Second International Symposium on Distributed Generation:
Power System and Market Aspects
October 2 – 4, 2002, Stockholm, Sweden

ELECTRIC RESTRUCTURING DANGER: WE COULD END UP WHERE WE'RE HEADED

by Thomas Stanton, Prepared in Association with the Regulatory Assistance Project*

ABSTRACT

U.S. regulators are restructuring electric utilities, so that generation and some customer service functions will be to open to market competition. Theoretically, compared to regulated monopolies, competitive markets will deliver greater economic efficiency and product and service innovation resulting in increased customer choice and better price setting. Done wrong, however, restructuring can cause more harm than good. Even under the best circumstances, re-regulation can bring surprises and unanticipated consequences. In a worst-case scenario, restructuring could increase costs significantly and unleash markets dominated by unregulated monopolies.

Distributed energy resources are potentially disruptive technologies (Christensen, 1997) that could achieve very rapid growth in market share, with or without better policies. A basic premise is that energy markets need to be redesigned to remove barriers that currently prevent distributed energy resources from meeting their economic potential. In the meantime, huge numbers of central station generation facilities are being built and demand for transmission capacity is significantly increasing as a result of growing quantities of long-distance power sales. If better policies are not implemented quickly, much new investment in generation and transmission may be stranded, once the economic, reliability, environmental, and other benefits of distributed energy resources become widely known and their market share grows.

This paper presents guidelines and policy proposals for solutions to promote competitive markets for the development of distributed energy technologies and services. The most appropriate policy options are both market based and technologically neutral; that is, equitable for the widest range of potentially competitive technologies and services and their accompanying infrastructures.

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INTRODUCTION

State and federal legislators and regulators are busy restructuring electric utilities so that electric generation and at least some customer service functions will be opened to market competition (see Hirsh, 1999). Michigan is one of 24 states in various stages of implementing electric utility restructuring, with 15 other states either already offering full competition or scheduled to start soon (see Energy Information Administration, 2002). Michigan entered the era of wide-open electric competition on January 1, 2002.

The basis for this movement is the theory that, compared to the regulated monopoly structure it is intended to replace, competitive markets will deliver greater economic efficiency and product and service innovation resulting in increased customer choice, and better price setting.

Done wrong, however, restructuring can easily cause more harm than good. Even under the best of circumstances, deregulation can bring surprises and unanticipated consequences. In worst-case scenarios, restructuring will increase costs significantly and unleash markets dominated by unregulated monopolies. Incomplete or sloppy restructuring could lock-in inefficient and uneconomical business structures, service and technology options.

Table 1 (p. 4) lists categories of potential benefits and costs of restructuring. Electric utility industry restructuring presents a perplexing conundrum. It may prove impossible for restructuring, on its own terms, to meet the goals its proponents espouse for it (see, for example: PricewaterhouseCoopers, 2000; Rosen, 2000). Nevertheless, restructuring may unleash other forces and create other opportunities that could result in significant benefits. It is entirely possible that those same benefits could have been obtained by other means, without undertaking industry restructuring. But, there may be no going back: Having opened the Pandora's box of restructuring, the best result now obtainable may be achieved only by focusing on how to assure that restructuring continues and is completed in such a way that the promised benefits can be obtained.

This time of major industry transition is ideal for addressing longstanding market *problematiques*, such as prices that do not reflect costs, large negative externalities, high information costs, and extensive incumbent market power. Regulators should recognize that this special time of flux in the industry structure could be a once-in-a-lifetime opportunity to address such troublesome, preexisting market failures and barriers. If the benefits of competition are to materialize, it is critically

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important for restructuring policies to surmount existing market barriers and be technologically neutral. Done right, electric industry restructuring will create opportunities both to do the same things in different, better ways, and entirely new things that offer even more promise (Woodall, 1996).

We ought to be wary of policies that purposefully or inadvertently promote some options and create barriers for others. Regulations should not pick winners and losers amongst technologies or the types of firms that might engage in various portions of the business. Regulators ought to establish policies that are equitable for the widest range of potentially competitive technologies, services, and accompanying infrastructures. Only then will it be possible to actualize the theoretical benefits of restructuring (see Rosen, 2000).

This paper presents of guidelines regulators can use to evaluate policies, and proposes some specific policies to support DER in industry restructuring plans. The proposed policies are designed to avoid potential pit-falls and promote competitive markets for the development of technologies and services, under the widest variety of likely scenarios.

A little known fact is that, already, a vast majority of all electric utility customers can be reliably and economically served by power plants that are many orders of magnitude smaller than today's and do not require any bulk transmission whatsoever. There is growing evidence that electricity systems can rely on small power plants (generically called distributed generation, or DG) and a variety of customer specific options for energy and power management (generically called distributed energy resources, or DER, indicating both supply and demand side resources). DER systems could serve customers with drastically reduced transmission costs or none at all, and significantly reduced distribution and total system costs. It matters not whether DER options are compared to the present industry structure or the image of a restructured industry most people hold today: Making power plants the right size for the task at hand, and locating them at or near the point of use promises more efficient, higher quality service and lower costs (Davis, 2000a; Davis, 2000b; Lovins, et al., 2002). Already, a recent market survey found "more than 10 percent of U.S. and Canadian businesses in five key business sectors surveyed identified themselves as 'strong candidates' for base-load distributed-energy applications during the next two years… [and, nearly half] are already actively evaluating distributed-energy options, including natural gas reciprocating engines, microturbines, and fuel cells (Primen, 2001).

If small-scale generation options pan out as promoters predict, huge portions of yesterday's, today's and tomorrow's bulk transmission and generation capability will be made, as the British say, redundant. From this point of view, new bulk generation and transmission facilities represent unwarranted additions to the already large stranded cost[2] burden and could turn out to be high-risk, low-return investments, too.[3]

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[2]"Strandable costs" are essentially the difference between what a utility charges a full-requirements service customer for generation, transmission and distribution, minus any cost it avoids if the customer exercises a choice for a competitive supplier and then purchases only distribution service from the utility. In the most commonly understood scenarios for utility restructuring, customers may choose a competitive supplier of generation service, but will continue to rely on regulated monopoly utilities for transmission and distribution service. Thus, some portion of the costs associated with existing generation service may be strandable. See Regulatory Assistance Project, 1995.

[3] In the aftermath of the September 11, 2001 terrorist attacks, there is also a heightened concern about the vulnerability of all centralized energy systems, including transmission lines. This may prove another powerful impetus for seeking more highly distributed energy systems (see Lovins & Lovins, 1982, Chapter 10). Ironically, in an incident unrelated to terrorism that demonstrates these kinds of risks, the Trans-Alaska oil pipeline had to be shut down to repair a leak when a drunk fired a rifle shot that ruptured the pipeline, resulting in about a 150,000 gallon spill (Clark, 2001).

Table 1: Summary of Likely Potential Benefits and Costs of Restructuring

Benefits	Costs
■ Savings due to efficiency gains (in both capital and labor efficiency) that result from increased competition in generation. ■ More competitive and efficient transmission markets, as regional transmission organizations eliminate “pancaked” rates. ■ More and faster innovation in products and services, including all aspects of the industry (e.g., generation, transmission, distribution, metering, billing, end-use controls, and customer service). ■ More customer choices of service quality, types of service, and service bundles. ■ Better price setting.	■ In many jurisdictions, over-payment for stranded costs and increased costs due to securitization. ■ Industry transition costs. ■ Risk that market power will be exercised, resulting in higher prices. ■ More duplication of generation and transmission facilities. ■ Required capacity reserves harder to ensure and more expensive. ■ Higher capital costs for utility construction, reflecting higher risk and need to recover investments more quickly. ■ Potential to "lock-in" uneconomical technologies, preventing or slowing innovation. ■ Abandonment of IRP process. ■ Abandonment of utility DSM programming. ■ Reduced or abandoned RD&D. ■ Increased environmental pollution and other negative externalities. ■ Added costs of contracting needed to recreate vertical industry relationships. ■ More "middle-men" and higher transaction costs. ■ More utility spending on branding and marketing. ■ Possibly, reduced customer service quality and declining system reliability, especially for small customers. ■ Need to educate customers of new market choices. ■ Time and effort customers spend shopping.

CRITICAL FEATURES OF THE EMERGING MARKETPLACE

As policy makers look to the future, three major features of the emerging marketplace deserve specific recognition: market power, customer sovereignty, and the growing concern for ultra-reliable electric service. This section reviews each of these subjects, in turn.

Market Power: Breaking Up is Hard To Do

There is a serious concern about market power in the U.S. electric utility industry. This reflects the fact that utility restructuring in the U.S. involves dismantling a monopoly industry structure that has existed for almost a century. In many other countries of note (such as Great Britain, Australia, and countries in eastern Europe, Asia, and South America), utility restructuring began instead with state-owned monopolies. There, it involved selling existing industry assets to new competitive market entrants. In some ways, that is an easier path to competition because all the new market entrants begin under similar circumstances. Maintaining workable competition in any market is difficult enough; crafting a competitive marketplace out of a long-standing monopoly structure is an even more daunting challenge. DER are relevant in this context because they offer additional competitive choices and thereby a potentially powerful check against market power. As Moskovitz (2000, p. 6) notes, DER "seem ideally suited" as competitive supply options and "may be the ultimate form of retail competition because they can be used…with or without industry restructuring."

The current circumstance created by utility restructuring in the U.S. is that existing monopolies are adjusting rapidly to a new industry structure. There is a fair amount of consensus about the major outlines of the industry structure that most observers expect to emerge: A generation company or "GenCo" will own and operate generation; a transmission company ("TransCo") will own and operate transmission; and a distribution company ("DisCo") will own and operate distribution. Depending on whether and how DER are thrown into this mix, they may prove to be disruptive technologies capable of blazing a new path over, under, around, and through these industry divisions. If that happens, a second transition of major importance (a rapid and widespread transition to DER) may be overlaid on the first (utility restructuring).

One important consideration for regulators on the brink of these dual transitions is how incumbent utilities are likely to react to the emergence of competition from DER. Using game theory principles, it may be possible to begin to formulate some insights into likely utility responses. Table 2 is a matrix that depicts a simplified version of the problem that DER present to electric utilities today. Of course, it is overly simplified. The interests of various segments of the utility industry will not all be aligned in the same ways, and various utility companies will employ different strategies, which will change depending on time and place. For some utilities, the strategy may be different for a regulated company operating in its own service territory compared to competitive affiliates who operate in other utility service territories. The industry is already starting to show divergent strategies. Some utilities are investing in DER companies and starting to develop their own DG capabilities, often through affiliate companies. One of the most prominent examples is DTE Energy (http://www.dteenergy.com), parent company of both the Detroit Edison Company, a regulated utility, and DTE Energy Technologies, an unregulated DER and DG affiliate. On the whole, however, most U.S. utilities have so far exhibited DER strategies most closely associated with what Table 2 characterizes as "low growth & penetration" and "thwarting".

Utilities and other major energy industry companies have been uniquely positioned to secure legislative and regulatory treatment that helps to stave off competitive threats. Dickson (1975) and Patterson (1999) report on the ability of utilities to manipulate political decision making processes to ensure that the criteria that are used in both energy systems planning and policy analysis will continue to support existing technologies, and that restructuring best serves perceived corporate self-interests. Mandel, Carney, and Reinhardt (2000) point out how utilities have successfully stifled innovation. Moskovitz (2000) explains, utilities frequently fight against DER, even when DER might be employed in a high-cost area and in a way that does not harm utility profits. This may result from the inertia of corporate culture, as much as any clearly articulated, goal-directed analysis of options. Hirsh (1989) relates, there are long-lived, interlocking relationships inside utility companies between technologies, corporate culture, and management styles.

All this may be about to change, however, as the momentous industry restructuring unleashes new organizations and waves of innovation. As PricewaterhouseCoopers (2000) reports, the electric utility industry is fast turning into one of the most innovative sectors of the economy, second only to what they call the technology sector. Furthermore, a consensus may be building that society must: (a) break the grip on government presently held by special interest groups, (b) employ the means necessary to align and rectify special interests with the public interest, or both (see, for example: Estes, 1996; Etzioni, 1993; Hawken, 1993; Hawken, Lovins, & Lovins, 1999; Korten, 1995; Schmidheiny & Zorraquin, 1996; Weizsäcker, Lovins, & Lovins, 1997, Part Two).

<u>Customer Sovereignty: Green Customer Choice</u>

Another major feature of the emerging marketplace for electricity services is evidence that some consumers prefer cleaner energy sources, termed “green power”. As Farhah (1999) reports in an extensive review of literature and customer preference surveys:[4]

- “National polls have, for 20 years, found majority preferences for renewable energy over other energy sources; …
- Majorities of 52% to 95% of residential customers say they are willing to pay at least a modest amount more per month on their electric bills for power from renewable sources. Deliberative polls show…willingness to pay increases when customers are educated about utility energy options; …
- A limited amount of data suggest that customers may be even more likely to pay more for electricity from renewable sources in a competitive market setting; and …
- Customers may view with favor and remain loyal to utilities that provide [green] power… .”

Such preferences have already resulted in customer participation in about 80 monopoly utility green pricing programs in 28 states. In the early stages of competitive electricity markets, access to green power has been the leading reason why small customers switched suppliers (Swezey & Bird, 2000). Typically, 1 to 2 percent of existing utility customers switched to green rates when the choice was offered, even though that meant paying a price premium averaging 2.5 cents per kilowatt hour more than standard rates (Swezey, Houston, & Porter, 1998). In the early stages of the California market, “virtually all” of the 160,000 residential customers who switched providers took green power offerings (Swezey & Bird, 2000, p. 9). Also, a handful of prominent California business and institutional customers widely publicized their green power purchasing as a badge of environmental citizenship. These included Birkenstock, Fetzer wines, Kinko’s, Patagonia, and Toyota, the cities of Oakland, Santa Barbara, and Santa Monica, and the Bay Area Episcopal Churches, who coined the phrase “Episcopal Power & Light” for their participation.[5]

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[4] For information about green power marketing and market research, see the U.S. Department of Energy Green Power Network Library: http://www.eren.doe.gov/greenpower/library.shtml.

[5] The green power purchasing by Episcopal congregations was later expanded to other denominations. It became known as “Interfaith Power & Light” and similar groups are now active in Massachusetts, Maine, Pennsylvania, and Tennessee. See www.interfaithpower.org and www.etdiocese.net/bingham.

Table 2: Utility Strategies & Distributed Generation Penetration Matrix

Rate of Growth & Penetration of DG→ Utility Company Strategy ↓	Low Growth & Penetration: 1% by 2010, 5% by 2050.	High Growth & Penetration: 10% by 2010, 50% by 2050.
Thwart	Sales decline very little. Utilities keep barriers in place and erect new ones. Utilities offer anti-DG prices to block development.	Utility brand image negative and shrinking. Many DG customers unplug entirely. Utility loses sales and all contribution to fixed costs. Stranded costs skyrocket. Utility threatened by death spiral (see p. 9).
Support	Penetration is slow & low, but utility participates, helping prime customers. Utility (GenCo or DisCo) may be owner/operator, thus preventing lost sales, or provides DG via affiliate.	Utility brand image positive & growing. GenCos & DisCos help customers implement DG. Utilities actively support removal of barriers and strive to include DG in their services. A utility may own and operate directly, or work via an affiliate. Customers stay grid-connected for backup & other services.

These early experiences are not overwhelming enough to indicate a groundswell of support for higher priced renewable energy, but the numbers of interested customers are certainly large enough to interest energy marketers. The relevance to DER is that customer preference for green power is another factor favoring market penetration for DG. Many renewable energy options are readily available in DG sizes. In today's emergent competitive markets, though, rules and regulations have frequently maintained old, or erected new, barriers to more widespread adoption of green products and services. In part because of the emphasis on bulk markets for G&T, a general trend has been for green power producers to try to package and sell their product like any other bulk power. That practice may add costs and inefficiencies compared to green power options for DG. To the extent these factors have been at play and higher efficiencies are available for smaller green power systems, increased market penetration will ensue as barriers to DER are removed.

One potentially important marketing innovation is for suppliers to be able to sell the "green" quality separate from the power. The Michigan Green Power Cooperative (2000) is developing an innovative system for "tagging" electricity so that producers can market separately green power attributes, pollution credits, distributed and bulk electricity. Plus, increasing numbers of customers are opting for their own on-site green power supplies. Even prior to the full impact of the Y2K scare, residential DG in the U.S. was already estimated to be a $300 million per year industry, with about 150,000 homes generating power without being connected to a local distribution utility (called "off the grid" or "off-grid"), about 2,000 interconnected (called "grid connected" or "on-grid"), and both markets growing rapidly (Vickery, 1999). It is especially noteworthy that many of the early innovators who will be among the first to act on the widespread preference for green power may be among the best customers, from the traditional utility standpoint. That is, they are often customers with relatively greater energy demands and good bill-paying histories. A combination of factors may make them the most likely either to leave the grid entirely or install at least some on-site power supplies; to express preferences for both green power and extra high reliability and quality of supply.

To the extent these customer preferences exist, green power's rapid expansion can be expected to continue, and utilities and competitive suppliers ignore it at their peril.

Reliability Trumps Prices and Policies

Power quality and reliability are also becoming major concerns for an increasing number of electricity customers. Rather suddenly, distributed systems appear to be the best means available to serve customers who require the highest reliability of supply and quality of power. This is particularly true for the "24/7/365" reliability demanded for operating computers and electronic equipment, including computer-controlled manufacturing. With approximately 95 percent of all utility outages resulting from problems in the distribution network, on-site power delivery is a logical solution: If the vast majority of outages are caused by problems with the wires between generators and loads, then it is axiomatic that many outages can be avoided by locating generators much closer to loads. In addition, most on-site power systems incorporate solid-state power conditioning equipment to insure that only steady and clean power will be delivered.

It is also noteworthy that the transmission network typically incorporates redundant circuitry, providing multiple paths through which power can reach various destinations. In the rare event of a transmis-sion circuit failure or bottleneck, many times an alternate delivery path is accessible and power can be routed where needed without any interruption to customers. On the contrary, the distribution network is mostly radial and not redundant. In most circumstances, an outage on a distribution circuit will interrupt power delivery to all customers downstream of the problem area and power can be restored only by working in the same direction, from the power source outwards towards the customers at the end of the line.

In fact, electric utility restructuring may already be sowing the seeds for the rapid influx of DER, as traditional monopoly utilities start to jockey for position in the new competitive markets. The general cause is that utilities may be tempted to skimp on distribution costs while they concentrate more resources on generation and transmission. A possible path to short-term profits is for a utility to minimize distribution system expenses. As long as customers do not seek alternatives to the existing utility distribution system, the monopoly remains and utilities can expect steady revenues from this portion of the business. If distribution system reliability and service quality falter, however, a tipping point may be reached where increasing numbers of customers become dissatisfied and aggressively start to seek alternatives. Early experience with industry restructuring is reportedly proving this theory on both counts: Reliability is suffering and customer interest in self-generation is growing rapidly (Hansen, 2001).

The seeds for the demise of the traditional utility and the spawn for the distributed utility paradigm are being sewn, particularly wherever load pockets experience frequent interruptions and anywhere that erratic power quality rises to the level of acute customer awareness. Interruptions are most frequent and longest in duration for those unlucky customers whose facilities are near the ends of radial distribution lines or in areas where the intensity of electricity use is outstripping available distribution capacity. In addition, a large and growing number of customers have electricity needs they consider mission-critical, that require steady, clean power supply.[6]

There are two important ways that DER could be precursors to radical changes in the public utility infrastructure as we know it today. One is that developers are already beginning to design new subdivisions and office and industrial parks to operate independent of existing electric utility infrastructure. Many of the initial concepts plan for continued dependence on a natural gas utility to provide fuel for DG, but designs may ultimately dispense with connections to any centralized utility infrastructures (Baldwin, 1996). Some researchers believe it is increasingly possible and economically attractive to make developments without any umbilical connections to traditional utilities, including gas, electric, telecommunications (through the already widespread use of a variety of wireless technologies) and even water and sewer (using small-scale, on-site wastewater treatment systems and possibly fuel-cells as a source of pure water). It is not too far-fetched to believe that autonomous buildings could have as great an impact on settlement patterns in the future as the water mill did for several centuries beginning in the Middle Ages, followed by the steam engine in the Industrial Revolution (see Dickson, 1975, pp. 51-52).

The second concern is what could happen to existing utilities if enough customers choose to reduce utility purchases, in favor of self-generation. That could snowball into what is called a death spiral or spiral of impossibility, where the utility company loses sales and then has to raise rates to its remaining customers in order to cover fixed costs. But, demand elasticity, given continuously improving DER, could favor even more customer generation and thus more lost sales. In theory, the point could be reached where each price increase would result in even more lost sales, and the utility's financial viability would be seriously jeopardized. In order to avoid that threat, utilities may seek to erect additional barriers to customers leaving the system. Most often, utilities will request rate structures with higher fixed and lower variable charges, combined with customer charges for the privilege of leaving the utility system, called "exit fees." Regulatory responses to these challenges are the subject of the next section.

[6] All classes of customers are now utilizing more and more electronic and digital equipment, but standards for electric distribution system service quality have not changed fundamentally since the middle of the 20th Century. Present standards that were arguably sufficient to protect equipment such as resistance heaters and incandescent lamps are now widely perceived to be insufficient to protect today's much more sensitive gear. See Lovins, et al., 2002, pp. 274-279.

RATIONALIZING REGULATION FOR A DISTRIBUTED RESOURCE WORLD

All of these issues and concerns about distributed technologies and the future of the electric industry make it imperative for utility regulators to consider how policies will affect the market for DER. Regulators can craft a market where distributed resources can compete head to head with other options, on a more or less level playing field. Or not. If they do not, or if they decide not to act and thereby leave in place existing regulations, with all of the inherent barriers to these new technologies, then DER faces serious obstacles. However, as John Rowe, Chairman and CEO of Unicom points out (in the forward to Moskovitz, 2000), in many circumstances DER is not only an alternative to other kinds of utility investments. If customers opt to unplug from the existing electric grid and use DER instead, then DER can become "an alternative to both utilities and to their regulators."

Moskovitz (2000) and the Regulatory Assistance Project (2000) explore the crux of DER issues for regulators. Regulators should care about DER, they say, for six reasons. DER can: (1) save money; (2) improve reliability; (3) reduce pollution; (4) enhance customer service and choice; and (5) produce favorable economic multiplier and spin-off effects. The sixth reason is of paramount importance, too: "Only regulators can implement the reforms needed to allow distributed resources to compete fully and fairly, in service to the public interest."

The first concerns Moskovitz identifies involve the incentives inherent in almost all utility regulatory regimes. The findings in Moskovitz's 2000 paper on distributed resources mirror those of his similar report from a decade earlier (Moskovitz, 1989): A major conflict exists between utility interests and customer, public, and social interests when utility profits are linked directly to sales. When regulators analyzed energy conservation activities in the 1980s, they came face to face with this overwhelming obstacle: Under existing regulatory practice, anything utilities or their customers did to save energy subtracted from utility profits, even if it cost nothing. And, in mirror image, anything that increased energy use increased utility profits, no matter how costly that marginal energy supply. Upon close examination, it became clear that the most basic regulatory structure was perverse. Utility profits grew when customers were wasteful and their energy use inefficient. Conversely, utility profits shrank when customers were frugal and their energy use efficient.

The outcome of this analysis, a decade ago, was for the National Association of Regulatory Utility Commissioners (NARUC) to pass a resolution memorializing the need to align regulatory incentives so that a utility's least-cost plan would also be its most profitable plan (see Hirsh, 1999, pp. 207-210). A metamorphosis took place in the normative approach to utility regulation, towards mechanisms that, at least theoretically, would make utility companies indifferent to sales levels. The U.S. Congress affirmed this approach in the Energy Policy Act of 1992 (16 USC 2621d7-9). Congress did not make such provisions enforceable, but simply required utilities and public utility commissions to consider: (1) employing integrated resource planning; (2) having rate structures where energy conservation would be "at least as profitable, giving appropriate consideration to income loss from reduced sales…[as] investments in and expenditures for the construction of new generation, transmission, and distribution equipment;" and (3) establishing rates that would encourage utilities to make "all cost-effective improvements in the energy efficiency of power generation, transmission and distribution" after considering "the disincentives caused by existing ratemaking policies, and practices, and…incentives that would encourage" better efficiency in these areas.[7]

Regulatory practices to realign the incentives were developed in the late 1980s and early 1990s (Hirsh, 1999). Though some isolated efforts were tried with some success, the recommended practices were never widely implemented. Generally speaking, the prescribed practice of IRP combined with realignment of regulatory incentives was eclipsed by the slowly progressing move towards industry restructuring. Proponents of competitive markets denigrated the emerging regulatory practices, characterizing them as examples of a flawed or failed centralized planning paradigm and avowing that

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[7] The Michigan PSC ruled in Case No. U-10574, on October 12, 1994, that it was already in compliance with these standards, concluding that it need not "alter its method of regulating utilities in response to the new federal standards" (Order, p. 20). A few months later, starting with a June 19, 1995, Order in Case No. U-10554, the MPSC began dismantling those regulatory underpinnings.

competition would soon supplant them. In most jurisdictions, a tacit *quid pro quo* for utility cooperation with restructuring legislation was to abandon public IRP processes and utility sponsored DSM programs. The promised competitive market replacements, however, are still almost nowhere to be seen (see Kushler & Witte, 2001). In the meantime, regulatory incentives for almost all electric utilities remain the same – profits tied directly to sales – and that causes fits when utilities think about the likely effects on their profits if customers install DER.

As Moskovitz points out, if a utility installs and operates DG on the utility side of the meter, then there is little effect on utility profits. The utility continues to generate and sell electricity just as before. On the other hand, if DG is installed and operated on the customer side of the meter, then energy produced by the DG directly offsets utility generation and results in lost sales. Fortunately, appropriate regulatory mechanisms to correct this fundamental obstacle are already fairly well understood. Utility profits can be decoupled from sales and, preferably, any other significant factors over which utility management wields no control (Eto, 1994; Hirst, 1993; Nadel, 1992). For example, greater than average variability in summer heat or winter cold can trigger sagging or soaring utility profits.

Decoupling profits from sales may be a necessary, but not sufficient, requirement for establishing markets where DER can compete to fulfill their economic potential. In addition to decoupling, there are three major ways to realign regulations so that competitive markets function properly with respect to DER. First, adequate information is needed for all parties to comprehend the potential benefits and costs of DER implementation. Second, mechanisms are required to equitably share those benefits and costs. Third, prices must be adjusted, if necessary, to accurately reflect underlying production costs.

More and better information about DER is rapidly coming to the fore. Still, as of now, regulated local distribution companies (LDCs) are the only market participants positioned to obtain and disseminate infor-mation about the full benefits and costs of DER. This stems from the LDC's exquisitely detailed knowledge about system resources and loads in each subdivision of their service territory; essentially down to the level of each substation, each distribution line, and even each individual customer or meter.

As early research and case studies are showing, distribution costs are highly variable (see Cowart, 2001; Shirley, 2001). In essence, each LDC is comprised of a group of distribution circuits and at any given point in time a few are high-cost areas. The marginal cost of distribution for a specific circuit at a specific time is often 20 or more times the average for the whole utility service territory. The cause may be any combination of a few different factors. For one, growth in power use density may start to exceed the capacity of existing distribution equipment.[8] Another is because equipment simply wears out and needs replacement. And a third is that new growth in formerly vacant or less utilized areas necessitates the addition of new distribution circuits, like what happens when new subdivisions, shopping centers, or office and industrial parks are built.

The trick is to make the information about the detailed costs and benefits of DER deployment, in specific locations and at specific times of use, known early enough in the decision making timetable so that DER options might compete in providing needed services. Regulators play a crucial role in determining what information markets need to function adequately and then making sure it is provided. For example, utilities could make available full information about geographically differentiated power supply costs, perhaps for each distribution substation or even each distribution feeder. Markets might start to respond to information on variable costs, even if retail prices continue to be based on system averages. U.S. electricity markets may change soon to incorporate more information about the value of

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[8] This is very similar to what has happened with telephone area codes in recent years. As telecommunications devices proliferated, telephone area codes had to be subdivided to accommodate the greater density of phone numbers needed per area of land. In a similar manner, if electric power use intensifies because customers use more and more appliances and electronics, distribution systems may have to be upgraded or repartitioned in order to meet the growing needs for capacity.

DER. The new Federal Energy Regulatory Commission (FERC) Notice of Proposed Rulemaking on Standard Electricity Market Design (2002) proposes to: (a) establish locational marginal pricing for transmission resources, to reflect the costs of both congestion and transmission losses; (b) open electric markets to bids from demand side resources; and (c) institute a resource planning process designed to insure supply adequacy, explicitly incorporating both demand-side resources and DG. In addition, separate FERC rules have been proposed that would standardize both large and small generator interconnection agreements and procedures (http://www.ferc.fed.us/Electric/gen_inter.htm).

Next, regulators have a critically important role in assuring that the benefits and costs of DER installations will be equitably shared. Utility regulators have long championed the principle of cost causation: When a utility incurs costs in order to serve certain customers, those same customers ought to pay those costs. The other side of this coin is equally important: Customers who produce benefits for the utility system deserve appropriate rewards. At the same time, however, the need to accurately assign costs and benefits must be balanced against the need for administrative simplicity. It could prove hopelessly complicated for all concerned, if regulators tried to achieve too much precision in such cost and benefit allocations. Nevertheless, regulators need to make an effort to identify all major categories of DER costs and benefits, quantify them, and assign them fairly. Right now, in the absence of this allocation, it can be demonstrated that DER are not being deployed in many situations where benefits far exceed costs. In general, that is because the benefits are not well understood or quantified, and they often accrue to parties other than DER developers.

This situation leads directly to the third admonition for regulators: Prices should accurately reflect costs. The goal for LDC rates should be to encourage all cost-effective DER. Customers should receive accurate price signals and be allowed to employ any means available to respond to those price signals by altering their demand patterns, including using DG. Similarly, transmission systems should be managed so that energy efficiency, load management and DG can participate in those markets, too (Federal Energy Regulatory Commission, 2002; Regulatory Assistance Project, 2001; Sioshansi, 2001).

Already, several policies have been proposed for breaking down presently existing regulatory barriers to DER, and some promising regulatory innovations for DER have been proposed. The major barrier breakers include: (1) standardized and simplified interconnection practices; (2) net metering for small generators; and (3) incorporating greater demand responsiveness in energy markets.[9] And, regulatory innovations include: (4) geographically de-averaged DER credits; (5) DER development zones; (6) symmetrical pricing flexibility; (7) ending predatory pricing and buyouts; (8) expanding utility auctions to incorporate DER options; (9) altering environmental regulations and (10) altering tax policies and removing adverse subsidies to reward improved energy efficiency. Here is a brief description of each of these proposals:

(1) Standardized and Simplified Interconnection Practices. There are three major areas of concern regarding interconnection practices: technical, contractual, and financial.[10] A forthcoming Institute of Electrical and Electronics Engineers (IEEE) "Standard for Distributed Resources Interconnected With Electric Power Systems" is addressing technical concerns (http://grouper.ieee.org/groups/scc21/1547/). In addition, Under-writers Laboratory and the National Fire Protection Association have developed various standards regarding technical and safety issues. Contractual arrangements between utilities and distributed generators and financial aspects (that is, utility rates and tariffs) are the subject of federal, state, and sometimes local utility regulations (see NARUC, 2002; NARUC Staff Subcommittee on Energy Resources and the Environment, 2000). It appears that a consensus is taking shape that a single federal standard is appropriate, at least regarding

[9] For more complete descriptions and analyses of potential barriers and policies proposed to remove them, see Alderfer, Eldridge, & Starrs, 2000; Lovins, et al., 2002, Part Three; and Moskovitz, 2000.

[10] For additional information, see the "Connecting to the Grid" section of the Interstate Renewable Energy Council Web site, http://irec.solarhost.com/connect/index.html. See also Alderfer, Eldridge, & Starrs, 2000; and Hansen, 2001.

safety concerns. Plus, some advocates are calling for national standards on financial and contractual arrangements, as well (see, for example, Perez, 2001). Clearly, progress is being made on technical and safety standards, and various states and FERC are presently establishing interconnection rules and standards, which will govern administrative and contractual details.

(2) Net Metering for Small Generators. Net energy metering is an accounting mechanism whereby customers are billed for net energy consumption during each billing period.[11] Where it is available now, in about 35 U.S. states, net-metered service is for utility customers who have small electric generating equipment installed and operating on their side of the electric meter. At times when their generator produces more energy than they can use themselves, the excess is sent through the meter and sold to the utility company. At other times, when the customer produces less than they need, they buy from the utility. With net metering, at the end of each billing period the amount used by the customer is calculated after subtracting the amount delivered to the utility. With most net metering programs, the price paid is the same for kilowatt-hours sold and used. In some jurisdictions the customer can reduce their bill to zero by delivering to their utility at least as much as they use and any net excess generation (NEG) is simply awarded to the utility.

Net metering is not intended to be available to all generators, nor is it intended to make it possible for small generators to be in the business of generating electricity for sale as a profit-making endeavor. Instead, the purpose of net metering is to support small energy producers who wish to serve a portion of their own needs (sometimes called “self-service” power generation). In marketing and diffusion of innovation theory parlance, for all kinds of consumer goods there is a potential market amongst early adopters who are interested "in purchasing the latest cutting edge technologies…before economies of scale begin to kick in and lower costs" (Cohen-Rosenthal, 2000). Net metering provides a very modest level of financial support to early adopters of small-scale power generation technologies. And, the early adopters are assisting the development of emerging power generation industries, through their purchases and by demonstrating the technologies.

The primary function of net metering is to minimize the complexity and difficulty for small, self-service generators to interconnect with their LDC. Exchanging electricity at retail price is merely an expedient, low-cost means of greatly simplifying interconnections and metering, minimizing utility administrative and billing costs, and avoiding the need for more complex accounting of the quantities and even timing of electricity bought and sold. Perhaps the primary rationale for net metering is that the alternatives might require significantly more equipment and administrative expense. For example, one alternative is to use two separate meters and account for energy used versus produced at two different prices. Or, an added layer of complexity would be to employ different prices based on the time of use or production.[12] In a nutshell, net metering proponents argue: (a) infinitesimal quantities of electricity will be purchased by the LDC;[13] and (b) even if one assumes, for purposes of discussion, that the retail price is not the correct one to use, administratively determining the method for calculating correct price and then accounting for it could easily cost more than it is worth.

(3) Incorporating Greater Demand Responsiveness in Energy Markets. This proposal seems so reasonable on its surface that it may be hard to believe that a conscious policy response is needed to address it. But, the fact is that many aspects of today’s competitive electric power markets make it

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[11] Some states and utilities call this net billing, rather than net metering. Net billing could suggest two meters, as opposed to net metering with a single meter. However, the two terms are frequently used interchangeably. For more information, see http://www.eren.doe.gov/greenpower/netmetering/.

[12] The DG tariff available to Detroit Edison customers uses two meters, and offers customers an options of time of use (on-peak/off-peak) or hourly pricing. See February 14, 2001 Order in Case No. U-12827 (http://cis.state.mi.us/mpsc/orders/electric/2001).

[13] Nearly all state’s net metering programs establish modest maximum system penetration levels for net metered generation; typically 1% or less of LDC peak load. Those ceilings effectively limit both utility exposure to lost revenues and any cross-subsidization between participating and non-participating customers.

difficult for changes in demand to occur in response to short-term changes in supply and price (Regulatory Assistance Project, 2001; Sioshansi, 2001). Early studies indicate that shaving a few percent off of demand year-around can cut total power supply costs by 10 percent or more, and put significant downward pressure on wholesale supply costs. The effect is reported to be even greater during times of peak demand; in Michigan, typically during summer heat waves where peaks are driven by air conditioning loads. One study concluded that a 5 percent reduction in peak use for just a few dozen hours per year could result in a 50 percent reduction in the peak wholesale price (Hirst, 2001). Several researchers are proposing changes to existing markets which will make it much easier for demand to shift according to variations in supply, and there is already evidence that straight-forward means are available to facilitate a significant demand response (Lively, 2000; Lively 2001).[14]

(4) Geographically De-Averaged DER Credits and (5) DER Development Zones. These proposals are intended to draw DER developments into high-cost areas, where deployment could be a win-win proposition for distribution utilities, customers, and DER developers alike (Moskovitz, 2001). The concept is for distribution utilities to identify their high-cost areas and then offer customers and developers financial incentives to locate DER there. This could be accomplished by utilities publishing directories showing credits available for installing, in particular geographic areas, DER that is assured to meet specified performance criteria. Establishing de-averaged DER credits could necessitate the utility providing the functional equivalent of a cost-based map of its whole service territory, with variable credits for DER installations on each circuit or substation, ranging from zero on up.[15] Or, DER Development Zones would identify a few specific high-cost zones where credits would be offered, similar to other kinds of geographically targeted governmental incentive programs. Ideally, the amount and duration of the credit would be based on and scaled to reflect the benefits to the LDC, in terms of postponed or avoided distribution system reinforcements or expansions. There could be many variations on this theme, including competitive bidding where the amount of credit requested would be one criterion used to select winning projects. As Moskovitz proposes, at least some pilot programs are warranted to learn whether the intended results can be achieved.[16]

(6) Symmetrical Pricing Flexibility and (7) Ending Predatory Pricing and Buyouts. Symmetrical pricing flexibility means that if utilities are allowed to decrease prices to some customers in order to prevent DER bypass, they should mirror that by increasing prices in high-cost areas to encourage cost-effective DER. In some cases, public utility commissions established special rates open to various customer types. In others, utilities were allowed to offer exceptional price discounts to individual customers, especially to prevent bypass. The justifications for such approvals were seldom fully articulated in commission rulings, but they were typically instituted in response to competitive pressures. Bilateral contracts between utilities and major customers were often approved as part of an industrial recruitment, retention or expansion strategy. For example, they might be invoked in order to forestall factory closures, prevent industries from moving production to another utility service territory, or sometimes explicitly to block a proposed cogeneration plant.[17]

(8) Expanding Utility Auctions to Incorporate DER Options. In the 1980s and 90s, many utility commissions implemented auction procedures for utilities that were in need of new generation capacity. It was generally believed that competitive bidding would result in lower cost generation.[18] In order to

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[14] On February 14, 2002, a joint FERC and U.S. Department of Energy "Demand Response Conference" was held in Washington, DC. See http://www.eren.doe.gov/electricity_restructuring/ferc.html.

[15] The government of New South Wales, Australia (2001), has already adopted something extremely similar, in its Demand Management Code of Practice.

[16] See Cowart (2001) for preliminary reports on several DER case studies.

[17] See, for example, the Michigan PSC September 12, 1996 Order in Case No. U-11153, and Concurring Opinions of all three Michigan commissioners (http://cis.state.mi.us/mpsc/orders/electric/1996/). When bilateral contracts were approved in Michigan, protections against cross-subsidization were incorporated.

[18] The Michigan PSC developed a structure for competitive bidding, but auctions were never implemented. See April 14, 1998 Order in Case No. U-10480 (http://cis.state.mi.us/mpsc/orders/electric/1998/).

support development of cost-effective DER, utility auctions should be expanded to include all major utility expenditures, whether for generation, transmission, or distribution. Under an auction system, whenever a utility plans to invest any substantial amount in new resources, they would invite competitive bids for any and all options that would meet the specified engineering requirements. The utility would publish details about its plans for any significant G, T & D expenditures, and then let all comers bid against the utility preferred plan. The opportunities open to competitive bids would include both new infrastructure and plans for significant repairs or replacement of existing infrastructure. Open bidding would insure that all means of providing the necessary services would be allowed to compete, including both supply- and demand-side options.[19] In general terms, this type of planning process and invitation to all market responses is the essence of some of the provisions of the newly proposed FERC (2002) Standard Market Design, though that process would be driven by transmission requirements to a much greater extent than generation or distribution.

(9) Altering Environmental Regulations to Reward Improved Energy Efficiency. Existing environmental regulations were developed prior to widespread introduction of DER. The general concern now is to develop and implement an air emissions regulatory scheme that removes any unintended barriers to DER and supports deployment of cost-effective, environmentally sound DER. U.S. efforts to craft model rules for DER are nearing completion. The model rules will be neutral to various technologies and fuels, and "encourage, or at least not discourage, the deployment of non-emitting distributed resources" (Regulatory Assistance Project, 2001; see http://www.rapmaine.org/workgroup.html). The Regulatory Assistance Project has been developing a model rule, with a working group of more than two dozen state energy regulators, state and federal air quality regulators, DER equipment manufacturers, and environmental and industry interest groups. The group is drafting a model rule to address emissions of nitrogen oxides, particulate matter, carbon monoxide, sulfur dioxide, and carbon dioxide. The rule will be output-based; setting limits in pounds per megawatt-hour and designed so that the more a generator operates, the lower its emissions limits. It supports a fuel- and technology-neutral approach, intended to promote innovation and efficiency. It supports a phase-in of limits, in three steps over a ten-year period, intended to give manufacturers a reasonable opportunity to develop and implement compliance options. The expectation is that the model rule can be adopted by states, but it is recognized that national consistency will help reduce compliance costs for suppliers and ease administrative burdens for regulators. The hope is that if enough states adopt this model rule, or something very similar, it will promote national consistency in emissions regulations for DG.

(10) Altering Environmental Tax Policies and Removing Adverse Subsidies to Reward Improved Energy Efficiency. The objective of these policies is to better align market signals with ecological realities (see, for example Center for a Sustainable Economy, 2002; Hoerner 2000; Roodman 1998; Schmidheiny & Zorraquin, 1996). Because these kinds of policy changes would tend to make all fossil fuel and polluting technologies relatively more expensive – and energy-saving and cleaner technologies relatively cheaper – they would help correct price signals throughout the economy. This is arguably the most powerful policy option for supporting DER.

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[19] In Michigan, the PSC cannot direct utilities to undertake any specific management practices. The Michigan Supreme Court found in *Union Carbide v PSC* (431 Mich 135-163) that the PSC "has the power generally to regulate public utilities, including utility rates and charges" but, that power "does not carry with it, explicitly or implicitly, the power to make management decisions" (431 Mich 136). Thus, the PSC could not explicitly direct utilities towards any specific course of action. In a convoluted exercise of regulatory authority, the Michigan PSC could likely encourage utilities to adopt specific proposals by limiting rate recovery based on bid results. The utility would be free to choose to build some other alternative or accept another bid, but their rate recovery could be limited to the amount of the best bid.

SUMMARY AND CONCLUSION

In summary, electric utility restructuring is already well underway, and the political constellation supporting it does not appear to be weakening, even in the face of the problems evidenced in California, which were then followed by Enron's collapse, and then revelations about billions of dollars of round-trip trading. Early experiences in many industries show that serious problems regularly interfere with transitions to more competitive industry structures (Consumer Reports, 2002). Perhaps there is a growing awareness that regu- lators need to be vigilant in monitoring utility markets and making mid-course corrections. For example, FERC's news release on Standard Electricity Market Design talks in terms of "impediments…preventing markets from realizing their full potential" and "persistent and costly problems" which necessitate the proposed overhaul. Although there is some evidence that restructuring may never prove successful on its own terms, one of its perhaps initially overlooked or even unintended results may be to open up important oppor-tunities for doing new things in new ways. One of the primary technical and service options is the broader introduction of DER. There is growing evidence that in scores of applications DER can save money, improve the environment, support local economies and employment creation and retention, and provide customers with important reliability and power quality benefits. Nevertheless, there is still a lot of work to do if state and federal utility regulators are going to fix existing market barriers and failures so that DER can effectively compete against traditional central station generation and transmission options. Although some progress in this direction is noticeable, much more remains to be done.

Perhaps the most important step utility regulators can take is to break the link between utility profits and sales. If the link is not broken, then most DER will hurt utility profits and they will, quite understandably, take whatever steps they can to block DER implementation. It is practically impossible to overestimate the creativity that a profit-motivated utility company can bring to bear on achieving and maintaining competitive advantages, through whatever not-illegal means can be imagined. As long as the link between profits and sales is not broken, regulators must exercise due vigilance to prevent utilities from implementing new rate structures that are intended to discourage cost effective DER. For example, some utilities have already asked regulators to approve exit fees and rates with high fixed and low variable charges, both of which reduce or remove the incentive for customers to conserve or produce their own electricity.

A second critically important policy change is green tax shifting. This is outside of the purview of public utility regulators, but they can help lead the call for change. In fact, I believe that utility regulators must enter into dialogues with their counterparts at many other administrative, financial, and regulatory agencies in order to clearly articulate the many barriers that are preventing DER from fulfilling their economic potential. The obstacles to be cleared touch on many aspects of the building and construction trades, environmental regulations, finance and insurance, and more (see, for example, Cohen-Rosenthal, Schlarb, & Thorne, 2000).

Knowing the political power wielded by public utilities, I am tempted to conclude (paraphrasing Moskovitz, see p. 10) that only utilities can request that regulators implement the reforms needed to allow DER to compete fully and fairly, in service of the public interest. Market newcomers face an uphill battle for getting their issues attended to by legislatures and regulators alike. As long as utilities fight against DER reforms, it will be difficult. Nevertheless, there are many hopeful signs on the horizon. They include the newly proposed FERC SMD rules and both state and federal progress towards interconnection standards. There is even a growing worldwide consensus, exemplified in the Plan of Implementation produced by the just-concluded Johannesburg World Summit on Sustainable

Development (2002, pp. 3-4, 7-9), that future energy system development must emphasize renewable fuels, indigenous fuels and infrastructures, and efficient, distributed and decentralized energy systems. The Plan (p. 9) also explicitly supports policies to reduce and remove "market distortions, including restructuring taxation and phasing out harmful subsidies… ."

What is truly remarkable about electric utility restructuring is that a political consensus could have formed around an idea whose foundation rested on such shaky ground. We have embarked on a massive restructuring of an industry whose product is a vital public necessity, based on little more than a religious belief in a fragmented, partial theory of market economics. One can only hope that the means to improve (dare we say, to perfect?) competitive markets for electricity can be discovered and applied before the costs of the present experiment become unbearable.

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