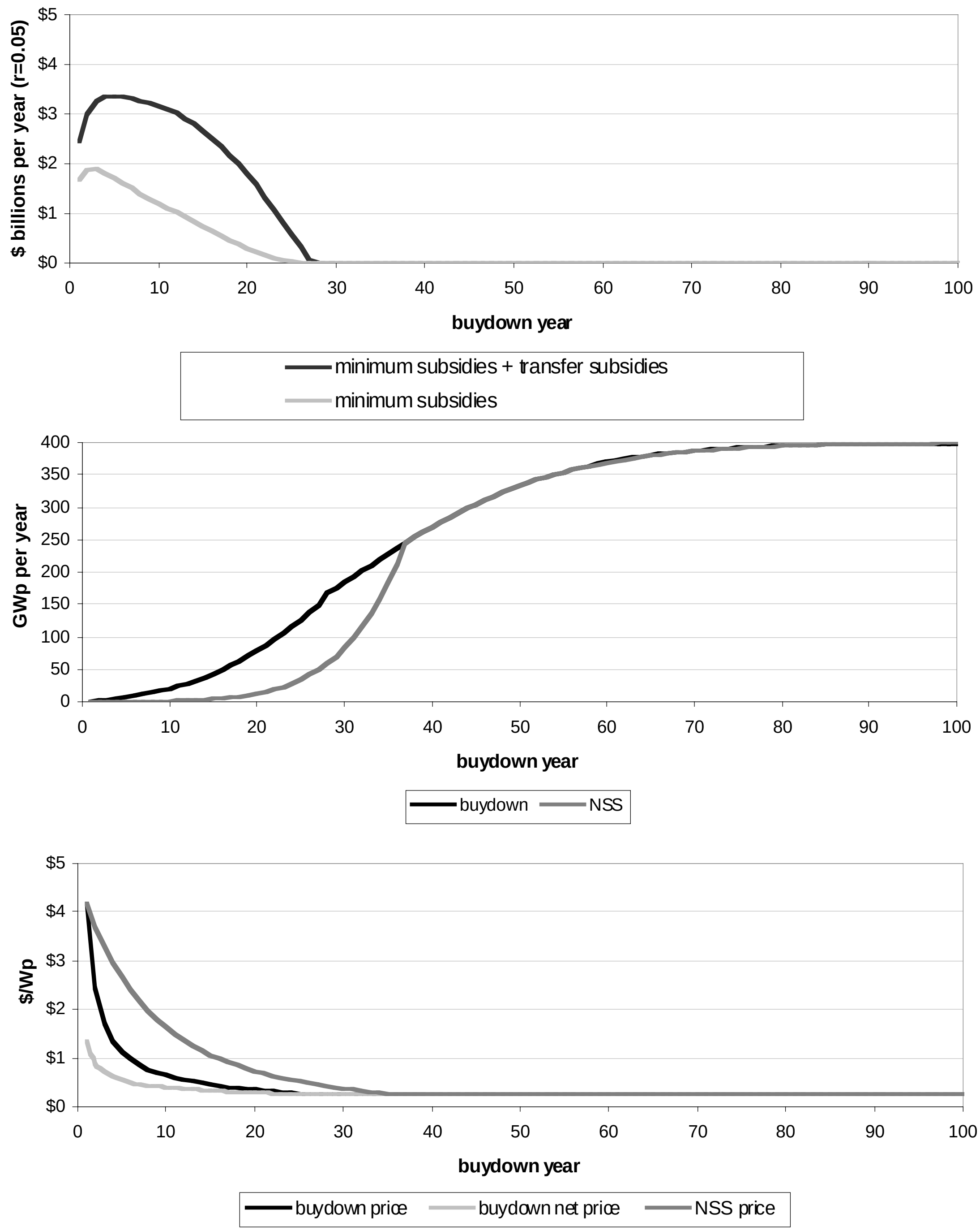

Figure 32. Thin-film experience curve (Y_{2002} = 0.19 GWp, z = \$0.25/Wp)

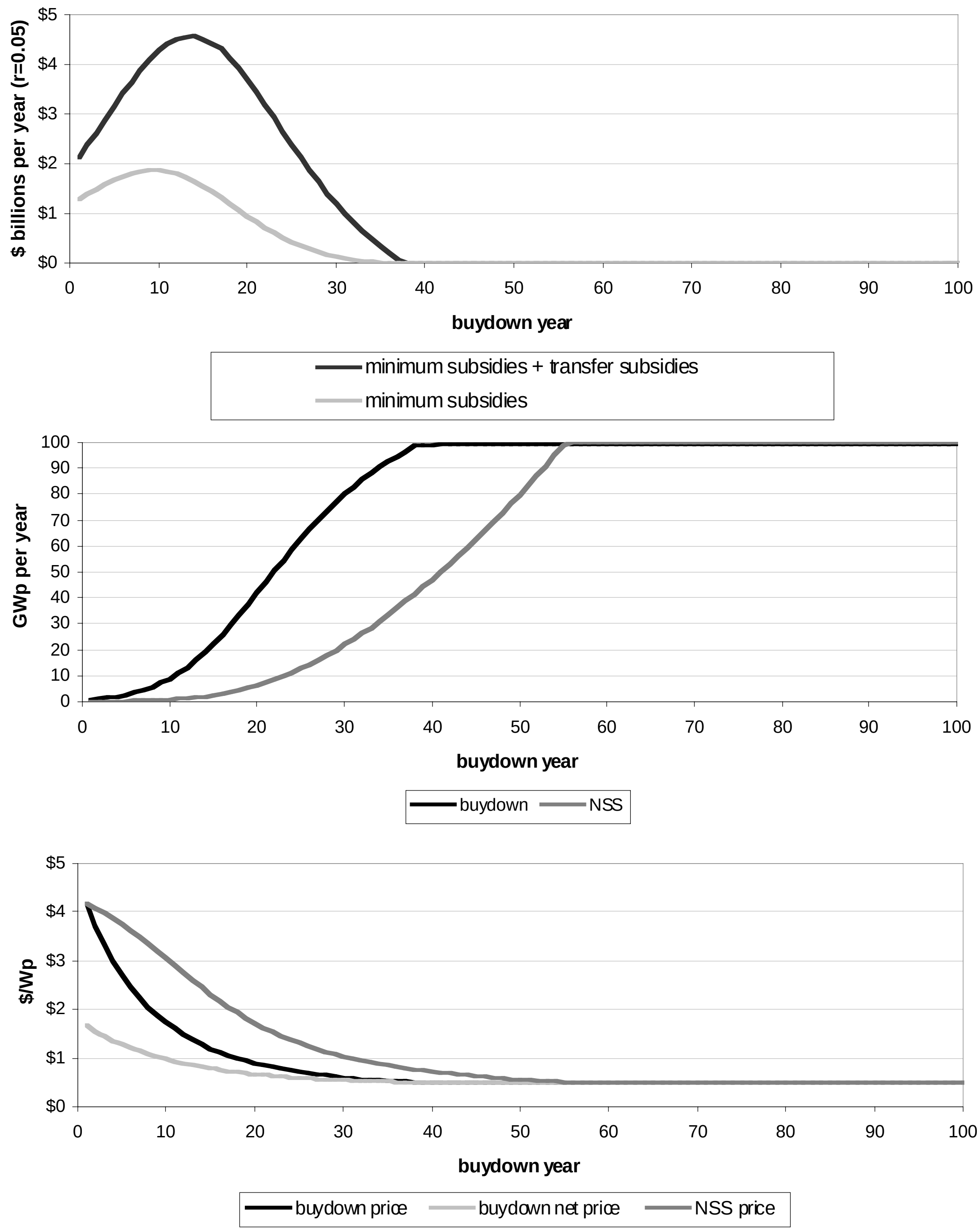

Figure 33. Fast demand shift (_t = 25 years)

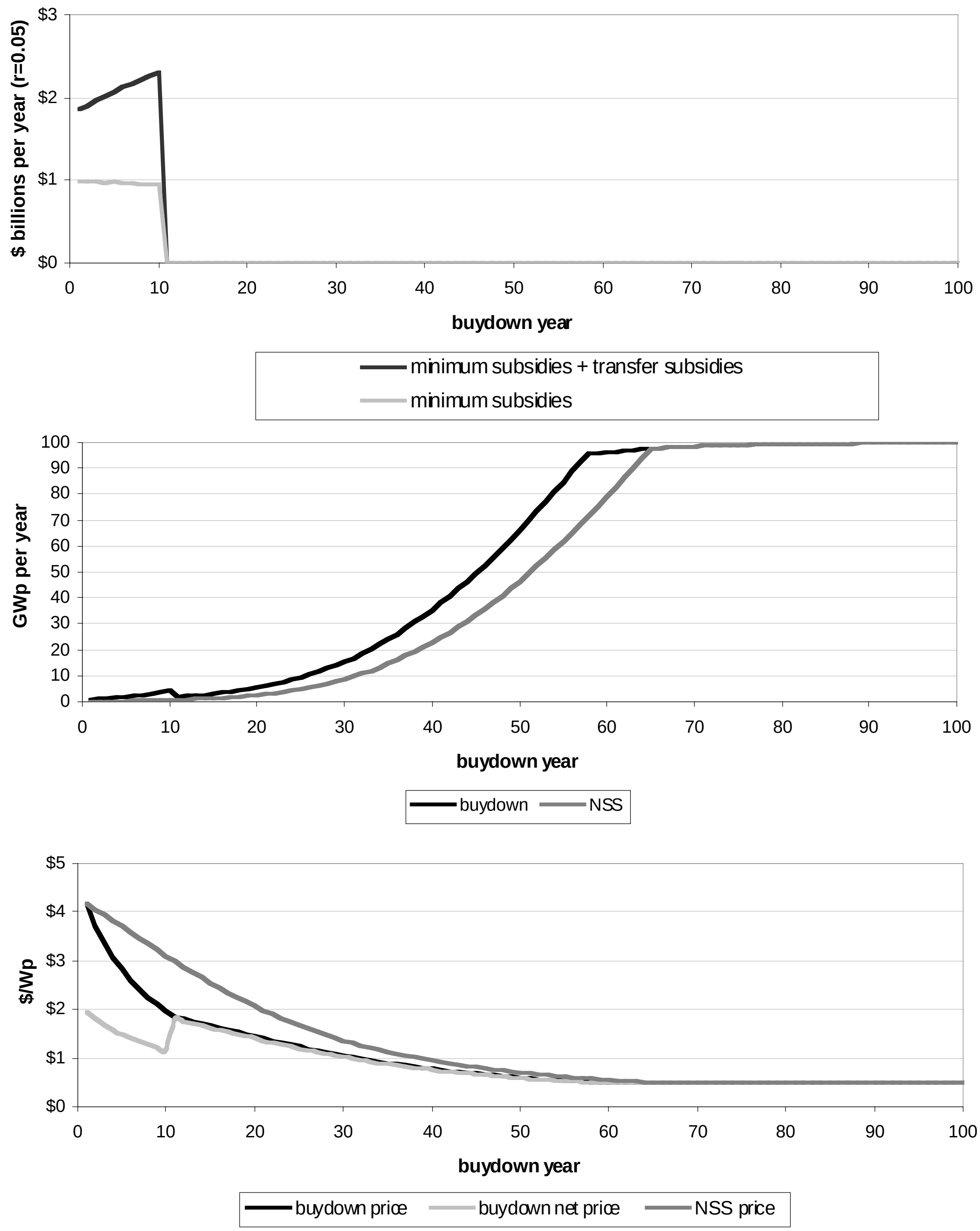

Figure 34. Buydown cut short after ten years

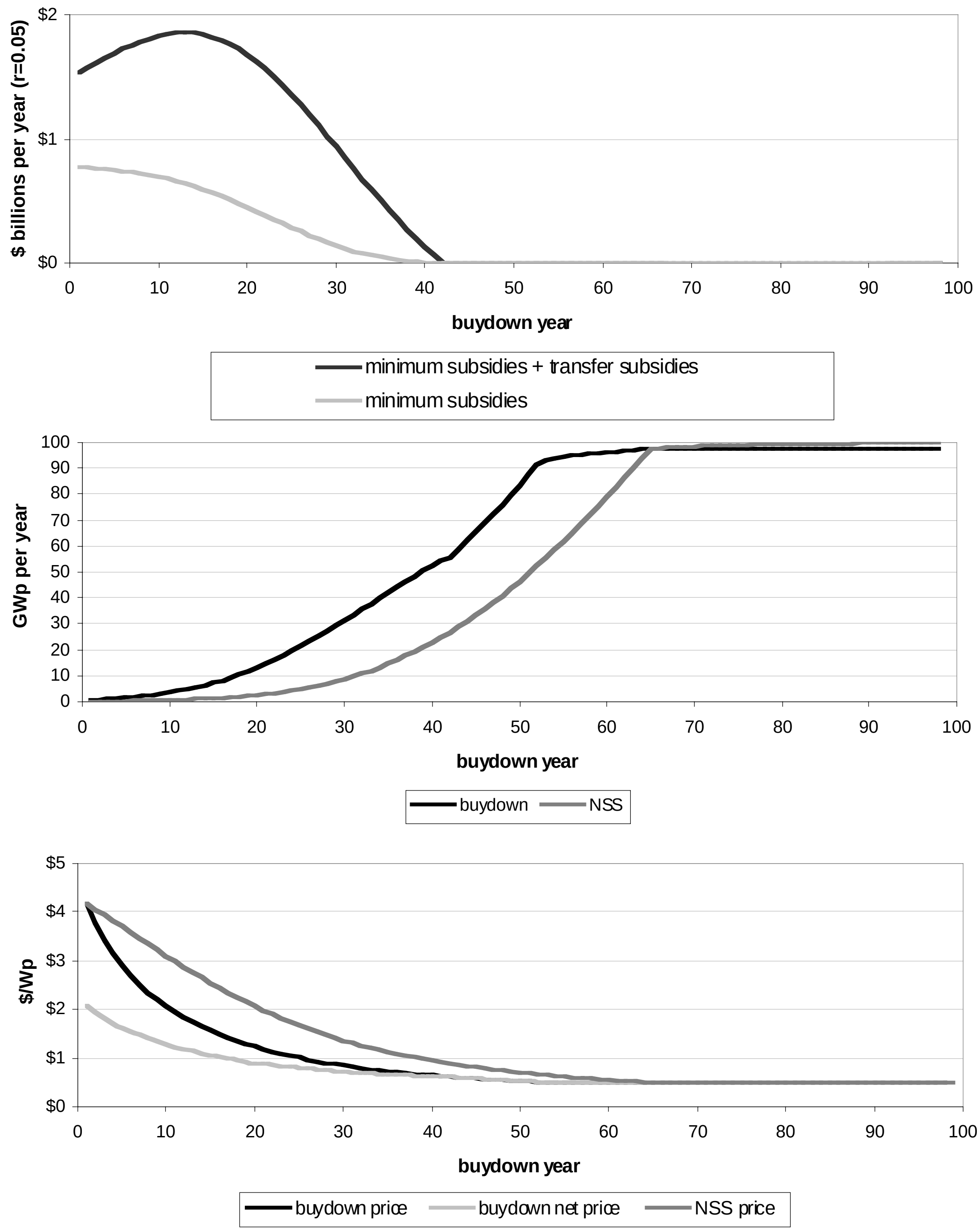

Figure 35. Optimal path to maximize NPV net of transfer subsidies

Chapter 6: Conclusion

Energy is the keystone input for industrialization, and sustained innovation has thus far contained overall energy costs despite expanding consumption of geologically finite resources. Fossil fuels continue to supply nearly 90 percent of commercially traded primary energy, yet the ratio of proven reserves to annual production has generally been stable or increasing as the industry develops increasingly innovative exploration and extraction techniques.[161] Resource optimists (Simons, 1981) have thus been winning the debate so far—but this very abundance imperils the environment.

Even in the relatively well-regulated OECD context, air pollution from coal-fired electricity plants imposes externality costs that are comparable to retail electricity rates in some cases (Rabl and Spadaro, 2000). In terms of climate change, the IPCC expects average temperatures to increase by 1.4-5.8 °C over the period from 1990 to 2100, driven largely by carbon dioxide emissions from fossil fuel combustion (IPCC, 2001). On the economic front, increased reliance on oil and natural gas poses serious energy security concerns.

Despite these threats, a global regulatory regime to control carbon emissions remains elusive, and it is difficult for governments to diversify away from currently inexpensive fossil fuels. In this context, technology policy offers a crucial escape hatch—giving individual nations motivated by national interests the tools to develop local markets for clean and secure energy alternatives.

Governments can shape the evolution of energy technologies using three levers: 1) market tuning, 2) supply-push programs, and 3) demand-pull buydowns (Figure 16). Market tuning sets the stage with measures such as pollution controls that encourage socially efficient choices among existing energy options while fostering the development of clean alternatives. Industrialized nations have achieved major progress regulating localized energy emissions, but fossil fuel combustion continues to impose a serious public health toll even in industrialized countries—and carbon emissions remain a largely unregulated global threat.

Even the best market tuning offers little protection against *innovation* inefficiencies. It is therefore widely recognized that public support of energy RD^2 is crucial, particularly since patents are of little value for energy technologies (Chapter 1).

As in the case of RD^2, private firms are inadequately motivated to invest in technology cost buydown because they cannot appropriate the full benefits of the associated learning-by-doing. This is particularly true for energy technologies that must be integrated into complex systems (*e.g.* housing designs and electricity grids) since forward pricing firms generally cannot exclude current and potential competitors from these market conditioning benefits. Nonetheless, the conventional wisdom still holds that public sector support for innovation should not extend to commercialization (other than indirectly via patents).

This dissertation argues that governments should make full use of the third, and most neglected, technology policy lever—subsidizing demand in order to commercialize

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[161] During the period from 1975 to 2001, the ratio of proven reserves to production has increased from 33 to 40 for oil and from 51 to 62 for natural gas. Recoverable coal reserves are especially abundant, with proven reserves of over 200 years at current consumption rates (BP, 2002).

new technologies. The following section summarizes the principal findings regarding buydown theory and the PV case.

Principal findings

Radical energy technology innovation will be required to address the environmental and energy supply security challenges of the 21st century. Adding demand-pull support to comprehensive energy innovation policies would greatly improve the prospects for meeting this challenge but very little analysis has been carried out to provide a theoretical basis or practical implementation guidelines for clean energy buydowns. This dissertation addresses this gap, drawing the conclusions listed below.

Buydown rationales

- As with more conventional RD^2 (supply push), innovation spillovers provide a strong rationale for public-sector support for clean energy technology buydowns (demand pull).
- Spillovers (and market power effects) would justify buydown support for clean energy technologies even if negative externalities could be fully internalized in energy prices—but the potential benefits from clean energy technology buydowns are greater if pollution controls are sub-optimal.

Sector and technology selection criteria

- Buydowns targeting technologies in the clean energy sector are likely to be uniquely promising because: 1) clean energy technologies provide major non-learning public benefits; 2) energy technologies diffuse exceptionally slowly, giving governments time to design and implement effective buydowns; 3) innovation spillovers are severe in the energy sector; 4) many energy technologies benefit from strong learning effects characterized by consistent experience curves; 5) it is possible to quantify buydown benefits based on the stream of cost savings relative to the no subsidy case because new energy sources often displace close substitutes rather than creating radically new categories of consumer surplus; and 6) energy is a commodity product with thin profit margins and substantial risk of price collapses, making innovation difficult without public sector support.

- Despite legitimate taboos against technology picking in research and development programs, governments must actively choose which clean energy technologies to subsidize because buydowns are too expensive to permit a “shotgun” approach and there is relatively good information available at the deployment stage of the innovation process when demand-pull efforts are relevant.
- Governments should consider buydown support for specific clean energy technologies that are: 1) produced in a competitive industry; 2) characterized by a strong experience curve with a low expected long-term price floor; 3) selling slowly at present but with a large market potential under a buydown; 4) at least as promising as existing and foreseeable substitutes in the same niche markets; and 5) likely to provide strong non-learning public benefits.

- Insisting on conformity to these criteria is crucial because it is difficult to terminate a subsidy once clear beneficiaries emerge to lobby for its continuation (*e.g.* the U.S. grain ethanol program)
- Certain large-scale technologies may merit buydown support but the hurdle is higher because gaining production experience is inherently risky for such technologies.

Analytic methodologies

- Univariate experience curves provide a parsimonious analytic tool and attempts at refinement are often counterproductive (*e.g.* apparent microstructures are often spurious).
- This dissertation improves the conventional breakeven method for analyzing buydowns by accounting for the benefits from sales in niche markets under the NSS and defining the analytic timeframe by assuming a price floor—yet this approach still requires arbitrary assumptions about both sales growth rates and the duration of the subsidy.
- The optimal path method developed in this thesis has major advantages over the breakeven model because it: 1) specifies the buydown sales/subsidy trajectory that would generate the maximum possible net economic benefits and, 2) allows analysts to characterize possible transfer subsidy costs.
- This approach shows that subsidies are justified until the technology price floor is reached (~45 years in the PV case), contrary to the conventional

wisdom that any commercialization subsidies should end as soon as the technology *begins* to become competitive in significant market segments.

The PV Case

- PV satisfies all five technology selection criteria and the required parameters for estimating the optimal path for a PV buydown are either available empirically or can be estimated with reasonable confidence.
- The optimal path method suggests that global PV buydown efforts should be tripled as quickly as possible (though buydown NPV suffers only marginally if the annual growth in subsidized module sales is capped at a "guesstimated" maximum feasible annual growth rate of 50 percent) with $2/Wp subsidies driving about 80 percent of total PV sales initially, $0.20/Wp subsidies driving 50 percent of the overall PV market by the 25th year, and total phaseout of the buydown when the price floor (~$0.50/Wp) is reached after 45 years.
- The optimal global PV module buydown yields an NPV of $54 billion based on minimum possible subsidies of $37 billion (*e.g.* excluding the possible economic cost of any transfer subsidies that may be necessary).
- PV buydown would be "politically affordable" even if only electricity consumers were to pay for the buydown, because the projected global PV buydown cost would be less than 0.5 percent of retail electricity expenditures even during the most expensive year if the buydown were restricted to OECD countries.

- In the event that the PV progress ratio deteriorates unexpectedly, policymakers could substantially mitigate NPV losses by reducing buydown intensity with a mid-course correction to the program.
- It is also possible that the PV progress ratio will accelerate, particularly if there is a transition to a thin-film PV experience curve, in which case the buydown NPV increases by 30 percent to $70 billion and the buydown duration is cut by over 40 percent to 25 years.
- Governments should not restrict buydown support to specific PV sub-technologies (*e.g.* thin-film PV) since bureaucracies are ill equipped to judge their relative prospects and, in the context of a competitive, rapidly expanding overall PV market the best sub-technologies stand a good chance of emerging from the fray.[162]
- For the all-PV experience curve base case, the buydown NPV is *negative* if the government cannot exclude transfer subsidies (*e.g.* free riders or price discrimination failures) and if these transfer subsidies are conservatively treated as pure economic costs.
- If transfer subsidies cannot be eliminated and these are treated as pure economic costs, shortening and scaling back the buydown (Compare Figures 26 and 35) raises NPV net of transfer subsidies to positive $15 billion. However, it is preferable to maintain the optimal path and minimize transfer subsidies by means of market segmentation, *i.e.* 1)

excluding fully commercial off-grid markets from subsidies to reduce free riders and, 2) implementing buydowns at the regional level and adjusting them to evolving local conditions.

Implementation

- Beyond reducing transfer subsidies, regional buydowns offer additional benefits by 1) allowing individual nations or regional government entities to take leadership roles in commercializing PV and thereby obtain the potential benefits of "going first," without having to participate in tedious international negotiations; 2) reducing the risk to manufacturers that overall sales levels will plummet if any single program is prematurely eliminated; 3) facilitating learning about alternative buydown implementation strategies.
- Decentralized buydowns reduce overall implementation risk, because lagging regions can adjust their buydown plans based on the observed buydown outcomes from leading regions.
- Since funding commitments are visible and electorates often favor strong investment in renewables, international coordination of regional buydowns could help to ensure that each OECD country contributes its fair share (*e.g.* a *pro rata* contribution based on population or GDP) of the optimal global buydown for PV and other clean energy technologies.

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[162] Sub-technology targeting may make sense for other clean energy technologies. For example, restricting subsidies to *cellulosic* ethanol would help this promising new technology to compete against mature grain ethanol.

- Net metering is a crucial market tuning measure that provides a rough proxy for the non-learning public benefits of distributed PV electricity.
- Market tuning efforts should be pursued at the broadest possible level to generate a clear framework for manufacturers, system integrators, and customers (*e.g.* national level net metering laws would eliminate possible confusion over widely divergent state level net metering caps that may prove restrictive in certain important states).
- Buydowns tend to be regressive, but it is better to address inequality concerns directly (*e.g.* utility bill assistance or rural electrification programs using low-cost established commercial technologies) rather than attempting to build large markets for expensive new technologies among low-income customers.

Applicability to clean energy technologies other than PV

The *qualitative* findings listed above apply to emerging clean energy technologies other than PV. *Quantifying* the buydown prospects of each of these unique technologies, however, would require detailed analysis that lies beyond the scope of this dissertation. The next section offers an agenda for future research, including the steps required to apply the optimal path method to wind, advanced biomass, fuel cell, and energy efficiency technologies.

An agenda for further research

This dissertation develops clean energy buydown theory and suggests implementation strategies, with particular attention to the PV case. The field remains embryonic, however, and there is ample room for further research to 1) refine buydown analytics; 2) develop best practices guidelines for implementing buydowns; and, 3) extend the optimal path analysis to clean energy technologies beyond PV.

Buydown analytics

This dissertation develops analytic tools for assessing clean energy buydowns, but there are considerable opportunities for further refinement. This section identifies critical issues related to quantifying both demand and supply side market forces. There are also important questions about the role of net metering as a market tuning measure and the geographic scope of buydowns.

The logistic demand shift assumption

This dissertation estimates the price elasticity of demand for PV based on historical sales data for unsubsidized off-grid markets as well as the prospective financial breakeven schedule for grid-connected distributed markets. It then applies a logistic coefficient to the isoelastic demand function such that the demand schedule shifts outward solely as a function of time. This ignores the "social contagion of the adoption process" (Bass, 1980) as well as any learning-by-doing on the part of users (Vettas, 1998). Accounting for these effects (*i.e.* making the logistic demand shift a function of cumulative production experience as well as time) would increase the estimated NPV for any proposed buydown by revealing accelerated learning-by-observing and learning-by-using under the buydown scenario.

Experience curves

On the supply-side, experience curves require closer scrutiny. It is particularly important to explore the possible impacts of buydown programs on progress ratios—both negative and positive potential impacts. One hypothesis is that progress ratios will worsen (increase) under an aggressive buydown because some of the observed pre-buydown price reductions were actually a function of time or other omitted variables rather than cumulative output. Available data suggest that learning effects are, in fact, the primary driver (chapter 3) but researchers can further examine this hypothesis by observing whether the PV progress ratio holds steady despite the growing market share of subsidized sales. It is also crucial to monitor the progress of thin-film technologies to detect a possible shift to an accelerated thin-film only experience curve.

Net metering

It would be useful to better understand how closely net metering reflects the true economic value of distributed electricity. The preliminary analysis in Chapter 4 suggests that net metering is a reasonable proxy for the true value of distributed PV electricity, but the specifics will vary: 1) regionally depending on PV penetration levels, the utility load profile (peak coincidence), and the conventional generation displaced (avoided pollution benefits) and, 2) locally depending on distribution capacity constraints. Further research would indicate the extent to which net metering over- or under-compensates PV system owners, as well as whether other distributed generation technologies deserve similar net metering treatment (*e.g.* fuel cells are less peak-coincident since they run most efficiently if used continuously, but they have the advantage of potentially being dispatchable).

Regionally specific issues relating to buydowns

Regional buydowns also make comparative analysis possible. As described above, the regional experience curve for installed system prices includes both global equipment and localized *delivery mechanism* price components. The latter breaks down into installation fees and various markups to cover market development. More work is needed to determine whether delivery mechanism prices follow typical experience curve patterns.

Appropriate geographic scope of buydowns

It is also essential to better understand the appropriate geographic scope for buydowns. Presumably, equipment manufacturers and system integrators can draw on experience in one region to market systems in a proximate and similar region; however, the preconditions for delivery mechanism expertise to "trickle down" from industrialized to developing countries remain to be explored.

Implementation strategies

Academics might help to improve implementation strategies by subjecting buydown efforts to critical independent scrutiny. As more implementation experience accumulates, comparative studies could shed light on the relative virtues of alternative generic strategies— *e.g.* fixed buyback tariffs (*e.g.* Germany), upfront equipment rebates (*e.g.* Japan), and fixed quantity purchase requirements (*e.g.* the NFFO in the UK and various manifestations of the RPS/Green Certificate Market concept) as alternative approaches to PV buydown. Government agencies could assist researchers by intentionally designing buydowns to facilitate learning. For example, cross-sectional studies generally suffer from omitted variables bias, but the government could mitigate this problem by randomly assigning different subsidy formats to different people in the same region.

Note also that under a well-designed quantity mandate, obligated parties would have the flexibility and incentive to experiment with a range of different mechanisms for recruiting program participants. Government and academic researchers could catalyze this process by documenting and publicizing both success and failure stories.

Assessing clean energy technologies beyond PV

Governments should apply the optimal path method to other emerging clean energy technologies (*e.g.* wind, fuel cells, advanced biomass, and advanced energy efficiency) in order to generate a more complete picture of their energy policy options. The steps required for the analysis are straightforward in principle, but each case has unique attributes.

Wind electricity

Wind electricity, for example, has already benefited from substantial buydown efforts, but careful application of the optimal path method would help policymakers decide the appropriate subsidy schedule as the technology matures. It is important to consider that wind electricity is not as peak-coincident as PV. Thus, relative to PV, the marginal value of wind electricity declines more rapidly as a function of grid penetration levels. Also, a careful analysis of the prospects for wind electricity would have to consider the relative scarcity of excellent wind sites (since electricity output from a wind turbine is a cubic function of wind speed). Of course, the value of PV also varies as a function of differing insolation levels, but the PV demand analysis in this dissertation fully accounts for that variation.

Fuel cells

Massive private and public efforts to commercialize fuel cell technologies are underway; however, the technology remains largely pre-commercial (chapter 4) making it difficult to apply the optimal path method with confidence. There are also multiple sub-technologies that may follow independent experience curves and serve radically different markets. For example, phosphoric acid fuel cells are the most mature technology (with over 200 units in place worldwide) but the pioneering company for this technology has decided to shift to potentially lower cost proton exchange membrane fuel cells.[163] It is possible to postulate an experience curve based on progress ratios for similar technologies but it is important to understand that tremendous uncertainties remain. For example, Whitaker (1998) sketched out a potential phosphoric acid fuel cell experience curve, but this has proven overly optimistic and ultimately irrelevant since the technology is no longer under active development. Analysts must also consider major fuel cell market segments independently since the associated technologies and market conditioning requirements are radically different. Nonetheless, as fuel cell technologies

[163] See www.utcfuelcells.com/residential/faq.shtml for a description of their current technology plans. Note that alternative fuel cell technologies might end up serving primarily very different markets. For example, proton exchange membrane fuel cells offer high energy density and fast output variation—qualities that are particularly valuable for automotive applications, whereas solid oxide fuel cells which offer high-quality heat as a byproduct of electricity generation, are especially well-suited for stationary power applications and may prove to be more attractive in certain applications than PEM fuel cells, even though PEM fuel cells seem to have more overall promise than phosphoric acid fuel cells.

develop a track record, the optimal path method could help analysts to set buydown goals at both the global and the regional level.

Advanced biomass

Advanced biomass technologies are also at an early stage of development and bottom-up technology assessments suggest major long-term potential for certain options like cellulosic ethanol (Lynd, 1996; Wyman, 1999). As with fuel cells, full-blown application of the optimal path method must await better data, but substantial buydowns are already under consideration, including a proposed quantity mandate for cellulosic ethanol as part of a renewable fuel standard (Gatto, 2000). Preliminary application of the optimal path method using postulated experience curves could help to guide program development—but false analytic precision must not be allowed to mask the underlying uncertainties.

Advanced energy efficiency

Finally, new advanced energy efficiency technologies are continually emerging—often with public buydown support in the form of demand-side management programs. The experience curve data are often excellent, especially for small appliances, *e.g.* the efficient lighting technology assessed in Duke and Kammen (1999), and it is relatively easy to estimate potential demand based on sales rates for incumbent low-efficiency substitutes and the observed willingness to pay for energy savings in other contexts. Careful application of the optimal path method would allow policymakers to optimize the overall level of buydown support for various energy efficient technologies.

It is, however, particularly important to consider the risk of displacement by more advanced technologies given the tendency towards continual incremental energy efficiency improvements.

Institutionalizing clean energy buydowns

This dissertation introduces the optimal path method as a strategy for mapping out efficient global buydowns targeting particular technologies, and it offers preliminary suggestions for efficient buydown design. This falls far short of a comprehensive global strategy for energy innovation, however, and therefore raises concerns that demand-pull investments in particular technologies might prove misguided once a fuller picture of the energy future emerges. In any case, even assuming that an optimal path method analysis for a particular technology is accurate, the messy business of real-world implementation remains.

In the face of these uncertainties and risks, there is a temptation to revert to the conventional wisdom and leave energy technology commercialization entirely to the market. In this sector, however, public inaction is hardly risk-free. Without government buydowns, private firms facing innovation spillovers will continue to lag in deploying clean energy technologies—at great cost to the global environment and economy. Energy innovation is simply too important (and the private sector process is far too flawed) to assign the technological innovation task to the vagaries of the market. Muddling through via experimentation is the appropriate response to this uncertainty. In other words, governments must actively "learn by buying down." All of this argues for *regional* buydowns in order to maximize experimentation and minimize the risk from the failure of any single program.

There are, however, major scale economies in technology assessment and innovation policy analysis, so this work is best done nationally and perhaps also internationally. Governments with major RD^3 programs (including large developing countries like Brazil, India, and China) should establish an *energy commercialization policy agency* to ensure that a high-caliber group of technologists, economists, and scientists has a mandate to improve demand-pull technology policy in the energy sector. The legacy of the now-defunct Office of Technology Assessment (OTA) proves that it is possible for such a group to provide valuable forward-looking advice.[164] It is also important that this group be distinct from conventional RD^2 agencies to ensure that its staff is not overly committed to particular technologies that have been sponsored with supply-push support. More generically, its work should be subject to rigorous external review by academics and managers with generic expertise in technology commercialization (but no particular attachment to the technologies in question).

An energy commercialization policy agency would have important advantages that would complement private-sector efforts to perceive and commercialize long-term energy technology opportunities. First, the agency would have a mandate to develop a comprehensive menu of technologies aimed at promoting the overall social good. Thus, it would take pubic benefits fully into account, including learning-by-doing spillover as well as environmental and risk management considerations. Second, the agency would consider a scale of decades rather than years. Energy technologies often take up to a century to reach their full potential (chapter 1), but typical corporate planning horizons

[164] For background see www.wws.princeton.edu/~ota/. The agency's premature demise also underscores the vulnerability of an agency attempting to provide non-partisan counsel on ideologically contentious

are far shorter.[165] Third, an energy innovation agency would have access to proprietary data submitted by firms as a condition for public funding.[166] Fourth, the agency would have a mandate to learn actively from program development experience and propose legislative and regulatory reforms to ensure that buydown efforts inform RD^2 priorities and vice-versa. The agency could also develop program evaluation tools based on measurable parameters and qualitative peer review to gauge the performance of each component of the overall RD^3 effort. Finally, an energy innovation policy agency should be required to develop and publicize criteria for tracking its own success and to solicit an independent review based on those criteria every few years. For example, the agency should be expected to produce prospective technology assessments that adequately acknowledge analytic uncertainty. At the same time, it should not be held liable for forecasts that were contingent on political developments that failed to occur.

Loose international coordination would also be useful in order to share program experience and sustain global sales of the core technology at an approximately optimal level. The International Energy Agency has begun to undertake some of this agenda through efforts like the Experience Curves for Energy Technology Policy project (Wene, 2000) and the Photovoltaic Power Systems Programme (EIA, 2000).

During the early stages when internationally traded technologies (e.g. PV modules, inverters, or fuel cells) remain expensive, countries that have little prospect of competitively manufacturing these components may prefer to hold off on major supply-

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issues. An energy innovation agency might prove more durable if established with a focused mandate and clear criteria for success.

[165] Standard corporate discount rates (*e.g.* r=0.15) reduce the present value of benefits accruing after just a decade to less than one-quarter of their current value.

push or demand-pull investments. Developing countries in particular may be best served by abstaining from clean energy technology buydowns until industrialized countries have born the brunt of the costs. After the price of the core technology comes down, however, they may want to initiate buydowns to reduce local delivery mechanism costs. PV reached this threshold for off-grid applications over a decade ago, and developing countries with good wind resources might now benefit from initiating local demand-pull programs aimed at taking full advantage of this maturing technology. Starting in 5 to 10 years, developing countries may also benefit from buydowns to develop internal markets for distributed grid-connected PV.

The challenge ahead

The energy sector continues to expand based primarily on fossil fuel combustion technologies, like coal-fired power plants which are expected to remain in place for perhaps half a century. Early action to develop and deploy clean energy technologies is essential in order to steer the inertial global energy economy towards alternatives offering much lower local and global emissions as well as enhanced energy security. The global community needs more effective tools to tackle this clean energy challenge. Fully incorporating environmental and security risk costs into the price of fossil fuels would likely be the single most effective strategy—but political constraints make this difficult and in any case supply-push and demand-pull support are also crucial.

Public support for supply-push programs in the energy sector has fluctuated and chronically fallen short of recommended levels (PCAST, 1997; Margolis and Kammen,

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[166] The manufacturing cost data generated by the U.S. PV Manufacturing Technology (PVMaT) program provides an example of this approach (www.nrel.gov/pvmat/).

1999), yet energy RD^2 programs have helped to develop a range of technologies that lay the groundwork for a transition to a clean energy future. Governments have, however, failed to develop the demand-pull programs necessary to take full advantage of these technological opportunities.

This dissertation has argued that learning spillovers seriously constrain efforts to commercialize clean alternative energy. Thus, even if adequate RD^2 funding and perfect pricing of pollution externalities were in place, sustained buydown of the most promising clean energy technologies would remain essential. In the absence of these policies, the imperative to provide demand-pull support for clean energy technologies is that much more compelling.

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