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Breaking The Consumption Habit

Ratemaking for Efficient Resource Decisions

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For most distribution companies, most of the time, today's dominant regulatory practices create thoroughly perverse incentives. The result is lost opportunities to reduce energy service costs and improve reliability by introducing a wide variety of efficient and cost-effective alternatives. Among the casualties are effective resources such as targeted energy efficiency, load management, and distributed generation, which can effectively avoid many costly capacity additions and greatly enhance grid reliability. Traditional rate design, which ties utilities' financial health directly to the volume of commodity sales, invites an exclusive focus on more traditional distribution and generation capacity expansions -- often in direct conflict with other important societal objectives. This antiquated design must be changed to reward utilities' for making more economically and environmentally efficient resource decisions. Adoption of these ratemaking reforms is critical to the effective integration of promising alternatives such as distributed resources.

Breaking the link between utilities' commodity sales and revenues is necessary but not sufficient. Additional mechanisms such as performance-based incentives to deliver cost-effective savings, and distribution enhancements, will be needed to align shareholder and customer interests. Some state public utilities commissions applied this concept to their rate designs (variously known as decoupling, revenue cap or revenue-per-customer mechanism, revenue indexing, and statistical recoupling) in the 1980's and 1990's, with generally positive results. Industry changes in the last few years make it more important than ever to re-examine this concept and discard the current antiquated rate design, regardless of how expansive or limited a role one believes a distribution company should have, or whether that distribution company is investor, or consumer-owned. Several utilities in California and Oregon now actively support adoption of a revenue cap mechanism. This is significant for two reasons. First, these utilities account for more than ten percent of U.S. gas and electric revenues. Second, Oregon and California arrived at very different structures for the distribution companies' role.

Weighing All the Options

Utilities have long had the responsibility of delivering least-cost, reliable energy services to customers. Increases in demand have traditionally led to increases in capacity -- of generation, transmission or distribution infrastructures -- regardless of the grid location, time period, permanence or reliability level of that demand. A quick look at the landscape reveals that as customer needs have grown, so have the range and the number of resources available to meet those needs.

The distribution system across the U.S. is under increasing stress for an increasing number of hours each year. There is a growing consensus that we need major new infrastructure investment. The nation is looking at very expensive grid enhancements if we rely solely on traditional solutions such as the construction of new peaking power plants. Targeted energy

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efficiency or load management, or well-placed distributed generation on either side of the meter, would likely prove much more cost-effective and much less environmentally disruptive.

In some cases, capacity expansion of the generation, transmission, or distribution infrastructure may very well be the most prudent solution to customer needs; in many more cases, the most prudent solution will be a portfolio of the many options. To come to the most economically and environmentally efficient resource decision, requires balanced consideration of all the options. If both the needs and the resource alternatives available to meet these needs have expanded, why have the utilities not added these new tools to their toolboxes? One answer is that current ratemaking encourages them not to.

Ratemaking for Efficient Resource Decisions

All ratemaking provides utilities with incentives or disincentives to behave in a certain manner. Ideally, utilities should be rewarded based on how well they meet their customers' energy service needs. However, most current rate design instead places the focus on commodity sales, tying a distribution company's recovery of fixed costs directly to its commodity sales.

This system of price cap regulation discourages even the most economical investments if they are likely to reduce throughput. As sales go down, the utility's shareholders or customer-owners lose dollars with every unsold kilowatt-hour. To actively encourage or promote demand- or supply-side resources installed on the customer side of the meter, or any other solutions that might reduce throughput, would undermine the institution's financial health. Under this system, it follows that capacity expansion is the primary response to projected load growth - to the exclusion of investments in energy efficiency and other distributed energy resources. This is economically inefficient, because there is no the incentive to choose the total least-cost option to provide energy service to its customers.

The response to the wholesale market volatility of 2000-01 makes these perverse incentives even worse. Public utilities commissions all over the West are responding with a move toward sharply tiered residential rate structures. (Table 1) Tiered rates are extremely useful in sending price signals to consumers to encourage energy efficiency and conservation; however, this structure also makes more revenues subject to unexpected change since short-term increases or reductions in residential consumption will occur in tiers or blocks that return significantly more revenue per kilowatt-hour to utilities than the relatively flat rates that prevailed until very recently.

Table 1: Tiered Rates for Residential Customers[a]

Utility	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
California					
PG&E[b]	Up to Baseline	101-130% of Baseline	131-200% of Baseline	201-300% of Baseline	Over 300%
	$0.116	$0.133	$0.184	$0.228	$0.248
SCE[c]	$0.130	$0.152	$0.197	$0.236	$0.260
Arizona					
APS[d]	0-400 kWh	401-800 kWh	Over 800 kWh		
	$0.763	$0.106	$0.124		
Nevada					
Sierra Pacific[e]	0-300 kWh	301-550 kWh	Over 550 kWh		

	$0.091	$0.106	$0.117	
Idaho				
Idaho Power[f]	0-800 kWh	801-2000 kWh	Over 2000 kWh	
	$0.062	$0.07	$0.84	

a. Some of these utilities include small fixed customer charges on their residential bills in addition to the volumetric rates illustrated in this table.

b. Pacific Gas & Electric Company Revised California Public Utilities Commission Sheet No. 18376-E, effective July 1, 2001.

c. Southern California Edison Revised California Public Utilities Commission Sheet No. 29197-E, effective June 3, 2001.

d. Arizona Public Service Company Revision No. 18 of Arizona Corporation Commission No. 5450, effective July 1, 2001. May-October Billing Cycles.

e. Sierra Pacific Power Company 75th Revised Public Utilities Commission of Nevada Sheet No. 64, effective July 7, 2001.

f. Idaho Power Company Idaho Public Utility Commission No. 26, Tariff 101 Eleventh Revised Sheet No. 1-2, effective October 1, 2001.

Breaking the Sales-Revenue Link

In order to motivate utilities to consider all the options when planning and making resource decisions on how to meet their customers' needs, the sales-revenue link in current rate design must be broken. Breaking that link between the utility's commodity sales and revenues, removes both the incentive to increase electricity sales and the disincentive to run effective energy efficiency programs or invest in other activities that may reduce load. Decision-making then refocuses on making least-cost investments to deliver reliable energy services to customers even when such investments reduce throughput. The result is a better alignment of shareholder and customer interests to provide for more economically and environmentally efficient resource decisions.

As an added benefit, breaking the sales-revenue link streamlines the regulatory process for rate adjustments. Contention over sales forecasts consumes extensive time in every rate case. If the sales-revenue link is broken, these forecasts carry no economic weight, so the incentive to game forecasts of electricity sales is removed and rate cases become less adversarial.

Many works have addressed the different forms that alternatives to the traditional rate design mechanism can take.[1] These alternatives, variously known as decoupling, revenue indexing, revenue cap or revenue-per-customer mechanism, or statistical recoupling, range from the simple to the complicated -- allowing the design to take into account the unique characteristics of different utilities or regions.

Eliminating the Disincentive is Necessary, But Not Sufficient

While revenue cap or revenue-per-customer rate designs make utilities neutral to investments that reduce throughput, they do not provide the utilities with incentives to actively promote energy efficiency, distributed resources, or other energy policy goals. Additional incentives or mechanisms are necessary to promote active investment in these areas. A non-bypassable system benefits surcharge provides a stable level of funding for public good investments in cost-effective energy efficiency, renewables, low income services and RD&D. Strong performance-based incentives could also be established to deliver cost-effective savings, distribution enhancements, and other least-cost system values.

Partial "Fixes" Do Not Get The Job Done

While there are many different ways to break the link between sales and fixed-cost recovery, that link must be broken to allow a more balanced consideration of all resource options. Several alternatives have been proposed to remove the disincentive to reduce throughput; however, decoupling mechanisms are able to do this much more successfully and comprehensively than any of the proposed alternatives which include a shift to more frequent rate cases, fixed customer charges, or lost revenue adjustments.

Frequent Rate Cases

Increasing the frequency of rate cases is neither an efficient nor an effective alternative to decoupling. Under any circumstances, most of life will be lived between rate case decisions. Increased frequency of rate cases could partially address many issues underlying the short-run profitability of incremental sales; however, since the frequency of rate cases directly influences the size and persistence of the disincentives that decoupling seeks to address, annual rate cases, at a minimum, would be necessary. Too much of life would then be lived in rate cases, which are lengthy, litigious, and expensive. Even then, the problem would not be resolved, since the disincentive to reduce sales would still exist, and revenues would still increase with sales between rate case decisions. In addition, frequent rate cases would dampen any cost-cutting incentives that utilities might have between rate cases.

Fixed Charge

Another proposed alternative to decoupling is to shift from volumetric customer charges to fixed charges. In this argument, since distribution costs are independent of consumption in the short run, the charges that recover these costs should not vary with consumption. Proponents of fixed charges contend that when fixed distribution costs are recovered by raising the cost of kilowatt-hours, customers are being overcharged for those kilowatt-hours and socially beneficial electricity use is being suppressed. Their preference is to recover the distribution costs instead as fixed monthly charges that do not vary with consumption. A response at that same lofty theoretical level is that distribution costs are extremely sensitive to consumption over longer periods, with sustained growth periodically requiring costly equipment replacements in order to handle the higher volumes safely. This argues for making customers pay higher distribution costs as their electricity consumption grows. Volumetric rates recognize the variability of distribution costs over time, and promote long run, dynamic economic efficiency.[2]

However one resolves the theoretical debate, it is difficult to contend seriously that society today is suppressing socially beneficial growth in electricity consumption by imposing excessive charges on its use. The opposite seems far more likely, given growing environmental strains and the abundant evidence that pervasive market barriers continue to block energy savings that are much cheaper than additional energy production. We should not make a bad situation worse by reducing customers' rewards for using less electricity, which is precisely what would happen if we raised their fixed charges and cut their usage-based distribution charges by a corresponding amount. Volumetric, or usage-based, rates provide a very valuable price signal by giving customers power over their own bills.

Lost Revenue Adjustments

Probably the most frequently proposed alternative to decoupling is lost revenue adjustment. Proponents contend that by estimating sales lost, or commodity not consumed due to energy efficiency or load management activities, and reimbursing the utility for those 'lost' sales, the disincentive to reduce throughput will be eliminated. The principal problem with such a system is that it fails to break the link, and it gets utilities' overall incentives very wrong. The most profitable energy efficiency programs under such systems are those that can be made to look good on paper and save nothing in practice. Such programs would leave overall revenues unimpaired (since consumption would not decrease), while yielding utilities a windfall in the form of restored lost revenues that were never in fact lost. Lost-revenue adjustment mechanisms also impose a high administrative burden associated with implementation and produce very complex and controversial measurement and evaluation issues.

Furthermore, lost-revenue adjustments deal only with revenue losses directly attributable to utility energy efficiency and load management activities while leaving the underlying incentive to pursue incremental sales unaffected. Lost-revenue adjustments do nothing to support environmental and efficiency objectives, and do everything to motivate utilities to oppose them. Under this type of mechanism, aggressive efficiency codes and standards would still threaten fixed cost recovery since they result in a reduction in throughput. Since utilities have been instrumental in the development and promotion of stringent standards, loss of their support -- or worse, active opposition -- would be devastating to environmental and efficiency goals.[3]

Learning From Experience

Rate designs that break the sales-revenue link are not new, nor are they merely theoretical. These mechanisms have been in operation in some form since the California Public Utilities Commission (CPUC) adopted an electric rate adjustment mechanism (ERAM) in 1982. While California has the most extensive experience, Oregon, Washington, New York and Maine have also adopted some form of revenue cap mechanism over the last two decades.

Reliance on decoupling mechanisms declined substantially in the mid-to late 1990s. This was due in large part -- at least in California -- to uncertainties related to and the structure imposed by the restructuring transition. The CPUC, however, never abandoned its policy of breaking the sales-revenue linkage (see discussion below), and California's legislature mandated reinstatement of the policy in April 2001.[4] Today, Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) all have either proposed, or have stated their intent to propose, some form of revenue cap mechanism.[5] Oregon is also actively considering revenue-per-customer mechanisms. A proceeding is underway in Oregon to consider adoption of revenue-per-customer mechanisms proposed by Portland General Electric (PGE), and NW Natural Gas. In addition, Pacificorp has stated their intent to propose some form of revenue-per-customer mechanism.[6] Of note is the fact that these utilities account for more than 10 percent of U.S. gas and electric revenues.

California

The California PUC adopted an ERAM for the three major California utilities beginning with PG&E in 1982[7]. SCE and SDG&E followed in 1983 and 1984, respectively. The mechanism applied to all electricity and gas sales for residential and small commercial customers. Not surprisingly, California utilities led the nation in their commitment to energy conservation in the early 1980s. In 1990, the CPUC supplemented decoupling with a system of performance-based financial incentives for utilities to promote even more cost-effective energy savings. In 1996, the California legislature approved a nonbypassable system benefits surcharge to be collected on bills for investments in cost-effective energy efficiency, renewables, low-income services, and RD&D.[8]

A Lawrence Berkeley Laboratory (LBL) report, *The Theory and Practice of Decoupling*, provides details on the historic impacts of ERAM in California as it examines the first decade of ERAM results.[9] The report concludes that ERAM "has had a negligible effect on rate levels and has, for PG&E, actually reduced rate volatility." In addition, "...the clearing of ERAM balances has accounted for only a small proportion of the total change in revenue requirements between 1983-1993."[10] In its first six years in operation in California, ERAM reduced operating revenues for California's three largest utilities nine times and increased them eight times; the average adjustment was one-fourth of one percent.[11] The LBL report also estimates a decrease in the standard deviation of annual rate changes for two utilities (for PG&E, 9.5% to 7.5%; for SDG&E, 7.9% to 7.4%). Based on these estimates, they conclude that there has been no risk shifting at all for these two California utilities. "The record in California indicates that the risk-shifting accounted for by ERAM is small or non-existent and, in any case, ERAM has contributed far less to rate volatility than have other adjustments to rates, such as the fuel-adjustment clause."[12] On the contrary, ERAM has been accompanied by rate risk reductions to customers and profit risk reductions to utilities. The LBL report also concluded that decoupling did not insulate management from the need to focus on expenses and customers.

Electric industry restructuring in California led the CPUC to suspend the existing ERAM mechanism in 1996, but the CPUC did not officially abandon its policy of breaking the link between utility revenues and kWh sales. Restructuring legislation in California established a competitive transition charge (CTC) meant to recover the utilities' stranded investments over a limited period of time. Since the utilities were not allowed to raise rates under this legislation, CTC collections could only come from excess revenues. The CPUC suspended ERAM, in large part, because of the challenge that the statutory rate freeze posed, under the continuation of ERAM, to the utilities' ability to collect their stranded costs. In Decision No. 96-09-092, the CPUC found that "[w]e do not consider today whether it is desirable or appropriate to apply some form of ERAM solely to the distribution revenue requirement. The details of implementing a distribution ERAM may also be considered in the distribution PBR [performance-based ratemaking] proceedings."[13]

Now that the official restructuring transition period is nearing an end -- the CTC largely expires March 31, 2002 -- all of the major California utilities have either proposed, or are developing, proposals to institute a revenue-per-customer mechanism.

Oregon

As early as 1992, the Public Utilities Commission of Oregon (OPUC) was "persuaded that the connection between profits and sales should be severed."[14]

The OPUC approved Pacificorp's alternative form of regulation (AFOR) in May 1998.[15] The AFOR included a revenue cap for distribution revenues. Rate impacts from this mechanism have been minimal. The affect on total rates on average was -- 0.23%, less than 1%, and 0.78% for 1999, 2000, and 2001, respectively. For those working with Pacificorp, there has been a noticeable shift in its corporate commitment to energy efficiency since the AFOR was established. Energy efficiency activity has increased and budget levels have doubled from pre-AFOR levels.[16]

Portland General Electric (PGE) and NW Natural Gas both recently proposed decoupling mechanisms to the OPUC. In addition, Pacificorp indicated at an August 2, 2001 OPUC workshop on decoupling that they are committed to developing a revenue-per-customer mechanism to replace their recently expired AFOR. NW Natural Gas representatives at that same workshop indicated that their customer service staff were "very aware" of the conflict in profit motive and were made "very uncomfortable" about providing energy efficiency advice that reduces revenues.

Washington

The Washington Utilities and Transportation Committee (WUTC) acted in April 1991 to sever the link between Puget Sound Energy (Puget) revenues and its kWh sales, thus making Puget's shareholders' interests consistent with the company's least-cost planning objectives. In Docket Nos. UE-901183-T and UE-901184-P, the WUTC adopted an experimental ratemaking mechanism for Puget that decoupled sales from revenues and established a "periodic rate adjustment mechanism" (PRAM). The two years following the institution of a decoupling mechanism in 1991 saw dramatic improvements in energy efficiency performance. In a September 21, 1993, Order (Eleventh Supplemental Order), the WUTC found that "PRAM has achieved its primary goal -- the removal of disincentives to conservation investment. Puget has developed a distinguished reputation because of its conservation programs and is now considered a national leader in this area."[17] This order extended PRAM for another three years.

One of the most telling indicators of the effects of decoupling, though the hardest to measure quantitatively, is the response from utility management. Management's ability to redirect scarce resources toward efficiency objectives depends on assurances that such efforts are consistent with shareholder interests. After all, in any market economy, a firm's performance will be affected by the incentives it receives. As the Testimony of Ralph Cavanagh in May 1993 details,[18]

> Puget reported energy savings for 1991 -- 17.6 average MW -- that almost equaled the totals for the three previous years combined; 1992 yielded a further large increase, to almost 28 average MW, while the average cost of savings dropped.[19]
>
> In 1991 alone, Puget's programs accounted for energy savings equivalent to

> 65% of those reported for the rest of the Pacific Northwest region.[20] Puget delivered more energy savings in that year than the Idaho Power Company, the Montana Power Company, Pacificorp, Portland General Electric, and Washington Water Power combined. In 1992, Puget did even better, and outperformed the entire BPA conservation program -- 27.9 aMW to 27.4 aMW -- although BPA's efficiency budget was more than twice that of Puget.[21]

While this transformation in performance was not entirely the result of decoupling, breaking the link between Puget's revenues and sales was a critical part of the change.

New York

Consolidated Edison in New York had an ERAM-type mechanism in place from 1992 to 1997. Rate impacts from this mechanism were minimal. In 1993, a $148.3 million shortfall (less than 3 percent effect on total rates) was collected from customers; for the next four years, over-collections totaling $155 million (less than 1 percent annual effect on total rates) were returned to customers. This period was also the pinnacle for Consolidated Edison energy efficiency investments, with average annual investments during this period of nearly $74 million. About 75 percent of total DSM investment in New York during this period can be attributed to Consolidated Edison. After 1997, and the elimination of the decoupling mechanism, the company's average annual energy saving investments dropped by nearly half.

Maine

There have been questions about the success of Central Maine Power's (CMP) decoupling mechanism in the early 1990s. A report by Eric Hirst in 1993 concluded that the prolonged Maine recession led to an overestimate of future load growth at the end of CMP's prior rate case.[22] Even then, the accumulation of CMP's decoupling-related rate adjustments averaged less than 3 percent per year over the mechanism's first two and one-half years, despite the sharp and unexpected economic downturn in Maine.

Hirst explains that "[r]ather than reopen the rate case, the parties agreed to stick with the pre-recession forecast and let decoupling address the ensuing revenue shortfall."[23] In its order terminating the three-year decoupling experiment, the Maine PUC (1993) noted, "a relatively small portion of these [decoupling] accruals was due to DSM efforts. The vast majority was because the recession had reduced sales."[24] Hirst concluded, "when adverse weather and/or a poor economy occur, price changes can be important."[25] But he concludes that even when this happened in Maine, decoupling worked as intended. Establishing a cap on the annual price adjustments, and a balancing account for the deferred refund or collection can mitigate significant fluctuations in collections that might arise from unexpected events such as a recession.

Realizing the Promise of Distributed Resources

As stated earlier, distributed resources are quite often the most cost-effective, but overlooked, resource alternative available to meet customers' energy service needs. The universe of distributed resources includes distributed generation (e.g., internal combustion engines, combustion turbines, wind turbines, photovoltaics and fuel cells), storage technologies, and targeted energy efficiency and load management activities.

An analysis by Amory Lovins and Andre Lehman provides one of the most comprehensive looks at the benefits of distributed resources.[26] The list is still growing and the nature of these benefits is still being discovered. Some of the more significant potential benefits include: reduced or deferred transmission and distribution investments, improved system and customer power reliability, reduced distribution system energy losses as a consequence of proximity to load (which also allows a closer match with customer load), reduced system demand in areas experiencing increasing peak load growth; and insurance against uncertainties in load growth.[27]

Most customers that rely on distributed generation will continue to take advantage of grid services such as load balancing, peak power needs, and sales of excess generation. These benefits and those discussed above illustrate that the real potential for distributed resources lies in grid enhancement, not grid replacement. In addition, regardless of what happens with the generation side of the business, distribution infrastructure balancing, integrating, and planning will continue to be an important role for utilities. It is clear that sponsors of distributed resources must have regulated utilities as motivated partners (or at least not adversaries) for these technologies to reach their full potential.

All of these technologies, however, when placed on the customer side of the meter, reduce throughput. As we have seen, utilities do not have the incentive to promote these technologies under traditional rate design, and in fact may actively discourage their use. The success of distributed resources depends a great deal on removing the utilities' intolerance to reduced throughput.

Conclusion

Recent events make clear that we need planning and investment that incorporates consideration of all available resource options to meet energy service needs at total least cost. This will not happen until today's dominant regulatory practices are changed. Until then, utilities have no incentive to make the most economically and environmentally efficient resource decisions. The solution is a shift from the perverse incentives of today's rate cap mechanisms that tie utilities' financial health directly to the volume of commodity sales, to a revenue cap mechanism that breaks this link.

Notes

1. See for example: S. Nadel, M. Reid, D. Wolcott, Editors, *Regulatory Incentives for Demand-Side Management,* American Council for an Energy-Efficient Economy, Washington D.C., 1992; J. Eto, S. Soft, T. Belton, *The Theory and Practice of Decoupling*, LBL-34555, Lawrence Berkeley Laboratory, January, 1994; E. Hirst, E. Blank and D. Moskovitz, *Alternative Ways to Decouple Electric utility Revenues from Sales*, Electricity Journal, July/August, 1994.

2. R. Cavanagh, Memo to Pacificorp, August 10, 2001.

3. Utilities have undertaken significant research and technological development that has provided the basis for aggressive standards. In addition, utility energy efficiency programs have often pioneered development and adoption of technologies that became the basis for more stringent standards. Utilities have also funded entities devoted to developing and promoting aggressive building and appliance standards.

4. California Public Utilities Code SEC. 9. Section 739 (3) and SEC. 10. Section 739.10 as amended by Assembly Bill X1 29 (Kehoe) [signed by Governor Davis on April 11, 2001].

5. See *Southern California Edison Company's (U 338-E) Expedited Petition for Modification of D. 96-09-092*, A. 93-12-029, May 4, 2001; *Emergency Application of Pacific Gas & Electric Company to Adopt a Rate Stabilization Plan (U 39 E)*, Chapter 6: Balancing Account Mechanisms and Revenue Requirements, October 3, 2001; and January 31, 2001 letter from San Diego Gas & Electric to the Natural Resources Defense Council stating SDG&E's intent to request a revenue-per-customer indexing mechanism in their 2003 PBR application.

6. See *In the Matter of Portland General Electric's Proposed Tariffs to Decouple Distribution Revenues from Residential and Small Nonresidential Consumers and the kWh Sales (UE 126)*; *In the Matter of the Application of Northwest Natural for Public Purpose Funding and Distribution Margin Normalization (UG 143)*; and oral comments of Bruce Hellebuyck of Pacificorp at the Oregon Public Utility Commission Special Public Meeting, August 2, 2001.

7. CPUC Decision No. 82-12-055.

8. Assembly Bill No. 1890, Chapter 854, Article 7, Section 381 [signed by Governor Wilson on September 23, 1996]. On September 20, 2000, Governor Davis signed Senate Bill 1194 and Assembly Bill 995, which extended the system benefits surcharge through 2011.

9. J. Eto, S. Stoft, and T. Beldon, *The Theory and Practice of Decoupling*, LBL-34555, Lawrence Berkeley Laboratory, 1993, at 46.

10. *Id.*, at 42.

11. R. Cavanagh, Comments of the Natural Resources Defense Council on the State of California's Experience with Regulatory "Decoupling" Options for Electric and Gas Utilities, Natural Resources Defense Council, June 1990.

12. *Supra*, note 9, at xvi.

13. California Public Utilities Commission Decision No. 96-09-092, at 21 September, 1996.

14. Public Utilities Commission of Oregon, Order No. 92-1673, Nov. 23, 1992.

15. Public Utilities Commission of Oregon, Order No. 98-191, May 5, 1998.

16. Scottish Power, *Environmental Report 2000/01*, at 27-28.

17. Washington Utilities and Transportation Commission, Eleventh Supplemental Order, September 21, 1993, at 10.

18. Direct testimony on behalf of Northwest Conservation Act Coalition, WUTC Docket No. UE-921262, May 1993, at 4.

19. Statement of Richard Sonstelie before the California Public Utilities Commission, Full Panel Hearing on Demand-Side Management Policy Issues, Feb. 25, 1993, transcript at 58.

20. Northwest Power Planning Council, The Green Book: Tracking Pacific Northwest Electric Utility Conservation Achievements 1978-1991, Feb. 17, 1993, at 7. In none of the previous three years did that percentage reach even 20%.

21. BPA data are from Bonneville Power Administration, Conservation Resource Energy Data, 1993, at 6.; Puget savings for 1992 are taken from Statement of Richard Sonstelie *supra* note 19, at 58.

22. E. Hirst, *Statistical Recoupling: A New Way to Break the Link Between Electric-Utility Sales and Revenues*, Oak Ridge National Laboratory, September 1993.

23. *Id.*, at 15.

24. Maine Public Utilities Commission 1993, Order Approving Stipulation, Docket Nos. 90-085-A, 90-085-B, and 92-346, Augusta, ME, February 5, at 15-16.

25. *Supra*, note 22.

26. A. Lovins, A. Lehman, *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, September, 1999 DRAFT.

27. With the notable exception of renewables, super clean fuels cells, and energy efficiency it is impossible to say that distributed resources are necessarily better or worse for the environmental than the alternative. Many, but not all distributed resource technologies have substantially lower environmental impacts than the generation/transmission/distribution infrastructure that they will offset or replace. These technologies do indeed have the potential to reduce air pollution, but only if states and the federal government adopt the right policy packages. The potential for distributed generation to actually worsen environmental conditions is a real concern. One analysis presents a very instructive comparison of electric generation technologies. See N. Greene, R. Hammerschlag, *Small and Clean is Beautiful: Exploring the Emissions of Distributed Generation and Pollution Prevention Policies*, Electricity Journal, June 2000, at 50-60.