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October 29, 2013

Via Personal Delivery

Mr. Jeff Derouen, Executive Director
Case No. 2013-00199
Kentucky Public Service Commission 211
Sower Blvd.
Frankfort, KY 40601

Re: Case No. 2013-00199 Direct Testimony of Frank Ackerman on Behalf of Sierra Club

Dear Mr. Derouen,

Enclosed please find one original and ten (10) copies of the public version of the Direct Testimony of Frank Ackerman on Behalf of Sierra Club filed today in the above-referenced matter. Also included in this filing is a confidential version of the document in a sealed envelope marked "Confidential" that Joe Childers will be submitting on behalf of Sierra Club. Pages 4, 6-12, 14-15, 19-20, 23, and 26 of Frank Ackerman's Direct Testimony include information that is subject to a petition for confidential treatment filed by James Miller and Tyson Kamuf, Counsel for Big Rivers Electric Corp. Please place this document of file.

Sincerely,

Kristin A. Henry

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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OCT 29 2013
PUBLIC SERVICE
COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC	)	Case No.
CORPORATION FOR A GENERAL	)	2013-00199
ADJUSTMENT IN RATES	)	

DIRECT TESTIMONY
OF

FRANK ACKERMAN
SENIOR ECONOMIST
SYNAPSE ENERGY ECONOMICS

ON BEHALF OF

SIERRA CLUB

Date
October 28, 2013

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position.

A. My name is Frank Ackerman. I am a senior economist at Synapse Energy Economics, Inc., 485 Massachusetts Avenue, Cambridge Massachusetts 02139.

Q. Please summarize your work experience and educational background.

A. I received a BA in mathematics and economics from Swarthmore College, and a PhD in economics from Harvard University. I have over 25 years of experience in economic analysis of energy, climate change, environmental policy, and related issues. Before joining Synapse Energy Economics, I held senior research positions at Tellus Institute in Boston; at Tufts University's Global Development and Environment Institute; and at the Stockholm Environment Institute's U.S. Center, located at Tufts University in Massachusetts. Beginning in the spring semester of 2014, I will lecture at the Massachusetts Institute of Technology.

I have published more than 40 articles in professional journals, written or edited more than a dozen books, and directed numerous studies for state and federal government agencies, non-governmental organizations, and international bodies such as the United Nations. More detail on my experience and publications is provided in my resume, which is attached as Exhibit FA-1.

Q. Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government, and utilities.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Sierra Club.

Q. Have you submitted testimony in other recent regulatory proceedings?

A. Yes. I submitted testimony in Duke Energy Indiana's Certificate of Public Convenience and Necessity Application before the Indiana Utility Regulatory Commission (Cause No. 44217) and in the Joint Application for Proposed Merger of NV Energy with MidAmerican Energy Holdings Company before the Nevada Public Service Commission (Docket No. 13-07021).

Q. Have you testified previously in Kentucky?

A. Yes, in the previous Big Rivers rate case – the "Century" rate case (Case No. 2012-00535).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the request by Big Rivers Electric Corporation ("BREC," or "the Company") for a rate increase, and to discuss alternative approaches to the underlying problem that has led to this request.

Q. Are you sponsoring any exhibits?

A. Yes. I have prepared the following exhibits to my prepared testimony:

1. Exhibit Ackerman-1	Professional CV for Frank Ackerman
2. Exhibit Ackerman-2	TVA Board Meeting Presentation
3. Exhibit Ackerman-3	U.S. DOE/Lawrence Berkeley National Laboratory - Benefits of Demand Response
4. Exhibit Ackerman-4	24/7 Hourly Response to Electricity Real-Time Pricing Study
5. Exhibit Ackerman-5	Using Real-Time Electricity Data to Estimate Response to Time-of-use and Flat Rates
6. Exhibit Ackerman-6	Synapse CO2 Price Forecast

Q. How is your testimony organized?

A. After the introduction and summary, my testimony presents four areas in which Big Rivers' analysis omits or misrepresents important facts and trends, in Sections 3 through 6, then addresses the likely implications for future rates in Section 7, and recommends alternative treatment of the Wilson and Coleman plants in Section 8.

In outline form, my testimony is organized as follows:

1. Introduction and qualifications.
2. Summary of conclusions and recommendations.
3. Projections of load growth and off-system sales are unrealistic.
4. Revised price forecasts now include implausible capacity prices.
5. Price elasticity impacts are underestimated.
6. Future transmission revenues from smelters are omitted.
7. Need for additional rate increases to support the existing plants.
8. Selling or closing Wilson and Coleman will reduce revenue requirements.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATION

Q. Please summarize your conclusions.

A. In Section 3, I review BREC's projections that within a few years, it will somehow gain access to enough new load and off-system sales to almost completely replace the demand from the two smelters. This is an enormous level of sales: in 2012 the two smelters consumed about 7,400 GWh of electricity, or 8 percent of total industrial electricity sales in Kentucky and Indiana.[1] (Or, since industrial sales were almost equal in the two states, the smelters amounted to about 16 percent of either state's industrial electricity use.) There are many competitors for the region's industrial customers, including utilities that are building large new gas plants. The meager new load acquired in BREC's first year

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[1] Retail sales of electricity to industrial customers in 2012 amounted to 47,898 GWh in Indiana and 44,753 GWh in Kentucky (downloaded from http://www.eia.gov/electricity/data/browser).

of post-smelter planning does not suggest any real chance of replacing the entire smelter load.

In Section 4, I evaluate BREC's price forecasts, which changed dramatically in the few months between the two rate cases. Since this case was filed, the Company's price forecaster has made another radical change in projections. [redacted] in contrast, recent experience in the more established PJM capacity market shows that capacity prices are typically no more than 40 percent of CONE.

In Section 5, I examine the treatment of price elasticities in BREC's current forecast. The elasticities adopted for rural customers are at the low end of published estimates, and may represent short-run rather than (more appropriate and larger) long-run elasticities. The Company's omission of all price elasticity effects for industrial customers is illogical; both common sense and economic research confirm that energy use by industrial customers declines in response to price increases. Larger price elasticities for rural customers and nonzero elasticities for industrials would imply that the more than doubling of rates that would occur from 2012 to 2016 under BREC's plan will cause significant reductions in BREC's existing load – reductions that the Company has failed to account for in its financial forecasting.

In Section 6, I turn to one area in which BREC has underestimated its expected future revenues. The Company should have included in the financial forecast the transmission revenues that it will receive from the smelters' future operations, roughly $7 million from the Hawesville smelter and $5 million from the Sebree smelter.

In Section 7, I discuss BREC's long-term financial forecast and the likely need for additional rate increases for the Company to have even the chance of achieving financial stability. Even under the Company's overly optimistic forecast, BREC would only barely achieve the 1.40 TIER that the Company's own witness argues is the minimum that BREC needs to reach soon for financial stability once in the next 15 years. If their expert is to be believed, then BREC will need additional increases in rates – particularly since, as I have shown in earlier sections, its current planning greatly overstates its prospective revenue.

Finally, in Section 8, I explore the obvious remedy for BREC's financial woes: either selling at greatly reduced prices or closing the Coleman and Wilson plants. To date, BREC has only offered to sell these plants at unrealistically high prices. Selling or shutting down these plants would save money via the avoided costs of planned environmental upgrades, and the avoided fixed costs of plant ownership such as insurance and property taxes. Idling but keeping the plants, as BREC proposes, is more expensive; it imposes the fixed costs of ownership of unused capacity on ratepayers, and it will require the substantial expenses of environmental upgrades before the plants can be brought back into service. In the worst case, if BREC cannot sell the plants, the Company could reduce revenue requirements by closing them rather than idling them.

Q. Please summarize your recommendation.

A. I recommend that the Commission grant BREC only short-term rate increases, sufficient to allow the Company to recalculate the costs and benefits of selling or closing Wilson and Coleman, and to modify its plans accordingly. The full, permanent rate increase requested by the Company should not be granted; it would impose substantial burdens on BREC's remaining customers, yet it would be far from enough to solve the underlying problem that BREC has approximately three times as much capacity as it needs.

As I will explain, BREC's analysis and forecasts appear deficient in several respects, perhaps strained by the attempt to prove the impossible case for keeping Wilson and Coleman. The Commission should direct them to develop revised and improved analyses, as a basis for more careful resource planning.

BREC can reduce revenue requirements and the burden on its customers can be eased by selling or closing the Coleman and Wilson plants. The Commission should direct BREC to immediately drop the asking prices, [redacted]

[redacted] arguably BREC could lower the prices could even further to reflect the avoided fixed costs of plant ownership. If no one offers to buy the plants at these greatly reduced prices, then BREC's plan to idle but preserve the plants is not adequate; to minimize revenue requirements and rate impacts, it is time to plan the shutdown of Wilson and Coleman. The Commission should design BREC's recovery of the stranded assets to provide the minimum necessary to pay its outstanding debts, without increasing burdens on its ratepayers.

3. PROJECTIONS OF LOAD GROWTH AND OFF-SYSTEM SALES ARE UNREALISTIC.

Q. Please describe the projections of load growth used by BREC in this case.

A. Big Rivers now projects that after idling the Wilson and Coleman plants for approximately five years, it will have sufficient sales to bring them back on line, at relatively high capacity factors, in May 2018 and July 2019, respectively. The resulting picture of load by customer class is shown in Figure 1.[2] The graph begins in 2012, the last full year of BREC sales to both smelters; it continues through the 2014-2017 trough, reflecting the loss of the smelter load, and then [redacted]

[2] Based on sales data from the spreadsheet "Financial Forecast (2014-2027) 5-16-2013", tab "Stmts RUS."

[redacted]

More precisely, total BREC sales are forecast to [redacted] While market sales are projected to [redacted] which BREC expects to [redacted]

Q. Are there any grounds for expecting the projected level of new market and replacement load sales to materialize after 2017?

A. No. The smelters represented a huge level of sales; there is no plausible path that leads to replacing their load. In 2012, the last full year in which both smelters were Big Rivers customers, they bought 7.4 TWH of electricity. This can be compared to statewide total electricity sales to industrial customers in 2012 of 44.8 TWH in Kentucky, and 47.9 TWH in Indiana. In other words, the two smelters represent 8 percent of the two-state total of industrial electricity use, or roughly 16 percent of either state's total. To sell that much to other customers, Big Rivers would have to capture one-sixth of all Kentucky or Indiana industrial electricity sales, or one-twelfth of the two-state total (or, of course, equivalent amounts of residential or commercial load). Other utilities, which currently sell to other customers in the region, are likely to compete vigorously to maintain their markets.

Q. Has BREC developed any new sales since learning of the loss of the smelters?

A. After a year of vigorous marketing, in which Big Rivers has [redacted] (response to PSC 2-16), BREC has been [redacted] and has reported the announcement or siting of 25 MW of new load through several small economic development opportunities in its service territory (response to SC 1-10). This is about 3 percent of the 850 MW of smelter demand it is attempting to replace. If the Company continues to acquire 25 MW of new load per year, it will take until 2046 to replace the smelters' 850MW.

Q. Will BREC have new market opportunities as other area utilities close their coal plants?

A. Not necessarily. While utilities are closing a number of coal plants, some are replacing their retired units with large new natural gas plants. AEP is planning to repower unit 1 of its Big Sandy plant as a gas-burning facility, and is replacing Big Sandy Unit 2 with a 50% share of the Mitchell plant in West Virginia. Louisville Gas & Electric and Kentucky Utilities are already proceeding with a 640MW natural gas combined cycle ("NGCC") plant at Cane Run, and recently proposed a second NGCC 700MW in size. Indianapolis Power & Light is also planning to build a 650 MW NGCC plant to replace retiring coal capacity.

In addition, increasing pursuit of demand response, energy efficiency, and renewable resources in the region will satisfy at least some of the capacity and energy lost due to the retirement of uneconomic coal units. While coal capacity is declining, this does not necessarily imply an impending scarcity of total generating capacity in the region.

Q. Is the regional economy likely to grow fast enough to create substantial increases in electricity demand?

A. As I noted in my testimony for the Century rate case, recent Kentucky state projections for economic growth ("Kentucky's Unbridled Future") do not focus on electricity-intensive sectors. The projections imply encouraging growth of incomes, technological capacity, and skilled jobs, but not substantial growth of demand for electricity.

A similar impression is created by a more detailed 2011 study, "Kentucky's Target Industry Sectors," done for a group of agencies and organizations including the Kentucky Department of Workforce Investment.[3] It selects and analyzes five areas of strength in which the Kentucky economy is likely to have a competitive advantage. Two relatively energy-intensive sectors, automobile and aircraft manufacturing, and energy production and transmission, are projected to have constant or slightly declining employment from now through 2018. Three other sectors that are projected to grow rapidly are much less energy-intensive: transportation, distribution, and logistics; business services and R&D; and health care and social assistance. Again, the expected direction of growth of the state economy is moving away from the older pattern of energy-intensive industry.

Meanwhile, one of Kentucky's largest energy-intensive industries has recently closed: the USEC uranium enrichment facility at Paducah shut down permanently in May 2013. At a recent board meeting, the Tennessee Valley Authority (TVA), USEC's former supplier, reported that the USEC closure is leading to a decline in energy sales of 8,200 GWH from fiscal year (FY) 2013 to FY 2014; in recent years, USEC had used more than 10,000 GWH of energy per year from TVA.[4] Thus TVA may have at least as much suddenly-excess capacity as BREC – greatly increasing competition for new load in the region, and making it very unlikely that TVA will want to buy or lease any of BREC's plants. [redacted]

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[3] http://workforce.ky.gov/KYTargetIndustrySectors.pdf.
[4] *TVA Board Meeting – Fiscal Year 2014 Financial Plan, Finance, Rates, and Portfolio Committee*, August 22, 2013, http://www.tva.gov/abouttva/board/pdf/aug-22-2013_public_board.pdf, pp.50, 48, attached as Exhibit Ackerman – 2.

[redacted] TVA itself is putting a priority on incentives to win new and expanded manufacturing load, including offers to match other utilities' rates.[5]

4. REVISED, STILL-FLAWED PRICE FORECASTS NOW INCLUDE IMPLAUSIBLE CAPACITY PRICES.

Q. In the Century rate case, you criticized BREC's electricity price forecasts for their unexplained upward surge starting in 2019. Is the Company using the same price forecasts in this case?

A. No. In the current case, the ACES consulting firm, the source of Big Rivers' price forecasts, has provided a [redacted]. Since this case was filed, [redacted]

Q. What is the basis for these changing ACES forecasts?

A. In responses to SC 2-9 and PSC 2-14, BREC witness Robert Berry explained that ACES uses regularly updated broker values for the first 7 years of its forecasts, and Wood Mackenzie projections for year 10 and later. Between years 7 and 10, the two forecasts are "blended."

Based on these responses, I have graphed the three ACES forecasts provided in the (confidential) attachment to PSC 2-14. [redacted]

[redacted]

[5] *TVA Board Meeting*, August 22, 2013 (see note 4), pp.81-86.

[redacted]

[redacted] [redacted] **Does this mean that the Company's price forecasts are more reasonable in this case?**

[redacted] I would say that the underlying error in the ACES/BREC methodology, [redacted] has a less extreme, but still pronounced effect in this case. As Figure 2 shows, [redacted]

This unreasonable methodology produces results, in this case, [redacted]

[redacted]

Moreover, Big Rivers' forecasts of revenues now include projections of capacity revenues as well as the ACES-based energy forecasts. MISO capacity prices, near zero today, [redacted]

Q. Why would capacity prices be expected to increase in 2016?

A. MISO currently has a surplus of capacity, so it is not surprising that the price paid in the initial MISO capacity auction was close to zero. That capacity surplus may shrink or disappear in 2016, when some coal plants will retire to avoid the costs of MATS compliance.

Q. Has MISO addressed the risk of a capacity shortfall in 2016?

A. Yes. The 2013 MISO Transmission Expansion Plan (MTEP 2013) projected the retirement of about 10 GW of existing capacity by 2016; together with other minor capacity changes, this implies a potential shortfall of 3 - 7 GW for the MISO Midwest Region by 2016.[6] MISO projects that this could be mitigated by increased energy efficiency and DSM (much of it in response to existing state mandates), additional power imports from the MISO Southern Region (roughly speaking, Arkansas, Louisiana, and Mississippi), and transmission upgrades to

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[6] *MISO Transmission Expansion Plan 2013*, section 6.2 ("Long-Term Resource Assessment"), https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP13/MTEP13%20Report.pdf.

increase access to resources that are currently transmission-limited or lacking in firm transmission. MISO's conclusion is that the midrange estimate of a 5 GW capacity shortfall before these mitigation measures could be converted to a 1 GW surplus after mitigation.

Q. What determines capacity prices when there is no surplus of existing capacity?

A. In theory, the cost of new entry ("CONE"), i.e. the cost of constructing new capacity, should limit capacity prices. This is typically defined as the cost per MW of a new combustion turbine, the cheapest form of capacity to build. In practice, in PJM's capacity market, prices have remained far below CONE in recent years, despite capacity being tighter than in MISO.

Q. How do BREC's capacity price projections compare to CONE and to PJM market prices?

A. Figure 3 compares actual and projected capacity prices to CONE, both for PJM and for Midcontinent Independent System Operator ("MISO") zone 6 (the relevant region of MISO). The red triangles represent PJM; the upper, dashed red line is the PJM calculation of CONE, while the lower, solid red line is the actual market price in the PJM capacity market.[7] It is routinely calculated a few years ahead, and is now available through the 2016/2017 power year. (For comparability with BREC data, I have interpolated PJM power year prices to obtain calendar year data, as shown in Figure 3.

[7] PJM market (clearing) prices are available at https://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx; PJM CONE values are available at https://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx. Values used in Figure 3 are unweighted averages across all zones of PJM, interpolated to a calendar year basis for comparability with MISO prices and BREC forecasts. Because PJM prices are reported for a June-May year, the interpolation uses, e.g., 7/12 of the 2011/2012 value plus 5/12 of the 2012/2013 year for the 2012 calendar year value.

[redacted]

The blue circles represent MISO zone 6. The upper, dashed line shows MISO calculations of CONE for zone 6 for 2013 and 2014,[8] followed by an assumed 2 percent annual increase after 2014; the assumed values are shown with open circles. (Since the graph is in nominal dollars, a 2 percent annual increase is equivalent to a roughly constant real value.) The lower, solid line shows the BREC projection of MISO capacity prices, [redacted]

For PJM, Figure 3 shows that the capacity market has cleared at a price below 40 percent of CONE for every year from 2012 through 2016. [redacted]

[8] MISO Zone 6 CONE values are available for 2014 at https://www misoenergy.org/Library/Repository/Tariff/FERC%20Filings/LRZ%20CONE%20Filing_3%20Sept%202013.pdf and for 2013 at https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/LOLEWG/2013/20130508/20130508%20LOLEWG%20Item%2002%20RA%20Update.pdf. Annual values in $/MW-year were divided by 365 to obtain $/MW-day.

Q. Does BREC provide any justification for its projections that MISO capacity prices will [redacted]?

A. No, it does not. In response to SC 2-10, which asked about [redacted] capacity prices, Robert Berry said that:

> Big Rivers relies on industry experts to provide [capacity] price forecasts. As such, Big Rivers does not have the detailed drivers of the specific increases. However, Big Rivers believes the increase is driven by MATS compliance. ... Big Rivers relied on the May 2013 capacity price forecast prepared by Wood Mackenzie for MISO Zone 6.

Note that in projecting the price of capacity, as well as energy, Wood Mackenzie appears to be the source of [redacted] forecasts. A re-examination of the basis for Wood Mackenzie forecasts, and an exploration of alternatives, should be a priority for future BREC planning efforts.

Q. What is the effect on BREC's financial projections of [redacted]?

A. The [redacted] in capacity prices, together with the [redacted] energy prices [redacted], serves to [redacted] the economic benefits of keeping the Wilson and Coleman units as opposed to selling or retiring such units.

5. PRICE ELASTICITY IMPACTS ARE UNDERESTIMATED.

Q. What is price elasticity and why is it important in this case?

A. Price elasticity, more precisely speaking the price elasticity of demand, is the percentage change in the demand for a good (in this case, electricity) associated with a one percent change in the price. Price elasticity provides a quantitative yardstick to measure the common-sense notion that higher prices lead consumers to buy less, while lower prices lead them to buy more.

Price elasticity is important in this proceeding because BREC is requesting large rate increases, both in the Century rate case and in the current one. Projections of future sales should therefore include the effects of price elasticity, which will tend to reduce the consumption of electricity by the Company's customers.

Q. How has BREC addressed price elasticity in this case?

A. For the rural customer class, separate price elasticity estimates have been developed for each of the three member coops, -0.21 for Kenergy and -0.16 for Jackson Purchase and Meade County (Barron testimony, p.12). The average residential elasticity is -.174 (response to SC 2-15). For the industrial customer class, no elasticity has been estimated and no elasticity-based reductions in demand have been included in the forecasts (response to PSC 2-20).

Q. What is your evaluation of the rural price elasticities used in this case?

A. Elasticities of -.16 to -.21 are at the low end of the range of published estimates.[9] In response to a data request on the subject, Ms. Barron stated that Big Rivers' consultant who developed the elasticities compared their estimates to two national studies, from EIA and NREL (SC 1-20c, attachments). Both of those studies distinguish between short-run and long-run price elasticities: short-run elasticity is the effect of a price change in the current year, while long-run elasticity is the effect of a price change that persists over many years. Big Rivers' estimates are similar to some of the short-run estimates in both sources, but distinctly smaller than the long-run estimates.

The NREL study, which provides more easily summarized estimates, concludes that an analysis of national data from 1977 through 2004 implies a short-run residential price elasticity of -.20 and a long-run elasticity of -.32. The EIA study presents 14 separate estimates for residential price elasticity, from differing models; the unweighted average is -.10 for short-run and -.33 for long-run elasticity. Thus both studies recommend values for long-run elasticity that are almost twice as great as the Big Rivers estimates.

Q. Is long-run or short-run elasticity more relevant in this case?

A. In the year of a rate increase, a utility should use the short-run estimate. The projections presented in this case, however, extend for more than a decade beyond

[9] Price elasticities are negative, since an increase in price is associated with a decrease in demand. I follow the common convention of referring to elasticities closer to zero as "smaller," regardless of whether they are positive or negative.

the proposed rate increases. Therefore, the Company should use the long-run price elasticity for most of the years in this analysis.

Q. What is your evaluation of the failure to include any price elasticity effect in the industrial class?

A. I find it simply implausible to assume that industrial customers are unaffected by price increases. Yet that is the implicit assumption BREC made by excluding industrial price elasticity effects.

Q. Does BREC *explicitly* assume that industrial customers are not interested in electricity prices?

A. No. In response to SC 2-20, BREC witness Lindsay Barron said that the large industrial customers

> ...have a strong profit motive and incentive to minimize costs in order to maximize margins. ... Big Rivers expects that these customers have already taken steps to minimize their consumption and energy bills.

This statement, however, indirectly assumes that, since steps to minimize energy costs have already been taken, rate increases would have no further effect on consumption – effectively (and inaccurately) assuming a price elasticity of zero. Contrary to this assumption, the industrial customers' "strong profit motive" would be expected to lead to even more reduction in energy use at higher prices.

Q. Is there any published research on industrial customers' price elasticity?

A. There are fewer studies of industrial than of residential price elasticity for electricity demand, but the research literature is not completely silent on this question. A 2006 study performed for the U.S. Department of Energy by Lawrence Berkeley National Laboratory reviewed the state of knowledge on the subject.[10] A common finding is that industrial customers are quite diverse in their responses to electricity prices. In three studies of medium and large customers summarized in the 2006 U.S. DOE/Lawrence Berkeley National Laboratory

[10] LBNL, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them." See the estimates of "own-price elasticity" (the relevant measure for this discussion) in Table C-1, p.88. http://energy.gov/oe/downloads/benefits-demand-response-electricity-markets-and-recommendations-achieving-them-report, attached as Exhibit Ackerman-3.

study, different companies had different price elasticities, ranging from close to zero, up to a maximum of -.27, -.28, or -.37, depending on the study.[11]

One of these studies is an examination of large customers of Duke Energy, done by Duke employees in collaboration with an academic researcher. A 2005 article estimated price elasticities separately by hour of the day, finding all-customer average elasticities as large as -.26 in mid-afternoon, and -.155 for peak hours in general (2 – 9 PM).[12] A 2012 update from the same researchers, re-examining Duke's large customers who were on real-time electricity rates, found that hourly elasticities for the group of customers could be as large as -0.7, well above the 2005 estimate.[13]

In short, I conclude that it is not reasonable to exclude industrial price elasticity effects from Big Rivers' financial projects.

Q. How has BREC modeled the effects of price elasticity in this case?

A. Relatively little is said about this important topic in the Company documents. Barron's testimony on the load forecast does little more than mention the estimated elasticities for the rural class (p.12). Other statements seem to minimize the effective price increase, as well as the elasticity impact. For example, Mark Bailey's testimony, providing an introduction and overview to the Company's application, says that the average rural customer will experience a 44 percent increase over current rates (p.10). The response to KIUC 1-33 suggests that the elasticity effect will reduce the average rural user's energy consumption by 5.5 percent by 2016.

Q. What is your response to these estimates?

A. The actual decline in energy usage by BREC's customers due to rate increases is likely to be considerably higher than 5.5 percent both because rates are projected

[11] One of the three studies was Thomas N. Taylor, Peter M. Schwarz, and James E. Cochell, "24/7 Hourly Response to Electricity Real-Time Pricing with up to Eight Summers of Experience," *Journal of Regulatory Economics* 27:3 (2005), pp.235-262, which is attached as Exhibit Ackerman-4

[12] Taylor et al. (see previous note).

[13] Cochell, Schwarz, and Taylor, "Using Real-Time Electricity Data to Estimate Response to Time-of-use and Flat Rates: An Application to Emissions," *Journal of Regulatory Economics* 42:2 (2012), pp.135-158, attached as Exhibit Ackerman-5.

to increase far more than 44% and because the elasticity values that BREC used are understated.

Regarding rate increases, the effective rate for rural customers [redacted][14] In short, rates are projected to [redacted] within the next few years, for all remaining customers of Big Rivers.

Regarding the reported elasticity-driven reduction of only 5.5 percent in a rural customer's energy use by 2016, that is the reduction that would result from a 32 percent rate increase, if using the Company's average rural elasticity of .174. I see no way to derive a 2016 rate increase as small as 32 percent from the projections filed in this case. Even from 2014 to 2016, the effective rural rate is projected to [redacted]

Q. Can you estimate the magnitude of the elasticity effects that would result from the proposed rate increases?

A. Broadly speaking, the expected elasticity effects will be large: at an elasticity of .174, a doubling of rates reduces demand by 17.4 percent. In this case, rates are projected to [redacted] Using that elasticity, the increase in effective rates from 2012 to 2017-2018 would reduce rural sales by [redacted]; it appears that the Company has included only a small fraction of that reduction in its projections.

If the same elasticity applied to large industrial customers, sales to that customer class would decline by [redacted] in the peak years. The reduction in 2017 or 2018, from these elasticity effects on the rural and large industrial classes combined, would be [redacted], more than [redacted] of the Company's projected total sales in 2017.

[14] Calculated from the "Effective Rate ($/MWH)" lines in the spreadsheet "Financial Forecast (2014-2027) 5-16-2013", tab "Stmts RUS."

As I mentioned above, the Company's elasticity is near the low end of published estimates, and appears comparable to short-run elasticities in other studies; long-run elasticities for residential customers can be higher, perhaps .32 - .33. To reflect a "blended" average of short-run and long-run effects, suppose that the average elasticity throughout the forecast period is actually .25. Under that assumption, rural sales would fall [redacted] below 2012 levels by 2017-2018, while large industrial sales would fall [redacted] The combined effect would be a loss of [redacted] of the Company's total projected sales in 2017.

If everything goes as BREC is currently projecting, the Company says that it may be able to mildly reduce rural and industrial rates starting in 2019. But even if these projections end up being accurate, the elasticity effects would taper off only slowly as the projected rates begin to come down after 2018. By 2027, the end of the forecast period, elasticity-induced reductions, relative to the 2012 base year, would still be more than half the peak level.

Q. What effect would larger elasticity-induced sales losses have BREC planning and projections?

A. In the words of the Company's response to PSC 2-20 (a question about the absence of elasticity estimates for the Large Industrial class), "Lowering Big Rivers' projection of Large Industrial consumption would result in an increase in the revenue requirement for this case." Indeed, if a more accurate calculation of elasticity losses were included, Big Rivers' sales would be lowered throughout the forecast period, with the greatest reduction in 2017-2018, on the eve of the planned reactivation of the Wilson and Coleman plants. Additional revenue requirements, resulting from the decline in sales and the increase in fixed costs per MWH, would drive the need for even greater rate increases which, in turn, could lead to even further declines in rural and industrial demand and, in turn, even larger rate increases.

6. FUTURE TRANSMISSION REVENUES FROM SMELTERS ARE OMITTED.

Q. Please describe the smelter transmission revenues that BREC can expect to receive.

A. BREC has agreed to provide transmission service to the Hawesville (Century) smelter, and is likely to make a similar agreement with the Sebree (Alcan) smelter. Although the smelters are no longer customers of Big Rivers, they are dependent on Big Rivers to transmit the power purchased from other suppliers on the market. The agreements call for payments to Big Rivers for such transmission services.

Q. How are these payments treated in Big Rivers' financial projections?

A. The transmission payments are simply omitted, apparently because BREC had not finalized and signed the agreements with the smelters when it filed this case (see Berry testimony, p. 17, and the response to SC 2-17).

Q. How large are the smelter transmission payments?

A. Assuming that both smelters continue to operate at full capacity, the Hawesville smelter agreement will result in $7.5 million per year in transmission payments to Big Rivers (response to SC 1-12). A comparable agreement with the Sebree smelter, assuming that there are no offsets for system reliability (SSR) costs, would result in $5.7 million per year (response to SC 2-19). Once the SSR issue is resolved, BREC will receive approximately $13.2 million per year in transmission revenues, assuming both smelters continue to operate at full capacity.

These revenues, omitted from all current projections, will make an important contribution to Big Rivers' financial stability. It is worth noting that these revenues are independent of the continued operation of the Wilson and Coleman plants; they depend only on the continued operation of the smelters.

7. BREC WILL NEED ADDITIONAL RATE INCREASES TO SUPPORT THE EXISTING PLANTS.

Q. Will the rate increase requested in this case be sufficient to put BREC on a sound financial basis?

A. No, it will not. Fiscal soundness for cooperatives such as BREC is often measured in terms of TIER (Times Interest Earned Ratio), the ratio of earnings to interest obligations. According to the Company's own finance consultant, Daniel Walker,

> In order to attract capital in the capital markets and retain an investment grade rating, I believe a [cooperative such as Big Rivers] should set rates to earn, on a consistent basis, a TIER in the range of 1.40x to 1.60x. (Walker testimony, pp.12-13)

Walker clarified that Big Rivers was in a "transition period" toward the time when it could reach a TIER of 1.40 or more (testimony, p.13). When asked to "identify the duration of the transition period that would be acceptable" (SC 1-23a), he said, "It is expected that the transition period will take 1 to 3 years." (response to SC 1-23a). Yet BREC's own long term financial forecast, which incorporates the numerous implausibly favorable assumptions discussed above, leads to a TIER exceeding 1.40 only once in the next 15 years. (BREC Resp. to SC 1-23e).

In a related question, when asked whether BREC could reach a TIER of 1.40 to 1.60 without an additional rate increase, Company witness Christopher Warren simply answered, "Yes" (complete text of response to SC 1-23c). Billie Richert echoed this view in response to SC 2-6, asserting that the load-building measures described in the Load Concentration Analysis and Mitigation Plan would allow BREC to achieve a TIER between 1.40 and 1.60 without additional rate increases. Yet projections of TIER for 2016 and beyond (attachment to response to SC 1-23e) remain in the range of 1.10 to 1.13 from 2016 through 2020, only climbing above 1.20 in 2021, when the implausibly high price forecasts, discussed above, begin to boost BREC's projected fiscal health. Even then, the projected TIER dips back down to 1.11 in 2024 and 1.14 in 2026.

Moreover, the errors and omissions I discussed earlier will, on balance, make BREC's financial results even worse. The vast projected increase in energy sales and the imagined 2016 surge in capacity prices are not likely to occur; and price elasticities (and therefore sales reductions) will turn out to be much larger than the Company has assumed. These factors will more than outweigh the overlooked $13 million of transmission revenues.

Q. What consequences would you anticipate from the failure of this rate case to stabilize the Company's finances?

A. At that point, BREC's only recourse would be to request yet another rate increase. Coming on top of the increase from the Century case and this one, that could pose an intolerable burden on the ratepayers, and could prompt discussion of utility "death spiral" effects. Industrial and even rural customers would begin to explore self-generation or other options, including moving out of Big Rivers' service territory.

Q. What alternative would you suggest to avoid this bleak outcome?

A. The only viable alternative is to reduce the Company's revenue requirements, by shedding excess capacity and resizing to meet the existing, post-smelter load.

8. SELLING OR CLOSING WILSON AND COLEMAN WILL REDUCE REVENUE REQUIREMENTS.

Q. [redacted] What more can they do to reduce excess capacity?

A. To sell Wilson and Coleman, [redacted] As of July 31, 2013, net book values were roughly $187 million for Coleman and $454 million for Wilson (response to SC 1-22). This amounts to about $420 per kw for Coleman and $1,090 per kw for Wilson. Yet as I testified in the Century rate case, recent market transactions involving sale of coal plants (excluding transfers between divisions of the same corporate parent) have occurred at prices of roughly $160 per kw or less.

Q. Please summarize your description of recent coal plant sales, from your earlier testimony.

A. In August 2012 Exelon sold three Maryland power plants with a total capacity of 2,648 MW, of which more than 2,000 MW is coal, for $400 million, or an average price of $151/kw.[15]

In March 2013 Dominion Resources sold three power plants, the Brayton Point and Kincaid coal-fired plants (totaling 2,686 MW) and a 50% interest in the 1,424 MW Elwood gas-fired plant, to Energy Capital Partners. Although Dominion said its after-tax proceeds will be $650 million,[16] the *Platts* financial newsletter estimated the true purchase price at about $450 million, or $132/kw of capacity,[17] and the *Wall Street Journal* commented that "after stripping out tax benefits, the implied underlying price paid per kilowatt of capacity was just over $100."[18]

Also in March 2013, Ameren agreed to divest an Illinois-based subsidiary to Dynegy, involving five coal-fired plants totaling 4,100 MW, 80% of another 1,186 MW coal- and gas-fired plant, and other energy businesses. In payment, Dynegy assumed $825 million of Ameren's debt associated with the coal plants – equivalent to $163/kw for the 5,050 MW of capacity that Dynegy acquired.[19]

Q. Based on this evidence, what conclusions do you draw about the appropriate treatment of the Coleman and Wilson plants?

A. A serious attempt at selling these plants requires asking prices that recognize current market conditions. If they cannot be sold at these low rates, BREC's plan

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[15] See Exelon's press release, August 9, 2012, at http://www.exeloncorp.com/newsroom/PR_20120809_EXC_Mdcoalplantsale.aspx (accessed May 15, 2013).
[16] See Dominion's press release, March 11, 2013, at http://dom.mediaroom.com/2013-03-11-Dominion-To-Sell-Three-Merchant-Power-Stations-To-Energy-Capital-Partners (accessed May 15, 2013).
[17] "Recent plant sales establish new floor for coal assets," *Platts*, March 14, 2013, http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/6260790 (accessed May 15, 2013).
[18] Liam Denning, "There is Life After Death for Coal Power," *Wall Street Journal*, March 31, 2013, http://online.wsj.com/article/SB10001424127887323361804578390561956760382.html (accessed May 15, 2013).
[19] See Dynegy's press release, March 14, 2013, http://phx.corporate-ir.net/phoenix.zhtml?c=147906&p=irol-newsArticle_Print&ID=1796097&highlight= (accessed May 15, 2013).

to idle the plants is not sufficient to protect the ratepayers; instead, the Company should move to retire the plants.

Q. The Company's loans are tied to the value of its plants, and debt covenants restrict the ability to sell the plants for less than their book value. Doesn't this make your proposal infeasible?

A. No. If the Commission makes it clear that it will approve rates that allow repayment of the Company's debts after sale or closure of the plants, I believe that it will be possible to renegotiate the debt covenants. In particular, the Company's creditors may be interested to learn that this could be the only way they can hope to be repaid in full. If they insist on the letter of their agreements, forbidding sale for less than book value, they are likely to drive Big Rivers into a new bankruptcy, resulting in much less than full repayment. For the reasons I have described above, the Company's projections are out of touch with reality in several respects; BREC has essentially no chance of earning the future revenues that justify keeping Wilson and Coleman on the books.

Q. If the Commission approves rates that allow repayment of the Company's debts, why is it better for ratepayers to sell or retire Wilson and Coleman?

A. Because selling or retiring those plants would enable BREC's ratepayers to avoid having to pay for significant fixed costs each year. Consider the difference between two scenarios. I will call them the Status Quo scenario, as proposed by BREC in this case, and the Right-Sized scenario, in which BREC achieves the right size of capacity for its existing load by promptly selling Wilson and Coleman at whatever price the market will bear, or else retiring them.

In both scenarios, I assume that the Commission wants to ensure the continued, non-bankrupted existence of BREC, and therefore will grant rates sufficient to pay BREC's current debts. Revenue requirements in both scenarios include meeting all scheduled debt payments, so interest obligations are not a difference between the two options.

Q. Why is the Status Quo scenario the more expensive option for ratepayers?

A. Under the Status Quo scenario, revenue requirements include the fixed costs of maintaining Wilson and Coleman through several years when they are idled.

These costs include about $6 million per year of depreciation and $1 million of property tax and insurance at Coleman, and $19 million of depreciation and $2 million of property tax and insurance at Wilson (response to SC 2-12).[20] When the plants are brought back into service, they will incur one-time restart costs of [redacted] at each plant (attachment to response to AG 2-9). Before the plants can be restarted, they will also need a number of environmental upgrades.

Q. What environmental upgrade costs would be required in order to restart the Wilson and Coleman plants in 2018-2019?

According to the Sargent & Lundy study, commissioned by the Company its 2012 CPCN case, the remaining requirements for regulatory compliance at these plants could be substantial: $154 million (in 2011 dollars) at Wilson for MATS and other regulatory compliance (including the need for ACI, a new SCR, and DSI), and $96 million at Coleman for a series of regulatory requirements including CCR compliance (dry ash handling), MATS (ACI, ESP upgrade, lime DSI), 316(b) compliance (rotating circular intake screens), and CSAPR or its successor (low-NOx burners). Only a fraction of these costs are included in the projections for this case; BREC projects no additional environmental capital expenditures after June 2014 (financial forecast spreadsheet, tab "Capex & Depr"). Yet many or all of these costs would have to be incurred before the restart of Coleman and Wilson. None of them, of course, are required in the Right-Sized scenario.

An additional category of environmental costs could be required within the next few years. The Environmental Protection Agency (EPA) has announced its intention to develop CO_2 emission standards for existing power plants. While there are many steps between that announcement and the enactment of a binding standard, prudent planning at this point requires some consideration of possible carbon taxes or fees. Such policies would accelerate the movement away from

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[20] The response to SC 2-12 also cites interest savings of $10 million and $18.5 million that would result from sale of Coleman and Wilson, respectively. Since this response refers to BREC's response to SC 1-16, which assumed the plants were sold at net book value, it seems possible that these interest savings would result from using the sale proceeds to pay down BREC's debts. Since both scenarios assume equal responsibility for BREC's debts, I have omitted the potential interest savings from the costs of the Status Quo scenario.

coal, by increasing the competitive advantage of natural gas, renewables, and energy efficiency. With a fee on carbon emissions, BREC's coal plants would be less profitable, and alternatives involving less coal capacity would be even more attractive for the Company's ratepayers.

Synapse Energy Economics has surveyed carbon price assumptions made by utilities, government agencies, and other parties, and has developed recommended low, mid, and high case assumptions for future carbon prices, seeking to define a reasonable range of price estimates for use in utility planning. Our 2012 forecast, the latest currently available, assumes that carbon prices will begin in 2020. The low case starts at $15 per ton of CO2, rising to $22 in 2027 (the last year of BREC's financial forecasts in this case), and $35 in 2040. The mid case begins at $20 in 2020, reaches almost $36 in 2027, and $65 in 2040. The high case begins at $30, reaches $58 in 2027, and $90 in 2040.[21]

Q. What costs and risks would ratepayers face under the Right-Sized scenario?

A. This scenario would involve the transaction costs of selling or closing Wilson and Coleman. If no buyer can be found and it becomes necessary to retire the plants, some costs would be incurred for closing the plants. These costs are not enormous; a recent study by Navigant Research reportedly produced an estimated median cost of $18.9 million for decommissioning a coal plant with capacity between 350 and 500 MW.[22] Broadly similar estimates are provided for three case studies in EPRI's 2004 *Decommissioning Handbook for Coal-Fired Power.*[23]

Finally, the Right-Sized scenario means that ratepayers would lose the option to keep on gambling that a huge upturn in the market is right around the corner, making old coal plants profitable. If absolutely everything goes right – if BREC

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[21] Rachel Wilson, Patrick Luckow, Bruce Biewald, Frank Ackerman, and Ezra Hausman, "2012 Carbon Dioxide Price Forecast" (Synapse Energy Economics, 2012), available from http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf, attached as Exhibit Ackerman-6.
[22] Saqib Rahim, "Billions stand to be made in coal plant decommissioning," August 7, 2013, http://www.eenews.net/stories/1059985699, accessed October 28, 2013.
[23] *Decommissioning Handbook for Coal-Fired Power Plants,* EPRI, Palo Alto, CA: 2004. 1011220, available from www.epri.com.

and its consultants are right to imagine that MISO capacity prices will go through the roof in 2016, followed by energy prices in 2021-2023; if the load forecast is correct in showing that BREC will somehow acquire massive new load, on the same scale as the smelters, around 2019-2021; if BREC's requested more than doubling of rates has only a minor impact on rural demand and no impact on industrial demand; if no new regulations make coal plants even more expensive to operate in the future; if other utilities retire their coal plants, but stop building gas plants in order to continue serving their existing load – then keeping Wilson and Coleman available to restart in the future could turn out to be a bargain.

This is the future BREC is gambling on, when it refers to sales of Wilson and Coleman [redacted] as tantamount to throwing away a valuable asset (responses to SC 2-25, 2-26). They could, of course, win the gamble someday. But experience has shown, over and over, that they are far more likely to continue to lose. They have presented no persuasive evidence or arguments that their luck is about to turn.

Q. How would you summarize the costs of the two scenarios?

A. The Status Quo scenario includes several million dollars of annual fixed costs to keep the plants on standby, and likely more than $200 million of environmental upgrades before they can be restarted, in order to gamble on a very unlikely future. The Right-Sized scenario incurs only modest transaction costs and perhaps plant shutdown costs, and loses nothing except the opportunity to gamble on a future in which every one of BREC's hopes and forecasts comes true. Meanwhile, it leaves BREC and its ratepayers with an appropriately sized utility, without the risks of carrying the additional capacity that once served two enormous smelters.

Q. What is your recommendation to the Commission?

A. I recommend that the Commission grant BREC only very short-term rate increases, sufficient to keep the Company afloat while it recalculates the costs and benefits of selling or closing Wilson and Coleman, and adjusts its plans accordingly. The recalculation should include more sober estimates of future capacity and energy prices, more realistic load forecasts for a regional economy that is turning rapidly toward less energy-intensive technology and service sectors, accurate calculation of price elasticity effects, more realistic assessments of likely future environmental compliance costs facing those plants, and other corrections to the projections presented in this case.

The Commission should also make clear its willingness to allow rates that cover scheduled debt payments after the departure of Wilson and Coleman, but nothing more: there should be no additional markup, adders, or rate of return allowed on such payments. It will be challenging to produce a revised forecast of Big Rivers' prospects in this right-sized scenario – but it is the only solution that offers fair, just, and reasonable rates to the Company's ratepayers.

Q. Does this conclude your testimony?

A. Yes, it does.

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Stockholm Environment Institute - U.S. Center, Somerville, MA. Senior Economist and Director of Climate Economics Group, 2007 – 2012.
Wrote extensively for academic, policy, and general audiences, and directed studies for a wide range of government agencies, international organizations, and nonprofit groups.

Tufts University, Global Development and Environment Institute, Medford, MA. Senior Researcher, 1995 – 2007.
Editor of GDAE's *Frontier Issues in Economic Thought* book series, a coauthor of GDAE's macroeconomics textbook, and director of the institute's Research and Policy program. Taught courses in the Tufts Department of Urban and Environmental Policy and Planning.

Tellus Institute, Boston, MA. Senior Economist, 1985 – 1995.
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University of Massachusetts, Boston, MA. Visiting Assistant Professor of Economics, 1982 – 1984.

Dollars and Sense, Somerville, MA. Editor and Business Manager, 1974 – 1982.

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Harvard University, PhD, Economics, 1975
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AFFILIATIONS

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Co-founder and steering committee member, 2007 – present

Center for Progressive Reform, Washington, DC
Member scholar, 2002 – present

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Ex. Ackerman 2

TVA

TVA BOARD MEETING

AUGUST 22, 2013

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CONSENT AGENDA

- Health Savings Account Contract
- Pharmacy Benefits Managers Contract
- Assistant Corporate Secretary Designations

Ex. Ackerman 2

TVA

CHAIRMAN'S REPORT

AUGUST 22, 2013

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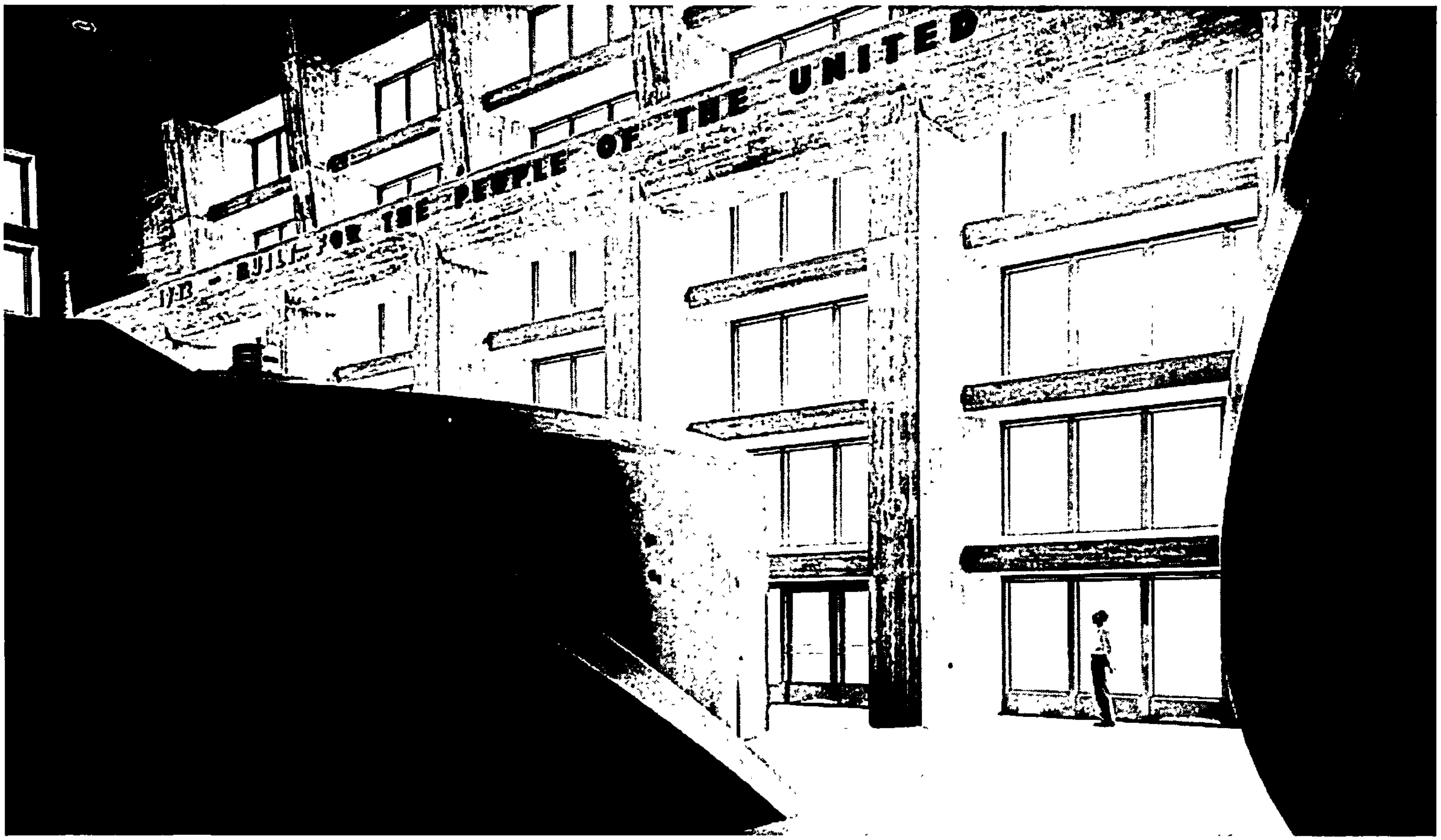
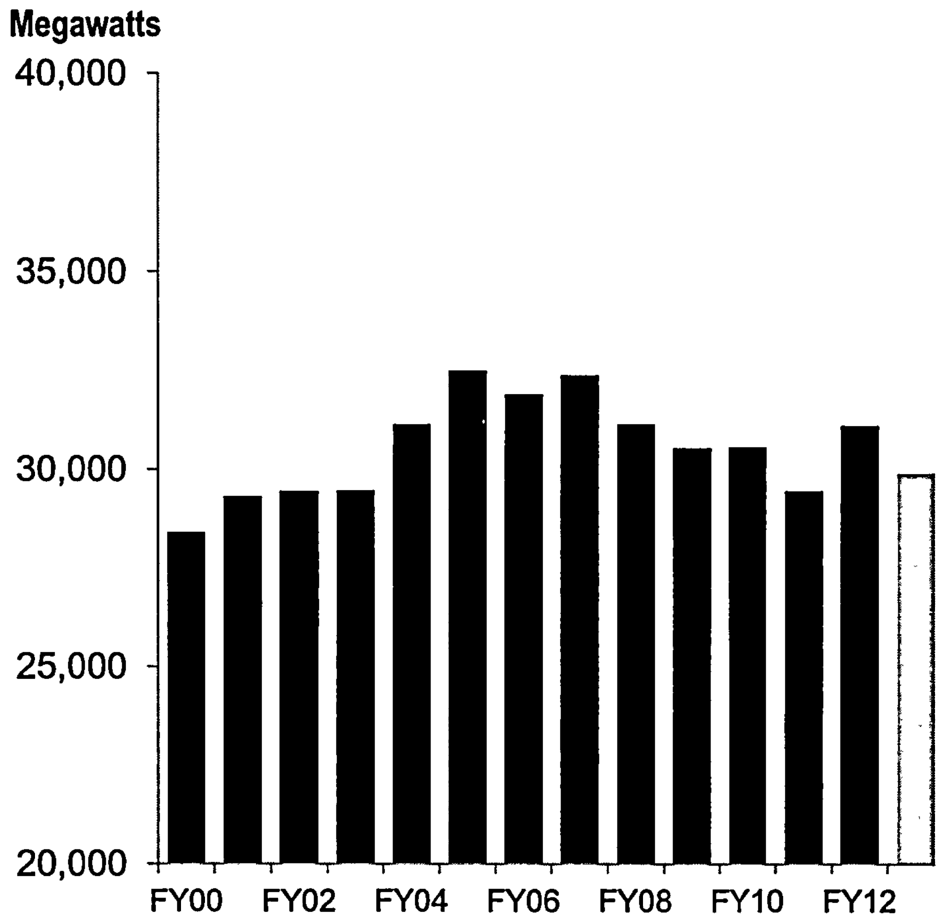
CHAIRMAN'S REPORT

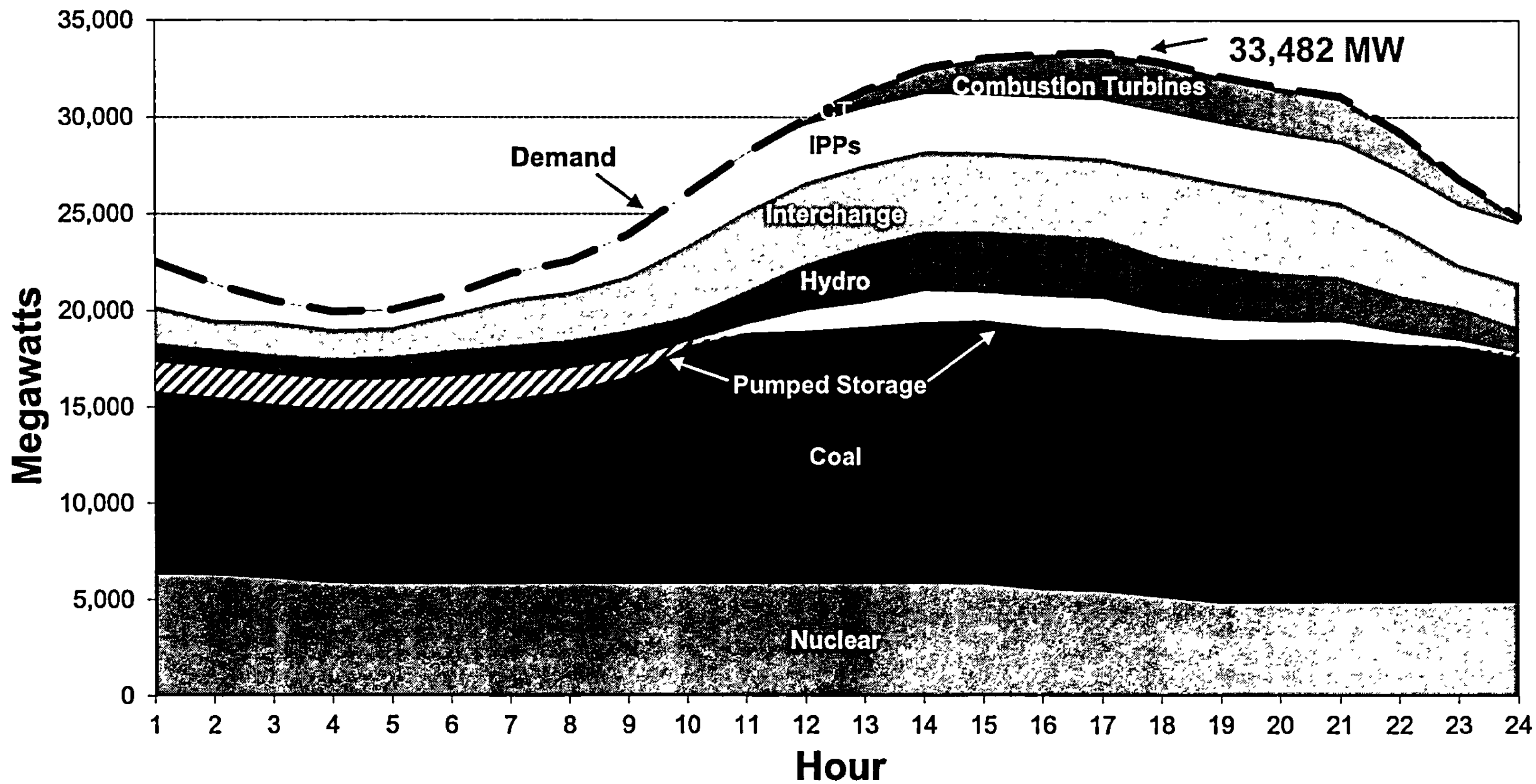


SUMMER PEAK DEMAND



Note: History is weather-normalized. All-time actual peak was 33,482 MW in August 2007 at 104.4°F.
Forecast does not include the impacts of TVA EE/DR programs.

DEMAND LOAD – AUGUST 16,2007



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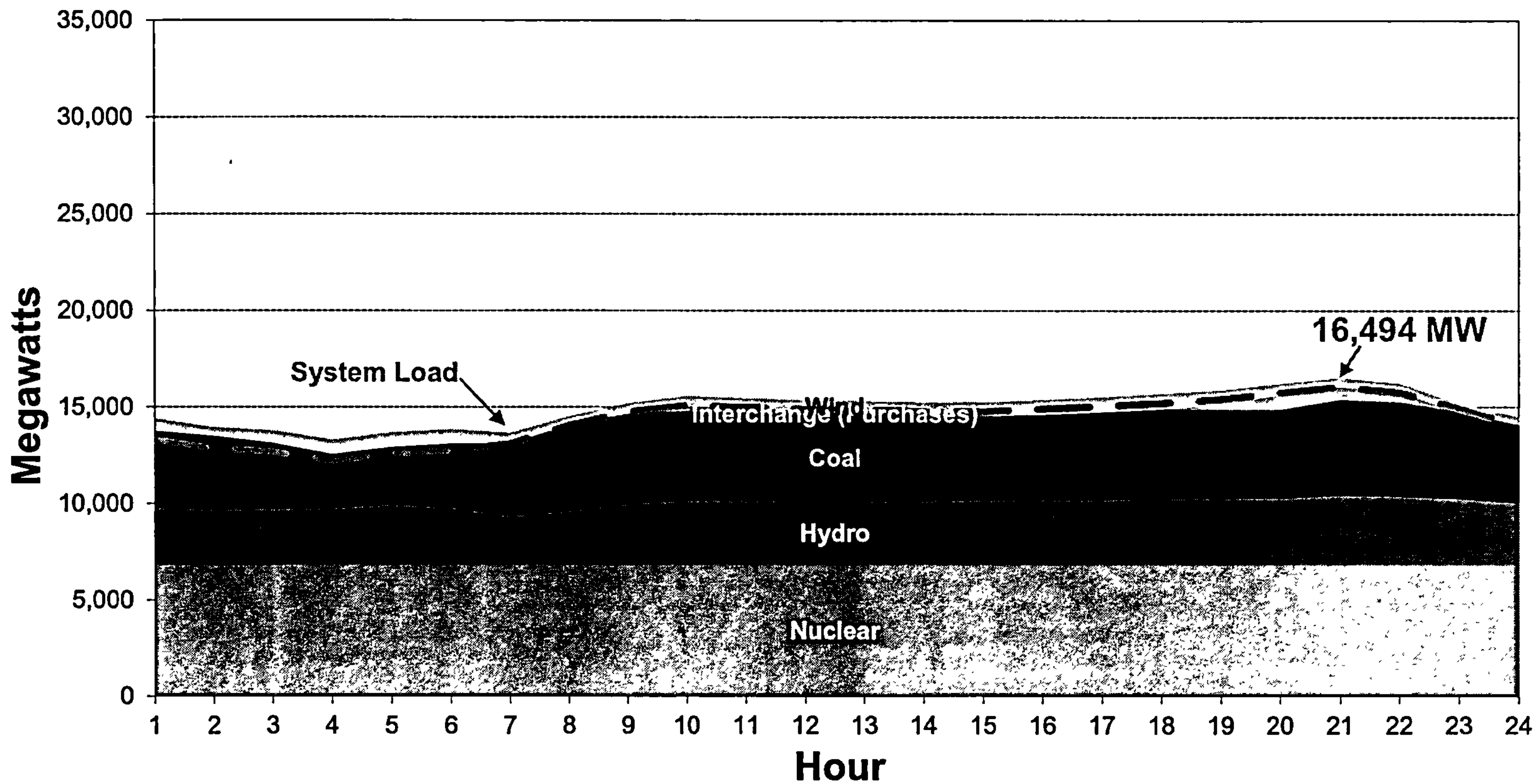
DEMAND LOAD – MAY 12, 2013



CHAIRMAN'S REPORT

- Find significant efficiencies in operating costs and functions
- Optimize the generation portfolio by developing a robust, flexible generation fleet
- Improve operational performance of generation fleet
- Focus on our economic development mission by recruiting and retaining good jobs
- Improve transparency and communication
- Focus on low rates and long-term financial health

Ex. Ackerman 2

TVA

CHAIRMAN'S REPORT

AUGUST 22, 2013

Ex. Ackerman 2

10

TVA

PRESIDENT'S REPORT

AUGUST 22, 2013

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WORK

THE PROMISE

WE MAKE TO

EACH OTHER

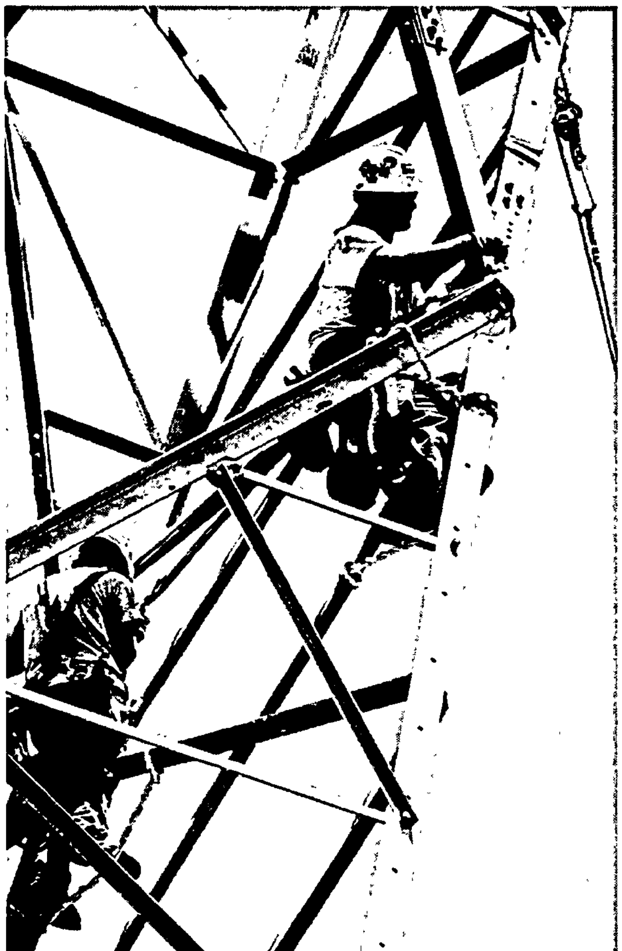
SAFE

TVA

OVERVIEW

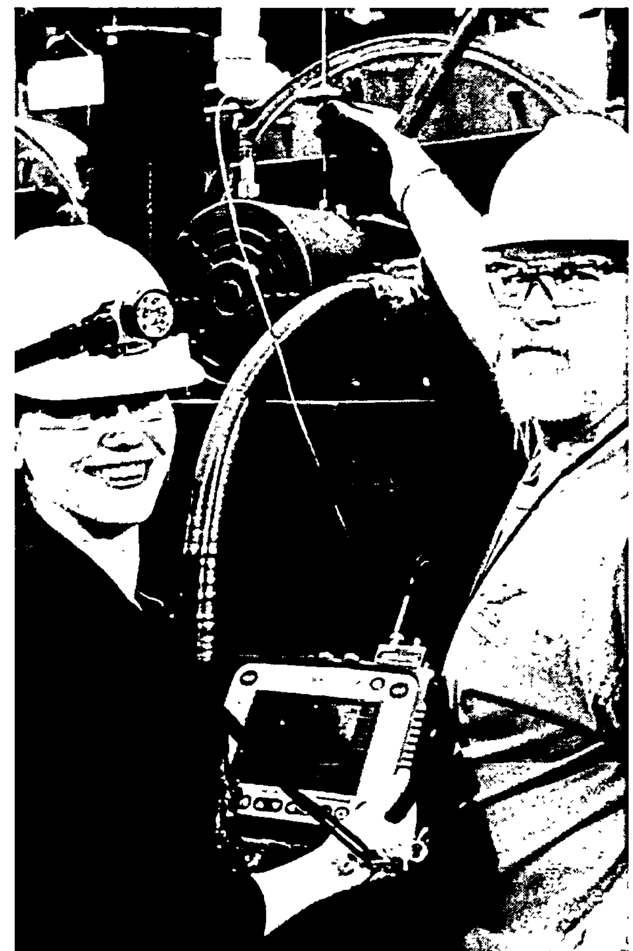
Ex. Ackerman 2

ACTION AREAS



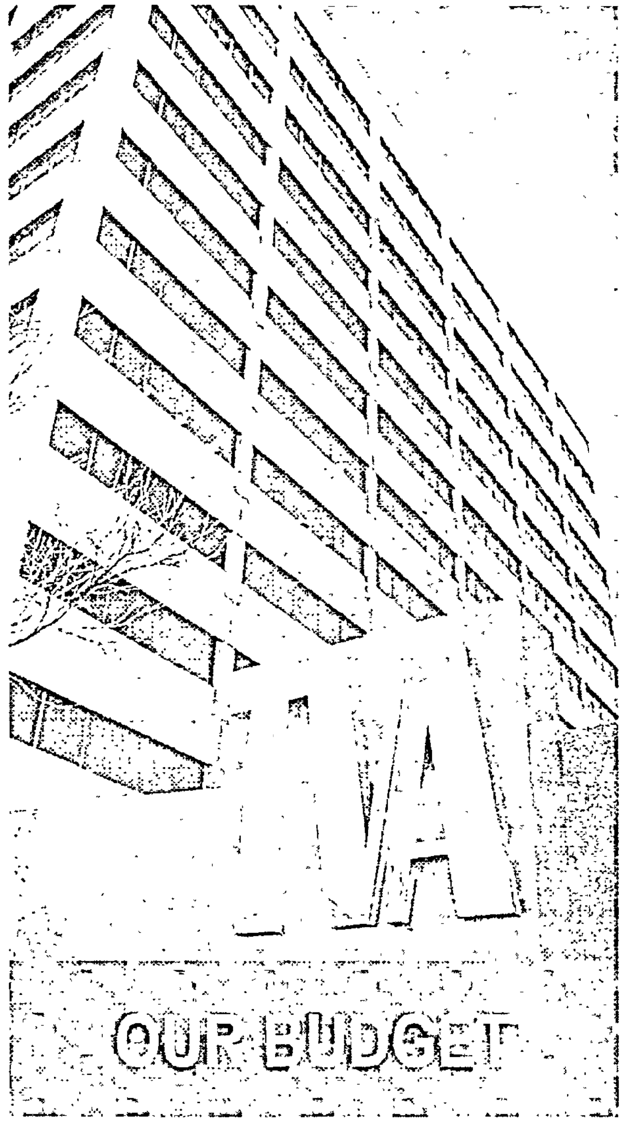
OUR WORK

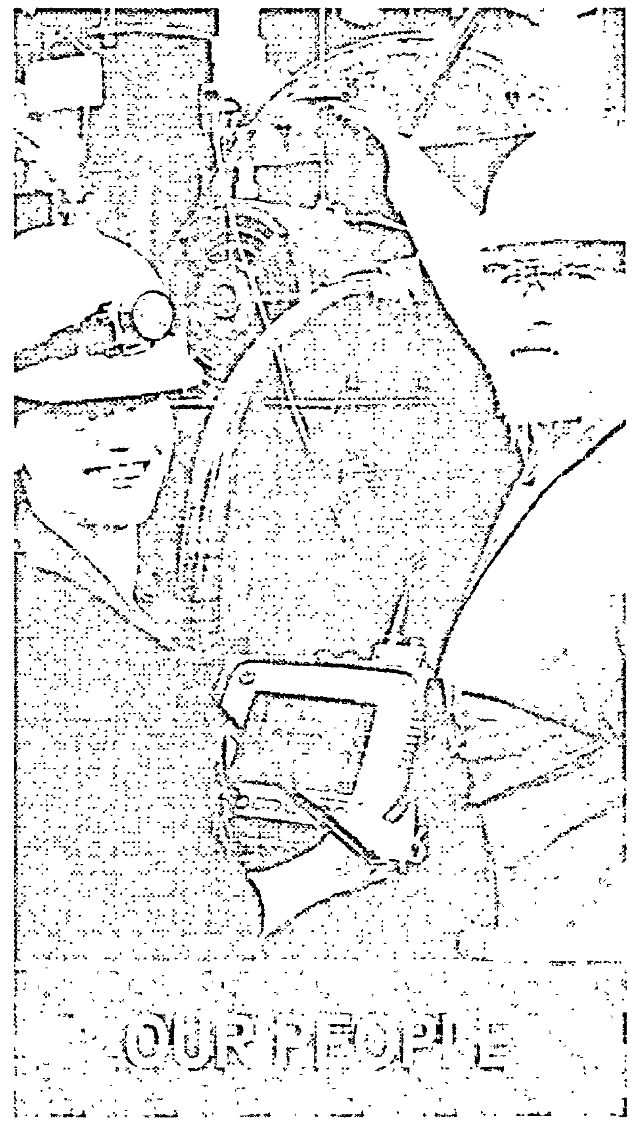
OUR BUDGET



OUR PEOPLE

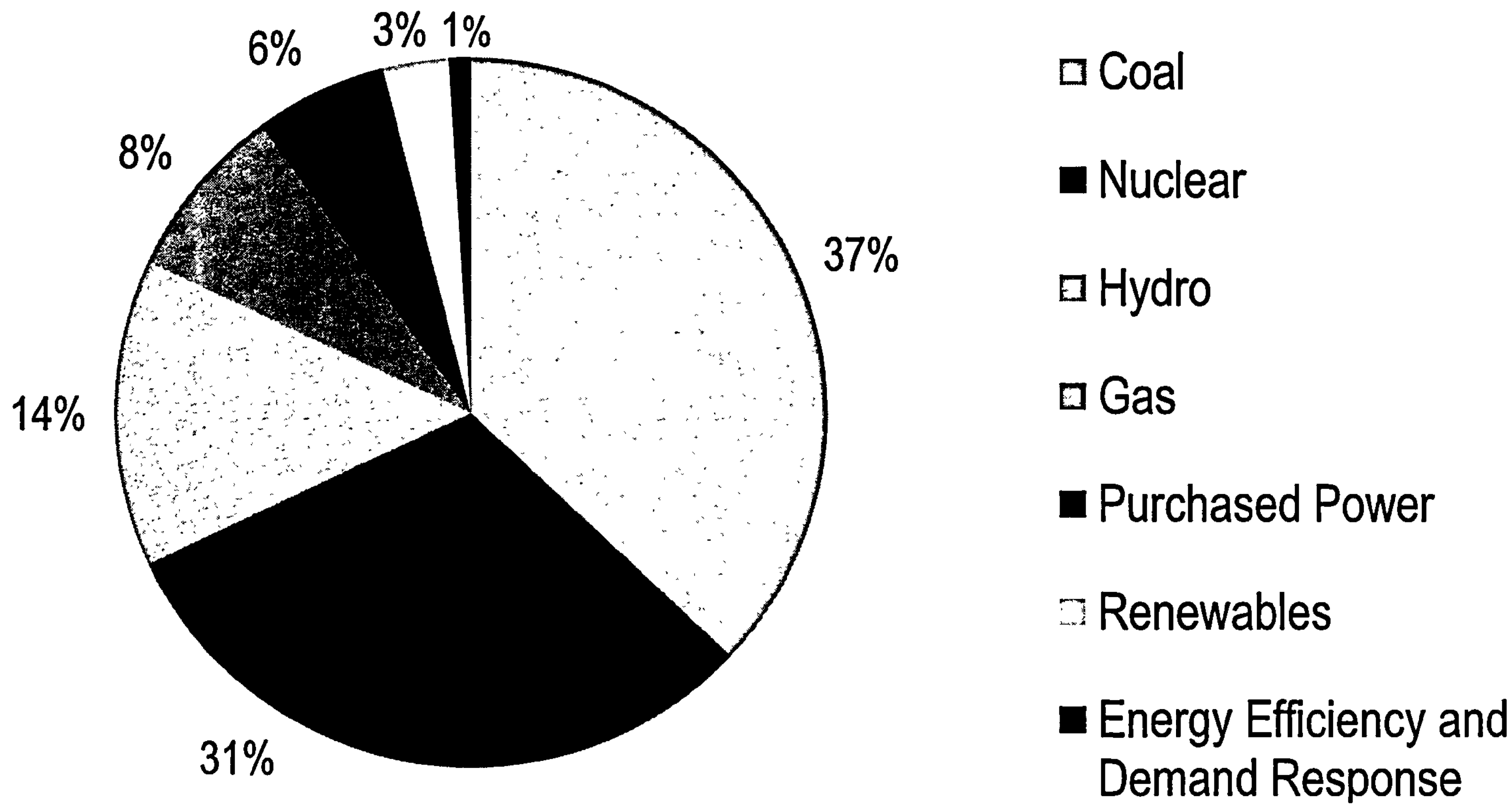
ACTION AREAS





GENERATION

Fiscal Year-to-date July 2013



Hydro and renewables include a portion of purchased power

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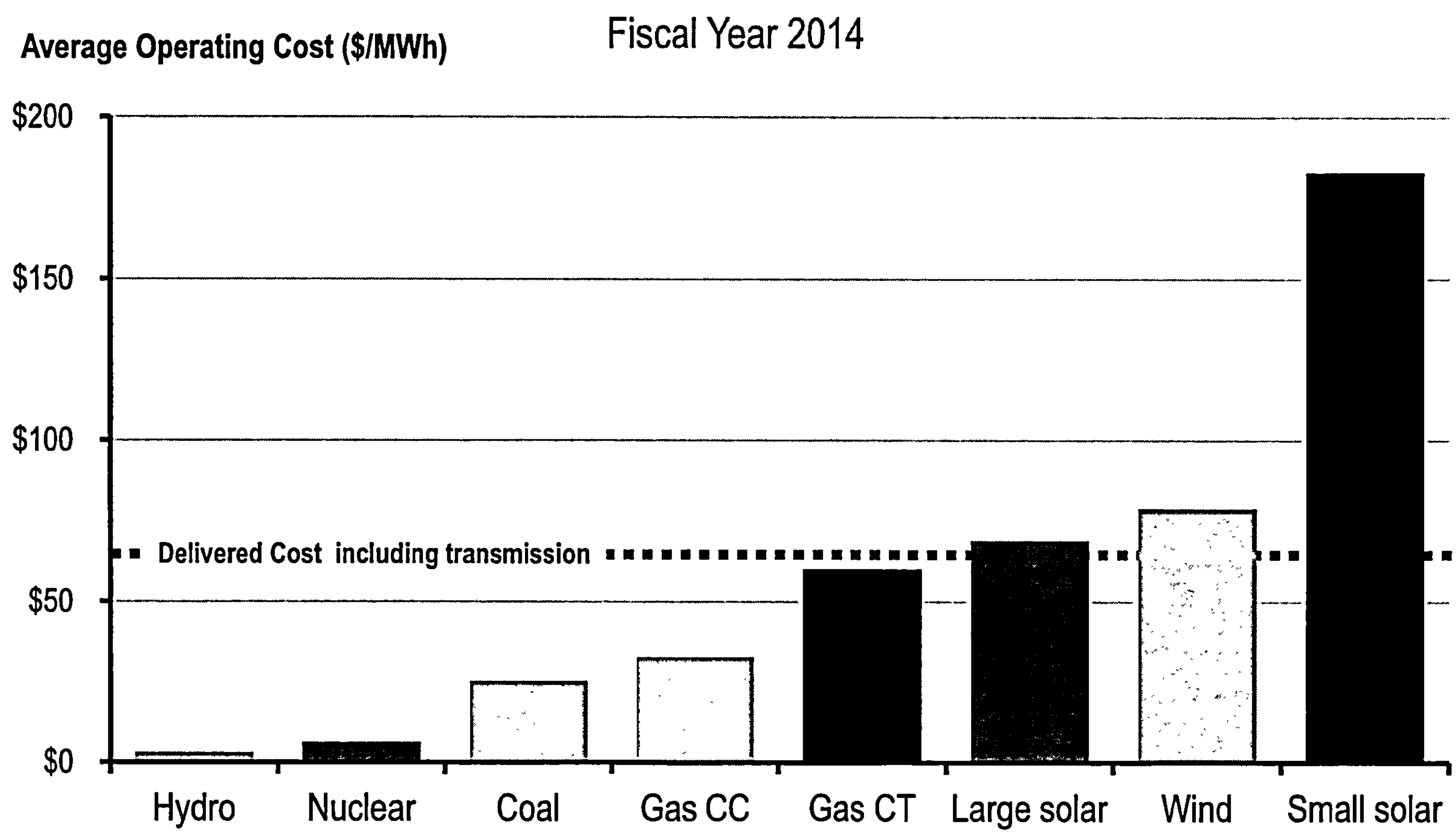
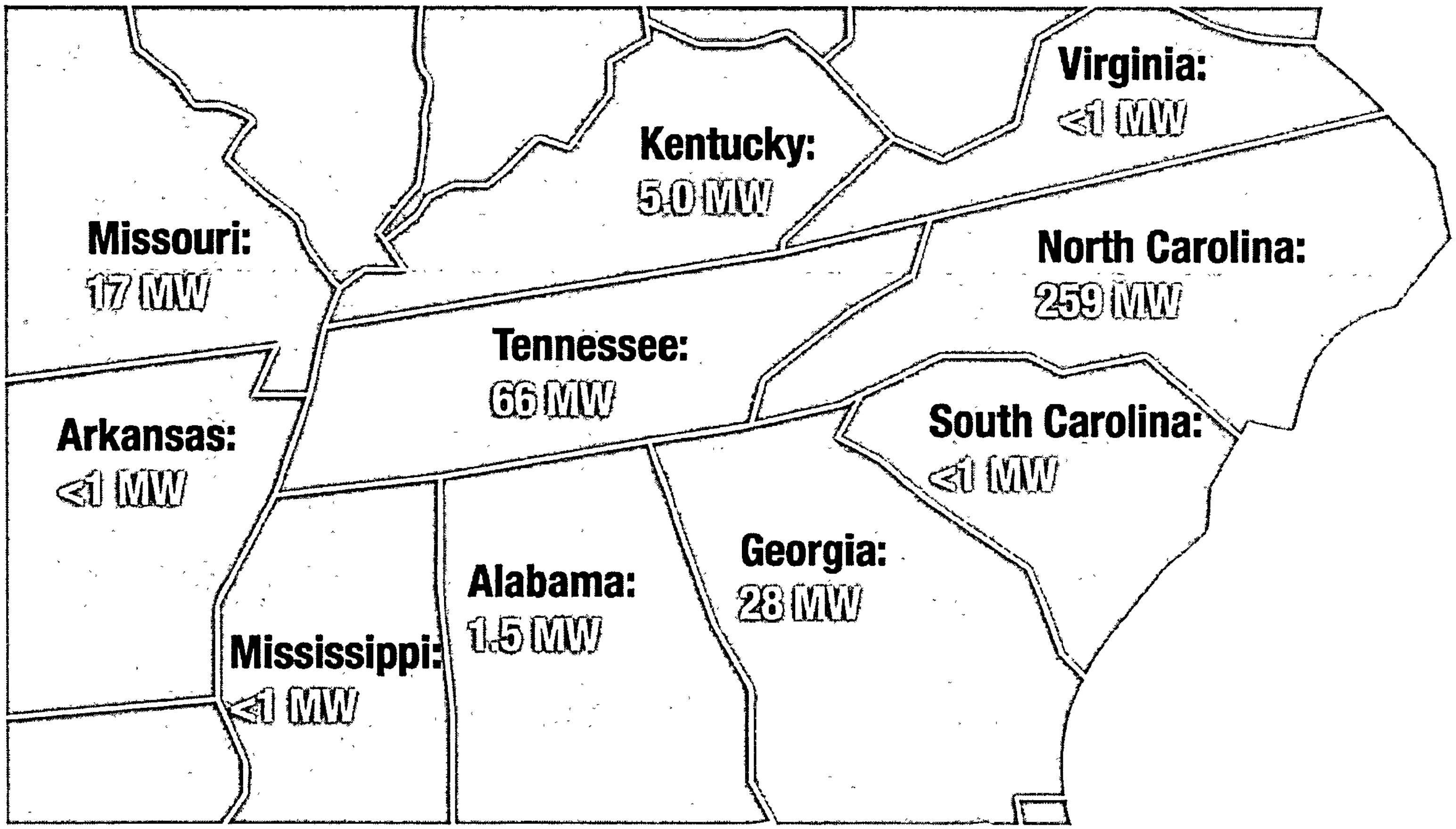
COST PER MEGAWATT HOUR



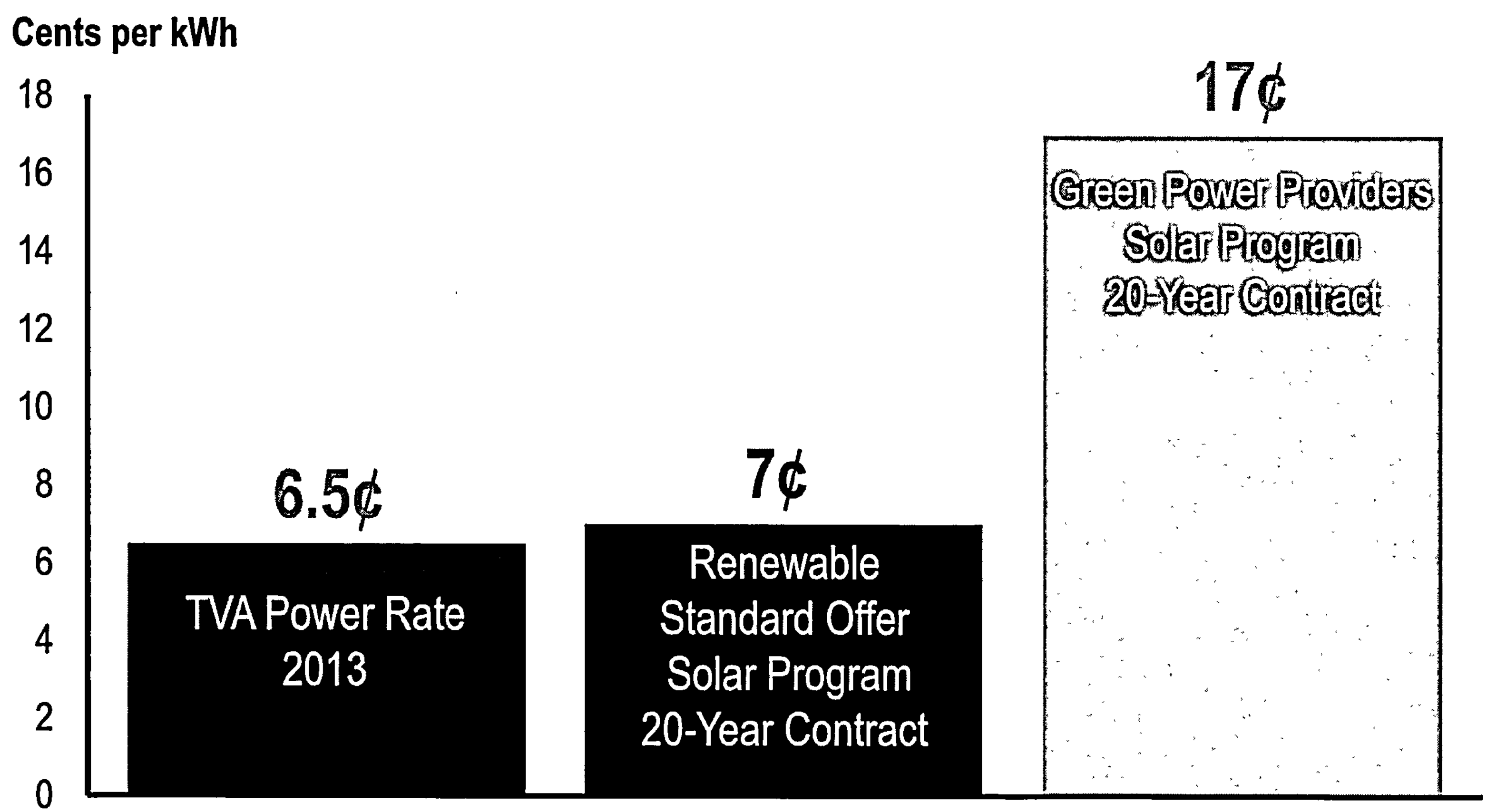
Ex. Ackerman 2

SOLAR GENERATION BY STATE



Source: SEIA through first quarter of 2013 except for Alabama, Kentucky, Mississippi and Virginia which use TVA data as of August 2013

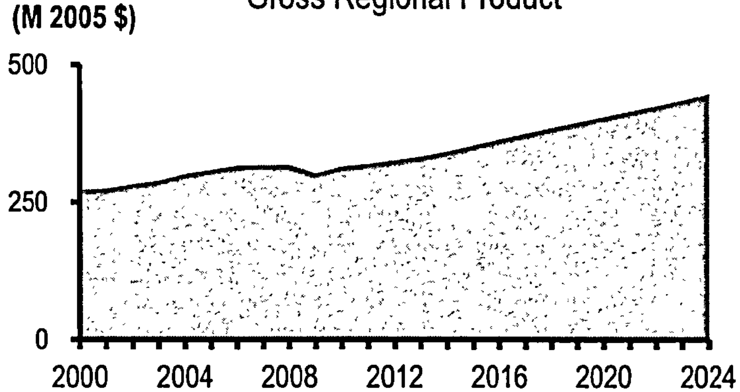
2013 SOLAR COSTS PER KWH



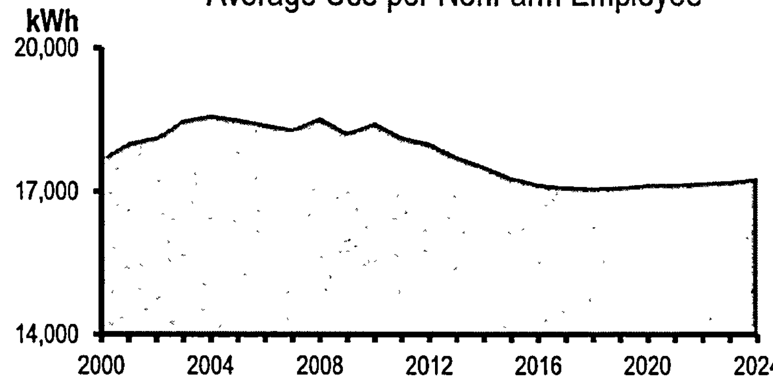
Ex. Ackerman 2

ENERGY EFFICIENCY AND DEMAND RESPONSE

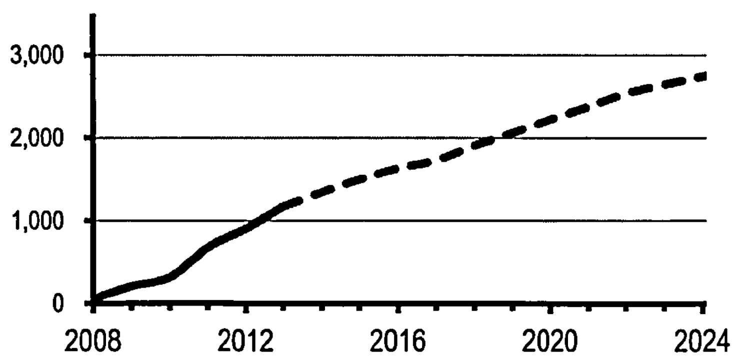
Gross Regional Product



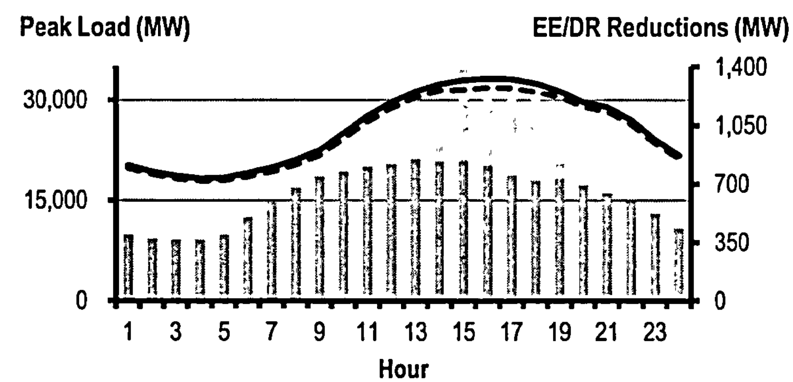
Average Use per NonFarm Employee



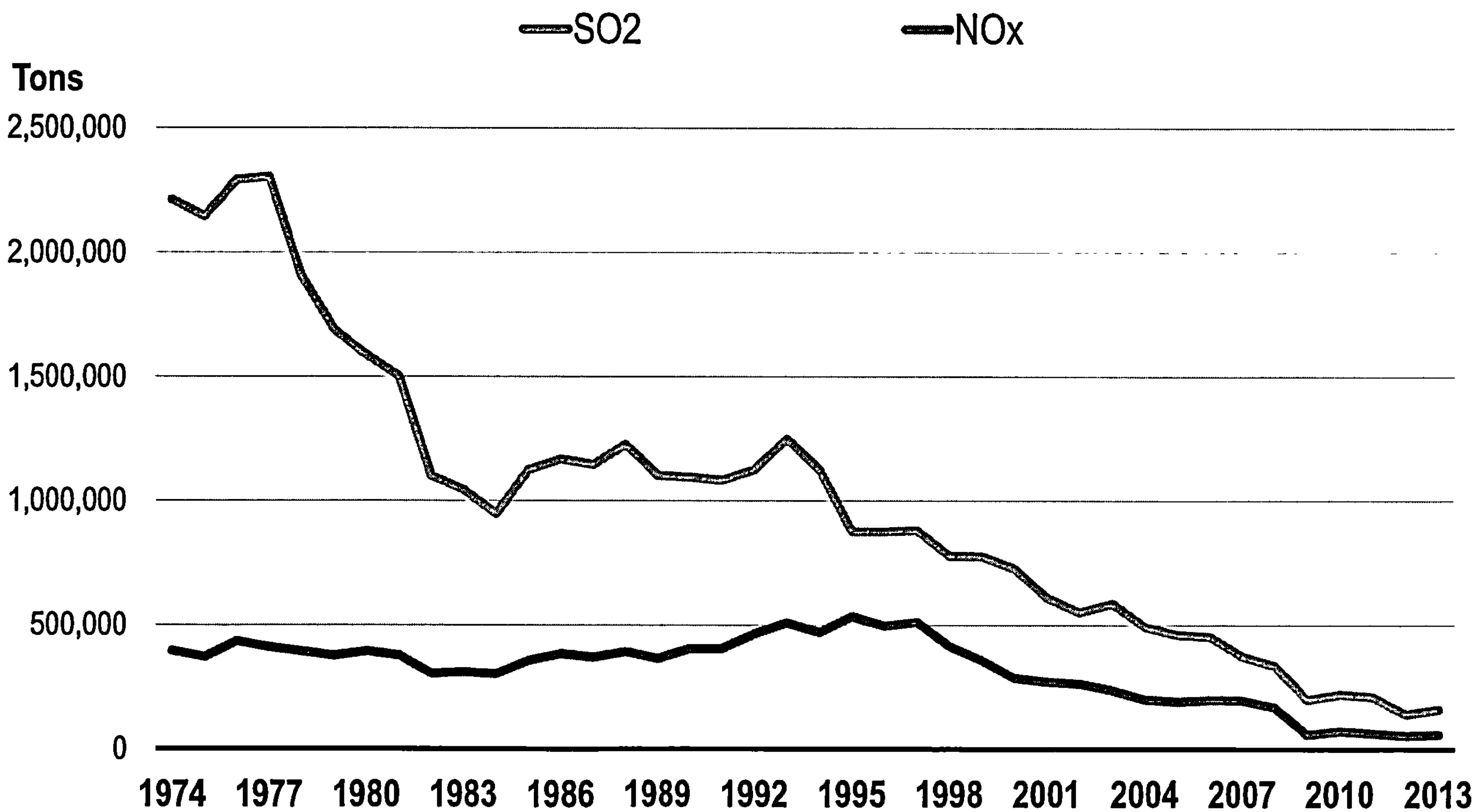
Capacity Savings through Energy Efficiency



Summer Season Hourly Peak Load Reductions from EE/DR

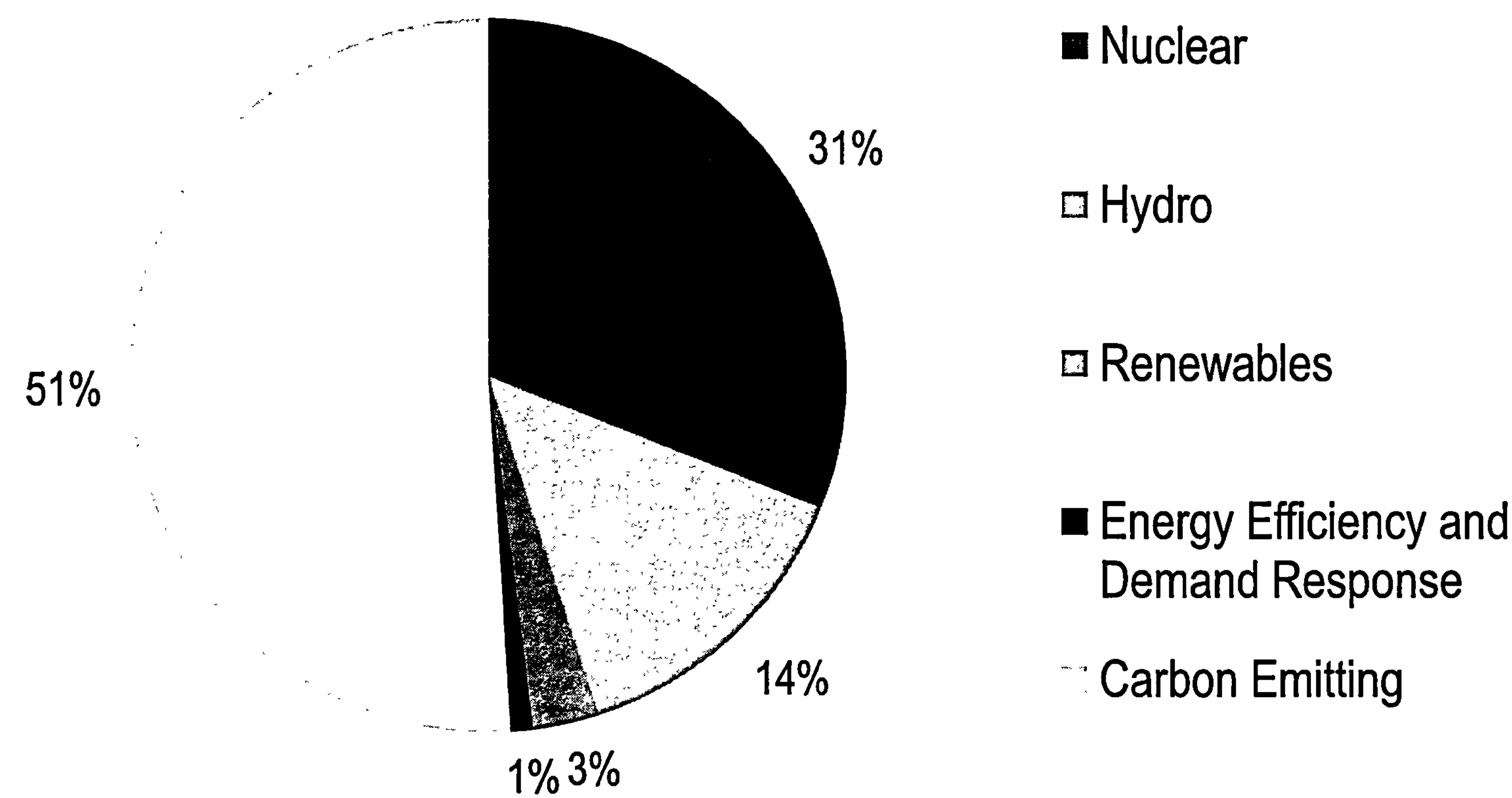


AIR QUALITY


SO2
NOx
Tons
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
1974
1977
1980
1983
1986
1989
1992
1995
1998
2001
2004
2007
2010
2013

POWER SUPPLY FROM CARBON-FREE SOURCES

Fiscal Year-to-date July 2013



STEWARDSHIP

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ECONOMIC DEVELOPMENT

	Direct Jobs Created and Retained	Capital Investment
FYTD 2013	46,000	$4.6 billion
FY 2008 thru FYTD 2013	250,000	$29 billion

VALUE OF CREATING JOBS

Example: Megasite Program

Direct Jobs	6,800
Indirect Jobs	24,200
Total Jobs	**31,000**

Direct Payroll	$433 million
Indirect Payroll	$925 million
Total Payroll	**$1.4 billion**

Total Capital Investment	**$3.8 Billion**

Source: Economic Impact Study of the TVA Certified Megasite Program, Younger Associates, April 2012

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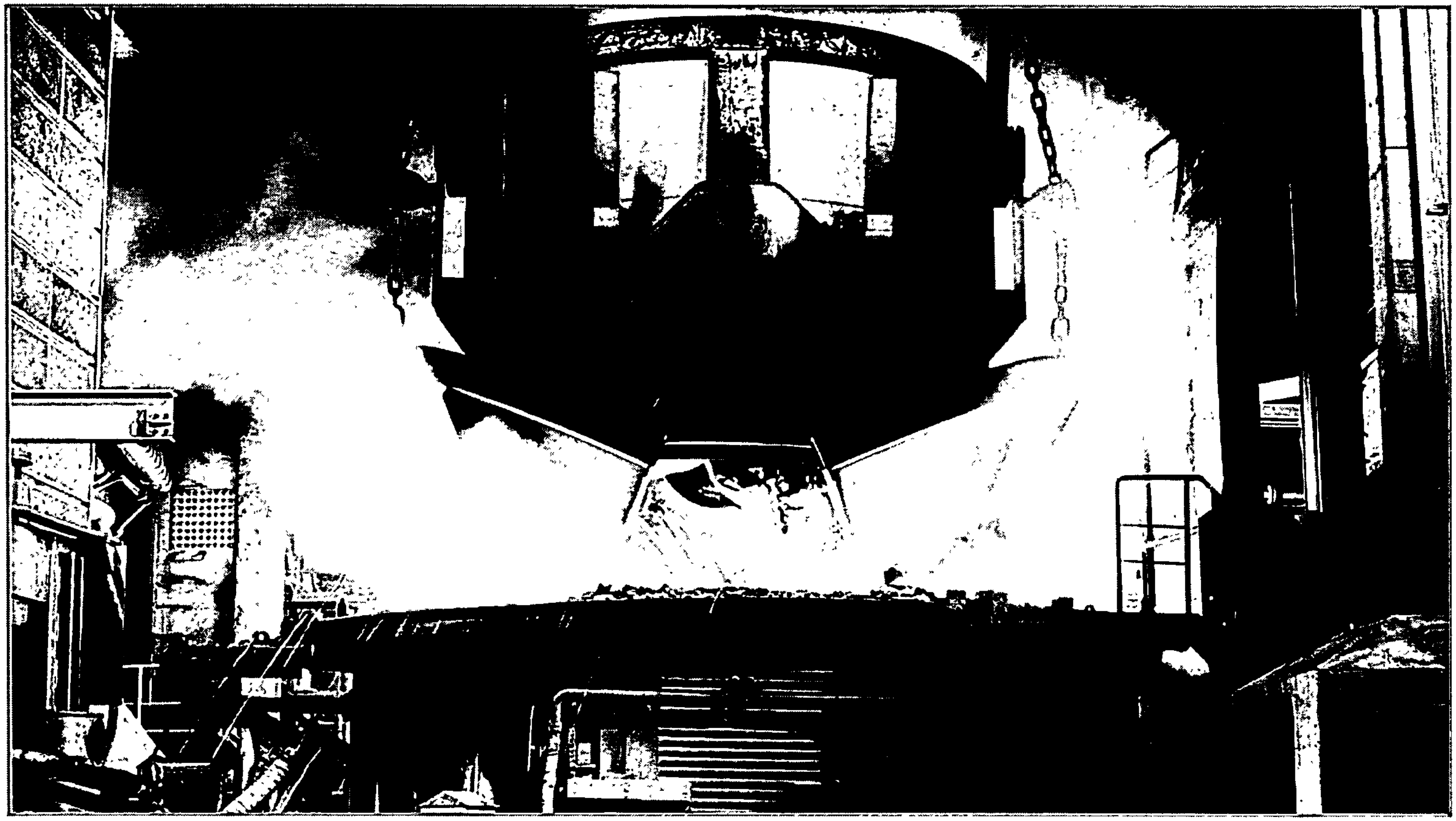
SEVERSTAL



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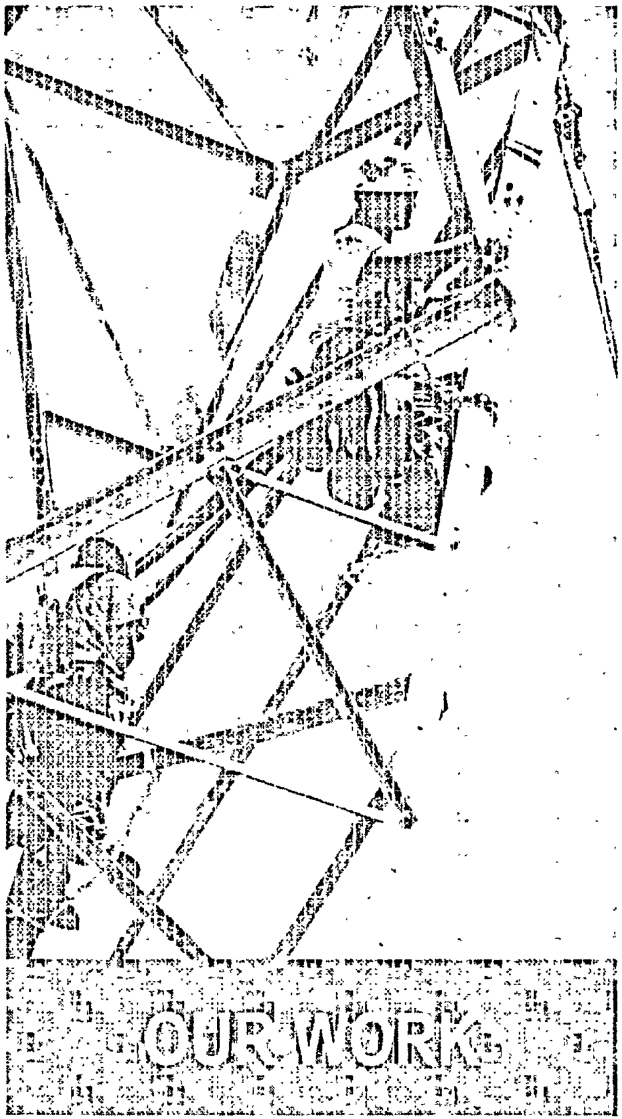
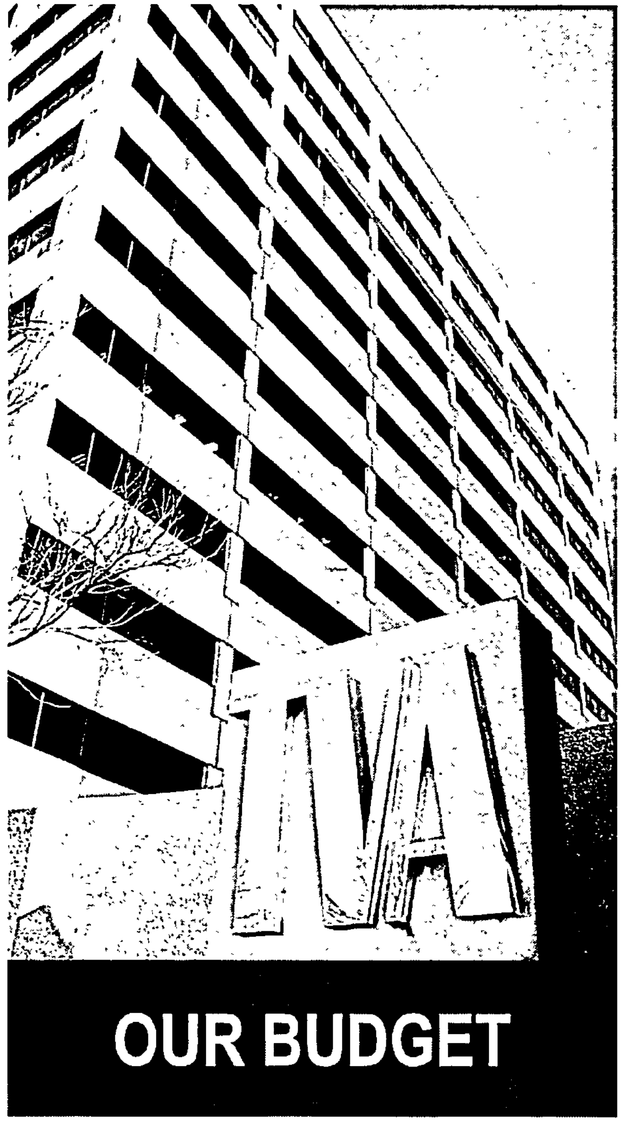
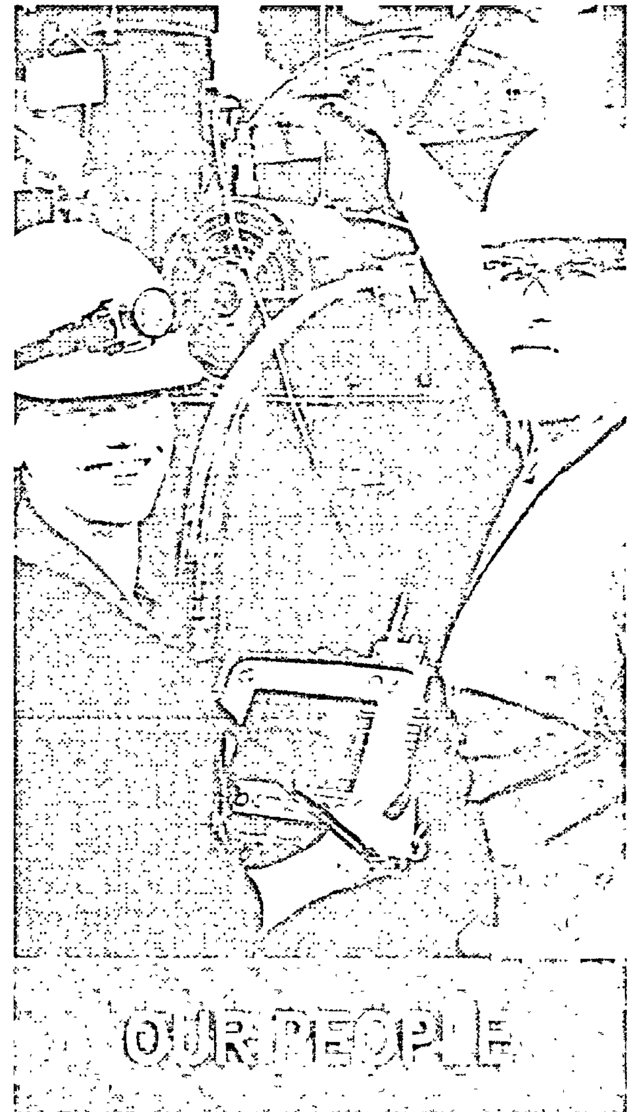
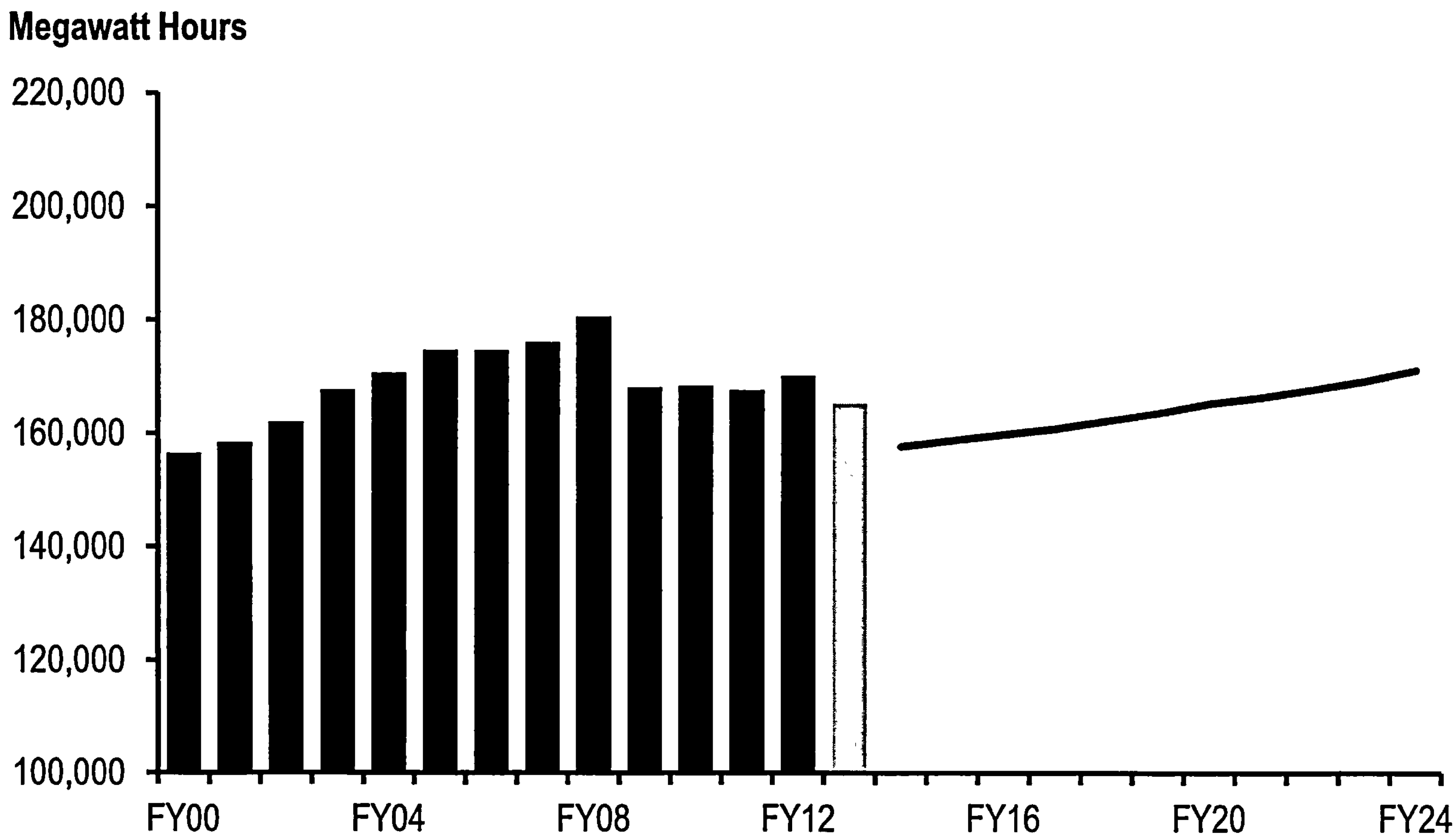
ACTION AREAS





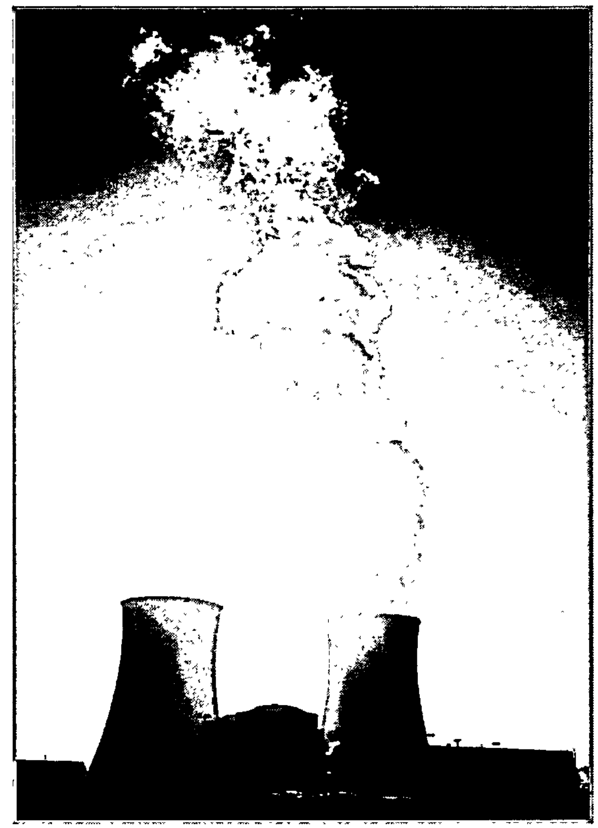


LOAD GROWTH PROJECTIONS



PRIORITIES

- O&M Expenses in line with revenues
- Complete Watts Bar 2
- Evaluate remainder of coal fleet
- Preserve Bellefonte as an option
- Continue exploring small modular reactor technology
- Attracting and retaining jobs for the region
- Update our Integrated Resource Plan



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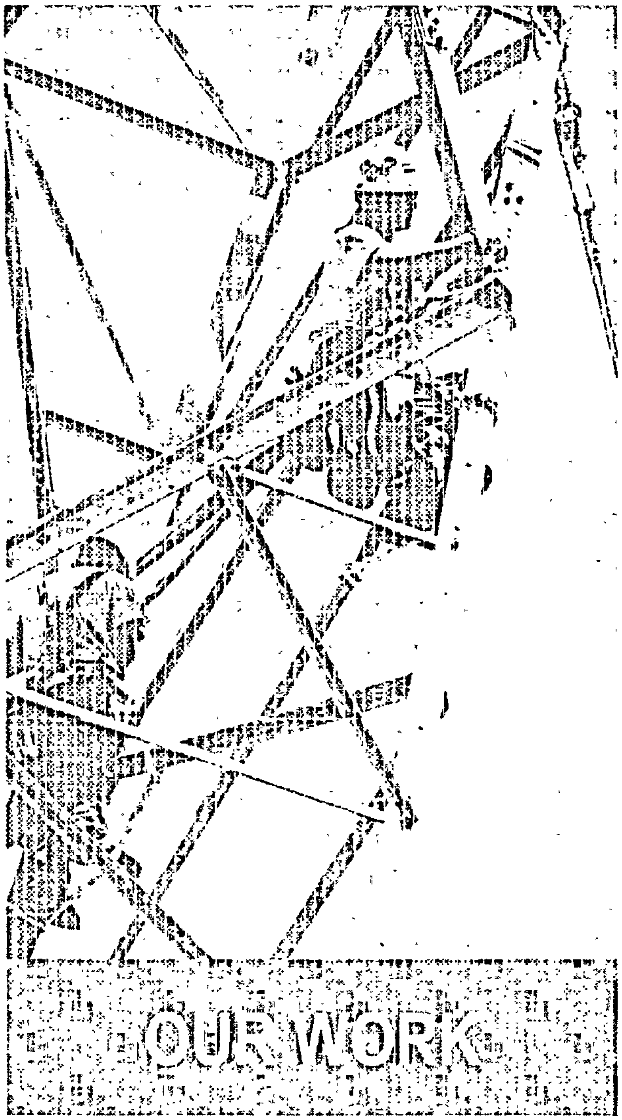
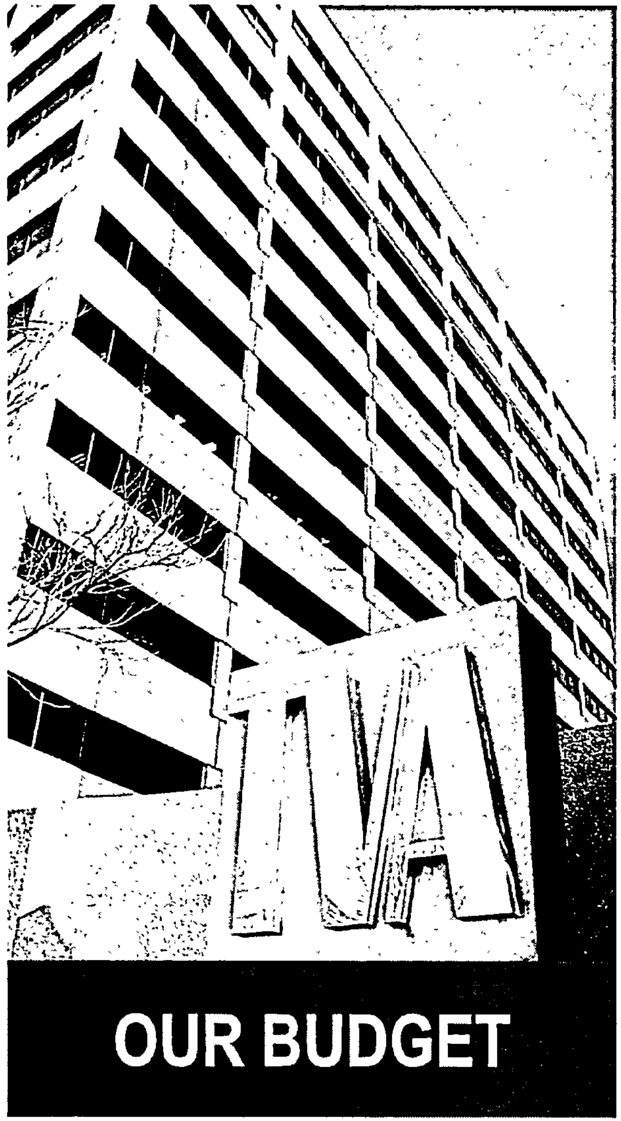
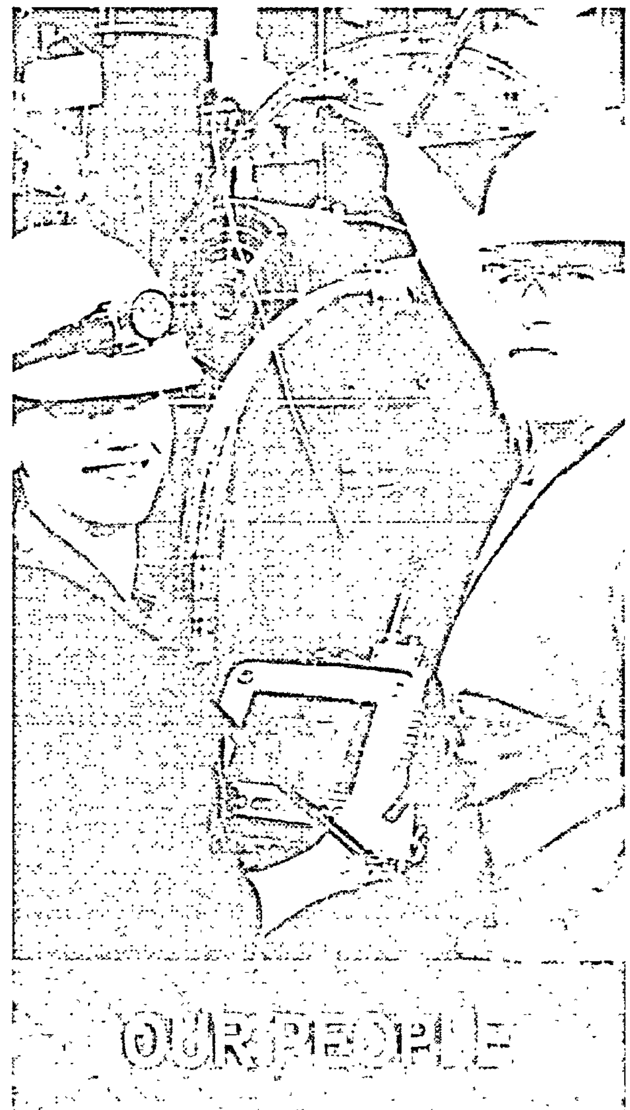
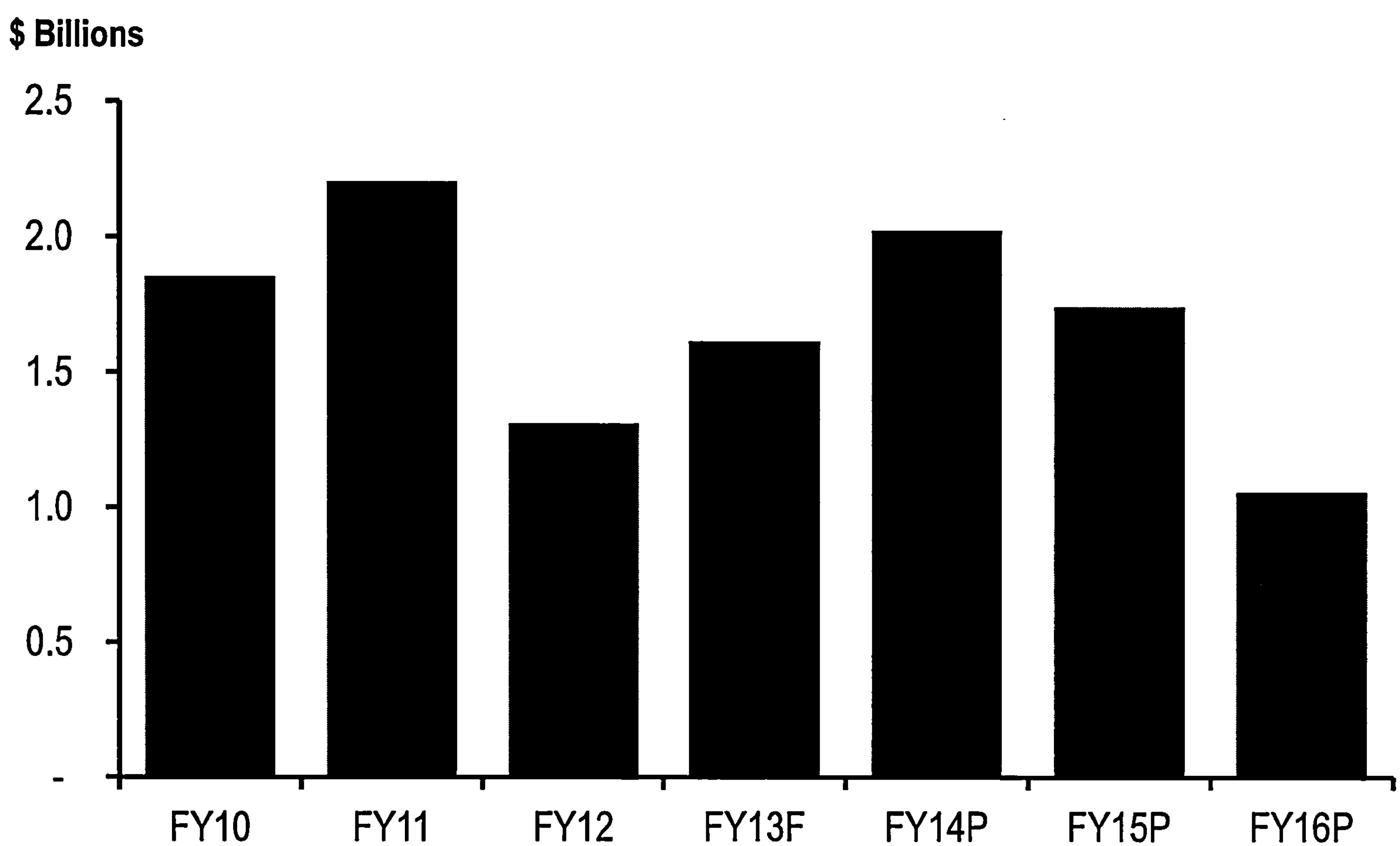
ACTION AREAS



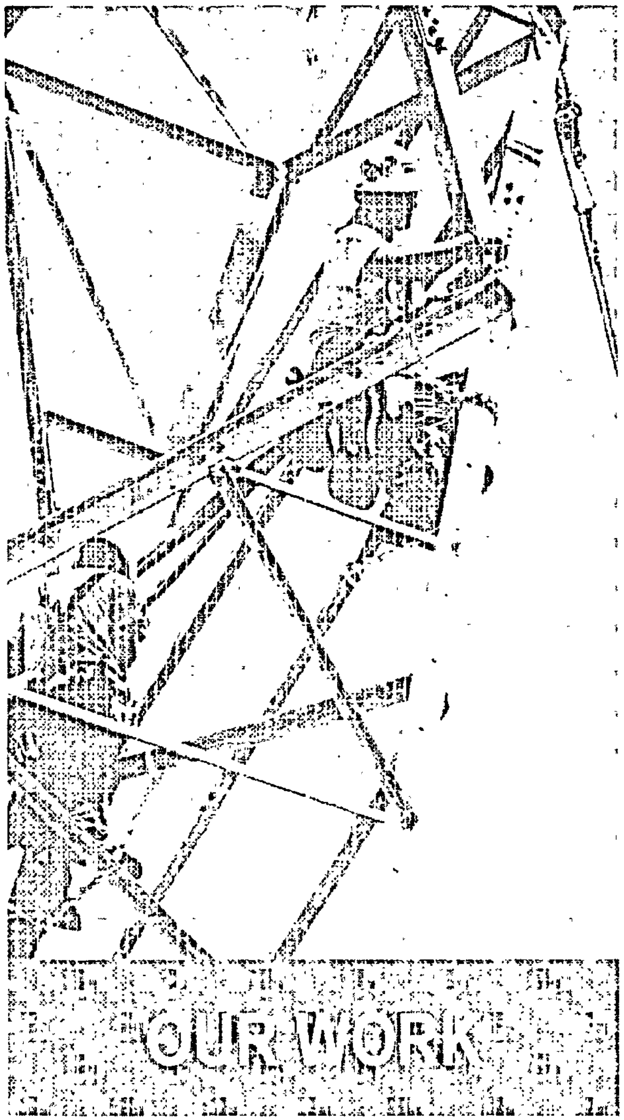


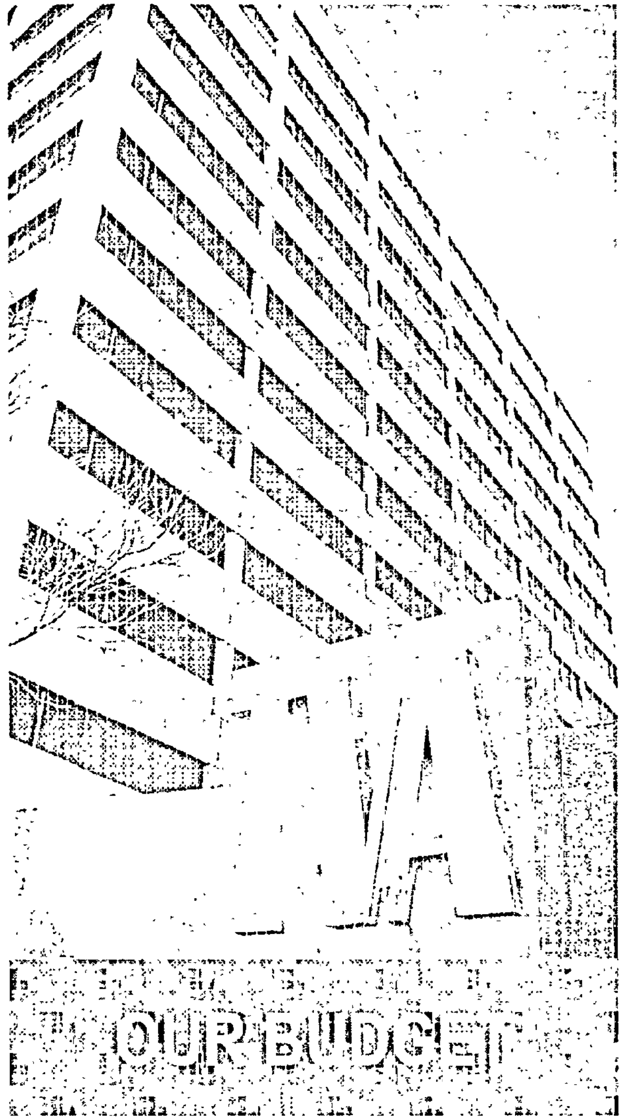


CAPITAL EXPENSES



ACTION AREAS





OUR PEOPLE

Rates

Asset Portfolio

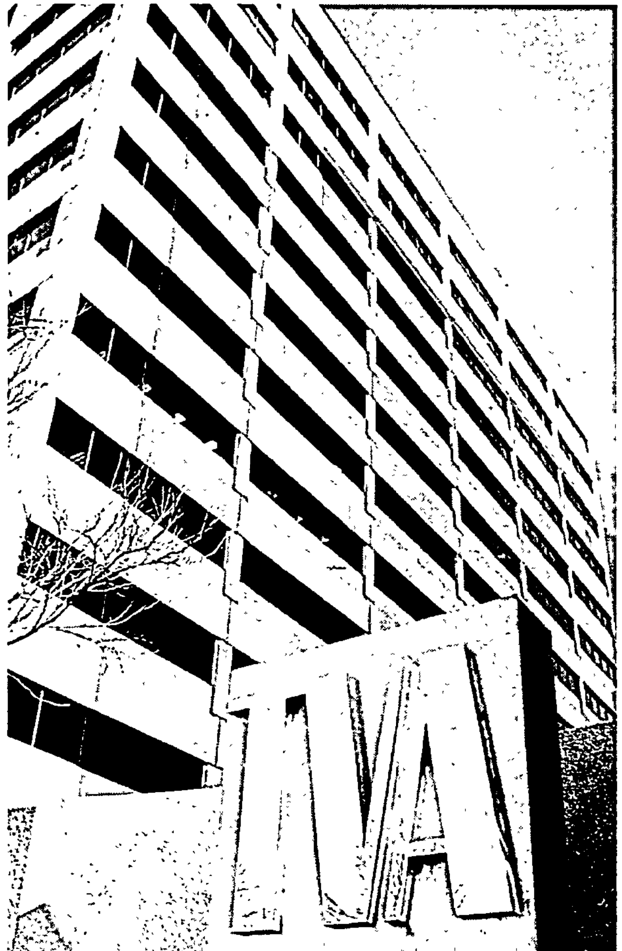
Serve the citizens of the Tennessee Valley

Stewardship

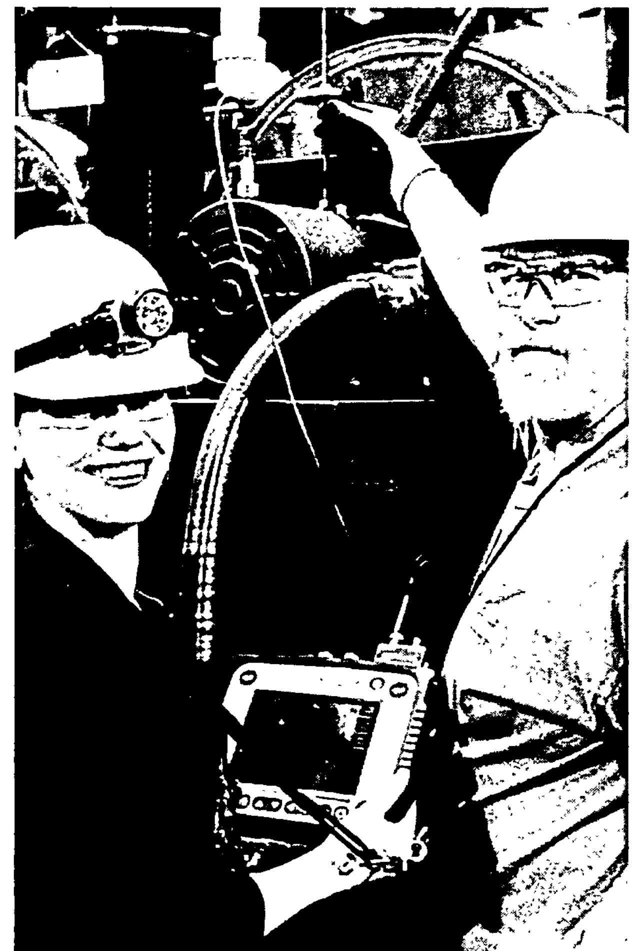
Debt

ACTION AREAS


OUR WORK



OUR BUDGET


OUR PEOPLE

TVA

FINANCE, RATES, AND PORTFOLIO COMMITTEE

AUGUST 22, 2013

FINANCE, RATES, AND PORTFOLIO COMMITTEE

FISCAL YEAR 2014 FINANCIAL PLAN

AUGUST 22, 2013

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FISCAL YEAR 2014 FINANCIAL PLAN

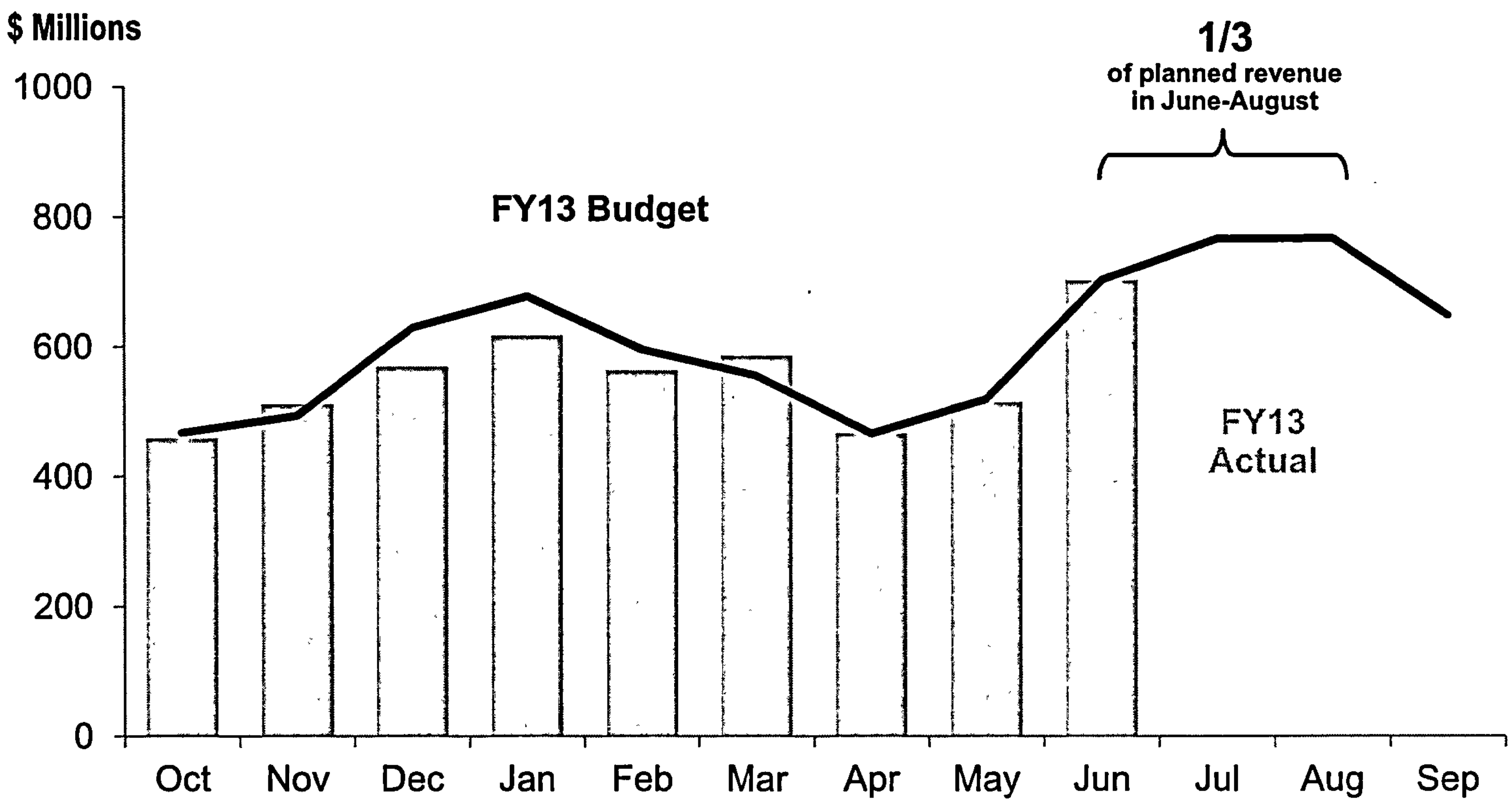
FISCAL YEAR 2013 FINANCIAL UPDATE

FISCAL YEAR-TO-DATE JUNE 2013

- Lower base revenues than planned with milder winter
- Fuel is favorable from increased hydro generation as result of higher rainfall/runoff – offset by higher than planned natural gas prices
- Cash Flow impacted by lower revenues but offset by management actions
- Capacity Expansion slowed to match current conditions

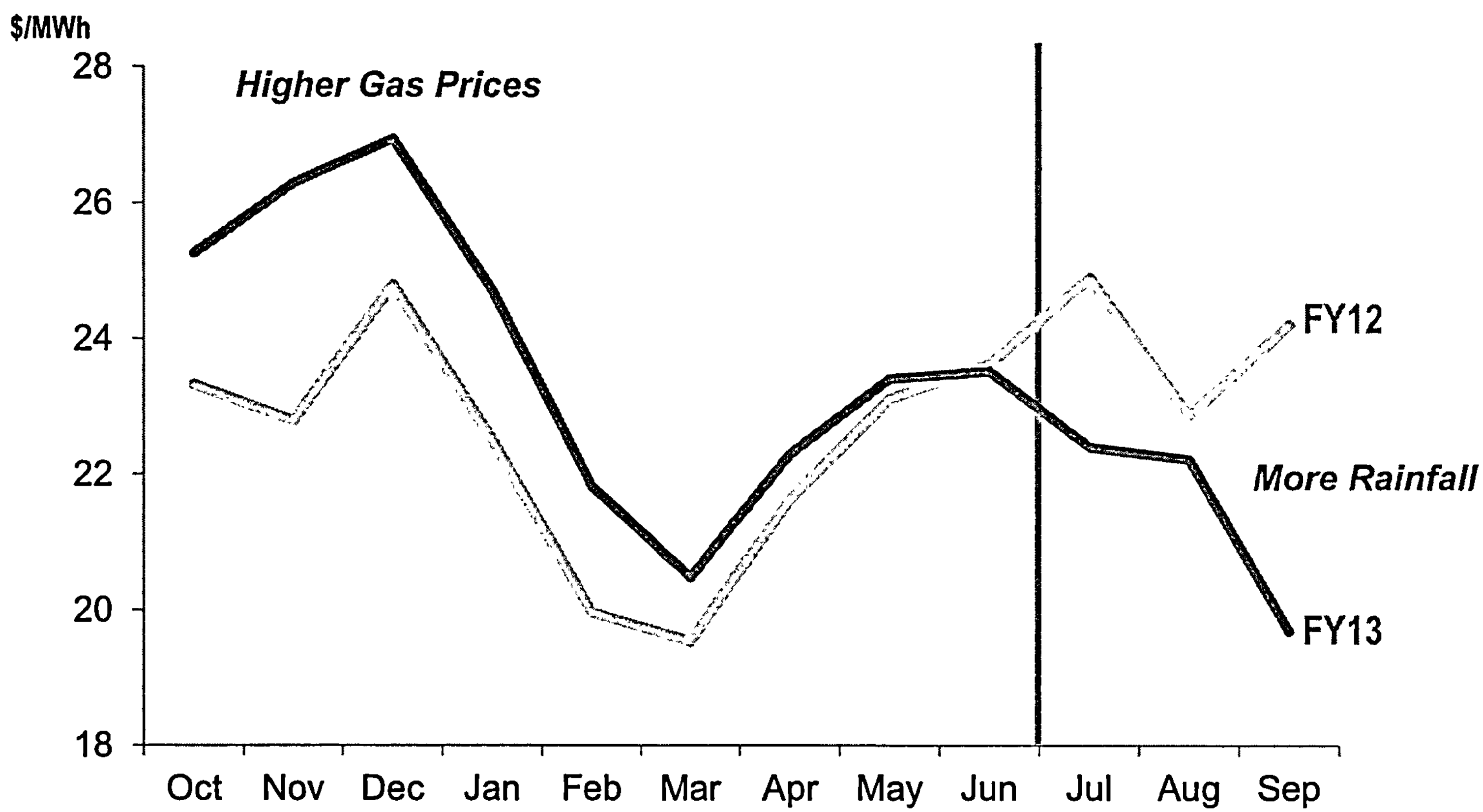
BASE REVENUES

FYTD Non-Fuel Revenue is $121M below budget



LOWER FUEL RATES

Rainfall helps move FY13 Fuel Rates below last year's



FYTD13 INCOME STATEMENT *(UNAUDITED)*

FYTD Income is favorable to budget by $79M & prior year by $87M

	FYTD13			FYTD12	
$ millions	**Actual**	**Budget**	**Variance**	**Actual**	**13 vs 12**
Total Operating Revenue	$ 7,922	$ 8,000	$ (78)	$ 7,949	$ (27)
Fuel and Purchased Power	2,914	2,916	2	2,772	(142)
O&M Routine	1,653	1,769	116	1,723	70
O&M Outage/Other O&M	1,009	957	(52)	902	(107)
Taxes, Depreciation, Other	1,616	1,638	22	1,875	259
Interest	933	1,002	69	967	34
Net Income/(Loss)	$ (203)	$ (282)	$ 79	$ (290)	$ 87

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FYTD13 CASH FLOW STATEMENT *UNAUDITED*

FYTD Change in Cash is favorable to budget by $112M

	FYTD13			FYTD12	
$ millions	Actual	Budget	Variance	Actual	13 vs 12
Beginning Cash/Short-term Investments	$ 868	$ 200	$ 668	$ 507	$ 361
Cash Flow from Operating Activity	1,478	1,458	20	1,252	226
Cash Flow from Investing Activity	(1,745)	(1,910)	165	(1,867)	122
Cash from Financing Activity	379	452	(73)	355	24
Ending Cash/Short-term Investments	$ 980	$ 200	$ 780	$ 247	$ 733
Statutory Debt	$24,678	$25,043	$ 365	$ 24,154	$ (524)
Total Financing Obligations	$27,328	$27,328	$ -	$ 27,002	$ (326)

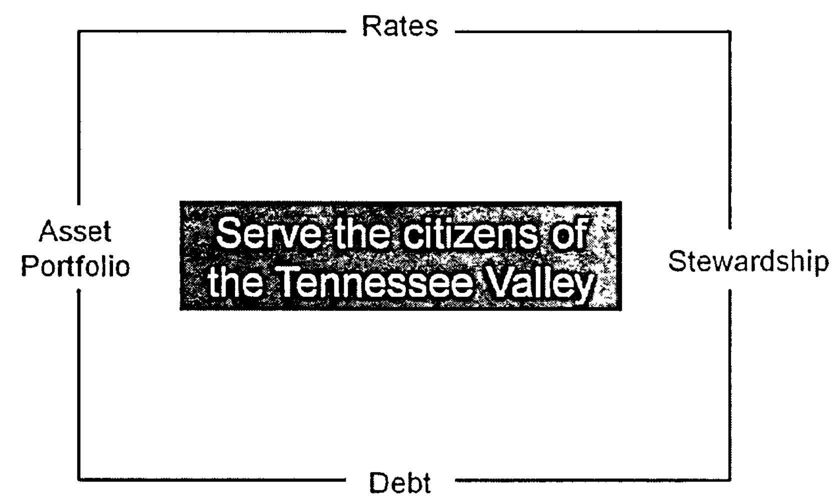
FISCAL YEAR 2014 FINANCIAL PLAN

BUDGET AND BUSINESS PLAN

Ex. Ackerman 2

FISCAL YEAR 2014
KEY FINANCIAL PLAN ASSUMPTIONS

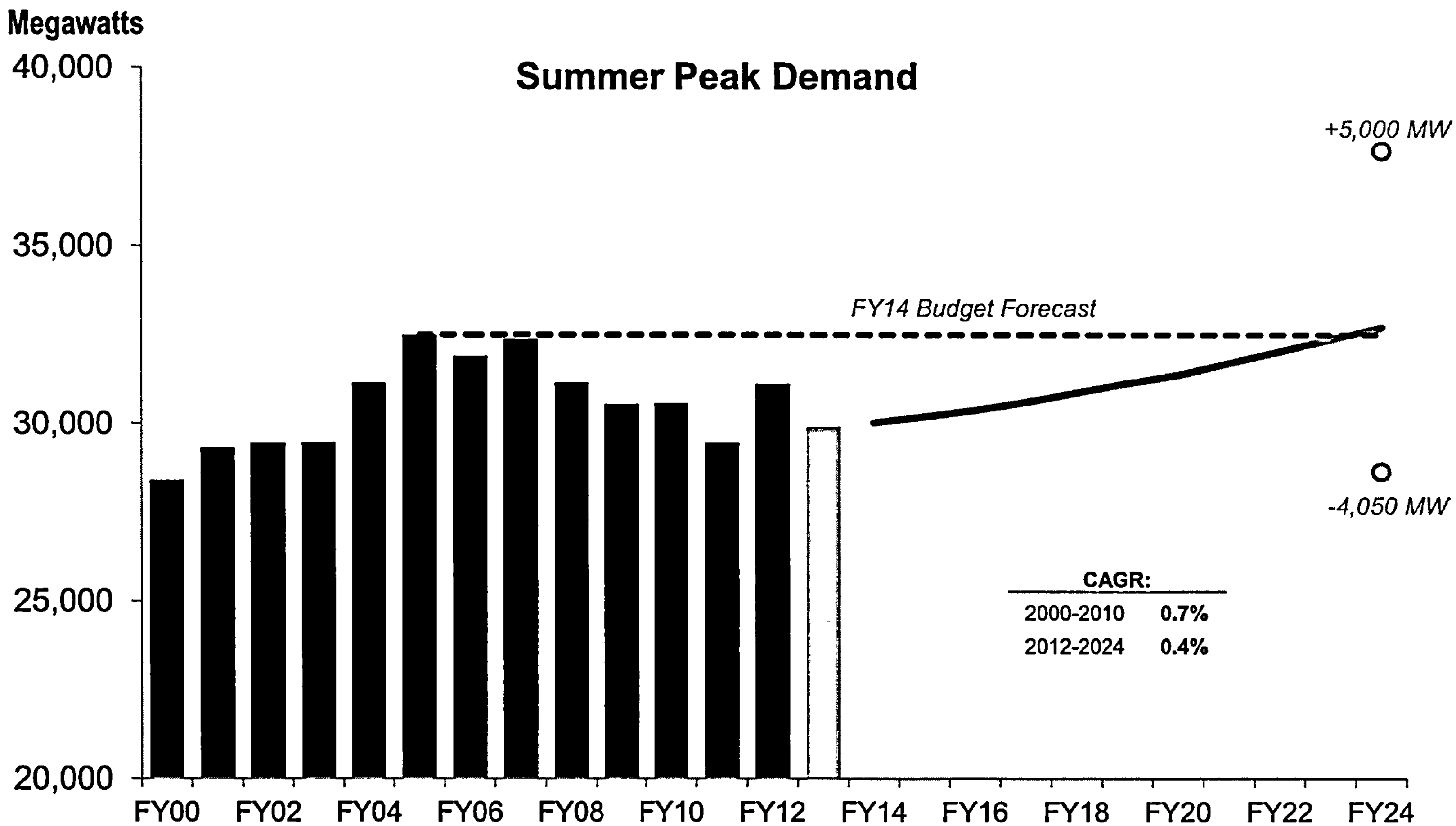
- Live within our means
- Reduce O&M $500M by 2015
  ($300M by FY14, $500M by FY15)
- Borrow for nuclear expansion
- Manage long-term debt
- Increase stewardship
- Plan for modest economic growth
- Continue commitment to energy efficiency, demand response and alternative energy



FISCAL YEAR 2014 FINANCIAL PLAN

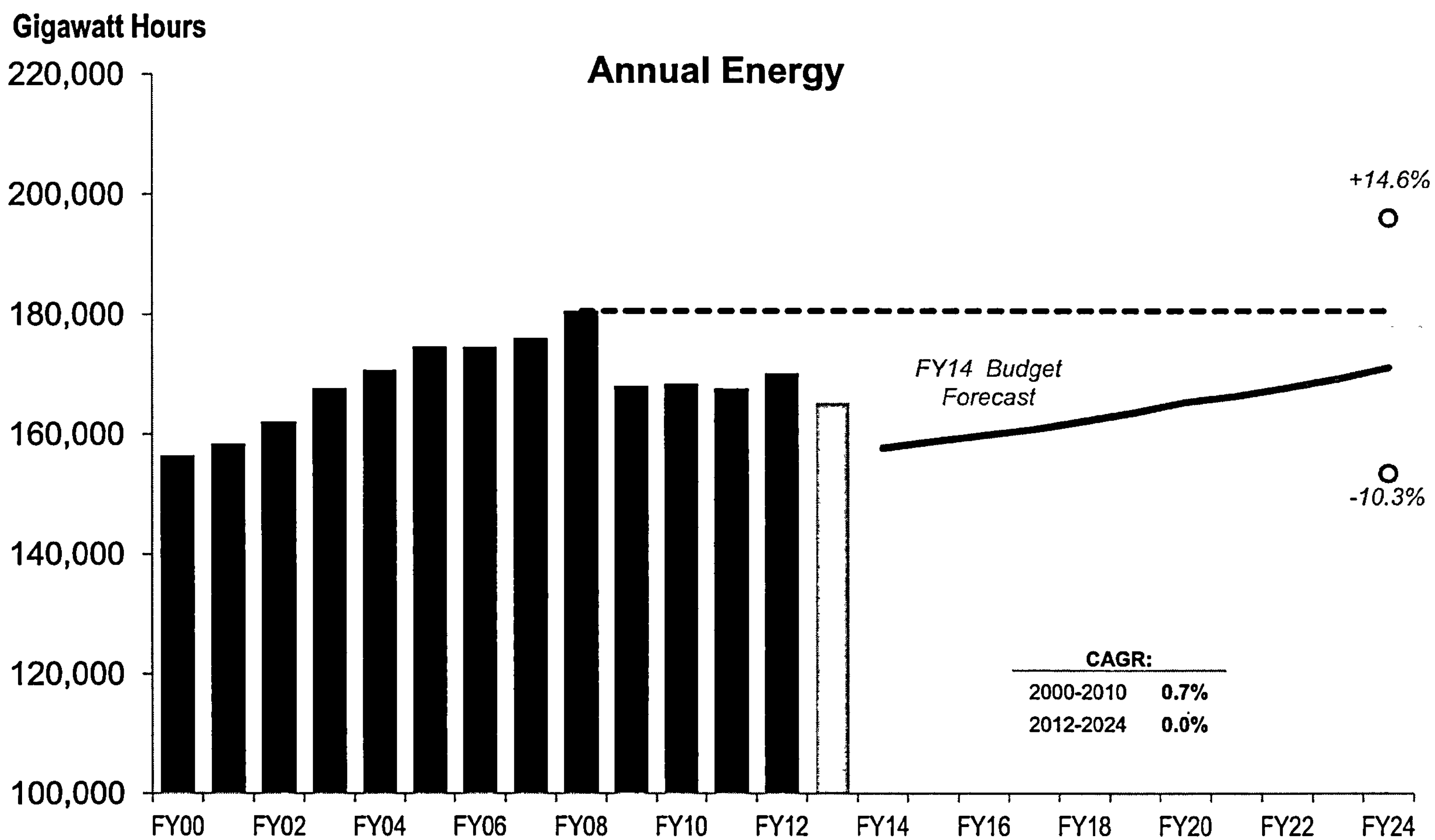
DEMAND AND SUPPLY BALANCE

FISCAL YEAR 2014 SUMMER PEAK FORECAST

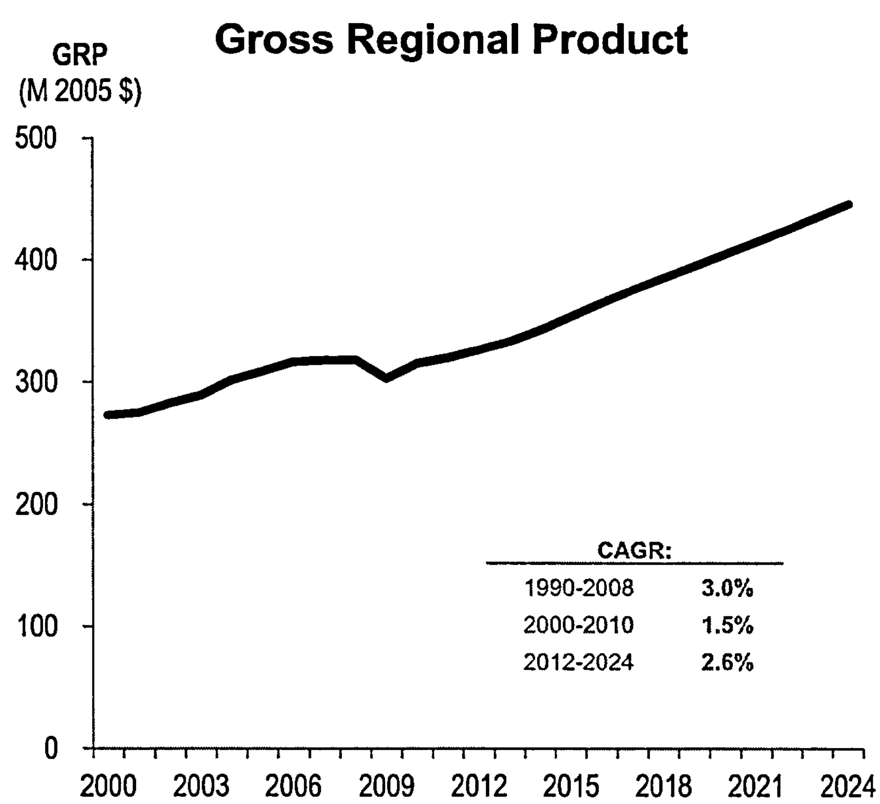


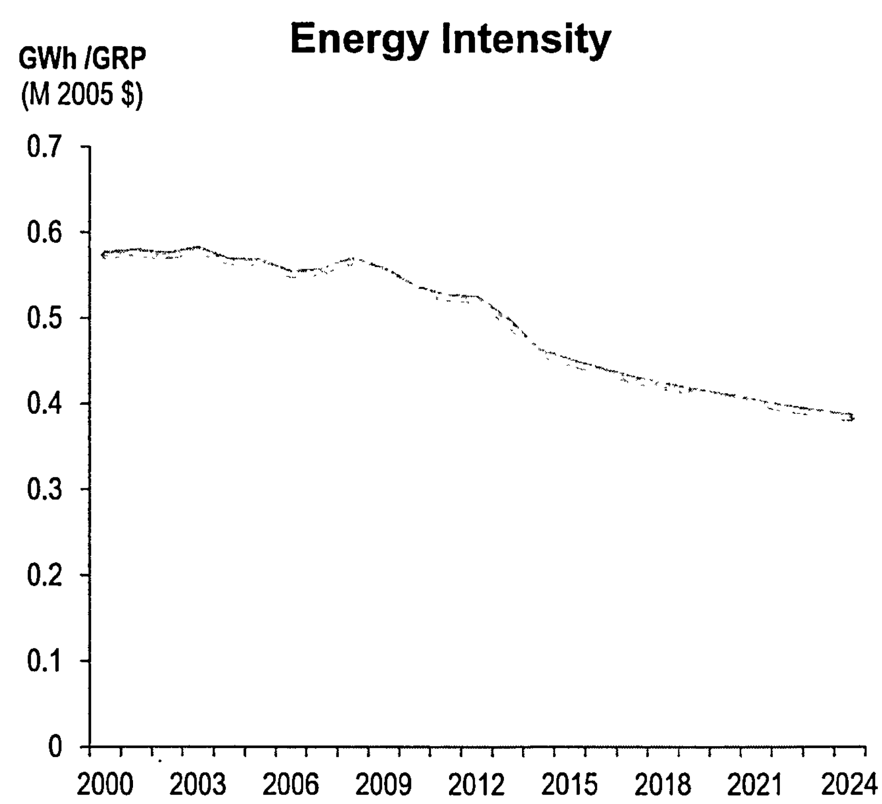
Note: History is weather-normalized. All-time actual peak was 33,482 MW in August 2007 at 104.4°F.
Forecast does not include the impacts of TVA EE/DR programs.

FISCAL YEAR 2014 ENERGY FORECAST

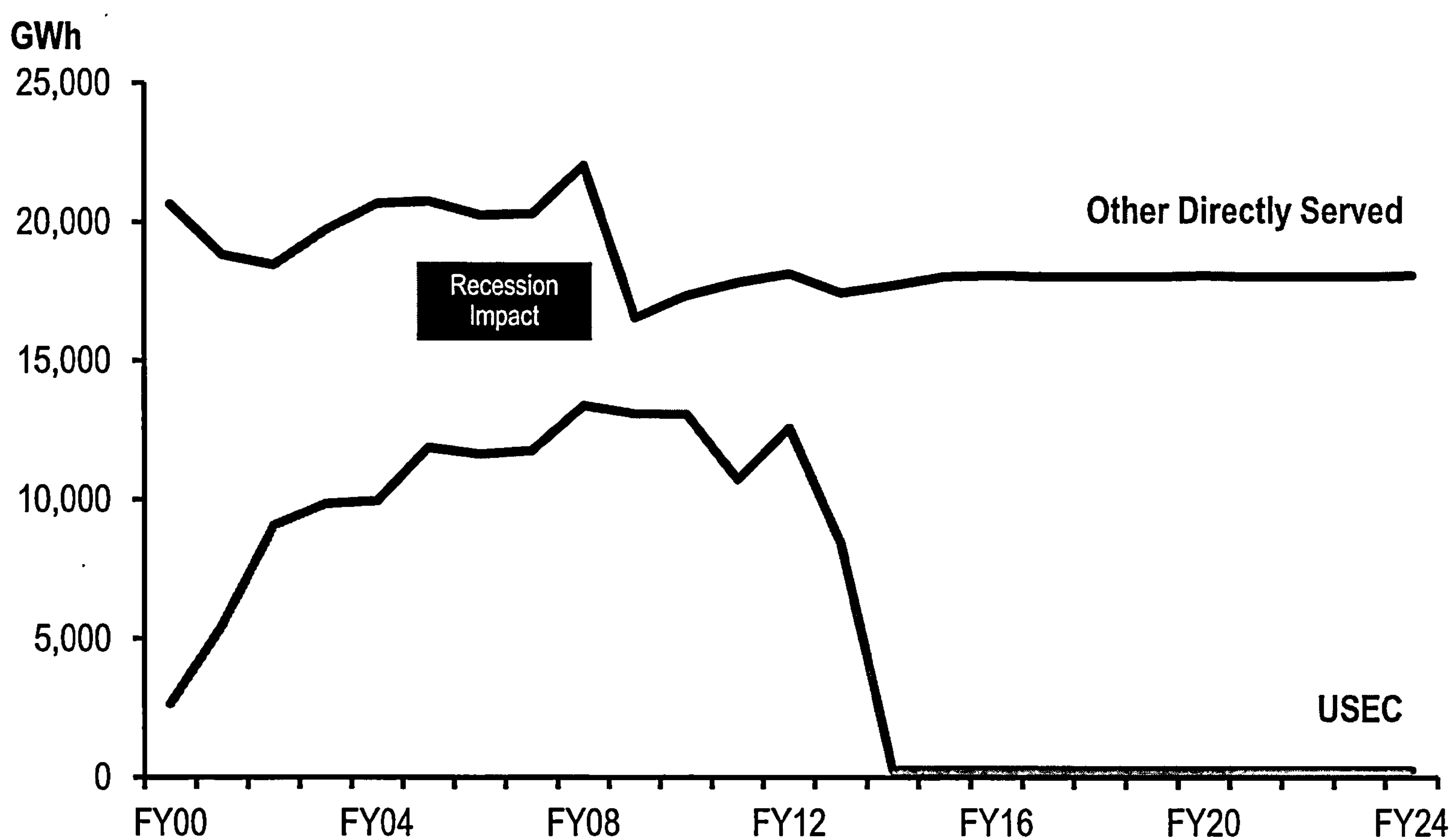


REGIONAL ECONOMY GROWING, BUT MORE ENERGY EFFICIENT





FISCAL YEAR 2014 DIRECTLY SERVED ENERGY USE

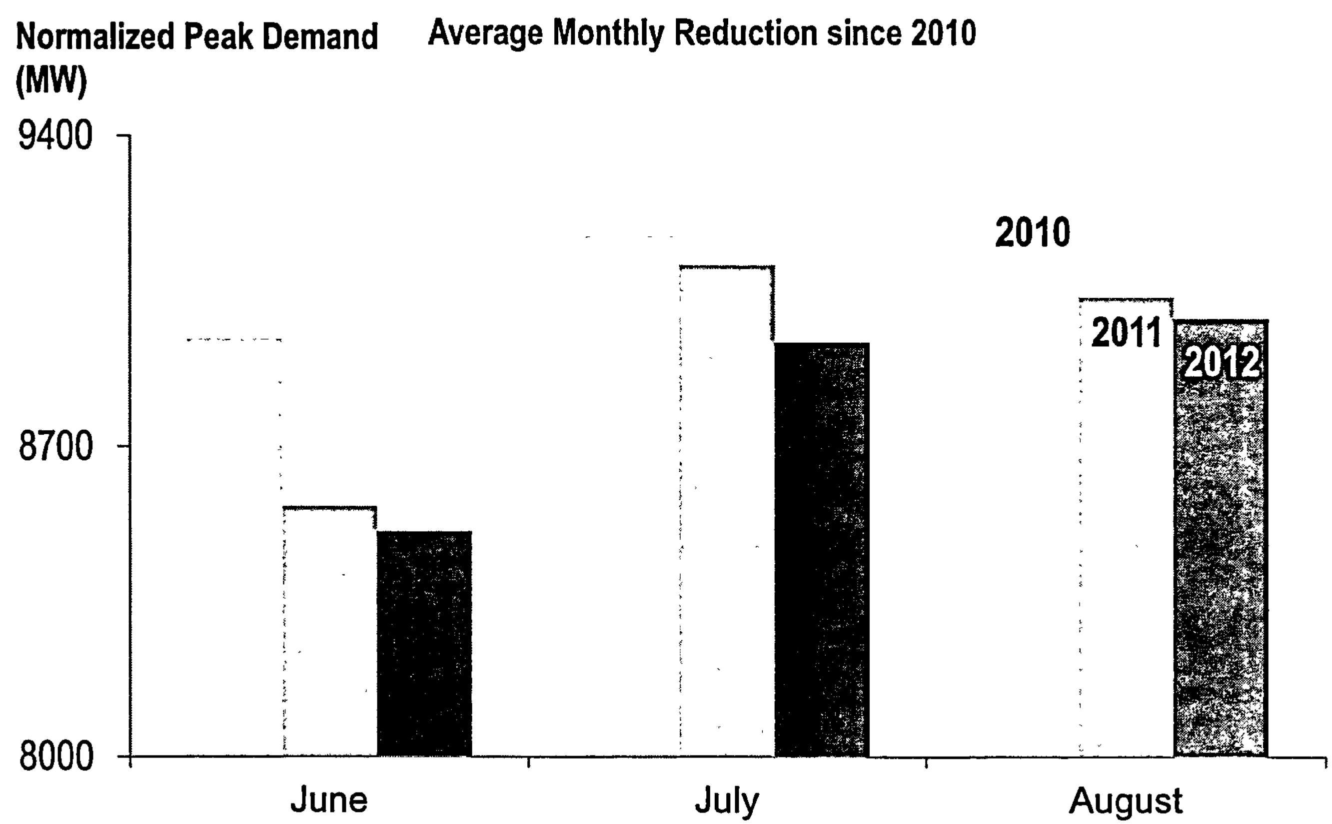


RESPONDING TO NEW RATES

Local Power Companies Have Reduced Peak Demand Under New Rate Structure

3.5%

Average Monthly Reduction since 2010



Rate change effective April 1, 2011; peaks are normalized for weather

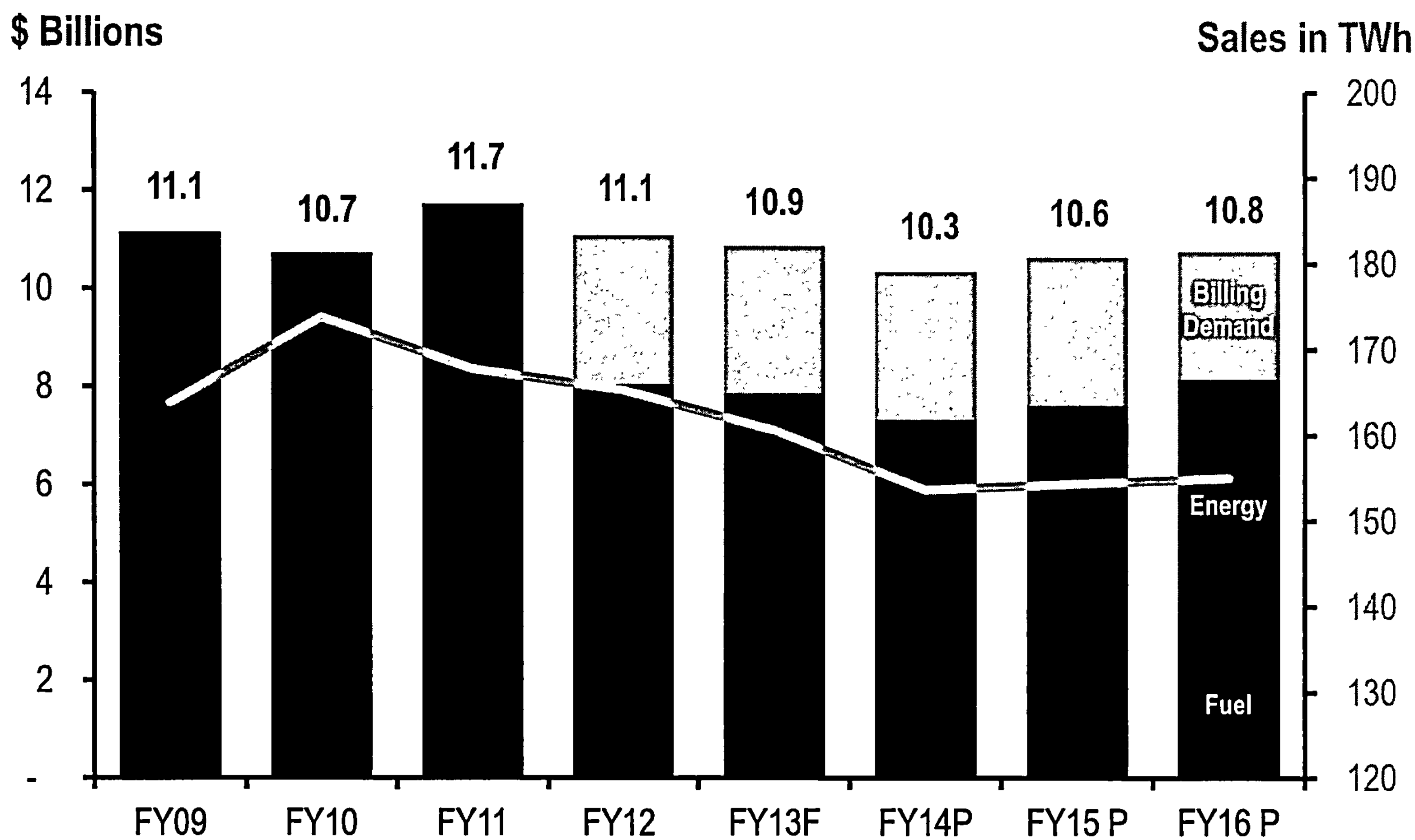
ENERGY SALES 4.6% LOWER

FY13 to FY14:

USEC Reduction	↓	8,200 GWh
Efficiency Gains	↓	750
Economic Growth	↑	1,200
Directly Served Customers	↑	300
Other (Losses)	↓	100
Net Change	↓	**7,550** GWh
TVA Energy Efficiency Program Impacts	↓	360

Energy: decreasing 4.6% driven primarily by USEC; decreasing 4.8% with TVA Energy Efficiency programs.
Demand: summer peak increases 0.4% from 29,914 MW in FY13 to 30,027 MW in FY14; 0% growth with TVA DR programs.

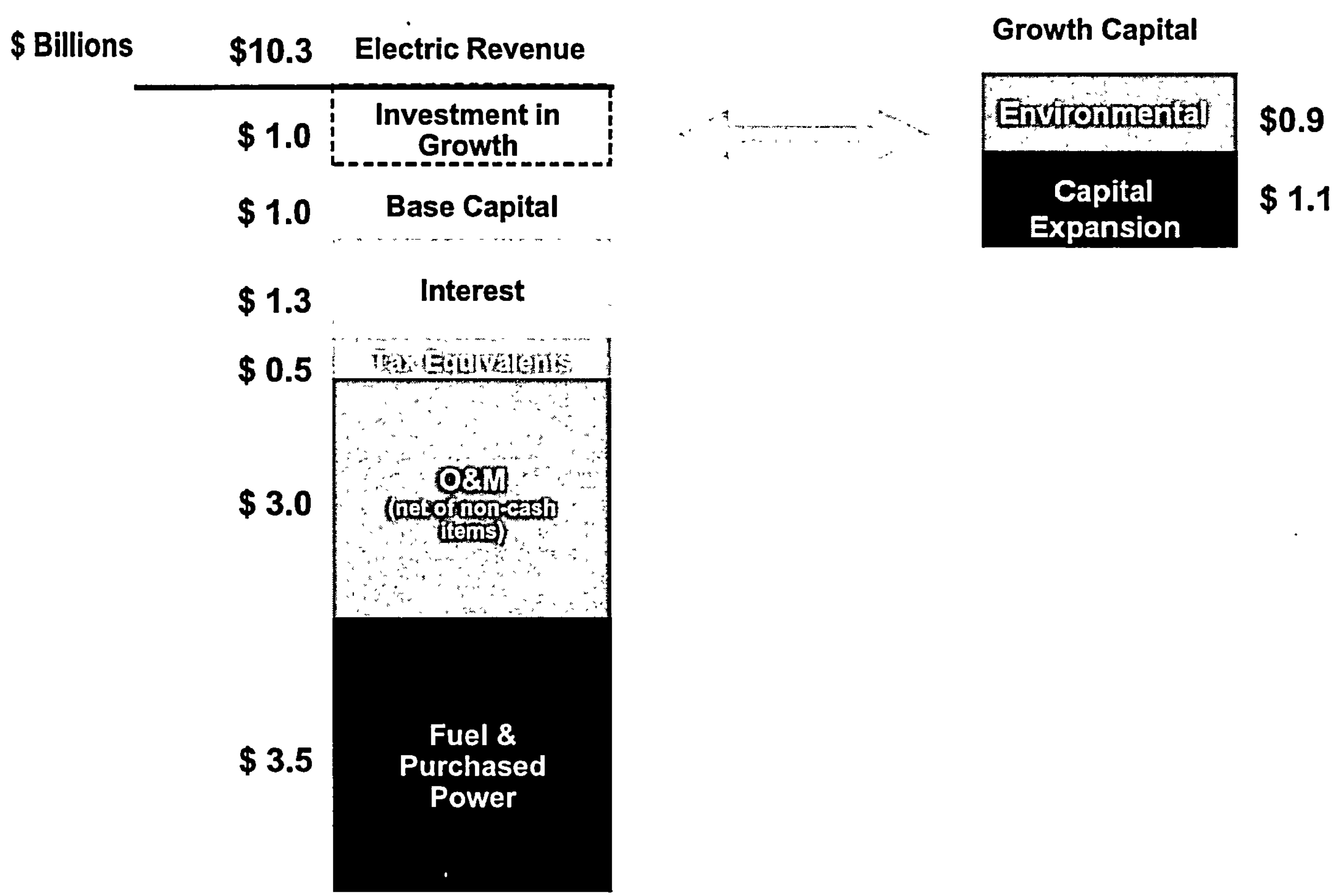
REVENUE TREND



Excludes other revenues

Ex. Ackerman 2

LIVING WITHIN OUR MEANS

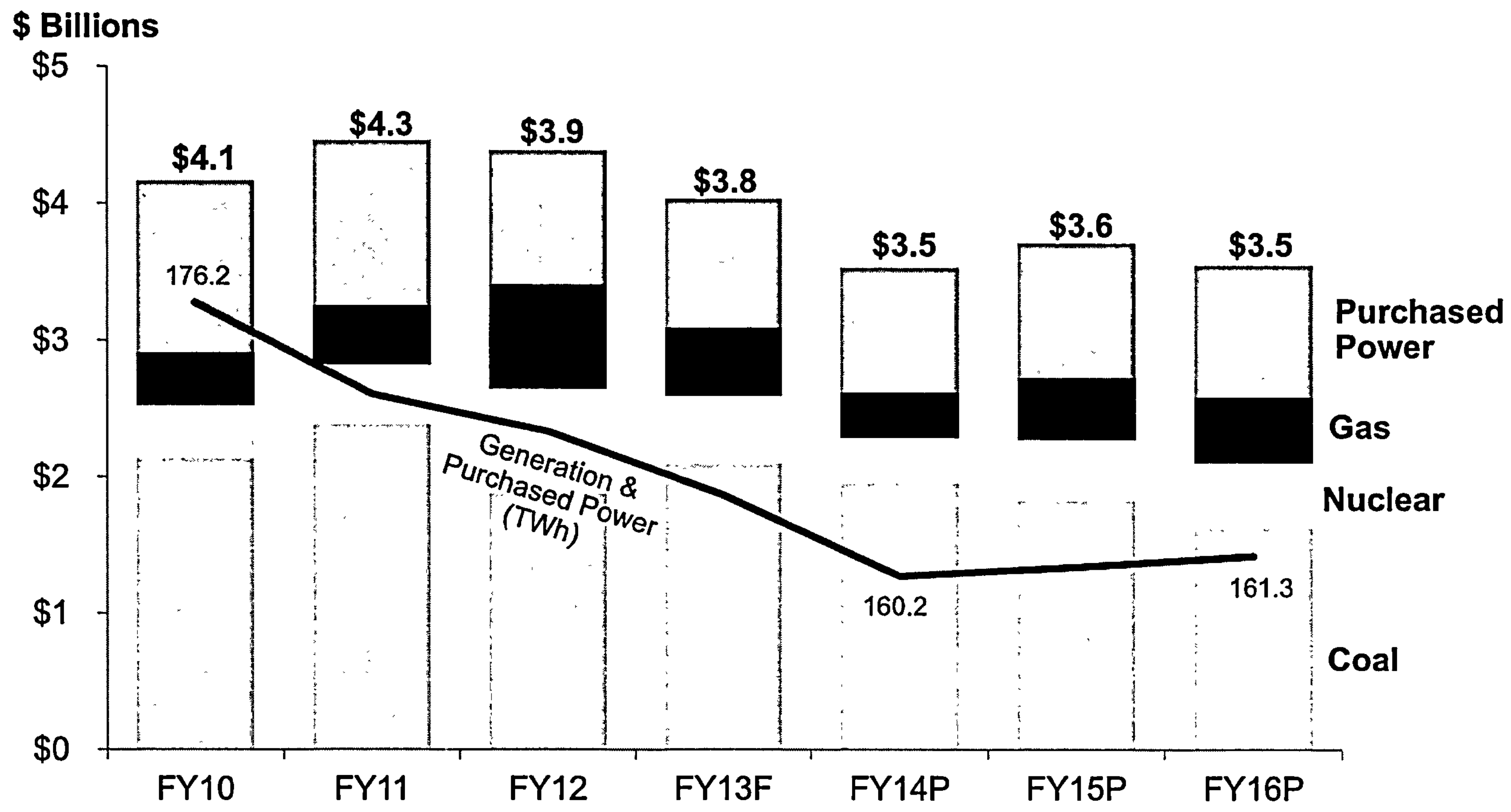


Excludes other revenues

FISCAL YEAR 2014 FINANCIAL PLAN

COST DRIVERS

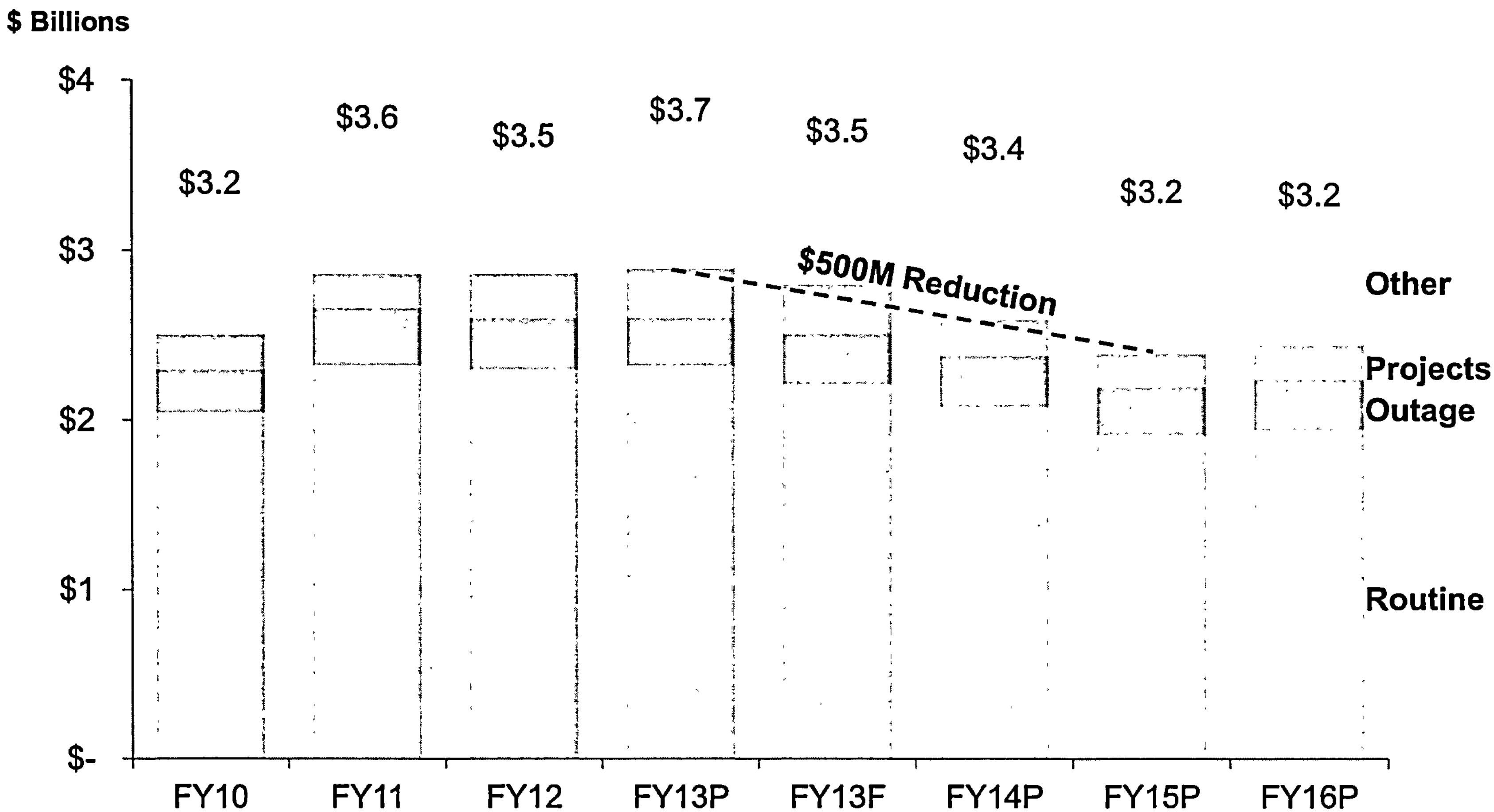
FUEL AND PURCHASED POWER



NOTE: Excludes adjustments to fuel expense related to FCA fuel revenue over/under recovery.

Ex. Ackerman 2

O&M EXPENSE TRENDS



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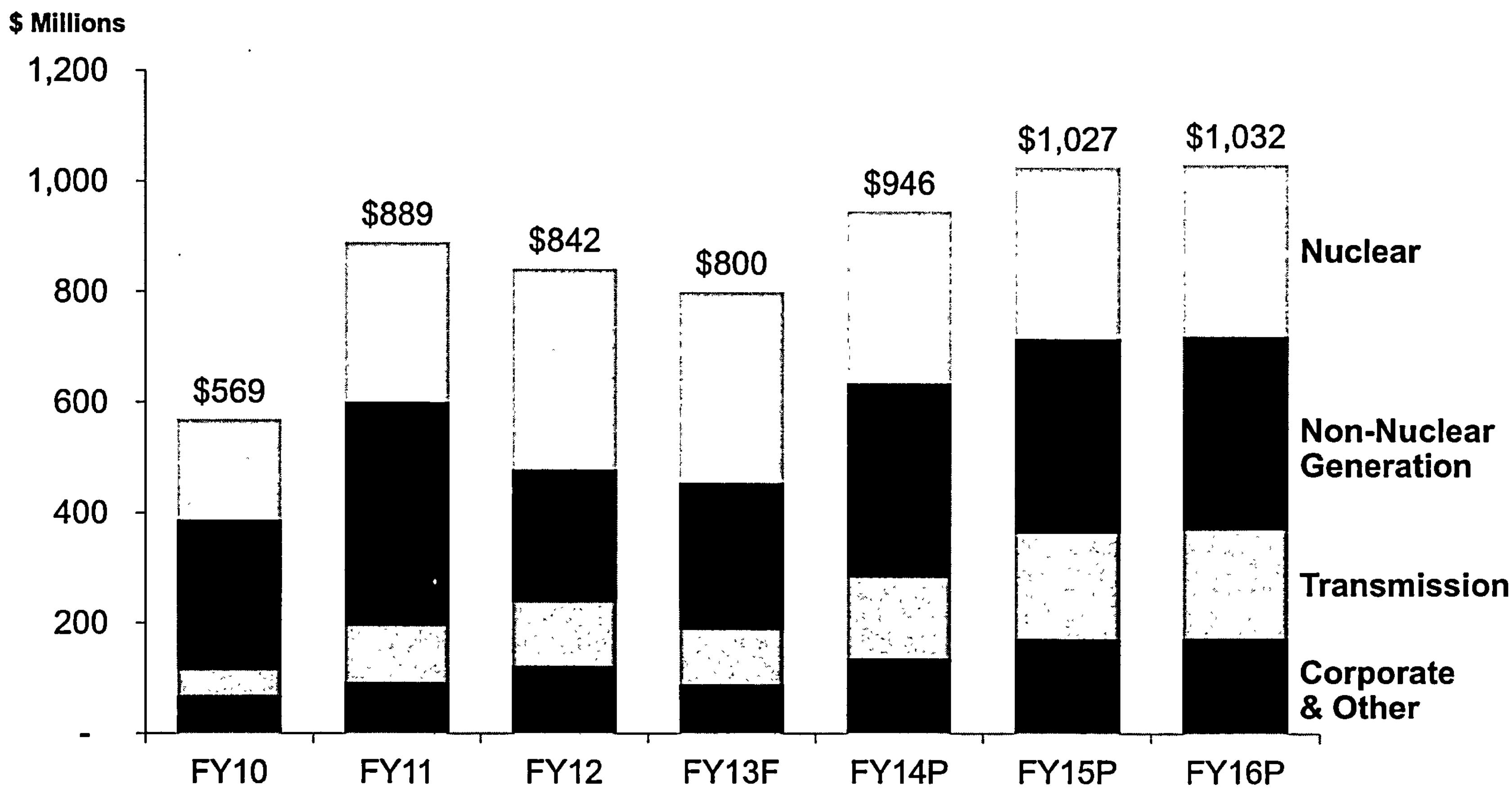
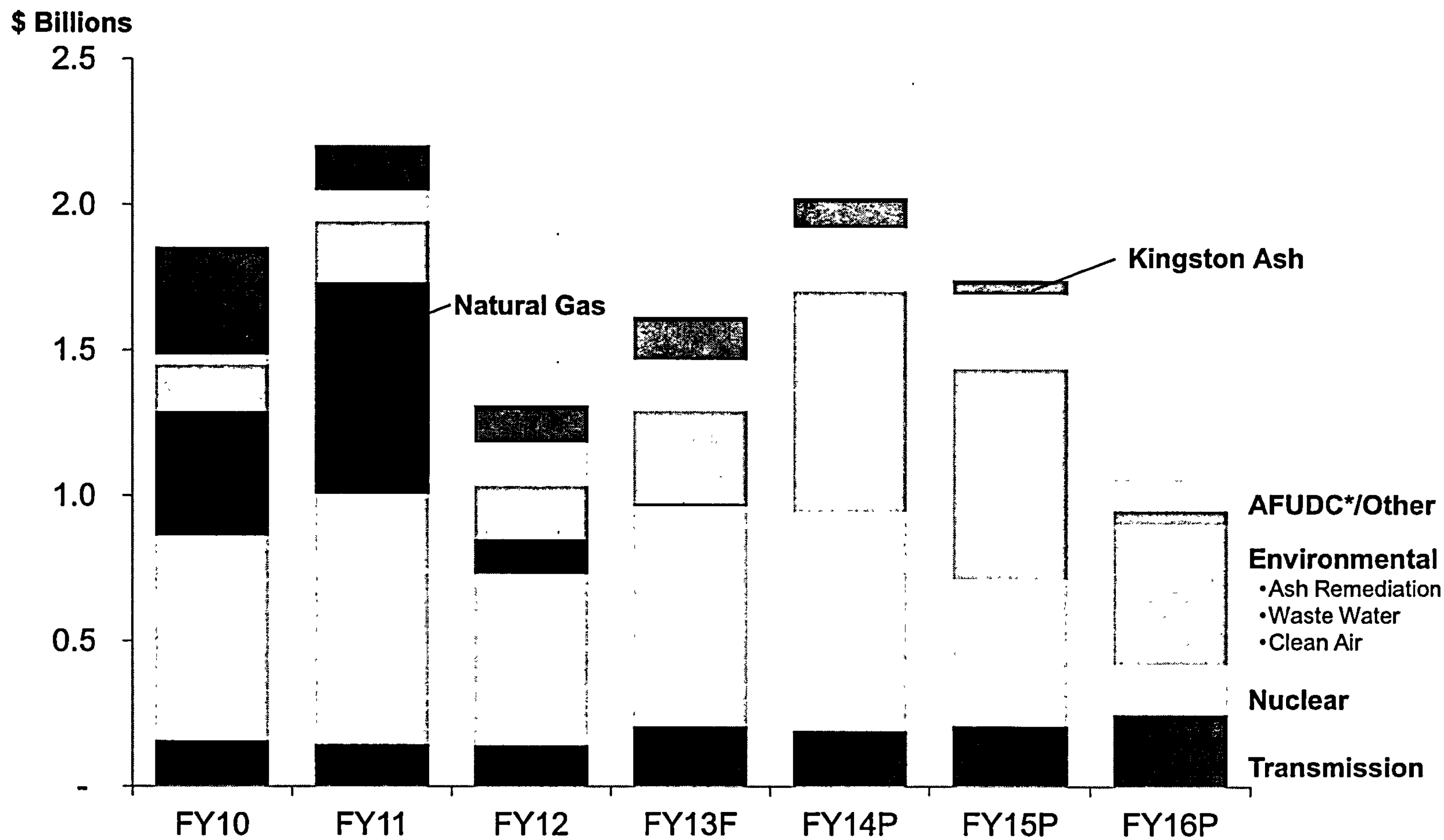
BASE CAPITAL SPENDING



Ex. Ackerman 2

CAPACITY EXPANSION AND ENVIRONMENTAL CAPITAL



*Allowance for funds used during construction

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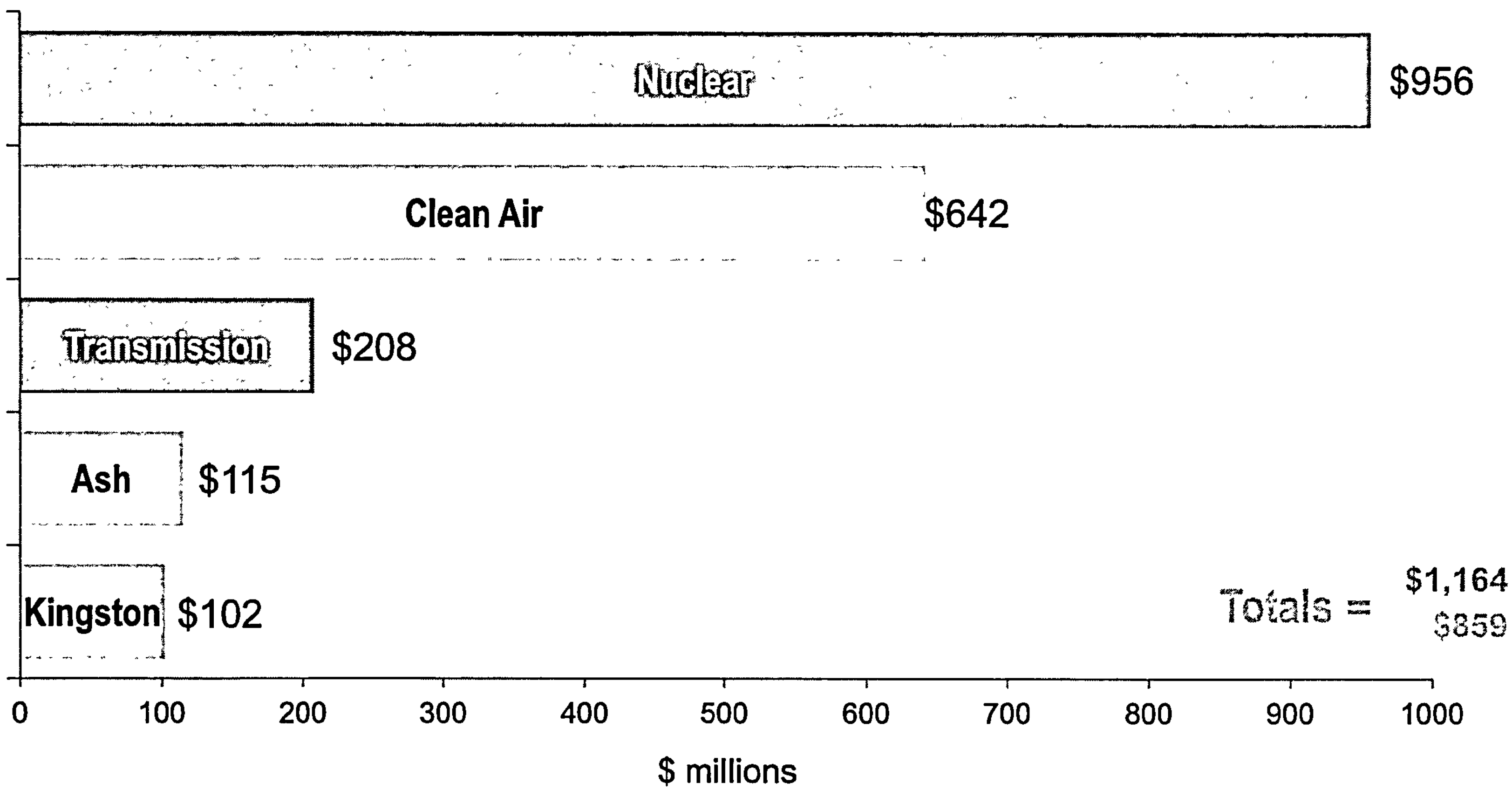
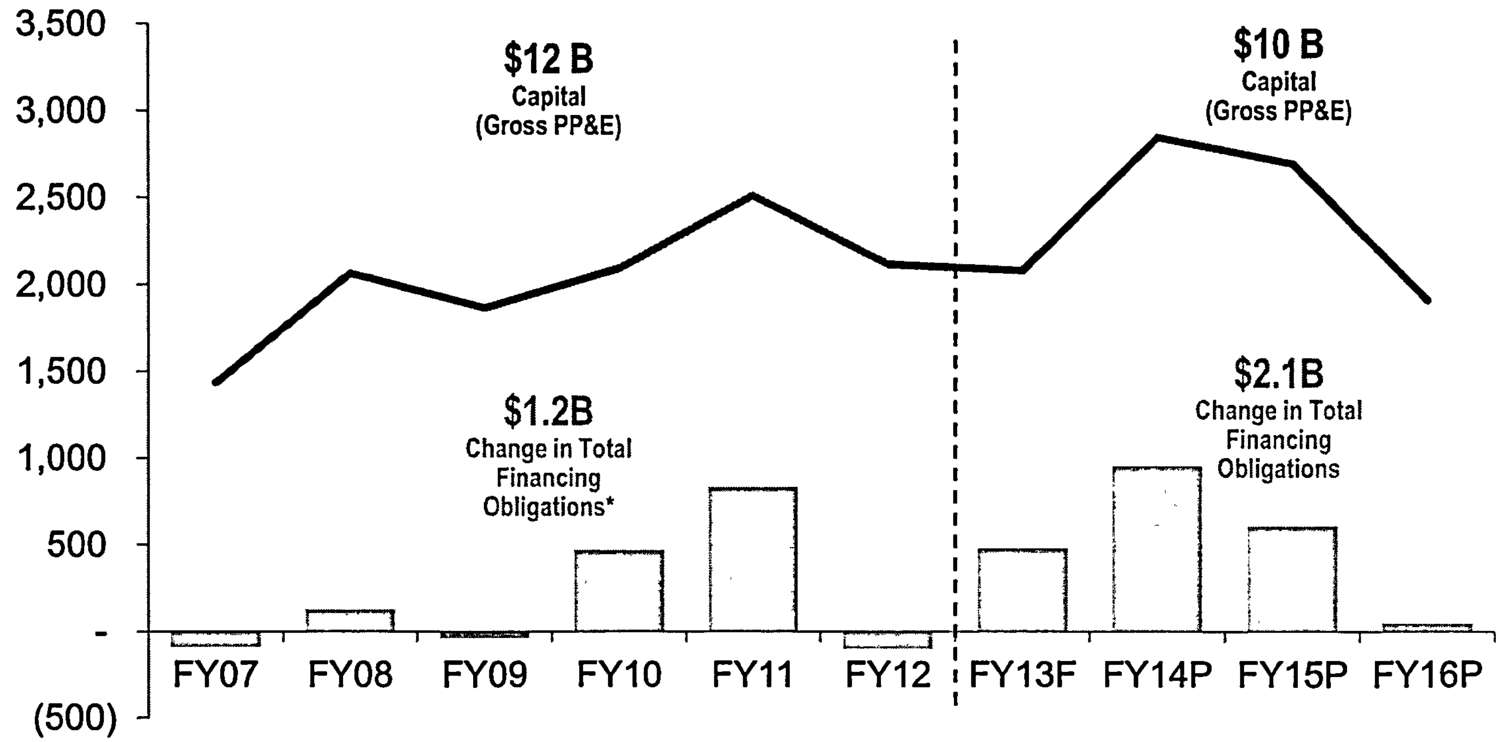
FISCAL YEAR 2014 SPEND: CAPACITY EXPANSION AND ENVIRONMENTAL



Ex. Ackerman 2

MANAGING CASH AND DEBT

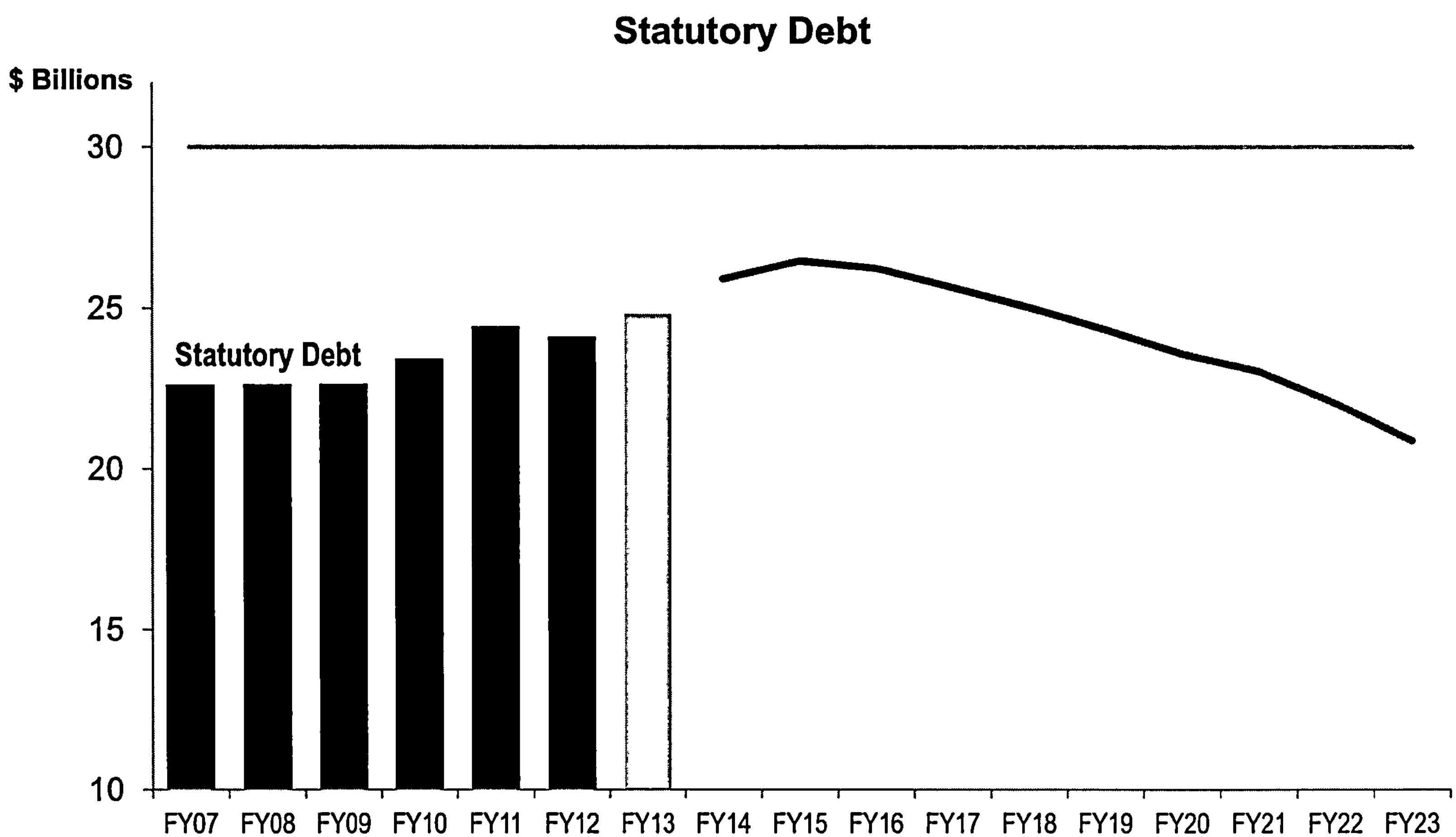
Increasing productive assets with cash generated from operations



Effective Interest Rate				5.4%	5.5%	5.4%	5.2%	5.2%	5.3%	5.6%

*TFO net of cash

LONG-TERM DEBT REDUCTION PLAN



Based off current load projections (32,366 MW in FY23)

FISCAL YEAR 2014 FINANCING NEEDS DRIVEN BY NUCLEAR CAPACITY

FY 14 Beginning Balance - Total Financial Obligations ($ Billions)			**$ 27.5**
FY 14 Debt:	New Issuance	Maturing/ Reduction	
Nuclear Expansion	**$ 1.0**		
New Debt to Replace Maturing Debt	0.2		
Converting Short Term Debt	2.8		
Total FY 14 Financing Shelf	**$ 4.0**	(3.1)	0.9
FY 14 Ending Balance - Total Financing Obligations			**$ 28.4**

FY14 Ending Statutory Debt balance is $25.9 billion.

RISKS AND CHALLENGES

- Weather
- Commodity Prices
- Sales: Economy/Customer Impacts
- New Regulations
- Asset Risk Management: Material Condition
- Sustainable Productivity Improvements

FISCAL YEAR 2014 FINANCIAL PLAN

RATE OUTLOOK

FY14 SUMMARY INCOME STATEMENT

$ millions	
Operating Revenue	**$ 10,468**
Fuel & Purchased Power	3,498
Operations, Maintenance	3,437
Depreciation, Amortization, Accretion	1,791
Tax Equivalents	513
Operating Expenses	**9,239**
Other Income	41
Interest Expense	1,269
Net Income	**$ 1**

FY14 SUMMARY CASH FLOW

$ millions	
Cash From Operations	**$ 2,230**
Cash (Used in) Investing	**(3,282)**
Cash From Financing	**952**
Net Change in Cash	(100)
Beginning Cash Balance	1,287
Ending Cash Balance	**$ 1,187**

RECOMMENDATION

Approve the 2014 budget:
- Revenues of $10.5 billion
- Operating Expenses of $8.7 billion
- Capital Expenditures of $3.3 billion

Approve Contracting Plan for Fuel and Purchased Power
- Fuel & Purchased Power of $3.5 billion (In Operating Expenses)

Rate actions effective October 1
- Extension of Environmental Adjustment
- Effective retail rate increase of 1.5%

Approve Financial Shelf for issuance of up to $4 billion of long-term bonds
- New debt of $0.9 billion

FINANCE, RATES, AND PORTFOLIO COMMITTEE

HYDRO-MODERNIZATION CONTRACT

AUGUST 22, 2013

FOR BOARD CONSIDERATION

Approval to enter into hydro-modernization contracts with Voith Hydro, Andritz Hydro and any future supplier meeting similar minimum requirements to improve reliability and provide additional hydroelectric capacity

BACKGROUND

- TVA's hydro-modernization (HMOD) program began in 1992 to address the reliability issues of an aging fleet and to provide additional hydroelectric capacity
- 55 conventional units have been completed for a gain of 421.9 megawatts
- All four Raccoon Mountain Units have been completed with a gain of 109.4 megawatts
- Currently Voith Hydro is the sole supplier for HMOD Services to TVA

GOING FORWARD

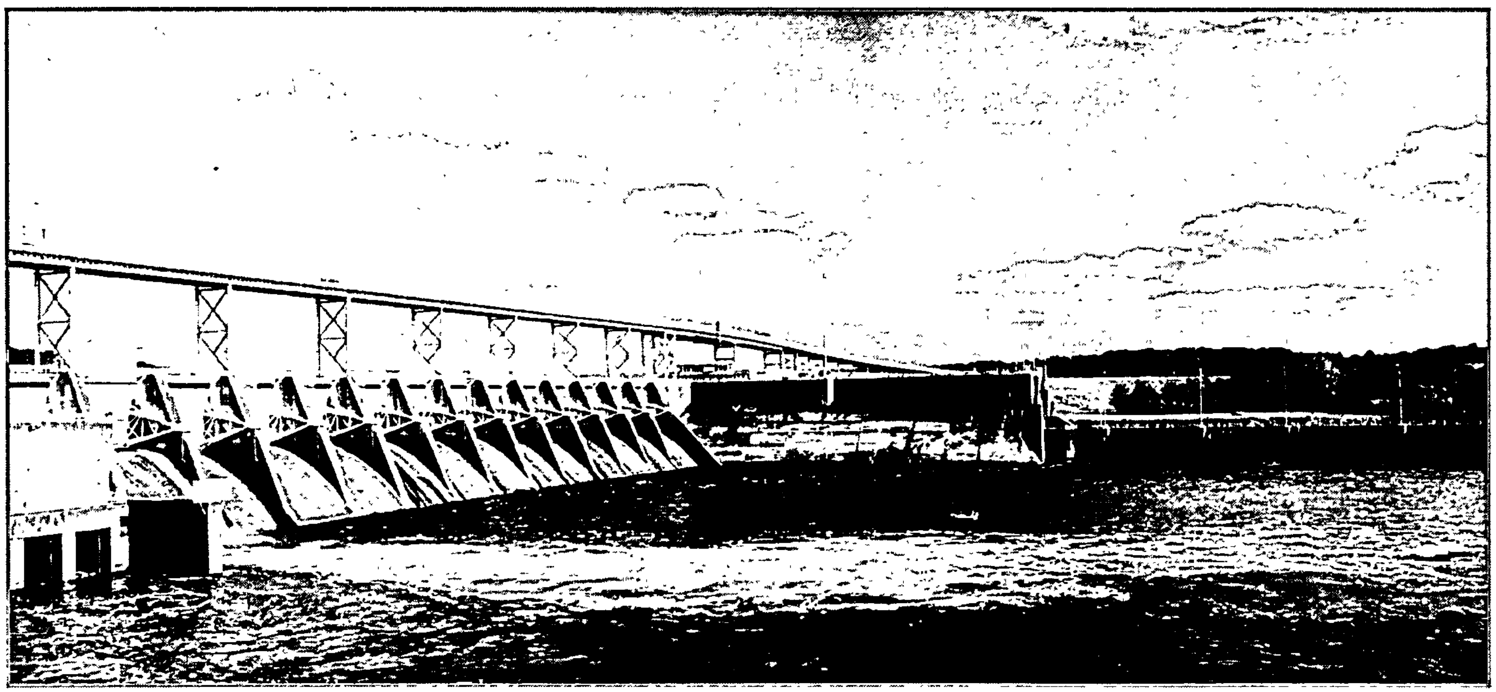
- HMOD program will address 51 units with an average age of 70 years
- A total capacity increase of 184 megawatts
- Contracts would carry an initial five-year term with option to extend up to an additional five years
- Total requested dollar amount for all contracts is $350 Million

CONTRACTING STRATEGY

- Proposed HMOD contracting strategy will expand the supplier base of these services, thereby ensuring availability of suppliers and encouraging competition, resulting in lower costs to TVA
- TVA would, at its option, award managed tasks using any combination of the following pricing methods
  - Fixed Price
  - Time and Material
  - Target pricing / Cost reimbursable
- Awards would be based on: Contractor task cost estimates and proposals; Schedule and Contractor availability; and Contractor experience and capabilities
- No minimum amount of work is guaranteed

RECOMMENDATION

Approval to enter into hydro-modernization contracts with Voith Hydro, Andritz Hydro and any future supplier meeting similar minimum requirements to improve reliability and provide additional hydroelectric capacity



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FINANCE, RATES, AND PORTFOLIO COMMITTEE

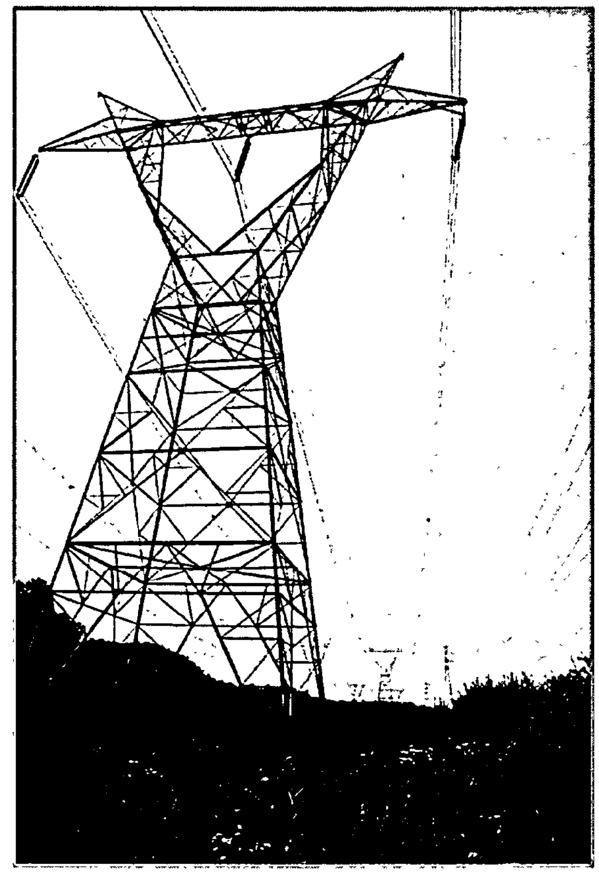
TRANSMISSION CONSTRUCTION CONTRACT

AUGUST 22, 2013

Ex. Ackerman 2

FOR BOARD CONSIDERATION

Approval to enter into transmission system construction and modification services contracts



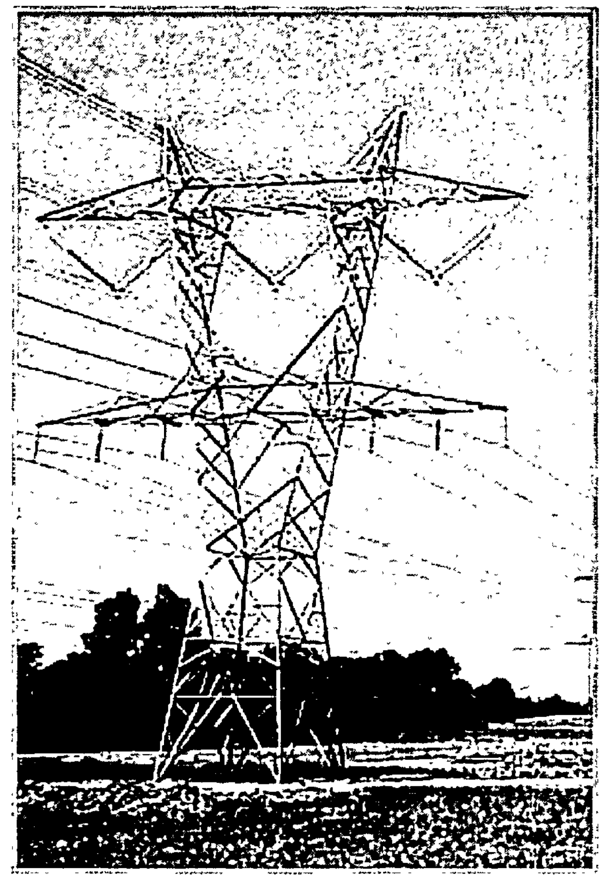
BACKGROUND

- Suppliers perform baseline transmission line and substation construction work along with TVA Employees
- Work-load based on project needs as well as outage seasons

Ex. Ackerman 2

GOING FORWARD

- L. E. Myers Company, Henkels & McCoy, Asplundh Construction Corporation and Service Electric Company were selected after a competitive solicitation
- Requested contracts would carry an initial five-year term with options to extend up to five additional years
- Combined spend of $400 million



CONTRACTING STRATEGY

- Proposed contracting strategy solidifies the supplier base of these services, thereby ensuring availability of suppliers and encouraging competition, resulting in lower costs to TVA
- TVA would, at its option, award managed tasks using any combination of the following pricing methods
  - Fixed Price
  - Time and Material
  - Target pricing / Cost reimbursable
- Awards would be based on: Contractor task cost estimates and proposals; Schedule and Contractor availability; and Contractor experience and capabilities
- No minimum amount of work is guaranteed

RECOMMENDATION

- Approval to enter into transmission system construction and modification services contracts

FINANCE, RATES, AND PORTFOLIO COMMITTEE

ECONOMIC GROWTH STRATEGY

AUGUST 22, 2013

FOR BOARD CONSIDERATION

Request Board approval of short-term actions to attract, retain, and expand industry through TVA Valley Commitment Program and Small Manufacturing Program.

INDUSTRIAL RATE COMPETIVENESS

- Electricity is a significant cost for industry in the Valley
- Many industrial customers within the Valley compete with sister facilities and competitors outside the Valley

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INDUSTRY IN THE VALLEY

- 10,000 manufacturing companies
- 527,000 direct jobs
- $32 billion direct wages

PRESERVING VALLEY INDUSTRY

- Long-term actions
  - Cost Management
  - Long-Term Pricing Strategy
- Near-term actions
  - Valley Commitment program
  - Small manufacturing rate schedule

VALLEY COMMITMENT PROGRAM

- Voluntary program for all industrial and manufacturing customers
- Requires two-year commitment
- Two-year program with CEO option to extend up to an additional two years

SMALL MANUFACTURING PROGRAM

- Optional rate schedule
- Applies to industrial customers with contract demands from one megawatt to five megawatts
- Aligns customer's bill with Local Power Company's cost to serve
- Provides incentive for customers to operate outside of Local Power Company's peak-demand period

RECOMMENDATION

1) Approve the Valley Commitment Program for two years with a delegation to the CEO to extend the program for two years
2) Approve the Optional Manufacturing Service Rate and the Direct Service Manufacturing Power Rate for small industrial and manufacturing customers under 5MW

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TVA

NUCLEAR OVERSIGHT

COMMITTEE

AUGUST 22, 2013

PEOPLE AND PERFORMANCE COMMITTEE

NUCLEAR SAFETY POLICY

AUGUST 22, 2013

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TVA

PEOPLE AND PERFORMANCE
COMMITTEE

AUGUST 22, 2013

PEOPLE AND PERFORMANCE COMMITTEE

ANNUAL AND LONG-TERM GOALS

AUGUST 22, 2013

FISCAL YEAR 2014 PERFORMANCE GOALS

- Adopt design changes to TVA Performance Goal Programs and approve scorecards for FY14
  - Annual Incentive Program (Winning Performance)
    Designed to promote teamwork, create a high performance culture, and motivate and reward all eligible employees for achieving goals
  - Executive Long-Term Incentive Plan (ELTIP)
    Designed to support achievement of long-term strategic goals

WINNING
PERFORMANCE DESIGN CHANGE

- Adjust board modifier to a corporate multiplier between 0 and 1.0
- Board defines key strategic imperatives to be included in multiplier
- Board / CEO assess performance above or below the target to determine final multiplier
- CEO establishes operational scorecards
- Multiplier applied to operational scorecard results
- Board continues to use judgment in all aspects of corporate performance

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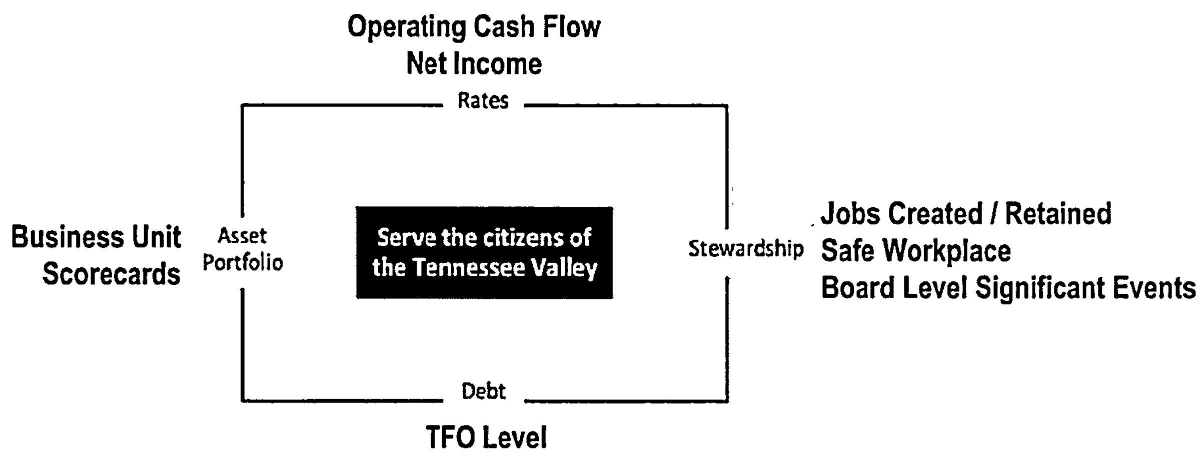
CORPORATE MULTIPLIER



TVA must be successful.... ***...to enable business unit payouts***

Corporate Multiplier **0 – 1.0 multiplier**

Aligns to Financial and Stewardship Strategic Imperatives Outlined by Board
"Manage the Business"

X

Business Measures **0% - 150% of payout**

Align to Operational Plans & Benchmarks
Demonstrated Improvement
"Run the Business"

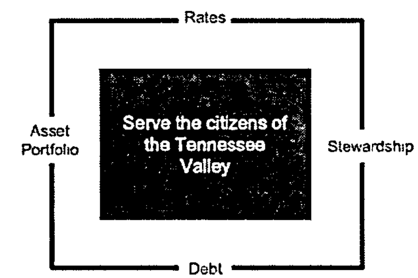
- **Corporate Measures include only a target**
- **CEO / Board will assess performance**

- **Business Measures include a threshold, target, and stretch performance (formulaic) for line of sight**

MULTIPLIER MEASURES

Corporate Multiplier
Aligns to Financial and Stewardship Strategic Imperatives Outlined by Board "Manage the Business"

0 – 1.0 multiplier



Measure	Target
Safe Workplace	0
Operating Cash Flow	Budget
Net Income	Budget
TFO Level	50,000
Jobs Created / Retained	0
Board Level Significant Events	Budget

- **Corporate Measures include only a target**
- **CEO / Board will qualitatively assess performance**

CHANGES TO EXECUTIVE LONG-TERM INCENTIVE PLAN

- Organizational Health Survey
  - 2013 – use Pulse Organizational Health Survey
- Retail Rate (2014-2015)
  - Change measure to wholesale rate less fuel
  - Align targets to Board-approved financial plan
- Adopt External Measures indicator
- Approve 2016 Executive Long-term incentive plan cycle scorecard

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CORPORATE MEASURES – ALIGNED TO MISSION

		TVA Mission				
	Measure	Low-Cost Reliable Power	Economic Development	Environmental Stewardship	Technological Innovation	River Management
Corporate Multiplier (Winning Performance)	Operating Cash Flow	✓	✓	✓	✓	✓
	Net Income	✓	✓			
	TFO Level	✓		✓		
	Jobs Created & Retained	✓	✓	✓		✓
	Safe Workplace	✓		✓		✓
	Board Level Significant Events	✓	✓	✓	✓	✓
	Wholesale Rate excluding Fuel	✓	✓	✓		
Executive Long Term Incentive Plan	Load Not Served	✓	✓		✓	
	External Measures:					
	INPO Index	✓	✓	✓	✓	✓
	Stakeholder Survey	✓	✓	✓		✓
	Media Tone	✓	✓	✓	✓	✓
	Customer Loyalty	✓	✓		✓	✓

RECOMMENDATION

Winning Performance

- Approve change to corporate multiplier
- Approve multiplier measures and targets

Executive Long-term Incentive Plan

- 2013 Cycle
  - Approve use of Pulse Survey for Organizational Health goal
- 2014 and 2015 Cycle
  - Approve changes to Rates and Organizational Health measures
  - Approve External Measures indicator
- 2016 Cycle
  - Approve scorecard and targets

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PEOPLE AND PERFORMANCE COMMITTEE

COMMITTEE CHARTER AMENDMENTS

AUGUST 22, 2013

TVA

AUDIT, RISK, AND REGULATION COMMITTEE

AUGUST 22, 2013

AUDIT, RISK, AND REGULATION COMMITTEE

FISCAL YEAR 2014 EXTERNAL AUDITOR SELECTION

AUGUST 22, 2013

AUDIT, RISK, AND REGULATION COMMITTEE

AMENDMENT TO RATE REVIEW PROCESS

AUGUST 22, 2013

TVA

EXTERNAL RELATIONS
COMMITTEE

AUGUST 22, 2013

EXTERNAL RELATIONS COMMITTEE

NONCONFORMING LOADS POLICY AMENDMENT

AUGUST 22, 2013

FOR BOARD CONSIDERATION

Allow nonconforming loads to participate in TVA incentive programs provided they participate in TVA's Instantaneous Response product and meet guidelines

NONCONFORMING LOADS

- Industrial loads greater than 50 megawatts that use power intermittently and subject the system to extreme fluctuations
- Require extra generation assets to be allocated to follow their load swings

PILOT PROGRAM

- January 2012 pilot program using instantaneous response product
- Pilot demonstrates that it is cost effective for TVA to incentivize these companies to locate and grow in the valley

RECOMMENDATION

Allow nonconforming loads to participate in TVA incentive programs provided they participate in TVA's Instantaneous Response product and meet guidelines

EXTERNAL RELATIONS COMMITTEE

STAKEHOLDER GROUP MEMBERSHIP

AUGUST 22, 2013

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TVA BOARD MEETING

AUGUST 22, 2013

Using Real-Time Electricity Data to Estimate Response to Time-of-Use and Flat Rates: An Application to Emissions*

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*We wish to acknowledge helpful comments from Dick Stevie of Duke Energy Company, Herb Thompson and other participants at the Environment and Public Utilities session of the 2010 American Economic Association meetings; Pete Cappers and other participants at the 2011 Thirtieth Eastern meeting of the Advanced Workshop in Regulation and Competition; participants at the 2011 International Association of Energy Economics; Stephen Holland, John Neufeld and other participants at the University of North Carolina at Greensboro; and two anonymous referees. We thank Hualiu Yang for excellent research assistance.

Abstract: Using a Generalized McFadden specification, we estimate the determinants of hourly response for the years 2006 through 2010 for all sixteen standard retail customers who were on an optional real-time electricity rate offered by Duke Energy as of 2010, and provide a method to estimate how these customers would respond to time-of-use and flat rates. We generalize the model to allow for inter-day response, as well as threshold prices, above which individual customer response may increase or decrease. With these inclusions, we find hourly elasticity for the group of customers to be as large as -0.7, larger than previous studies. We apply the method to examine a recent finding that time-differentiated rates could increase electric utility emissions. However, that result did not differentiate between real-time and time-of-use rates, and furthermore held energy use constant in comparing flat rates and time-differentiated rates. We perform a case study to examine emissions of SO_2, NOx, Hg, and CO_2 based on predicted energy use changes as well as for an energy-neutral case for real-time, time-of-use and flat rates. Employing energy-use predictions from the model, increased energy use results in increased emissions in almost all cases. For the energy-neutral case, time-differentiated rates increase CO_2 as compared to flat rates, and the time-of-use rate causes a larger increase than does real-time pricing. But both rates decrease other emissions in the majority of years, particularly SO_2. In addition, time-differentiated rates reduce NOx potency by shifting it to non-daylight hours when conditions for the formation of smog are less favorable. Our application leads to the conclusion that the effect of the rates on emissions must consider total energy use as well as the shift from peak to off-peak. Furthermore, the predictions require consideration of the generating mix at a more detailed level than was contained in previous studies.

Key Words: Real-time pricing, time-of-use pricing, flat rates, electricity, emissions
JEL Codes: L94, Q53, Q54

Using Real-Time Electricity Data to Estimate Response to Time-of-Use and Flat Rates: An Application to Emissions

1.Introduction

Holland and Mansur (HM) (2008) raised the question of whether electricity restructuring that increased use of time-differentiated rates could increase emissions. They predict that time-differentiated rates will increase emissions in parts of the U.S. that rely upon relatively dirty coal for base-load generation and relatively clean natural gas to meet peak demand. In this paper, we compare retail customer electricity use under different rate structures, such as real-time pricing (RTP), time-of-use pricing (TOU) and flat rates. The data are for the years 2006 through 2010 for all 16 commercial and industrial customers who, as of 2010, were on an optional real-time rate offered by Duke Energy Company, a southeast utility that uses coal and nuclear for base-load generation, and natural gas and hydro to meet shoulder and peak demands. We provide a method to estimate electricity use for these customers had they had been subject to TOU or flat rates. Finally, we perform a case study by applying the energy estimates to project corresponding system emissions of sulfur dioxide (SO_2), Nitrous Oxide (NOx), mercury (Hg) and carbon dioxide (CO_2).

We reach a considerably more nuanced conclusion than did HM. To the extent that the rates affect total energy use, an increase in total energy use increases emissions in almost all cases, outweighing the change in emissions due to a change in the pattern of load, an effect that could not be seen given the energy-neutral assumption in HM. Furthermore, the changes in emissions are emissions-specific.

We find that time-differentiated rates are likely to increase CO_2 and reduce SO_2. There is evidence that they may also reduce NOx and Hg. These findings require a greater level of detail than suggested by HM. Even though Duke Energy uses coal for base-load capacity, it also uses intermediate coal units during some peak hours. The intermediate units tend to be older, smaller units with higher emissions than the base-load coal. In particular, unlike the base-load units, they do not contain scrubbers that were installed on base-load units to reduce sulfur emissions.

RTP can change hourly with changes in marginal cost, whereas TOU prices are set well in advance and have multiple pricing periods differentiated seasonally.[1] Over the monthly billing period, flat rates stay the same regardless of marginal costs. Economists have long advocated that prices reflect marginal cost as closely as possible. As RTP more closely approximates marginal cost than does TOU, and TOU is closer than flat rates, the three rates typically rank accordingly on efficiency grounds. The advent of smart meters will strengthen the efficiency case for RTP as compared to the alternatives. In fact, Chao (2011) maintains that with the availability of smart meters, RTP should be the default, with customers who opt for other rates paying a premium to reflect the risk to the electric utility of charging prices that differ from real-time marginal costs.[2] However, the case for time-differentiated rates implicitly assumes that these rates accurately reflect social marginal costs. In a second-best world where calculation of marginal costs does not incorporate all emissions costs, the case for time-differentiated rates is weaker. We examine the effect of an actual real-time rate offered to industrial and commercial customers in the Carolinas by the Duke Energy Company (Duke Energy Company's Schedule HP (hourly pricing)). Our data includes hourly electricity usage for each customer on the RTP tariff for the peak summer months of June through September, for the years 2006 through 2010. Hourly prices are based on marginal energy cost and include a rationing charge when capacity is tight.

Building upon the Generalized McFadden model of price response first applied to real-time response by Patrick and Wolak (1997, 2000) and further developed by Taylor, Schwarz, and Cochell (2005), we estimate how customers would respond to TOU and flat rates. We generalize the model by allowing for inter-day substitution as well as the possibility of threshold prices, above which customer response to hourly rates may increase or decrease. We use the energy estimates to calculate the corresponding system emissions based on the optimal use of generating units. [3] As in HM, the comparison is for the short run, and so does not consider the possibility of capacity expansion and technological change.[4]

Generally, Duke Energy industrial customers who opt for RTP would otherwise be billed on TOU (Schedule OPT - Optional Power Service, Time-of-Use). Duke's TOU rate is subject to adjustment at the time of periodic rate cases. It contains a price differential for designated peak and off-peak hours and consequently provides incentives for load shifting. However, as compared to RTP, TOU prices may not match real-time conditions.

[1] In actuality, retail hourly prices are typically day-ahead prices set before real-time costs are known, such as at 4 PM of the previous business day. See Taylor and Schwarz (2000) for details on the role of advance notice in real-time rates.

[2] Naturally, there will be customer resistance. Flat rates are the current default for most residential customers, so for customers who prefer flat rates, they will resist a changeover that would charge a risk-based premium for customers staying on flat rates. It is common for industrial customers to be subject to TOU as the default, with an option for RTP; industrial customers who prefer TOU to RTP will resist a change in the default rate from TOU to RTP. See Borenstein (2007) for analysis of the implications of customer response to taking on greater price risk with time-differentiated prices.

[3] This data was supplied by the Duke Energy System Operating Center (SOC). The SOC provided the optimal generating stack under the assumption that all units are in service.

[4] Utilities can, however, selectively choose technologies in the short run that reduce emissions at the expense of reduced production efficiency. See Martin, Joskow, and Ellerman (2007).

We pay particular attention to the different incentives of RTP and TOU. Whereas TOU rates include a peak/off-peak price differential on every day, RTP is episodic, raising price only when it is needed as indicated by cost conditions. In addition to the energy charge that varies hourly according to marginal energy cost, the utility applies a rationing charge of considerably larger magnitude on days when combustion turbines are scheduled for operation due to tight capacity conditions, and also on days when system demand is expected to reach 90% or more of the forecasted demand for the summer. The different price incentives of RTP and TOU are likely to lead to differing levels and patterns of energy use and emissions.

Under the assumption that all units are available, generating units are brought on line in order of increasing marginal cost, subject to the constraint that certain units must be brought on line before others. Total emissions is the sum of the emissions of all fully used units plus pro-rated emissions from the marginal unit. We compare emissions based on our energy use results and find that in almost all cases, an increase in energy consumption under one rate compared to another rate leads to an increase in emissions, regardless of the temporal pattern of use. So in order to isolate the effect of price on the time pattern of energy use and consequent emissions, we examine an energy-neutral case where we adjust energy use to be the same for all three rates. As such, our results are directly comparable to those of HM who also assume energy neutrality. We are able to differentiate the effects of RTP and TOU on emissions, as compared to flat rates, a distinction that was not made in HM. Finally, we make an additional distinction by considering emissions potency. For some emissions such as NOx, the link between emissions and social cost is indirect. In order for NOx to produce pollution in the form of smog , it requires heat and sunlight. By transferring NOx emissions to non-daylight hours, their potency is reduced.

Section 2 contains the GM model, generalized to include inter-day substitution and the possibility of threshold prices above which customer response changes. Section 3 contains total energy estimates, as well as peak and off-peak estimates, for the three rates. It also contains peak and off-peak estimates where total energy use has been adjusted to be the same for all rates. Section 4 presents emissions for SO_2, NOx, Hg, and CO_2 based on estimated total energy as well as the energy-neutral case. Section 5 closes with a summary and conclusions.

2. Model

We follow the procedure established in Taylor, Schwarz, and Cochell (2005) using the Generalized McFadden (GM) as our model. The GM is a flexible functional form that satisfies the global curvature restrictions implied by economic theory, while being able to capture substitutability and complementarity among inputs.

We generalize that model in two ways. First, we allow inter-day as well as intra-day substitution. A second generalization, not considered in the 2005 paper or by HM, is that we consider the possibility of a threshold price above which response can increase or decrease.[5] The concept of a price threshold is relevant to RTP because hourly prices are extremely high when capacity is expected to be tight.

A set of demand equations derived from a Generalized McFadden (GM) cost function is as follows:[6]

$$E_{idyk} = \frac{Y_{dyk}}{PPI_{my}}[\sum_{j=1_1}^{24} c_{ijdyk}P_{jdyk} + L + b_{iyk}] + a_{iyk} + T + U_{idyk} \qquad (1)$$

Variables are defined as:
E_{idyk} – Demand in mWh (megawatt hours) for hour i, day d, year y, customer k;
PPI_{my} – Producer price index for month m, year y;
P_{jdyk} – Price in \$/mWh (megawatt hour) for hour j, day d, year y, customer k; [7]
L – A combination of leading and lagging prices specific to the hour and the day of the week;

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[5] Two types of price thresholds are defined - one for maximum daily price and another for average daily price. For example, a customer may show a relatively small response until the maximum daily price reaches $100/mWh, and then show a larger response. Similarly, an average price threshold is identified if customer response increases or decreases when the average daily price reaches a certain level. The existence of thresholds can generally be determined by inspection of price, quantity scatter diagrams. We developed an algorithm that accomplishes this objective in a more precise manner. The algorithm searches the price, quantity space in a grid pattern. The pattern is defined by price on the horizontal axis and quantity on the vertical. The search determines if there is an upper right-hand quadrant that is essentially devoid of observations. If so, the left-hand boundary of that quadrant defines the threshold value on the horizontal axis. The specification we use for estimation of equation (1) incorporates a binary variable to indicate whether a threshold exists. We do not utilize the actual value of the threshold.

[6] This equation is similar to PW (1997), 4-12, equation (7). PW show that this demand equation is obtained by application of Shephard's Lemma to the GM expected variable cost function.

[7] The price used for estimation is the hourly price of the Duke tariff. Duke Power's RTP rate is a standard two-part tariff. It contains a customer baseline with charges for consumption above the baseline assessed at the hourly price and reductions below the baseline credited at the hourly price. The hourly price is provided on a day-ahead basis.
There are two charges that are applied *ex post*. An "Incentive Margin" of $0.005 per kWh is assessed to "Net New Load". Net new load is the amount by which the total of hourly consumption above the baseline exceeds the total of hourly consumption below the baseline. If net new load is negative, the incentive margin does not apply. For simplicity, we added the incentive margin directly to all hourly prices. The great majority of customers in the Duke population have net new load greater than zero and even for those with negative net new load, adding the incentive margin does not change relative prices across hours of the day.
In addition to the incentive margin, the Duke tariff assesses an *ex post* "Incremental Demand Charge" on the order of $0.25 per kW to the amount by which maximum demand for the month exceeds the billing demand of the baseline charge. This charge is small in comparison to the demand charges of Duke's standard rates which are on the order of $10 to $13 per kW. We examined bills for a typical month drawn from our population and found the share accounted for by this charge to be just over 0.5% on average. At its greatest, the share was just over 2.5%. Given such a small influence on customer bills, we did not incorporate the incremental demand charge in our analysis.

T – Function of temperature humidity index in degrees;
Y_{dyk} – Daily output on day d, year y for customer k;
U_{idyk} – Unobserved random vector with mean 0 and covariance matrix Ω;
where i = 1, …, 24 (1= hour ending at 1 AM, 24 = hour ending at midnight); d = 1,…, 122 (June 1=1,…, September 30=122), y = 1, …, 5 (1 = 2006,…, 5 = 2010); k = 1,…, 16.

Hourly energy use (E_{idyk}) is in units of mWh; however, results are in kWh to be consistent with units generally applied in retail markets. The producer price index (PPI_{my}) is available quarterly, so it takes on one value for June, and a second value for July, August and September for each summer.[8]

Leading and lagging prices allow inter-day substitution. Leading price information is available because of the timing of price notification. Customers are guaranteed that they will be notified of hourly prices by 4 P.M. of the previous business day. As a result, during late afternoon and evening, customers will know not only what their prices are for the current day, but also what prices will be on the following day and perhaps even further out depending on weekends and holidays. For hours 17-24 on weekdays, customers know prices for the following day. On Friday, they also receive prices for the weekend as well as the following Monday. Since this information is available to the customer for planning, it is included in the model in the form of average daily prices for a number of leading and lagging days determined by the amount of information available. A detailed discussion of the variables is in Appendix 1. Details on the estimation procedures are in Appendix 2.

In Equation (1), the expression in brackets describes hourly electricity demand as a linear function of prices for each hour of the day along with a constant term. Theoretical rigor calls for the inclusion of the firm's output (Y_{dyk}) in the derived demand for an input such as electricity. In this study, however, as in many studies of industrial energy use, output is unavailable.[9] As a proxy for output, we construct an index based on the firm's daily energy use. We perform an auxiliary regression where we regress daily energy use on prices, weather and other variables. From these estimates we obtain the predicted value of daily energy removing weather effects, and form an index by dividing this predicted value by the firm's average daily energy use for the entire summer.

Customer response to hourly prices of equation (1) is captured in the elements of the C matrix. This 24x24 matrix is not estimated directly, but is the product of matrices, where the matrices

[8] As pointed out by a referee, costs may vary by industry, which would not be reflected in a single producer price index. This problem would be more serious if data were pooled over customers and years. However, because estimates are obtained for each customer by year separately, and with just two values for the PPI, the gains to an industry-specific PPI would be likely to be small.

[9] For competitive reasons, firms consider this information confidential. Even if it were available, it is unclear how to measure output in service industries such as, for example, a university.

contain estimated terms. The elements of the C matrix are not actual own and cross elasticities, but do provide a measure of price response. While making use of the assumption that the matrix is symmetric reduces the number of elements, there are still 300 unique elements, too many to estimate directly. As a result, we follow the approach of Patrick and Wolak (2000), who make use of Fourier series and symmetry of C matrix elements to reduce the number of estimated parameters. We fit 24 equations, one for each hour of the day, with a total of 121 parameters. For each equation there are 122 unique daily observations for a total of 2,928 observations (24x122). Because the parameters are shared across equations, our approach provides nearly 117 degrees of freedom for each equation. By constructing our C matrix as the negative of the product of a lower triangular matrix and its transpose we insure that the negative of C is positive definite. If a customer has no price thresholds, the C matrix does not change. But for customers with a marginal or average price threshold, that customer has a different C matrix for those days when prices exceed the threshold. Details are in Appendix 1.

Duke's RTP program began in 1994, and we include all16 customers who remained on the program as of 2010. In total, there are 80 separate customer-year estimates of equation (1). There are 24 hourly equations, each with 122 daily observations for June, July, August, and September, and these equations are estimated simultaneously, by year, for each of the five years 2006 through 2010.

The data are organized as a time series containing 2928 observations per customer for each year. The error is specified as AR(m) -EGARCH(p,q) and accounts for both intra- and inter-day autoregression as well as heteroskedasticity. [10] A sequential approach first determines the autoregressive process across hours within the day and then transforms the data accordingly and determines the autoregressive process across days. The EGARCH portion of the model is fit in a separate step. When the data transformation is complete, final estimates are from non-linear OLS and Seemingly Unrelated Regression.

III. Energy Estimation

Table 1 shows pricing information for a representative North Carolina RTP tariff. Rationing charges are incorporated into hourly prices to signal that capacity is getting tight. Their use depends upon demand-side factors such as extreme temperatures and supply-side factors such as the necessity to use combustion turbines to meet peak demands. Average energy prices are highest in 2008 and lowest in 2009. The driver for the high 2008 prices was the rising cost of fuel. The economic slowdown started to impact demands and prices around September 2008. The magnitude of the rationing charges and the number of days with rationing charges were lower in 2008 than in 2006 and 2007. The summer of 2009 was exceptionally cool, and rationing charges were imposed on only two days, by far the lowest number of the five summers. In contrast, the summer of 2010 was exceptionally hot and rationing charges were imposed on 55 days, the highest number of the five summers. Summer 2007 was the next hottest summer, and

[10] In our case, the order m is ((1), (24)).

August of that summer was the hottest August on record. Summer 2006 was the 2nd coolest summer of the five years, and September 2006 was the coolest month of the five-year period.[11]

Our objective is to estimate energy consumption for the group of customers billed on RTP as if they were billed on Duke's TOU rate, or alternatively, on a flat rate. We use equation (1) in conjunction with marginal prices for the TOU rate and the flat rate to obtain these estimates. So, we first must develop the marginal prices associated with these alternative rates.

Duke's TOU rate contains a monthly demand charge ($/kW) that applies during the on-peak hours over the month. The on-peak period is from 1 P.M. to 9 P.M. on weekdays (except for holidays). All other hours are off-peak.[12] There is also a fixed on-peak energy charge ($/kWh) and a fixed off-peak energy charge ($/kWh). The marginal price for all off-peak hours in the month is equal to the off-peak energy charge. For on-peak hours, the marginal price must incorporate both the demand charge and the on-peak energy charge. We calculate this price as equal to the On-Peak Energy Price + the On-Peak Demand Charge / On-Peak Load Factor / On-Peak Hours.[13] Note that to obtain the contribution of the demand charge, this calculation effectively holds On-Peak Load Factor constant for a marginal change in On-Peak Energy.

The flat rate is simply the load weighted average of all hourly prices from the customer's RTP rate. Calculations are performed on a month by month basis for each customer individually. We do not include the price threshold for TOU or flat rate estimation, as these rates do not change on days when real-time hourly prices are exceptionally high.

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[11] There are other factors that influence when Duke Energy activates rationing charges, so the anecdotal data suggesting an association between temperature and the use of rationing charges may exaggerate the connection. Duke is currently reexamining its criteria for when to use rationing charges.

[12] In North Carolina, July 4 and Labor Day are off-peak, in South Carolina they are not.

[13] We use customer loads observed as they are billed on RTP to calculate on-peak load factor defined as the average hourly energy consumption during on-peak hours divided by peak demand. Only hours which do not have rationing charges and are not quiet periods or outliers (these two terms are described in Appendix 1) are used in this calculation. As an example of the calculation of peak price, assume the energy price is $.07/kWh, the demand charge is $10/kW, on-peak energy consumption equals 22,000 kWh, peak demand equals 1000 kW, and there are 176 peak hours in the month. The peak load factor is calculated to be 0.8 and the marginal price for all peak hours is $0.141/kWh.

Table 1

Real-Time Prices (HP Rate), North Carolina Transmission Industrial Service[a]

Year	Month	Average Energy Price ($/mWh)	Average Rationing Charge ($/mWh)	Hours with Rationing Charges	Average RTP Price ($/mWh)
2006	6	43.59	99.83	35	48.44
	7	48.64	99.35	123	65.06
	8	46.37	97.31	151	66.12
	9	29.08	0	0	29.08
	Summer	41.92	74.12	309	52.18
2007	6	29.06	60.05	30	31.56
	7	43.43	78.95	74	51.28
	8	73.68	111.22	315	120.77
	9	42.48	62.8	19	44.14
	Summer	47.16	78.25	438	61.94
2008	6	91.68	73.55	209	113.03
	7	75.69	43.88	114	82.41
	8	66.62	39.97	74	70.59
	9	60.99	0	0	60.99
	Summer	73.74	39.35	397	81.76
2009	6	36.01	0	0	36.01
	7	37.74	0	0	37.74
	8	39.11	60.82	15	40.33
	9	38.58	0	0	38.58
	Summer	37.86	15.21	15	38.17
2010	6	39.01	78.16	117	51.71
	7	43.84	94.52	244	74.84
	8	47.03	94.57	160	67.36
	9	41.07	69.81	56	46.5
	Summer	42.74	84.27	577	60.10

[a]In 2006 and 2007, the maximum rationing charge was $238.95/mWh with 37 days and 44 days of rationing charges, respectively. In 2008, the maximum rationing charge was $195.45/mWh with 35 days of rationing charges. In 2009, the maximum rationing charge was $151.96/mWh with 2 days of rationing charges. In 2010, the maximum rationing charge was $238.95/mWh with 55 days of rationing charges.

Table 2 shows actual electricity consumption for the 16 customers with RTP for all five summers. The table also contains estimated consumption for those customers if they had been billed on the other two rates.

Table 2

Total Electricity Consumption for Customers

	Total Loads, mWh		
Year	**Flat Rate**	**TOU**	**RTP[a]**
2006	802,352	795,320	854,799
2007	912,807	930,727	888,372
2008	937,430	934,231	899,014
2009	846,152	786,282	837,859
2010	888,582	865,794	892,258
Average	**877,465**	**862,471**	**874,460**

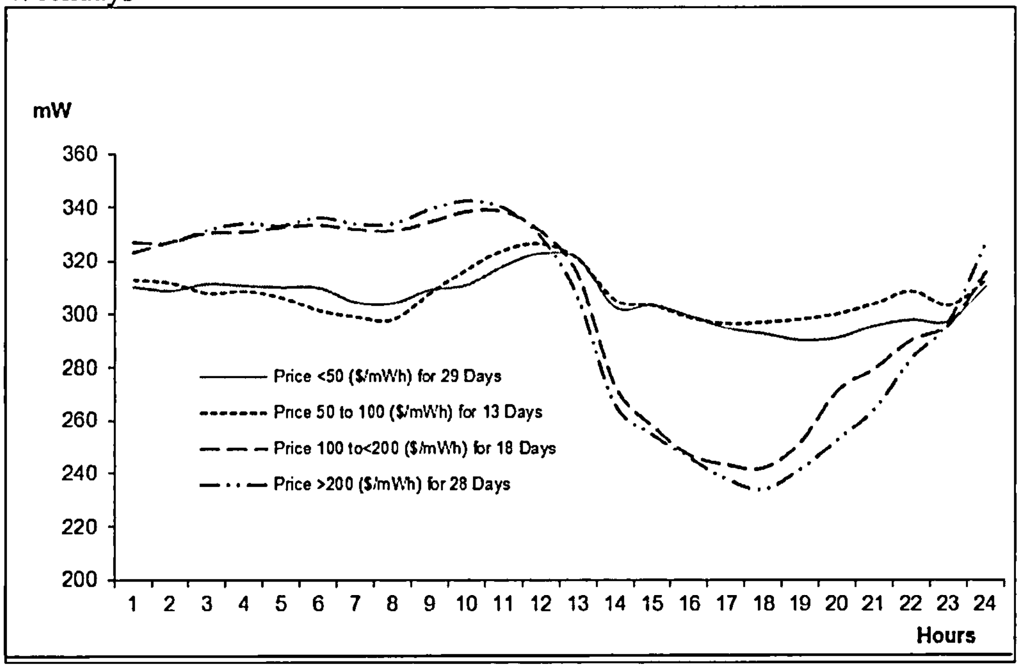
[a]RTP is actual usage, Flat Rate and TOU figures are estimated using equation (1). Total loads are for the summer months June through September.

Average customer size , obtained by dividing total load for each summer by the total number of summer hours (24*122) and then by the number of customers (16) is approximately 18 mW, with the typical customer closer to 10 mW. Total load trended up over the first three years. It dropped off dramatically in 2009, likely due to the slowing economy and moderate temperatures, before rebounding in the summer of 2010. Despite very hot weather in 2010, load was still below 2008, likely due to the economic downturn.[14]

Figure 1 shows the effect of RTP on load for different ranges of RTP prices. We choose 2010 because it was a year with a substantial range of hourly prices.

[14] Note that temperature is not as influential in determining industrial and commercial energy use as it is for residential use.

Fig. 1 Effect of RTP on Load Curve: 2010 RTP Load Shape by Maximum Daily Price for Weekdays



Load shows a much larger response for hourly prices of $0.10/kWh or higher. This pattern suggests the reason for including threshold prices. Some customers may show little response to hourly prices that do not exceed flat rate prices which typically range from $0.05 to $0.08 per kWh. But once price exceeds the typical flat rate price, customers do respond.

We show customer response to RTP in the form of hourly elasticities in figure 2.[15] We compare the magnitudes for two days in the summer of 2007 that are comparable except for prices, with July 24 being a day of low prices while August 7 is a high-priced day.

[15] Our modeling incorporates both own and cross price effects. In figure 2, we show only own price effects for simplicity.

Fig. 2 Weighted Average Own-Price Elasticities: July 24, 2007 versus August 07, 2007

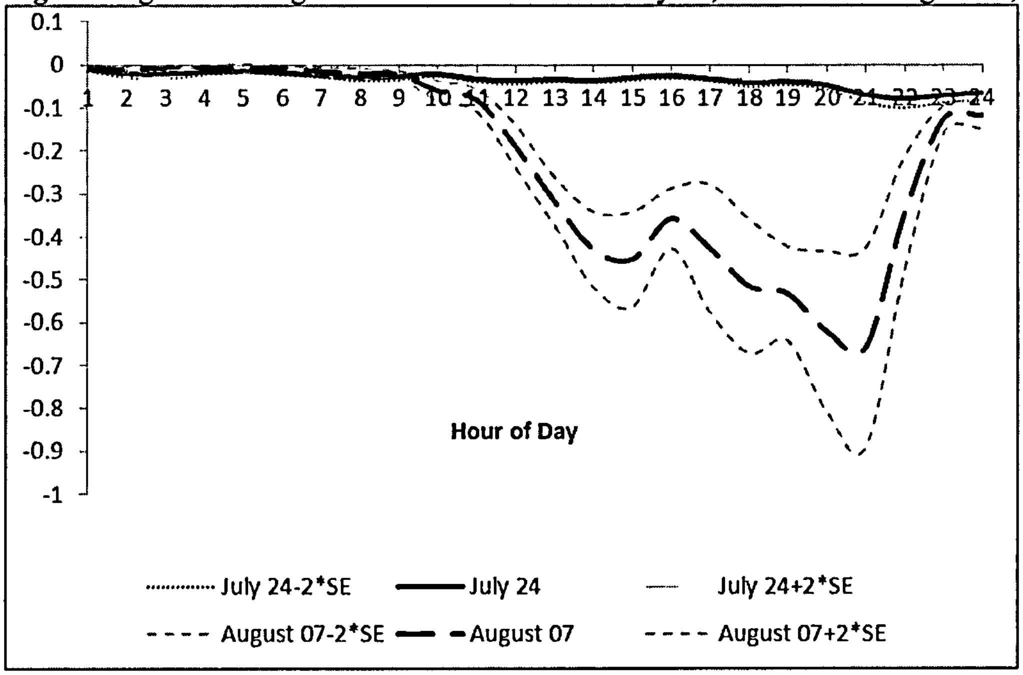


Figure 2 shows the weighted average of individual customer elasticities calculated as:

$$\eta_{iidyk}=Y_{dyk}*C_{iidyk}*P_{idyk}/ PI_{my}.$$

where we have weighted the elasticity by the customer energy use for the hour.

The standard error of this estimate is given by $x_{iidyk}V_{yk}x_{iidyk}'$ for each quantity $Y_{dyk}*C_{iidyk}*P_{idyk}/PI_{my}$, where V_{yk} is the estimated variance-covariance matrix for the parameters for customer k, year y, and x_{iidyk} is a row vector whose elements are the derivatives of $Y_{dyk}*C_{iidyk}*P_{idyk}/PI_{my}$ with respect to the estimated parameters. We sum these calculated quantities over all customers by hour, divide that sum by the summed E_{idyk} squared, and take the square root of this number.

There is relatively little price response by RTP customers on the low- priced day. For the high-priced day, we find elasticities towards the end of the high-priced hours to be approaching 0.7 in absolute value. The associated confidence interval includes a value as large as 0.9. While not shown, these elasticities are considerably larger than if we omit threshold prices. They also exceed elasticities in the literature including Cochell, Schwarz, and Taylor (2005), where elasticities were typically on the order of 0.2.

Figures 3a and 3b show actual load curves for the 16 customers on RTP for the summers 2009 and 2010, as well as predicted load curves for flat rates and TOU. The year 2009 has the smallest number of hours with rationing charges while 2010 has the largest. So, as we would expect, RTP customer loads look more like flat rate loads in 2009, and more like TOU loads in 2010.

Fig. 3a Hourly Load Average Weekday 2009

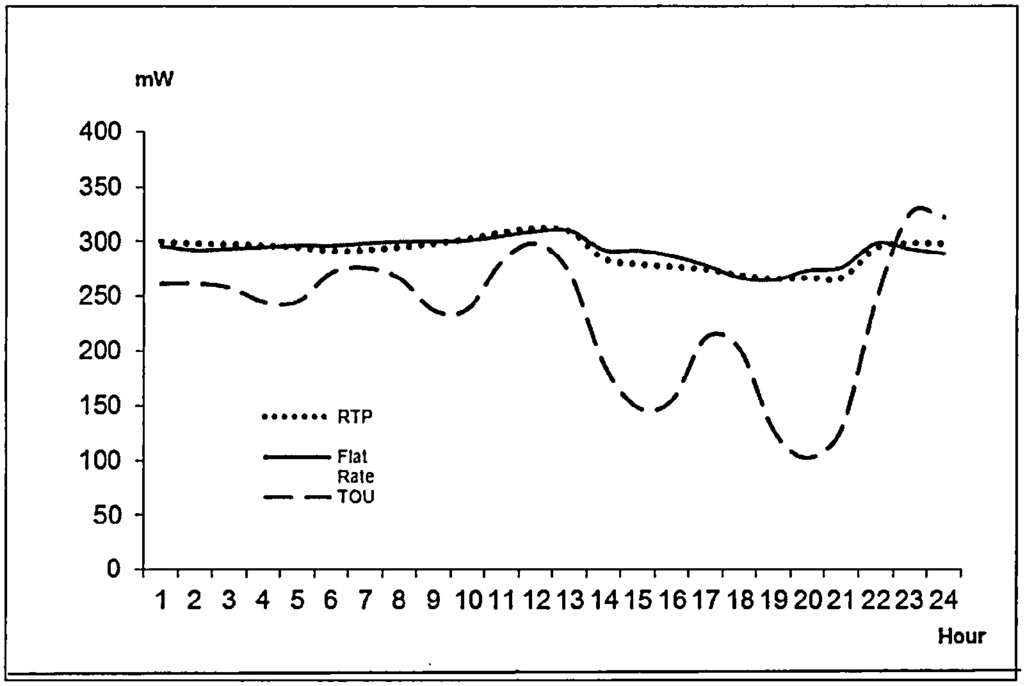
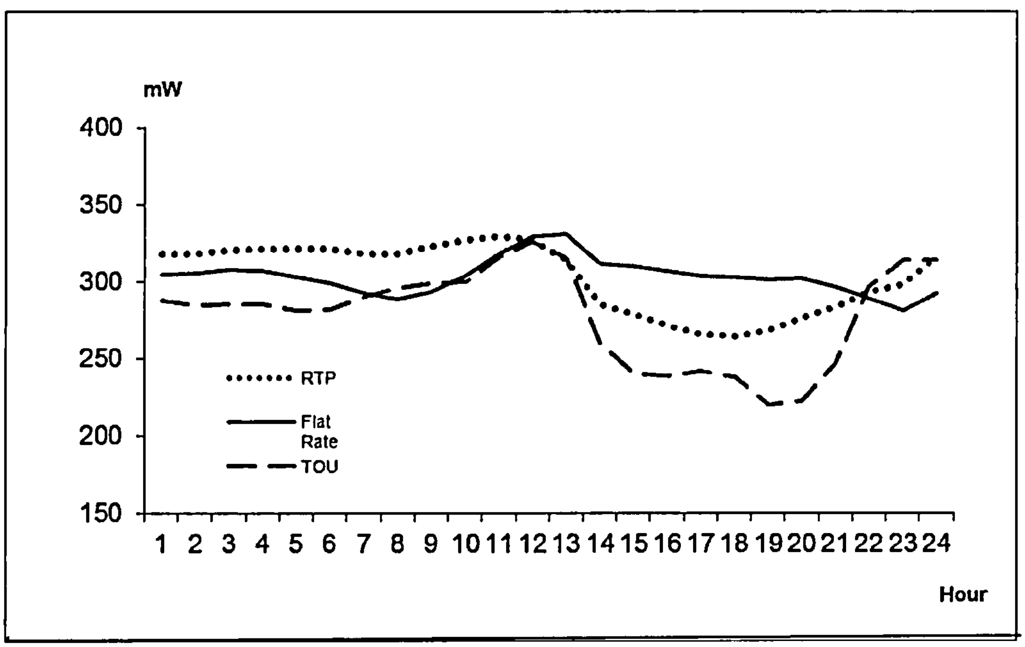


Fig. 3b Hourly Load Average Weekday 2010



In the TOU rate, Duke defines the peak hours as 1-9 PM (hours 13-21). Comparing the RTP and flat rate load curves, RTP reduces load during these hours, while increasing use during the other hours. The effect is much larger in 2010 as would be expected since customers on flat rates are not subject to higher prices during potential peak hours. Under TOU, usage during peak hours is lower, on average, than RTP. We again attribute the lower use under TOU to the episodic nature of RTP only reducing peak hour usage when it is most needed. Again, figure 3a shows that TOU leads to load reductions in 2009 even though the utility does not need such reductions in the sense that marginal costs are relatively low.

IV. Application: Using Energy Estimates to Compare Emissions

Recently, a new issue has arisen that challenges the argument in favor of RTP. Electricity prices do not incorporate full social costs. Palmer, et al. (2002) project that restructuring -- moving from cost-of-service to competition-- increases emissions of NOx and CO_2, and that RTP for industrial customers adds substantially to those increases. In a subsequent paper, Palmer and Burtraw (2005) note that while restructuring has stalled, its environmental impact would probably be small but beneficial. The positive effect is primarily due to greater use of natural gas, but that too could stall due to its volatile price. Holland and Mansur (2008) put forward evidence that time-differentiated rates could increase emissions as compared to flat rates in regions of the country where base-load plants use coal or oil and peaker units use natural gas or hydro.[16]

HM (2008) use electricity consumption under flat rates as a reference and predict how energy use and emissions would change with a rate that reduces demand variance. While they associate their result with RTP, they acknowledge that the result could be associated with any demand variance-reducing mechanism, which would include TOU pricing.[17] As an application of our

[16] To the extent that current real-time rates increase emissions beyond the efficient level, that result is due to not pricing emissions correctly. Utilities do take into account the cost of permits to emit sulfur in determining marginal cost, as well as NOx regulations. See Martin, Joskow, and Ellerman (2007) for an examination of the use of a NOx trading program that incorporates the link between emissions of NOx and formation of ground-level ozone. Currently, there are no federal regulations regarding carbon or mercury emissions, although the EPA finalized rules to limit mercury on December 11, 2011. However, utilities also have to meet state regulations. For example, the 2002 North Carolina Clean Smokestacks Act limits mercury emissions. Schwarz (2005) analyzes the effect of this Act on emissions from coal-fired generation.

[17] In an earlier paper, HM (2006) simulate the effects of RTP on social welfare and emissions as well as time-of-use (TOU) rates on social welfare, but not emissions. Using data for PJM, they find that RTP increases social welfare, while increasing emissions of SO_2 and NOx, but decreasing CO_2. They find that simpler TOU rates can achieve up to two-thirds of the welfare benefits of RTP. However, we find that TOU rates result in larger increases in CO_2 emissions, which they did not include in their welfare analysis.

estimation technique, we examine emissions of sulfur dioxide, NOx, mercury, and CO_2 for real-time, time-of-use, and flat rates. [18]

Figure 4 shows a normalized hourly pattern of emissions attributable to the marginal plant for the summer of 2010. For each hour, we obtain the rate of emissions from the marginal plant under RTP based on an optimal dispatch of generation units. We average these values by hour over the summer, then normalize based on the highest hourly average. Marginal emissions indicate how total emissions change as load is shifted from hour to hour. Predictions are accurate unless a shift in load causes a change in the marginal generating unit, or the optimal unit is unavailable. In our analysis, we find that changes in load lead to a change in the marginal generating unit from 1% to 13% of the time, depending on which rates and which years are being compared. So for the most part, figure 4 provides appropriate intuition for how rates will affect emissions. Except for SO_2, marginal emissions are relatively low during afternoon hours when peak demands are typically experienced. So, with the exception of SO_2, it might be expected that price signals causing a shift in demand from peak to off-peak hours would tend to increase emissions, especially for CO_2. However, this conclusion is based on the assumption that total energy use remains constant, so that the decrease in energy use during the high-priced hours is equal to the increase in energy use during the low-priced hours. If for example, energy use in the off-peak increases by less than the decrease during peak hours, CO_2 emissions would not necessarily increase.

[18] HM use monthly data for the four years beginning in January 1997 through December 2000. Electric utilities typically did not install scrubbers to reduce SO_2 until after 2000. So our results on SO_2 could differ as utilities were much more likely to have scrubbers on base-load coal during 2006-2010.

Fig. 4 Normalized Marginal Emissions

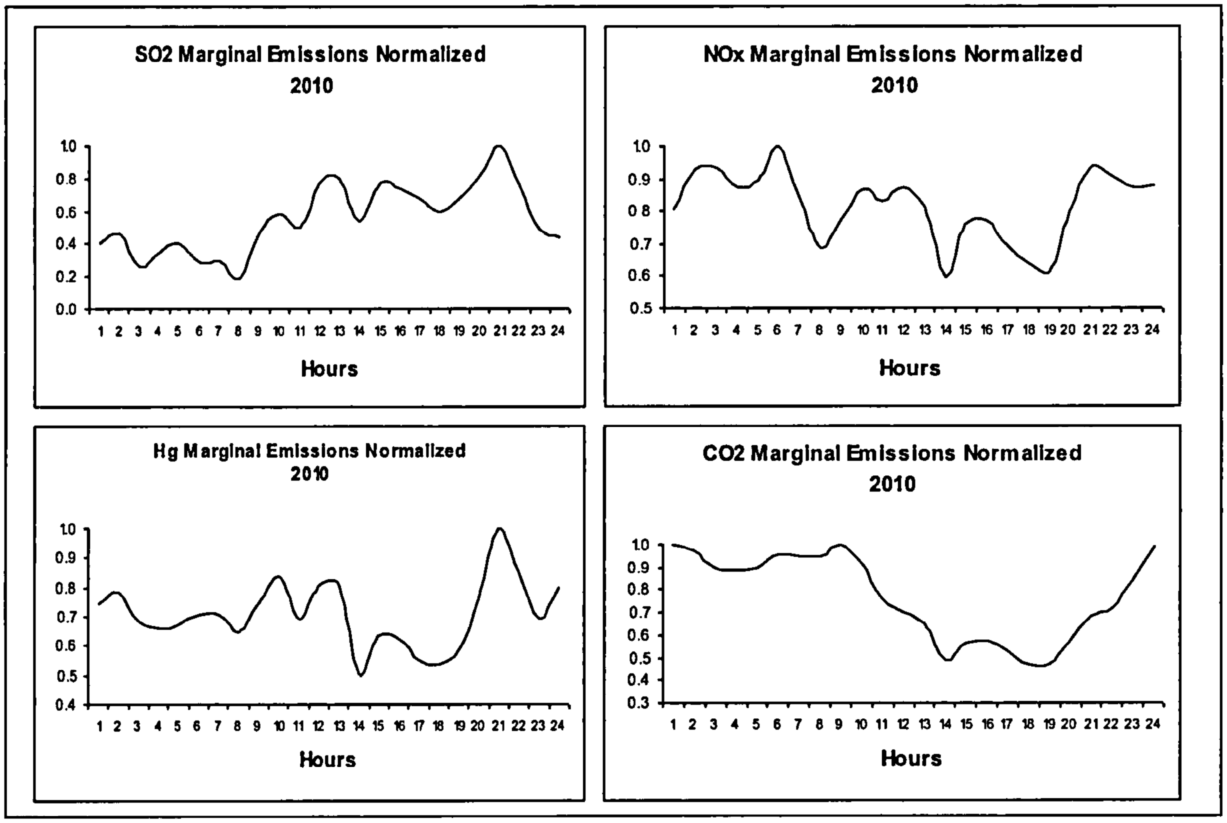


Table 3 presents emissions for the three rates. We show results for two cases: emissions based on predicted energy use, and emissions adjusted for an energy-neutral case, where energy use predicted under flat rates and under TOU is held at RTP levels. The energy-neutral case allows us to compare our results with those of HM (2008). Their modeling requires energy use to remain constant.

To obtain energy-neutral emissions for the flat and TOU rates, we first estimate consumption using equation (1) with flat or TOU rates in place of RTP, while constraining the output index to its RTP value. Then, for both flat rates and TOU rates, we simply increase or decrease the estimated hourly consumption by the same kWh amount for each hour until total monthly consumption is equal to that under RTP.[19] For ease of comparison, we use flat rate emissions as a baseline, and show emissions changes for RTP and TOU as compared to flat rates.

The generating stack consists of all resources dispatched by the System Operating Center. We start by ranking each resource based on its marginal cost to operate. The resulting stack is then modified so that any must-run resources enter the stack before any others that may dispatched as needed.

[19] We also considered other methods of holding energy use constant, such as using percentage changes rather than absolute changes. These methods required arbitrary adjustments.

Once we have determined the system load in any hour, we search the stack until we find the last resource that is utilized in meeting that load. For each resource we have a figure for emissions per kWh. For all units below this unit in the stack, we multiply the emissions per kWh by the installed capacity of the resource. For the last unit we determine how much of that unit's capacity is used and perform a similar calculation. The sum of all these values is the total emissions in the hour given the level of energy usage. This calculation is repeated for all hours for each of the rate scenarios -- RTP, TOU, and flat rates -- giving us three sets of hourly emissions profiles for each of the four types of emissions considered. This is the data on which the changes in emissions are based.

Table 3

Comparison of Emissions under RTP, Flat Rates, and TOU

Change in Emissions, Flat Rate versus RTP/TOU, tons[a]

	RTP					TOU				
	SO_2	NOx	Hg^b	CO_2	Δ Energy	SO_2	NOx	Hg^b	CO_2	Δ Energy
Unadjusted										
2006	69.71	17.5	1,104	39,320	52,446	-91.18	-14.62	-464	-4,226	-7,033
2007	-61.98	-17.87	-530	-20,050	-24,435	8.44	1.21	486	16,003	17,920
2008	-116.09	-24.14	-976	-27,359	-38,416	-76.6	-6.55	-242	4,111	-3,199
2009	-9.17	-2.7	-106	-4,035	-8,294	-80.35	-17.34	-863	-29,232	-59,870
2010	-17.42	3.13	211	13,465	3,676	-57.23	-9.54	-297	-6,887	-22,788
Adjusted										
2006	-23.68	-6.55	-89	-1,492	0	-60.32	-7.82	-194	3,575	0
2007	-11.83	-4.85	-3.22	-1,082	0	-31.21	-8.3	-22.89	897	0
2008	-29.72	-4.04	-43.61	2,596	0	-59.03	-3.15	-99.24	9,495	0
2009	1.59	1.09	57.56	2,346	0	29.9	8.96	501	20,825	0
2010	-20.57	1.54	114	9,780	0	-16.31	0.73	101	7,923	0

[a] positive number implies higher emissions for time-differentiated rate than flat rate. [b] in lbs.

The unadjusted results clearly show the importance of total energy use on emissions. In comparing RTP and TOU to flat rates, the emissions under RTP and TOU are higher when energy use is higher with only two exceptions (SO_2 emissions in 2010 are lower under RTP than under flat rates even though energy use is higher, and CO_2 emissions in 2008 are higher under TOU than under flat rates even though energy use is lower.) Since energy use under time varying rates is sometimes higher and sometimes lower than under flat rates, it is not possible to draw general conclusions about the directional effects of time varying rates on emissions. However, this result suggests that changes in overall energy use may be just as important in determining emissions as are changes in the time pattern of energy use.

In order to get a clearer comparison of our emissions results with the predictions of HM (2008), we turn to the adjusted energy-neutral case. Results indicate that when compared to flat rates, RTP increases CO_2 in three of five years while TOU increases CO_2 in all five years. The largest increase for RTP is in 2010, the hottest year with the most rationing charges. In this year, we would expect the strongest shift from peak hours to the off peak, with the consequent higher use of base-load coal, and in turn, CO_2 emissions. In all years except for 2010, we see that increases of CO_2 are greater under TOU than under RTP. Recall that RTP is episodic while TOU shifts energy use from the peak to the off-peak even when it is not called for by increases in marginal cost. So, except for the extremely hot summer of 2010, we would expect greater shifting of energy from peak to off-peak accompanied by greater CO_2 emissions under TOU.

The strongest evidence that emissions could actually decrease under time-differentiated rates as compared to flat rates is for SO_2. For both the unadjusted and adjusted cases, SO_2 emissions are lower under RTP and TOU than for flat rates in all but one of the five years. This finding is consistent with the intuition provided by figure 4, which shows lower SO_2 emissions during the off-peak hours. For the Duke system, base-load plants typically have scrubbers that reduce sulfur. The Duke system also includes older mid-range coal units that are frequently at the margin on warmer afternoons and do not have scrubbers. Furthermore, in the years covered in HM's study, utilities had not yet installed scrubbers on base-load coal units. For both RTP and TOU, emissions of NOx and Hg decrease in three of five years as compared to flat rates.

In our case study, the evidence supports the concern that time-dependent rates increase CO_2 if total energy use remains constant. But our results suggest that for this energy-neutral case, time-dependent rates will likely decrease SO_2 emissions, and there is slightly weaker evidence that they will also decrease NOx and Hg. Actual changes in emissions will depend on changes in total energy use as well as changes in the temporal pattern of energy use. In general, it will be necessary to consider the amount by which energy changes in peak and off-peak hours, as well as the specific stack of generating units for a given utility.

In Table 4 we compare RTP with TOU. As we saw in Table 3, the unadjusted results are dominated by total energy use. In 2006, 2009, and 2010, when energy use is higher for RTP than for TOU, emissions are higher as well.

Table 4

Comparison of Emissions under RTP and TOU

Change in Emissions, RTP versus TOU, tons[a]

	Emissions				
	SO_2	NOx	Hg[b]	CO_2	Δ Energy
Unadjusted					
2006	160.89	32.12	1,569	43546	59479
2007	-70.42	-19.08	-1016	-36053	-42355
2008	-39.49	-17.59	-734	-31469	-35217
2009	71.18	14.64	757	25197	51577
2010	39.81	12.67	508	20353	26463
Adjusted					
2006	36.64	1.27	105	-5067	0
2007	19.38	3.45	19.67	-1979	0
2008	29.31	-0.89	55.63	-6899	0
2009	-28.31	-7.87	-443	-18479	0
2010	-4.26	0.81	12.85	1856	0

[a]positive number implies higher emissions for RTP than TOU. [b]in lbs.

For energy-neutral results of our case study, CO_2 emissions are lower under RTP than under TOU in four of five years. Here again, the episodic nature of RTP rates comes into play. While figure 4 shows that load shifting induced by higher rates during the peak hours would result in higher CO_2 emissions, RTP rates are higher only when real-time conditions warrant. This effect is pronounced in 2009, the year when there are very few RTP rationing charges. In that year, CO_2 emissions for RTP are considerably lower than for TOU. The one year in which RTP results in higher CO_2 emissions as compared to TOU is 2010. This is the year with the highest number of rationing charges, hence the greatest shift from peak to off-peak for RTP customers.

For the energy-neutral case, there is evidence that the other emissions are higher under RTP than TOU. Mercury emissions are higher in four of five years, while SO_2 and NOx are higher in three of five years. The pattern is different for 2009, the year in which RTP approaches flat rates. In that year, TOU but not RTP shifts use to the off-peak, where for the Duke Energy system sulfur emissions tend to be lower. Hg does not show a consistent pattern of shifting from year to year.

Finally, it is useful to consider how time differentiated rates may impact the potency of NOx emissions. NOx produces a larger amount of pollution in the presence of heat and sunlight than in the absence of those ingredients.[20] Table 5 separates NOx emissions into daylight and non-daylight hours. Daylight corresponds to the time between sunrise and sunset.

Table 5

Comparison of Emissions for Daylight Hours versus Non-Daylight Hours

Change in Emissions (Total Time-Differentiated Rates less Flat Rate)[a]

	Daylight Hours		Non-Daylight Hours		Daylight Hours		Non-Daylight Hours	
	RTP				TOU			
	NOx (tons)	Δ Energy	NOx (tons)	Δ Energy	NOx(tons)	Δ Energy	NOx (tons)	Δ Energy
Unadjusted								
2006	10.70	35,962	6.80	16,484	-19.02	-17,873	4.40	10,840
2007	-15.28	-22,808	-2.59	-1,627	-8.98	-5,619	10.19	23,539
2008	-20.58	-31,148	-3.56	-7,268	-10.43	-8,445	3.88	5,246
2009	-3.37	-9,252	0.67	959	-8.88	-43,890	-8.46	-15,979
2010	-6.20	-14,088	9.33	17,764	-10.63	-24,446	1.09	1,659
Adjusted								
2006	-2.72	5,510	-3.83	-5,510	-16.23	-17,682	8.41	17,682
2007	-7.46	-9,002	2.62	9,002	-17.17	-22,235	8.88	22,235
2008	-8.48	-8,490	4.44	8,490	-9.06	-7684	5.90	7,684
2009	-1.27	-4,553	2.35	4,553	2.22	-11,466	6.74	11,466
2010	-6.40	-15,288	7.93	15,288	-5.51	-12,150	6.23	12,150

[a] positive number implies higher emissions for time-differentiated rate than flat rate.

As in earlier results, when we compare alternative rates, emissions increase when energy use increases. As daylight energy use is lower for the time-differentiated rates in all but one year for both unadjusted and adjusted cases, daylight NOx emissions are lower for time differentiated rates in all but one year, and hence less potent. So both adjusted and unadjusted results show that one advantage of time-differentiated rates not noted by HM (2008) is that by transferring use to night-time hours, NOx emissions are likely to be less potent.

[20] Real-time rates encourage a shift of electricity use to night time hours, when NOx potency may be only one-third as potent as during the day. Palmer and Burtraw (2005), p. 14 and fn 13, provide this statement, in turn citing Bharvirkar, et al. (2003). However, coming up with real-time emissions prices that depend in a complex way upon real-time weather conditions is a formidable task. For example, emissions levels in the winter of 2010-11 in parts of Wyoming exceeded typical summer emissions in Los Angeles, due to a combination of increased gas drilling and a temperature inversion. See http://www.npr.org/templates/story/story.php?storyId=134364421 (retrieved March 11, 2011). Weitzman (1974), p. 481 describes the difficulty of coming up with such ideal prices, noting the difficulty of developing complex "contingency messages".

When comparing RTP and TOU, actual case study results show RTP leads to higher daylight emissions in three of five years, and energy-neutral results show RTP is higher in four of five years.[21] So while TOU has the disadvantage that it shifts energy use even when it is not needed, there is a modest offsetting advantage that in the majority of years, it results in a greater shift of NOx emissions to the night-time hours, when NOx is less potent.

V. Summary and Conclusions

Using hourly energy data for customers on real-time rates, we have provided a method of estimating load response for customers on TOU and flat rates. The underlying model is the Generalized McFadden (GM), a flexible functional form that is able to capture substitutability and complementarity across hours of the day. In addition, we are able to capture inter-day substitution by including lags and leads to reflect customer knowledge of hourly rates on nearby days. We also include the possibility that customer response to RTP may differ when prices exceed average and maximum price thresholds.

Hourly own-price elasticities are as large as -0.7 in evening hours towards the end of the high-priced period. The RTP load curve typically shows larger response with increases in the hourly price. Load during high-priced hours is lowest on days where the price exceeds $200/mWh, the highest price range considered.[22]

Time-varying rates in general, and real-time rates in particular, are an improvement over flat rates in that they offer a better approximation to the marginal cost of supplying electricity. However, the marginal impact of emissions is generally not fully incorporated in these rates, raising the concern that time-differentiated rates can exacerbate the problems associated with unincorporated emissions. We utilize estimates of load response to examine the effect of time-varying rates on power plant emissions.

Such a concern is the focus of Holland and Mansur (2008) who conclude that real time rates and other mechanisms that reduce demand variance could increase emissions. In areas of the country such as the Carolinas, where coal plants account for much of base load generation, and natural gas combined-cycle units serve the peak, shifting energy to the off-peak increases the use of coal relative to gas and so has the potential to increase emissions. HM make this prediction for a decrease in demand variance, while holding energy use under alternative rates constant. They associate their results with RTP, but acknowledge that their predictions would hold for any demand-variance reducing mechanism, which would include TOU, and for that matter, any demand management program.

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[21] A separate table is not provided for these results, however, they can be deduced from Table 5.

[22] On August 7, 2007, most customers saw prices in the $430/mWh range. The maximum price for any customer class on that day was more than $1,100/mWh. The maximum price seen by a Duke standard retail customer on that day exceeded $870/mWh.

We examine energy use under RTP, TOU, and flat rates, and incorporate an energy-neutral case where energy under the three rates is held constant. In almost all cases, the change in emissions is in the same direction as the change in energy use. Higher energy use results in higher emissions for SO_2, NOx, Hg, and CO_2. The evidence suggests that in determining emissions, the effect of a rate on overall energy use may outweigh its effect on relative energy use during the high-use and low-use hours. Hence, HM's predictions based on the pattern of energy use does not appear to generalize if energy use is not held constant. Results will depend on overall energy use as well as the pattern of energy use, and furthermore will depend on a given utility's specific stack of generating units.

For the energy-neutral case, considered by HM, there is convincing evidence that time-differentiated rates do increase CO_2. However, there is also strong evidence that the rates reduce SO_2. We suggest two reasons why SO_2 emissions decrease under time-differentiated rates. First, utilities have typically installed scrubbers on their base-load coal plants, which remove some 90% of sulfur emissions. In the years covered by HM, utilities had not yet installed scrubbers. Second, Duke uses intermediate coal units, which are often at the margin on warm days. These units are smaller and older than base-load units, and do not have scrubbers.

We also compare RTP and TOU emissions. RTP results in lower CO_2 emissions. Our intuition for this result is that TOU rates shift load to off-peak hours on all summer days, while RTP is episodic, shifting load only when it is needed as reflected in marginal costs. Hence TOU makes heavier use of base-load coal. TOU produces less SO_2 than RTP; again the reasoning is that base-load coal units with scrubbers emit less sulfur than intermediate coal units.

Time varying rates appear to reduce NOx and Hg although results are not as pronounced as for SO_2. We note that NOx emissions, which require heat and sunlight to form smog, may be less potent if they are emitted during non-daylight hours than during daylight hours. We find that on balance, RTP and TOU do shift emissions to the non-daylight hours, making NOx less potent. TOU has a small advantage as compared to RTP in this regard, insofar as it shifts more of the load to the non-daylight hours.

Our emphasis in this paper is on the generality of our method of comparing energy use under alternative rates when there is information on only one rate, in this case RTP. The analysis of emissions provides a case study that illuminates some of the issues that were not apparent in the large-scale study done by HM. Our results suggest that an individual utility or individual region may have different results than those based on the HM study, so that it is necessary to consider total energy use, the pattern of energy use, and the composition of base-load and peak generation in order to adequately assess the impact of time varying rates on emissions.

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Appendix 1: Detailed Variable Descriptions

Temperature humidity information is incorporated as:

$$T = h_{iyk}\{\max(THI_{idy} - \text{cooling set point}, 0)\}$$

where h_{iyk} is a function of parameters to be estimated, and incorporates a Fourier specification.[23] The cooling set point is 72, and we define THI as

$$THI_{idy} = 17.5 + 0.55 * DryBulb_{idy} + 0.20 * DewPoint_{idy}.$$

$$h_{iyk} = t_{0yk} + \sum_{L=1}^{N_t} (t_{Lyk} * \cos\left(i * 2\pi * \frac{L}{24}\right) + t_{L+N_t,yk} * \sin(i * 2\pi * \frac{L}{24})$$

We choose N_τ=5 where N is the number of parameters in the Fourier series.

All temperatures are in degrees Fahrenheit for hour i of day d, and year y.

Term L consists of lagging and leading prices as follows:

$$a_{idyk}^{(2)} Lag2price + a_{idyk}^{(1)} Lag1price + b_{idyk}^{(1)} Lead1price + b_{idyk}^{(2)} Lead2price$$

The first lag term, Lag1price, included on all days, is the average of the previous day's prices. The second lag term, Lag2price, is included only on Sundays and Mondays. On Sundays it is the average price for Friday. On Mondays it is the average price for Friday and Saturday combined. It may be included on other days, depending on which day of the week the two holidays, July 4 and Labor Day, fall. The first lead term, Lead1price, is the average of the next day's prices and is always included for the hours 17 through 24 since the next day's prices are available after 4 pm. It is always included for hours 1 through 16 on Saturdays and Sundays since the prices for Saturday through Monday are available at 4 pm on Friday. It may be included for other days of the week for hours 1 through 16 depending on the two holidays. The second lead term, Lead2price, is the average of any days after the next day which are available at the time the load is observed. For example, on Saturday it is the average price for Monday. For Friday, for the hours 17 through 24, it is the average of Sunday and Monday combined. This term may also appear on days preceding holidays.

The coefficients associated with the lagging and leading price terms, $a_{idyk}^{(2)}$, $a_{idyk}^{(1)}$, $b_{idyk}^{(1)}$ and $b_{idyk}^{(2)}$ are themselves functions of estimated parameters of Fourier series.

[23] Patrick and Wolak (2000) used Fourier series in order to greatly reduce the number of parameters that need to be estimated.

The terms a_{iyk} and b_{iyk} in equation (1) vary by hour. Values for these terms are obtained by estimating the parameters of the following Fourier specification:

$$a_{iyk} = \alpha_{0yk} + \sum_{L=1}^{N_\alpha} (\alpha_{Lyk} * \cos(i * 2\pi * L/24) + \alpha_{L+N_\alpha, yk} * \sin(i * 2\pi * L/24)),$$

$$b_{iyk} = \beta_{0yk} + \sum_{L=1}^{N_\beta} (\beta_{Lyk} * \cos(i * 2\pi * L/24) + \beta_{L+N_\beta, yk} * \sin(i * 2\pi * L/24))$$

We choose $N_\beta = 5$ and $N_\alpha = 5$, where N is the number of parameters in the Fourier series.

The elements of the C matrix are defined as:

$$C_{ijdyk} = -\sum_{m=1}^{j} L_{imdyk} L_{jmdyk} \qquad j \leq i$$
$$C_{ijdyk} = C_{jidyk} \qquad j > i$$

For a customer with a marginal or an average price threshold, the value of the C matrix will be different on the days where price exceeds the relevant threshold. A further adjustment is that Y_{dyk}, the index of daily output, is a function of the vector of daily prices.

The elements of L are defined as:

$$L_{ijdyk} = B_{idyk} B_{jdyk} + E_{i-j,dyk} \qquad j \leq i$$
$$L_{ijdyk} = 0 \qquad j > i$$

The B are defined as:

$$\begin{aligned} B_{idyk} = {} & \beta_{00yk} + \sum_{l=1}^{N_\beta} (\beta_{lyk} \cos\left(\tfrac{i2\pi l}{24}\right) + \beta_{l+N_\beta,yk} \sin(\tfrac{i2\pi l}{24})) + \\ & D_{dyk}^{QP} \left(\beta_{00yk}^{QP} + \sum_{l=1}^{N_\beta} (\beta_{lyk}^{QP} \cos\left(\tfrac{i2\pi l}{24}\right) + \beta_{lyk+N_\beta,yk}^{QP} \sin\left(\tfrac{i2\pi l}{24}\right))\right) + \\ & D_{dyk}^{OL} \left(\beta_{00yk}^{OL} + \sum_{l=1}^{N_\beta} (\beta_{lyk}^{OL} \cos\left(\tfrac{i2\pi l}{24}\right) + \beta_{l+N_\beta,yk}^{OL} \sin\left(\tfrac{i2\pi l}{24}\right))\right) + \\ & D_{dyk}^{IS} \left(\beta_{00yk}^{IS} + \sum_{l=1}^{N_\beta} (\beta_{lyk}^{IS} \cos\left(\tfrac{i2\pi l}{24}\right) + \beta_{l+N_\beta,yk}^{IS} \sin\left(\tfrac{i2\pi l}{24}\right))\right) + \\ & D_{dyk}^{AP} \left(\beta_{00yk}^{AP} + \sum_{l=1}^{N_\beta} (\beta_{lyk}^{AP} \cos\left(\tfrac{i2\pi l}{24}\right) + \beta_{l+N_\beta,yk}^{AP} \sin\left(\tfrac{i2\pi l}{24}\right))\right) + \\ & D_{dyk}^{MP} \left(\beta_{00yk}^{MP} + \sum_{l=1}^{N_\beta} (\beta_{lyk}^{MP} \cos\left(\tfrac{i2\pi l}{24}\right) + \beta_{l+N_\beta,yk}^{MP} \sin\left(\tfrac{i2\pi l}{24}\right))\right) \end{aligned}$$

In this equation the D variables are binary variables indicating whether the day in question is a quiet period (QP) for this customer, an outlier (OL) for this customer, or a day when customers are asked to interrupt their load or run standby generators (IS). Outliers are periods during which demand is either much lower or much higher than for surrounding periods. Typically these periods are of short duration. Quiet periods are periods, usually of much longer duration, during which the load is much lower and much flatter than in the surrounding periods. The effect of a price threshold is incorporated in the binary terms D^{AP}_{dyk} and D^{MP}_{dyk} denoting days when the average price threshold (AP) is exceeded for this customer or when the maximum price threshold (MP) is exceeded for this customer. The βs are the estimated parameters.

The E terms are defined as:

$$
\begin{aligned}
E_{xdyk} = {} & \varepsilon_{00yk} + \textstyle\sum_{l=1}^{N_\varepsilon}\left(\varepsilon_{lyk}\cos\left(\frac{(x+1)2\pi l}{24}\right) + \varepsilon_{l+N_\varepsilon,yk}\sin\left(\frac{(x+1)2\pi l}{24}\right)\right) + \\
& D^{QP}_{dyk}\left(\varepsilon^{QP}_{00yk} + \textstyle\sum_{l=1}^{N_\varepsilon}\left(\varepsilon^{QP}_{lyk}\cos\left(\frac{(x+1)2\pi l}{24}\right) + \varepsilon^{QP}_{l+N_\varepsilon,yk}\sin\left(\frac{(x+1)2\pi l}{24}\right)\right)\right) + \\
& D^{OL}_{dyk}\left(\varepsilon^{OL}_{00yk} + \textstyle\sum_{l=1}^{N_\varepsilon}\left(\varepsilon^{OL}_{lyk}\cos\left(\frac{(x+1)2\pi l}{24}\right) + \varepsilon^{OL}_{l+N_\varepsilon,yk}\sin\left(\frac{(x+1)2\pi l}{24}\right)\right)\right) + \\
& D^{IS}_{dyk}\left(\varepsilon^{IS}_{00yk} + \textstyle\sum_{l=1}^{N_\varepsilon}\left(\varepsilon^{IS}_{lyk}\cos\left(\frac{(x+1)2\pi l}{24}\right) + \varepsilon^{IS}_{l+N_\varepsilon,yk}\sin\left(\frac{(x+1)2\pi l}{24}\right)\right)\right) + \\
& D^{AP}_{dyk}\left(\varepsilon^{AP}_{00yk} + \textstyle\sum_{l=1}^{N_\varepsilon}\left(\varepsilon^{AP}_{lyk}\cos\left(\frac{(x+1)2\pi l}{24}\right) + \varepsilon^{AP}_{l+N_\varepsilon,yk}\sin\left(\frac{(x+1)2\pi l}{24}\right)\right)\right) + \\
& D^{MP}_{dyk}\left(\varepsilon^{MP}_{00yk} + \textstyle\sum_{l=1}^{N_\varepsilon}\left(\varepsilon^{MP}_{lyk}\cos\left(\frac{(x+1)2\pi l}{24}\right) + \varepsilon^{MP}_{l+N_\varepsilon,yk}\sin\left(\frac{(x+1)2\pi l}{24}\right)\right)\right)
\end{aligned}
$$

The D variables in this equation are the same as in the equation for the Bs. Here the εs are the estimated parameters.

Appendix 2: Estimation Procedures

This appendix describes how we estimate Total TOU and Flat Rate loads. The approach is to modify actual observed RTP loads. We separate total RTP load into two parts. Part 1 is the load determined by RTP prices and Part 2 is the remainder of the load. We obtain estimates of Part 1 load for each of RTP, TOU, and Flat Rate, using parameters of the estimated General McFadden model. To obtain Total TOU load, we subtract estimated part 1 load under RTP from total RTP load and add back the estimated TOU part 1 load. Flat Rate load is estimated in the same manner. In the following discussion, we refer to the part 1 load as the price portion of the load:

Step 1 – Calculate the price portion of the load for the RTP rate using the following relationship drawn from equation (1) in the text as estimated by the GM functional form:

$$E_{idyk}^{RTP} = \frac{Y_{dyk}}{PPI_{my}}[\sum_{j=1_1}^{24} c_{ijdyk}P_{jdyk} + L + b_{iyk}]$$

We expand the term L to specify individual lag and lead variables.

$$E_{idyk}^{RTP} = \frac{Y_{dyk}}{PPI_{my}}[\sum_{j=1_1}^{24} c_{ijdyk}P_{jdyk} + a_{idyk}^{(2)}Lag2price + a_{idyk}^{(1)}Lag1price + b_{idyk}^{(1)}Lead1price + b_{idyk}^{(2)}Lead2price + b_{iyk}]$$

In this equation E_{idyk}^{RTP} is the price portion of the actual load in hour i determined by the 24 hourly prices plus the lagging and leading prices, as appropriate. All variables are explained in detail in the text or in Appendix 1.

Step 2 – To estimate load as if RTP customers were actually billed on TOU prices, substitute marginal TOU prices for each customer by month into the equation of Step 1. The calculation of marginal TOU prices is described in the text. Unlike RTP, we do not include threshold effects, as prices within the peak period do not vary.

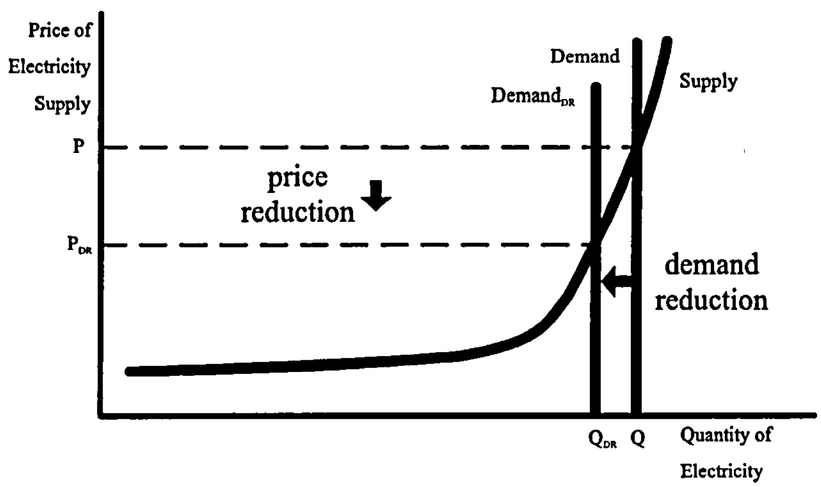
Step 3 – Calculate the total TOU load by subtracting the RTP price portion of the load from total observed RTP load and adding back the TOU price portion of the load from Step 2.

The calculation of load under flat rate prices follows the same procedure except that flat rate prices are used instead of marginal TOU prices. Calculation of marginal flat rate prices is described in the text.

Ex. Ackerman 4

BENEFITS OF DEMAND RESPONSE IN ELECTRICITY MARKETS AND RECOMMENDATIONS FOR ACHIEVING THEM

A REPORT TO THE UNITED STATES CONGRESS PURSUANT TO SECTION 1252 OF THE ENERGY POLICY ACT OF 2005



February 2006

U.S. Department of Energy

The Secretary [of Energy] shall be responsible for... not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007.

--Sec. 1252(d), the Energy Policy Act of 2005, August 8, 2005

EXECUTIVE SUMMARY

Sections 1252(e) and (f) of the U.S. Energy Policy Act of 2005 (EPACT)[1] state that it is the policy of the United States to encourage "time-based pricing and other forms of demand response" and encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public. The law also requires the U.S. Department of Energy (DOE) to provide a report to Congress, not later than 180 days after its enactment, which "identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007" (EPACT, Sec. 1252(d)).

Background

Most electricity customers see electricity rates that are based on average electricity costs and bear little relation to the true production costs of electricity as they vary over time. Demand response is a tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized.

- *Price-based demand response* such as real-time pricing (RTP), critical-peak pricing (CPP) and time-of-use (TOU) tariffs, give customers time-varying rates that reflect the value and cost of electricity in different time periods. Armed with this information, customers tend to use less electricity at times when electricity prices are high.
- *Incentive-based demand response programs* pay participating customers to reduce their loads at times requested by the program sponsor, triggered either by a grid reliability problem or high electricity prices.

Limited demand response capability exists in the U.S. today.[2] Total demand response and load management capability has fallen by about one-third since 1996 due to diminished utility support and investment.

States should consider aggressive implementation of price-based demand response for retail customers as a high priority, as suggested by EPACT. Flat, average-cost retail rates that do not reflect the actual costs to supply power lead to inefficient capital investment in new generation, transmission and distribution infrastructure and higher electric bills for customers. Price-based demand response cannot be achieved immediately for all customers. Conventional metering and billing systems for most customers are not adequate for charging time-varying rates and most customers are not used to making electricity decisions on a daily or hourly basis. The transformation to time-varying retail rates will not happen quickly. Consequently, fostering demand response through

[1] Public Law 109-58, August 8, 2005.
[2] In 2004 potential demand response capability equaled about 20,500 megawatts (MW), 3% of total U.S. peak demand, while actual delivered peak demand reduction was about 9,000 MW (1.3% of peak).

incentive-based programs will help improve efficiency and reliability while price-based demand response grows.

The Benefits of Demand Response

The most important benefit of demand response is improved resource-efficiency of electricity production due to closer alignment between customers' electricity prices and the value they place on electricity. This increased efficiency creates a variety of benefits, which fall into four groups:

- *Participant financial benefits* are the bill savings and incentive payments earned by customers that adjust their electricity demand in response to time-varying electricity rates or incentive-based programs.
- *Market-wide financial benefits* are the lower wholesale market prices that result because demand response averts the need to use the most costly-to-run power plants during periods of otherwise high demand, driving production costs and prices down for all wholesale electricity purchasers. Over the longer term, sustained demand response lowers aggregate system capacity requirements, allowing load-serving entities (utilities and other retail suppliers) to purchase or build less new capacity. Eventually these savings may be passed onto most retail customers as bill savings.
- *Reliability benefits* are the operational security and adequacy savings that result because demand response lowers the likelihood and consequences of forced outages that impose financial costs and inconvenience on customers.
- *Market performance benefits* refer to demand response's value in mitigating suppliers' ability to exercise market power by raising power prices significantly above production costs.

Quantifying the National Benefits of Demand Response

DOE reviewed recent studies that have quantified demand response benefits and assessed the analytical methods used and analyzed ten studies that estimated the benefits of actual or proposed demand response initiatives for specific regions. The results point out important inconsistencies in how demand response is currently measured.

To date there is little consistency in demand response quantification. Three types of studies have looked at demand response benefits; the time horizons and categories of benefits examined vary widely.

- *Illustrative analyses* quantify the economic impacts of demand response; the four studies examined here look within organized wholesale markets. These studies report relatively high levels of benefits in part because they assume high levels of demand response penetration over a large customer base and long-term sustained benefits.
- *Integrated resource planning studies* look at whether and how much to use demand response resources as part of a long-term resource plan. These studies

assume regional impacts over a long time period and report high levels of demand response benefits.

- *Program performance studies* measure the actual delivered value of demand response programs implemented by several independent grid operators (e.g., the PJM Interconnection [PJM], the New York Independent System Operator [NYISO], and ISO-New England [ISO-NE]). These studies report the lowest level of demand response benefits, in part because they reflect market conditions over a short time period and do not necessarily capture the full range of market circumstances or value long-term impacts.

Based on this review, DOE concludes that, to date, the estimated benefits of demand response are driven primarily by the quantification method, assumptions regarding customer participation and responsiveness, and market characteristics. Without accepted analytical methods, DOE finds that it is not possible to quantify the national benefits of demand response. Moreover, regional differences in market design, operation, and resource balance are important and must be taken into account. Estimates of demand response benefits are best done for service territories, states, and regions, because the magnitude of potential benefits is tied directly to local electric system conditions (e.g., the supply mix, the presence or absence of supply constraints, the rate of demand growth, and resource plans for meeting demand growth).

Recommendations

EPACT directs DOE to recommend how more demand response can be put in place by January 1, 2007. DOE concludes that eleven months is too short a time for meaningful recommendations to be implemented and have any practical impact. Instead, DOE offers recommendations to encourage demand response nation-wide, which are organized as follows:

- **Fostering Price-Based Demand Response**—by making available time-varying pricing plans that let customers take control of their electricity costs. More efficient pricing of retail electricity service is of the utmost importance.
- **Improving Incentive-Based Demand Response**—to broaden the ways in which load management contributes to the reliable, efficient operation of electric systems. Incentive-based demand response programs can help improve grid operation, enhance reliability, and achieve cost savings.
- **Strengthening Demand Response Analysis and Valuation**—so that program designers, policymakers and customers can anticipate demand response impacts and benefits. Demand response program managers and overseers need to be able to reliably measure the net benefits of demand response options to ensure that they are both effective at providing needed demand reductions and cost-effective.
- **Integrating Demand Response into Resource Planning**—so that the full impacts of demand response, and the maximum level of benefits, are realized. Such efforts help establish expectations for the short- and long-run value and contributions of

demand response, and enable utilities and other stakeholders to compare demand response options with other alternatives.

- **Adopting Enabling Technologies**—to realize the full potential for managing usage on an ongoing basis given innovations in communications, control, and computing. Innovations in monitoring and controlling loads are underway offering an array of new technologies that will enable substantially higher level of demand response in all customer segments.
- **Enhancing Federal Demand Response Actions**—to take advantage of existing channels for disseminating information, providing technical assistance, and expanding opportunities for public-private collaboratives. Enhancing cooperation among those that provide new products and services and those that will use them is paramount.

OVERVIEW: KEY FINDINGS AND RECOMMENDATIONS

Introduction

Sections 1252(e) and (f) of EPACT state that it is the policy of the United States to encourage "time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them." It further states that "deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary services markets shall be eliminated". To help implement this new policy on demand response, the Act creates new requirements for electric utilities and states with respect to demand response. States are charged with conducting investigations to determine how those new provisions could be applied and whether to adopt widespread time-based pricing and advanced metering for utility retail customers.

EPACT directs DOE to encourage demand response by:

- educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects, and
- working with States, utilities, other energy providers, and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs (EPACT, Sec. 1252(d)).

The law also requires DOE to provide a report to Congress, not later than 180 days after its enactment, which "identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007" (EPACT, Sec. 1252(d)). This report fulfills that requirement.

Defining and Characterizing Demand Response

Demand response, defined broadly, refers to active participation by retail customers in electricity markets, seeing and responding to prices as they change over time. Currently, most customers see only flat, average-cost based electric rates that give them no indication that electricity values change over time, nor any incentive to vary their electric use in response to prices.

Demand response can be defined more specifically as:

> *Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*

Lower electricity use in peak periods creates benefits by reducing the amount of generation and transmission assets required to provide electric service. Lower demand in response to high prices (particularly market clearing prices in an organized regional spot market) reduces the costs of electricity production and holds down prices in electricity spot markets. Reduced demand in response to system reliability problems enhances operators' ability to manage the electric grid—the network that transmits electricity from generators to consumers—and reduces the potential for forced outages or full-scale blackouts.

Why is Demand Response Important?

Demand response offers a variety of financial and operational benefits for electricity customers, load-serving entities (whether integrated utilities or competitive retail providers) and grid operators. Electric power systems have three important characteristics. First, because electricity cannot be stored economically, the supply of and demand for electricity must be maintained in balance in real time. Second, grid conditions can change significantly from day-to-day, hour-to-hour, and even within moments. Demand levels also can change quite rapidly and unexpectedly, and resulting mismatches in supply and demand can threaten the integrity of the grid over very large areas within seconds. Third, the electric system is highly capital-intensive, and generation and transmission system investments have long lead times and multi-decade economic lifetimes.

These features of electric power systems require that power grids be planned and managed for years in advance to ensure that the system can operate reliably in real time despite the many uncertainties surrounding future demands, fuel sources, asset availability and grid conditions. Working in a competitive bulk power market, load serving entities (integrated utilities or retail electric providers) buy or build from 60 to 95% of their electricity in advance, with the expectation that they will be able to generate or purchase enough spot market electricity in real time to meet changing system demands.

These challenges and uncertainties are what make demand response so valuable—it offers flexibility at relatively low cost. Grid operators—Independent System Operators (ISOs), Regional Transmission Organizations (RTOs) or utilities—and other entities can use demand response to curtail or shift loads instead of, traditionally, building more generation. And although it takes time to establish and recruit customers for a demand response program, well-structured pricing and incentive-based demand response can produce significant savings in close to real time, often at lower costs than supply-side resources.

Types of Demand Response

Demand response can be classified according to how load changes are brought about.

- *Price-based demand response* refers to changes in usage by customers in response to changes in the prices they pay and include real-time pricing, critical-peak pricing, and time-of-use rates. If the price differentials between hours or time periods are significant, customers can respond to the price structure with significant changes in energy use, reducing their electricity bills if they adjust the timing of their electricity usage to take advantage of lower-priced periods and/or avoid consuming when prices are higher. Customers' load use modifications are entirely voluntary.
- *Incentive-based demand response* programs are established by utilities, load-serving entities, or a regional grid operator. These programs give customers load-reduction incentives that are separate from, or additional to, their retail electricity rate, which may be fixed (based on average costs) or time-varying. The load reductions are needed and requested either when the grid operator thinks reliability conditions are compromised or when prices are too high. Most demand response programs specify a method for establishing customers' baseline energy consumption level, so observers can measure and verify the magnitude of their load response. Some demand response programs penalize customers that enroll but fail to respond or fulfill their contractual commitments when events are declared.[3]

The textbox below summarizes the major price-based and incentive-based demand response programs now in use.

EPACT encourages demand response that that allows customers to face the time-varying value of electricity and respond as they choose to those changes. Incentive-based demand response programs offer additional options to policymakers to help solve an area's or market's problems. For example, they can help address reliability problems or can be tailored to achieve specific operational goals, such as localized load reductions to relieve transmission congestion.

Over the long term, the maximum benefits of demand response will come about as the entire range of demand response programs are made available to customers—diversity has value on the demand side as well as the supply-side. Because power system and market circumstances change quickly, a variety of price-based and incentive-based demand response programs can help resolve longstanding industry challenges, such as matching the extended time required to site, approve and build generation and transmission assets to serve uncertain demand growth. In the meantime, it is necessary to understand how to identify and quantify the impacts and benefits of demand response, to facilitate effective and cost-effective implementation of demand response programs and enabling technologies.

[3] These performance-based requirements are intended to increase system operators' confidence that demand reductions will materialize when needed.

<table>
<tr><th colspan="2">Demand Response Options</th></tr>
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Price-Based Options

- *Time-of-use (TOU):* a rate with different unit prices for usage during different blocks of time, usually defined for a 24 hour day. TOU rates reflect the average cost of generating and delivering power during those time periods.
- *Real-time pricing (RTP):* a rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. Customers are typically notified of RTP prices on a day-ahead or hour-ahead basis.
- *Critical Peak Pricing (CPP):* CPP rates are a hybrid of the TOU and RTP design. The basic rate structure is TOU. However, provision is made for replacing the normal peak price with a much higher CPP event price under specified trigger conditions (e.g., when system reliability is compromised or supply prices are very high).

</td><td>

Incentive-Based Programs

- *Direct load control:* a program by which the program operator remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers.
- *Interruptible/curtailable (I/C) service:* curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. Penalties maybe assessed for failure to curtail. Interruptible programs have traditionally been offered only to the largest industrial (or commercial) customers.
- *Demand Bidding/Buyback Programs:* customers offer bids to curtail based on wholesale electricity market prices or an equivalent. Mainly offered to large customers (e.g., one megawatt [MW] and over).
- *Emergency Demand Response Programs:* programs that provide incentive payments to customers for load reductions during periods when reserve shortfalls arise.
- *Capacity Market Programs:* customers offer load curtailments as system capacity to replace conventional generation or delivery resources. Customers typically receive day-of notice of events. Incentives usually consist of up-front reservation payments, and face penalties for failure to curtail when called upon to do so.
- *Ancillary Services Market Programs:* customers bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.

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Current Demand Response Capability and Recent Initiatives

Limited demand response capability exists in the United States at present, as Figure O-1 illustrates. Several important trends are worth noting:

- Demand response potential in 2004 was about 20,500 megawatts (MW)—3% of total U.S. peak demand. Actual delivered peak demand reductions were about 9,000 MW, or 1.3% of total peak demand (EIA 2004).
- Total potential load management capability has fallen by 32% since 1996. Factors affecting this trend include fewer utilities offering load management services, declining enrollment in existing programs, the changing role and responsibility of utilities, and changing supply/demand balance. However, the demand-side

management (DSM) information reported by industry participants do not fully reflect current demand response activity levels.[4]

- Actual peak reductions are affected by the available installed load reduction capability (i.e., the demand response potential), whether utilities or grid operators need to call program events, and the extent to which enrolled participants respond during program events.
- In 2004, utilities reported spending about $515M on load management programs; this represents about a 10% decrease from the early to mid-1990s.

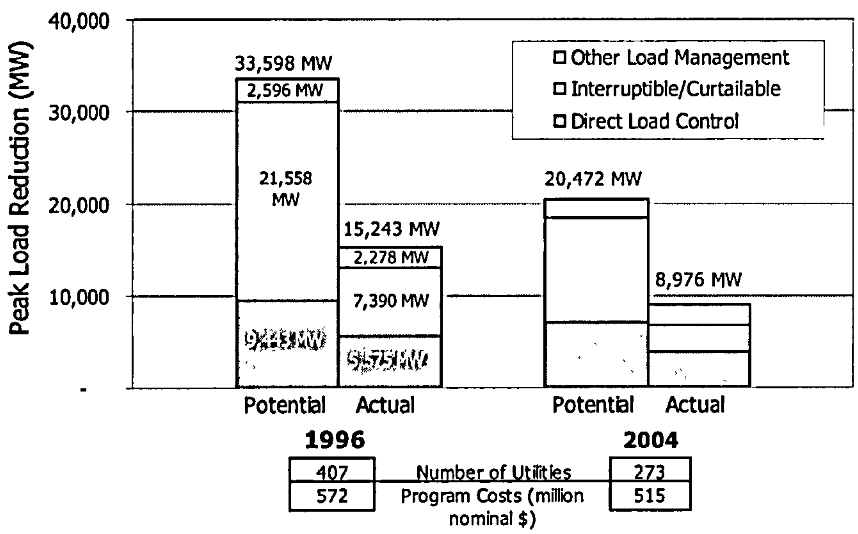

Figure O-1. Existing U.S. Demand Response Potential

A number of recent initiatives highlight renewed interest by federal and state policymakers, regional grid operators and utilities in strengthening demand response capability. Examples include:

- The Federal Energy Regulatory Commission (FERC) has recognized the value that demand response offers for grid reliability and resource adequacy, and has repeatedly encouraged its incorporation and expansion within regions with organized spot markets to enhance competition and more resource-efficient markets.
- Several regional grid operators (e.g., NYISO, PJM, ISO-NE, and the Electric Reliability Council of Texas [ERCOT]) have encouraged customer load participation and taken steps to integrate demand response resources into their wholesale markets.

[4] For example, information on time-varying tariffs (e.g. RTP, CPP, and TOU) is not systematically reported by utilities and competitive retailers do not systematically report the types and mix of contracts/products provided to retail customers.

- Regional initiatives and planning processes in New England and the Mid-Atlantic and the Pacific Northwest regions have involved many stakeholders and developed strategies to promote demand response and overcome barriers.
- Several states (Maryland, New Jersey, New York, and Pennsylvania) have adopted real-time pricing as the default service for large customers or implemented large-scale CPP pilot programs (e.g., California, Florida). Several utilities have aggressively implemented real-time pricing as an optional service for large customers and have attracted significant customer participation (e.g. Georgia Power, Duke Power, Tennessee Valley Authority).
- A number of utilities have deployed or are considering deploying advanced metering systems on a system-wide basis that enables "price-based" demand response for all customer classes.

DOE encourages more of these initiatives, shares Congress' views about the importance and value of demand response, and welcomes the opportunity to help make demand response a more effective, integral part of the nation's electricity markets and system.

Identifying the Benefits of Demand Response

Demand response produces benefits primarily as resource savings that improve the efficiency of electricity provision. It is instructive to trace the flow of these benefits through the market to ascertain who gains and by how much. Accordingly, the benefits of demand response can be classified in terms of whether they accrue directly to participants or to some or all groups of electricity consumers.

- *Participant bill savings*—electricity bill savings and incentive payments earned by customers that adjust load in response to current supply costs or other incentives.
- *Bills savings for other customers*—lower wholesale market prices that result from demand response translate into reduced supply costs to retailers and eventually make their way to almost all retail customers as bill savings.
- *Reliability benefits*—reductions in the likelihood and consequences of forced outages that impose financial costs and inconvenience on customers.

Demand response also provides other benefits that are not easily quantifiable or traceable, but can have a significant impact on electricity market operation. Examples include:

- *Market performance*—demand response acts as a deterrent to the exercise of market power by generators;
- *Improved choice*—customers have more options for managing their electricity costs; and
- *System security*—system operators are provided with *more flexible resources* to meet contingencies.

Quantifying the Benefits of Demand Response

Quantifying the potential nation-wide benefits of demand response is a difficult undertaking requiring the following key information and assumptions:

- *Demand Response Options*—the types of time-varying rates and demand response programs currently offered (or potentially available);
- *Customer Participation*—the likelihood that customers will choose to take part in the offered programs;
- *Customer Response*—documenting and quantifying participants' current energy usage patterns, and determining how participants adjust that usage in response to changes in prices or incentive payments;
- *Financial Benefits*—developing methods to quantify the short- and long-term resource savings of load response under varying market structures;
- *Other Benefits*—identifying and quantifying any additional benefits provided by demand response resources (e.g., improved reliability); and
- *Costs*—establishing the costs associated with achieving demand response.

Estimates of the Benefits and Costs of Demand Response

DOE conducted a literature review to understand how previous studies have estimated the benefits of demand response and selected ten recent studies to analyze the methods used to quantify demand response benefits and their impact on the results.

Three types of studies have estimated the benefits of demand response:

- *Illustrative analyses* quantify the economic impacts of demand response within an electricity market. The four examples selected by DOE examined regions with organized wholesale markets. The benefits of demand response are hypothetical and speculative in these studies, often with few details of where the demand response comes from. The ability of these studies to accurately estimate demand response benefits depends on how closely actual circumstances match the assumptions used in the analysis.
- *Integrated Resource Planning (IRP) studies* assess whether and how much demand response resources should be acquired in a long-term resource plan, based on avoided supply costs and anticipated loads and resource needs. The three selected IRP studies were performed by organizations responsible for long-term, regional resource plans or as an illustration of how that planning process could be conducted to include and value demand response.
- *Program performance analyses* measure actual outcomes of demand response programs implemented by regional grid operators (ISO-NE, NYISO, PJM) and provide an after-the-fact estimate of delivered value. The three selected studies estimated the impacts of load curtailments on market prices, quantified the level and distribution of benefits and explicitly accounted for reliability benefits.

DOE found that the estimates of demand response benefits depend on key assumptions, even for studies that seemingly adopted the same market framework. For example, two studies commissioned to measure the nation-wide benefits of demand response from its integration into wholesale market operations produced wildly disparate estimates of $362 million and $2.6 billion per year.

Consequently, in this report, DOE normalized the estimated gross benefits to allow more informative comparisons.[5] This normalization adjusts for differences in the time horizon, market size and the level of customer participation across studies and expresses annual benefits in terms of dollars per system peak load. This provides a better understanding of the impact of study methodologies and assumptions that produced such disparate benefit estimates. Figure O-2 illustrates the results, comparing the range of normalized gross benefit values over all studies and by the three study categories.

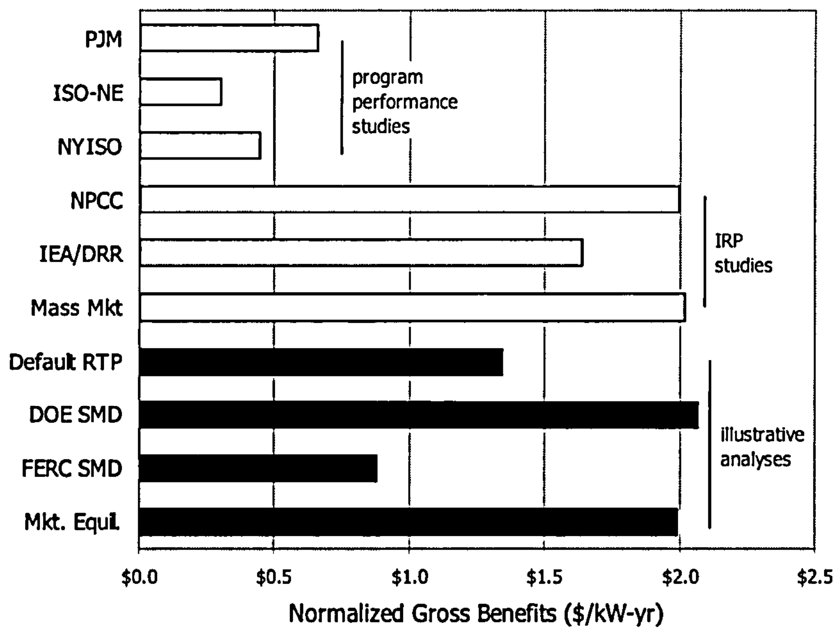

Figure O-2. Normalized Gross Demand Response Benefits: Estimates of Ten Selected Studies

Key findings from this cross-study comparison include:

- Even after normalizing results, the estimated gross benefits of demand response vary widely and are driven by the analytical methods used and the assumptions made.
- The illustrative analysis studies report relatively high gross benefits, in part because they assume high levels of demand response penetration over a large customer base and because they estimate demand response impacts under varying electricity market conditions over a multi-year time horizon.

[5] Net benefits were not reported because program cost data were not included in all ten studies.

- The IRP studies also report high levels of benefits because they consider and simulate the potential impacts of demand response over the full range of electricity market conditions over a multi-decade period. Their explicit treatment of key uncertainties allows demand response to be deployed during low probability but high consequence events over a long planning horizon. These studies assume that demand response programs and benefits will persist for as long as the physical assets they would complement or replace.
- The program performance studies conducted by regional grid operators report the lowest demand response benefits, in part because they reflect market conditions over a short time period and do not necessarily capture the full range of market circumstances. Program impacts and benefits also do not explicitly account for the forward value of demand response.

This analysis reveals that demand response is viewed and evaluated differently in regions with ISO- or RTO-managed organized spot markets than in regions with vertically integrated utilities with a monopoly franchise. Vertically integrated utilities internalize and pass through all of their energy production, transmission and distribution costs, so they (and their regulators) take a long-term view and evaluate demand response against the alternative of building (or buying) new generation. Thus, utilities with retail monopolies evaluate and measure demand response benefits primarily in terms of avoided capacity costs over the long run. In contrast, regions with organized wholesale markets have active energy trading opportunities with transparent market clearing prices (and in four of the seven ISO/RTO regions, no comparable capacity market), so they tend to evaluate demand response benefits primarily in terms of time-varying energy and capacity values in competitive markets. This view frames demand response benefits in the short run, and tends to understate long-term benefits.

Based on this review, DOE concludes that, to date, the estimated benefits of demand response are driven primarily by analysis methods, assumptions regarding customer participation and responsiveness, and market characteristics. Without standardized and accepted analytical methods to quantify the benefits of demand response, DOE finds that it is not possible to produce a meaningful estimate of the national benefits of demand response. Moreover, DOE recognizes that regional differences in market design, operation, and resource balance are important and must be taken into account. Estimates of demand response benefits are best done for service territories, states, and regions, because the magnitude of potential benefits is tied directly to local electric system conditions (e.g., supply mix, the presence or absence of supply constraints, the rate of demand growth, and resource plans for meeting demand growth).

DOE Recommendations

EPACT directed DOE to offer recommendations for achieving specific levels of demand response benefits by January 1, 2007. DOE concludes that it is not possible to offer recommendations in 2006 that can produce meaningful new demand response by January 2007.

The recommendations outlined below, and covered in more detail in Section 5 of this report, aim to expand the availability and effectiveness of demand response programs, expand the reach and effectiveness of enabling technologies, and suggest tasks for the electric industry to better analyze and use demand response in system planning and operations. These recommendations are summarized below and detailed in Table O-1.

- **Fostering Price-Based Demand Response**—by making available time-varying pricing plans that let customers take control of their electricity costs;
- **Improving Incentive-Based Demand Response**—to broaden the ways in which reliability-driven programs contribute to the reliable operation of electric systems;
- **Strengthening Demand Response Analysis and Valuation**—so that program designers, policymakers and customers can anticipate demand response impacts and benefits;
- **Adopting Enabling Technologies**—to realize the full potential for managing usage on an ongoing basis;
- **Integrating Demand Response into Resource Planning**—so that the full impacts of demand response are recognized and the maximum level of resource benefits are realized; and
- **Enhancing Federal Demand Response Actions**—to take advantage of existing channels for disseminating information and forming public-private collaboratives.

Table O-1: List of Recommendations	
Fostering Price-Based Demand Response	In accordance with EPACT, State regulatory authorities must decide whether their utilities must offer customers time-based rate schedules (i.e., RTP, CPP and TOU rates) and advanced metering and communications technology. <u>Large Customers</u> • In states that allow retail competition, state regulatory authorities and electric utilities should consider adopting RTP as their default service option for large customers. • In states that do not allow retail competition, state regulatory authorities and electric utilities should consider offering RTP to large customers as an optional service. • Regional entities and collaborative processes, state regulatory authorities, and electric utilities should provide education, outreach, and technical assistance to customers to maximize the effectiveness of RTP tariffs. <u>Medium and Small Business Customers</u> • State regulatory authorities and electric utilities should investigate new strategies for segmenting medium and small business customers to identify relatively homogeneous sub-sectors that might make them better candidates for price-based demand response approaches. • State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for medium and small business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis. • State regulatory authorities and electric utilities should consider conducting policy or business case analysis of RTP for medium business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis. <u>Residential Customers</u> • State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for residential customers. Results from existing pilot programs should be carefully evaluated and included in the analysis. • State regulatory authorities and electric utilities should investigate the cost-effectiveness of offering technical and/or financial assistance to small business and residential customers to enable their participation in CPP or TOU tariffs and enhance their abilities to reduce demand in response to higher prices.

Improving Incentive-Based Demand Response	• Traditional load management (LM) programs such as direct load control of residential and small commercial equipment and appliances (e.g., air conditioners, water heaters, and pool pumps) with an established track record of providing cost-effective demand response should be maintained or expanded.
	• State regulatory authorities and electric utilities should consider offering existing and new participants in these LM programs "pay-for-performance" incentive designs, similar to those implemented by ISOs/RTOs and some utilities, which include a certain level of payment to customers who successfully reduce demand when called upon to do so during events.
	• Regional entities, state regulatory authorities, and electric utilities should consider including the following emergency demand response program features:
	  o Payments that are linked to the higher of real-time market prices or an administratively-determined floor payment that exceeds customers' transaction costs;
	  o "Pay-for-performance" approaches that include methods to measure and verify demand reductions;
	  o Low entry barriers for demand response providers, and in vertically integrated systems, procedures to ensure that customers have access to these programs; and
	  o Multi-year commitments from regional entities for emergency demand response programs so that customers and aggregators can make decisions about committing time and resources.
	• State regulatory authorities should investigate whether it would be cost-effective for default service providers to implement demand response. They should also provide cost recovery for demand response investments undertaken by distribution utilities.

Table O-1: List of Recommendations	
Strengthening Demand Response Analysis and Valuation	• A voluntary and coordinated effort should be undertaken to strengthen demand response analysis capabilities. This effort should include participation from regional entities, state regulatory authorities, electric utilities, trade associations, demand response equipment manufacturers and providers, customers, environmental and public interest groups, and technical experts. The goal should be to establish universally applicable methods and practices for quantifying the benefits of demand response.
Integrating Demand Response into Resource Planning	• FERC and state regulatory agencies should work with interested ISOs/RTOs, utilities, other market participants and customer groups to examine how much demand response is needed to improve the efficiency and reliability of their wholesale and retail markets. • Resource planning initiatives should review existing demand response characterization methods and improve existing planning models to better incorporate different types of demand response as resource options. • ISOs and RTOs, in conjunction with other stakeholders, should conduct studies to understand demand response benefits under foreseeable future circumstances as part of regional transmission planning and under current market conditions in their demand response performance studies.
Adopting Enabling Technologies	• State regulatory authorities and electric utilities should assure that utility consideration of advanced metering systems includes evaluation of their ability to support price-based and reliability-driven demand response, and that the business case analysis includes the potential impacts and benefits of expanded demand response along with the operational benefits to utilities. • State regulatory authorities and electric utilities should evaluate enabling technologies that can enhance the attractiveness and effectiveness of demand response to customers and/or electric utilities, particularly when they can be deployed to leverage advanced metering, communications, and control technologies for maximum value and impact. • State legislatures should consider adopting new codes and standards that do not discourage deployment of cost-effective demand response and enabling technologies in new residential and commercial buildings and multi-building complexes.
Enhancing Federal Actions	• DOE, to the extent annual appropriations allow, should continue to provide technical assistance on demand response to states, regions, electric utilities, and the public including activities with stakeholders to enhance information exchange so that lessons learned, best practices, new technologies, barriers, and ways to mitigate the barriers can be identified and discussed. • DOE and FERC should continue to coordinate their respective demand response and related activities. • FERC should continue to encourage demand response in the wholesale markets it oversees. • DOE, through its Federal Energy Management Program, should explore the possibility of conducting demand response audits at Federal facilities. • DOE and the Environmental Protection Agency should explore efforts to include appropriate demand response programs and pricing approaches, where appropriate, in the ENERGY STAR® and other voluntary programs.

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ACRONYMS AND ABBREVIATIONS

A/C	air conditioning
AMI	advanced metering infrastructure
AMR	automated meter reading
AMS	advanced metering systems
CAISO	California Independent System Operator
CPP	critical peak pricing
DLC	direct load control (program)
DOE	United States Department of Energy
DSM	demand-side management
EIA	United States Energy Information Administration
EPACT	United States Energy Policy Act (of 2005)
ERCOT	Electric Reliability Council of Texas
EUE	expected un-served energy
FERC	Federal Energy Regulatory Commission
I/C	interruptible/curtailable (rate)
IRP	integrated resource plan (planning)
ISO	Independent System Operator
ISO-NE	ISO—New England (RTO)
kW	kilowatt
kWh	kilowatt-hour
LM	load management
LSE	Load Serving Entity
MISO	Midwest Independent System Operator
MW	Megawatt
NYISO	New York Independent System Operator
PJM	Pennsylvania/New Jersey/Maryland Interconnection (RTO)
PURPA	Public Utilities Regulatory Policy Act
RTO	Regional Transmission Organization
RTP	real-time pricing (rate)
SMD	Standard Market Design
SPM	Standard Practice Manual
SPP	(California) Statewide Pricing Pilot
TOU	time-of-use (rate)
VOLL	value of lost load

SECTION 1. INTRODUCTION

Sections 1252(e) and (f) of EPACT state that it is the policy of the United States to encourage "time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them." It further states that "deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary services markets shall be eliminated." To help implement this new policy on demand response, the Act creates new requirements for electric utilities and states with respect to demand response. States are charged with conducting investigations to determine how those new requirements should be applied and whether to adopt widespread time-based pricing and advanced metering for utility retail customers.[6]

EPACT provides specific guidance to DOE in encouraging demand response. Specifically, the Secretary of Energy is authorized to:

- educate consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects; and
- work with States, utilities, other energy providers, and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs (EPACT, Sec. 1252(d)).

The law also requires DOE to provide a report to Congress, not later than 180 days after its enactment, that "identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007" (EPACT, Sec. 1252(d)).

This document is the report to Congress. DOE views the report requirements as consisting of two parts: the first, "identifies and quantifies the national benefits of demand response" is addressed by Sections 2, 3, and 4 of this report; the second, "makes a recommendation on achieving specific levels of such benefits by January 1, 2007", is addressed by Section 5 of this report. Table 1-1 summarizes how this report is organized to respond to the EPACT requirements.

The report is further organized as follows:

- Section 2 characterizes and defines demand response options, summarizes the role of demand response in our nation's provision of electricity, and introduces a framework for customer decisions about demand response.
- Section 3 includes a conceptual and qualitative discussion of the benefits of demand response.

[6] Public Law 109-58, August 8, 2005.

- Section 4 provides a comparative review and analysis of ten studies that estimate demand response benefits for specific regions or purposes. DOE also suggests methods and considerations for future state or regional efforts to quantify benefits of demand response.
- Section 5 presents specific recommendations for state, regional and federal agencies, electric utilities and consumers to enhance demand response in varying wholesale and retail market structures.
- There are several technical appendices. Appendix A lists interested parties that provided suggestions to DOE on actions or policies to encourage demand response. Appendix B provides a more in-depth conceptual and qualitative discussion of the benefits of demand response. Appendix C summarizes studies on customer response to time-varying prices and demand response programs (e.g. load impacts). Appendix D provides suggestions and technical discussion on protocols and methods for future state or regional efforts to quantify benefits of demand response.

Table 1-1. Response to EPACT Requirements

EPACT Requirement	Approach	Section of Report
Identify national benefits of demand response	• Synthesize literature and stakeholder input	Section 3
Quantify national benefits of demand response	• Review empirical studies of demand response benefits, normalize results and report range of estimates • Synthesize literature and stakeholder input to develop recommended methods	Section 4
Make recommendation on achieving specific levels of benefits by January 1, 2007	• Solicit stakeholder input and review literature to develop recommendations for encouraging and eliminating barriers to demand response	Section 5

Some discussion is warranted on how the report organization and content aligns with DOE's responsibilities for the report to Congress, as set forth in Section 1252(d) of EPACT.

With respect to the first major requirement ("identifies and quantifies the national benefits of demand response"), no existing study provides a comprehensive estimate of the net benefits of demand response *on a national scale*, nor was it possible for DOE to undertake such a detailed and complex analysis given the timeframe and resources available for completion of this report.[7] Instead, DOE selected ten studies that have estimated demand response benefits for specific regions or purposes that provide a range of estimates and illustrate important methodological issues (see Section 4). DOE believes that estimates of demand response benefits are most usefully done at a utility, state, or regional level, as part of policymakers' decisions on what is the appropriate level of demand response for that geographic footprint under consideration.

[7] While a number of studies have attempted to estimate local, regional, or national demand response benefits, empirically or conceptually, they lack a common methodological framework and scope.

With respect to the second requirement ("make a recommendation on achieving specific levels of such benefits by January 1, 2007"), DOE concludes that it is not possible to offer recommendations in 2006 that can produce significantly greater levels of demand response at a national level by January 2007. Instead, DOE offers a set of recommendations for consideration by state, regional and federal agencies, electric utilities and consumers to enhance demand response in a manner that is consistent with the existing market structures of various states and regions. DOE developed these recommendations after consideration of suggestions gained from a public input process in which interested parties provided suggestions, through a web survey, for actions to encourage demand response in different wholesale and retail market structures.[8]

Finally, this report makes the following new contributions to the continuing policy and technical discussions on demand response:

- It is the first study to systematically compare the results of existing quantitative assessments of demand response benefits that use different methods, types of demand response programs, and time horizons.
- It explicitly addresses differences in valuing demand response benefits in vertically integrated utility systems compared to organized electricity markets in which an ISO/RTO administers organized spot markets, and offers recommendations on valuation methods and policy approaches for policymakers.

[8] Appendix A identifies the contributing organizations.

SECTION 2. DEFINING AND CHARACTERIZING DEMAND RESPONSE

What is Demand Response?

Demand response, defined broadly, refers to participation by retail customers in electricity markets, seeing and responding to prices as they change over time. Any commodity market—oil, gold, wheat or tomatoes—consists of both sellers, or suppliers of the commodity, and buyers, or consumers of the goods. For a variety of reasons, very few consumers of electricity are currently exposed to retail prices that reflect varying wholesale market costs, and thus have no incentive to respond to conditions in electricity markets, with results that are detrimental to all.

Demand response may be defined more definitively as:

> *Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*

From the perspective of the electric system as a whole, the emphasis of demand response is on *reductions* in usage at critical times.[9] Critical times are typically only a few hours per year, when wholesale electricity market prices are at their highest or when reserve margins are low due to contingencies such as generator outages, downed transmission lines, or severe weather conditions.

Demand response may be elicited from customers either through a retail electricity rate that reflects the time-varying nature of electricity costs, or a program—an attempt to induce customers to change their consumption behavior—that provides an incentive to reduce load at critical times. The incentive is unrelated to the normal price paid for electricity (e.g., supplemental) and may involve payments for load reductions, penalties for not reducing load, or both.

Demand response represents the outcome of an action undertaken by an electricity consumer in response to a stimulus and typically involves customer behavioral changes. However, its value to society is derived from its cumulative impacts on the entire electric system. Understanding and reconciling these two perspectives is key to characterizing and valuing demand response as well as recognizing its limitations.

The discussion in this section begins by establishing why demand response is important and classifying options for obtaining it. Information on current U.S. demand response capability is then presented. Next, demand response is characterized from the system perspective, illustrating how it fits into electricity system planning and scheduling.

[9] Demand response may also result in *increases* in electricity usage during the majority of hours when electricity prices are lower than average. This too results in more efficient use of the electric system and may also promote economic growth.

Finally, demand response is discussed from the customer perspective, focusing on how and why customers make decisions to participate and respond (or not).

Why is Demand Response Important?

There is a growing consensus that insufficient levels of demand response exist in the U.S. electric power system.

In recent years, there has been growing consensus among federal and state policymakers that insufficient levels of demand response exist in the U.S. electric power system (EPACT 2005, FERC 2003, NARUC 2000, GAO 2004 and 2005). Due to its physical properties, electricity is not economically storable at the scale of large power systems. This means that the amount of power plant capacity available at any given moment of time must equal or exceed consumers' demand for it in real time. Electricity also has few substitutes for certain end uses (e.g. refrigeration, lighting). The marginal cost of supplying electricity is extremely variable because demand fluctuates cyclically with time of day and season and can surge due to unpredictable events (e.g., extreme temperatures) and because generation or transmission capacity availability fluctuates (e.g., due to a generation plant outage or transmission line failure).[10] While the cost of electric power varies on very short time scales (e.g., every 15 minutes, hourly), most consumers face retail electricity rates that are fixed for months or years at a time, representing *average* electricity production (and transmission and distribution) costs.

The disconnect between short-term electricity production costs and time-averaged, fixed retail rates paid by most consumers leads to an inefficient use of resources.

This disconnect between short-term marginal electricity production costs and retail rates paid by consumers leads to an inefficient use of resources. Because customers don't see the underlying short-term cost of supplying electricity, they have little or no incentive to adjust their demand to supply-side conditions.[11] Thus, flat electricity prices encourage customers to over-consume—relative to an optimally efficient system in hours when electricity prices are higher than the average rates, and under-consume in hours when the cost of producing electricity is lower than average rates. As a result, electricity costs may be higher than they would otherwise be because high-cost generators must sometimes run to meet the non-price-responsive demands of consumers. The lack of price-responsive demand also gives

[10] LSEs must secure access to capacity for generation, transmission, and distribution in place before demand occurs, given that electricity can not be stored and must be supplied in real-time to meet geographically dispersed demand. Typically, the most costly generators to operate are only used when demand is at its highest or when other units are temporarily unavailable.

[11] This disconnect between short-term power costs and what retail electricity customers pay may also lead consumers to acquire appliances and pursue applications of electricity that build in long-term inefficiencies and barriers to change.

generators the opportunity to raise prices above competitive levels and exercise "market power" in certain situations.[12]

An important benefit of demand response is avoided need to build power plants to serve heightened demand that occurs in just a few hours per year.

In the long term, the impact of insufficient demand response may be even greater as non-price-responsive peak demand can result in long-term investments in expensive generation capacity. An important benefit of demand response is therefore avoidance of capacity investments in peaking generation units to serve heightened demand that occurs in just a few hours per year.

Demand response also provides short-term reliability benefits as it can offer load relief to resolve system and/or local capacity constraints. During a system emergency or when reserve margins are low, it may be necessary for a utility to ration end user loads to preserve system integrity and/or prevent cascading blackouts. Selectively curtailing service to customers that place lower values on loss of service and voluntarily elect to participate in an emergency demand response program is less expensive, less disruptive and more efficient than random rationing (e.g. curtailing loads via rotating outages).[13] It is also possible for time-varying rates (e.g., RTP) to provide load relief that can help resolve system capacity constraints as customers respond to high on-peak prices.

Many regions are facing significant energy price pressure, demands for substantial grid infrastructure modernization, and concerns regarding excessive reliance on natural gas to fuel electric generation. Improved demand response is critical to improving all of these situations.

Classifying Demand Response Options

There are two basic categories of demand response options: retail pricing tariffs and demand response programs. The specific options for demand response are defined and described in the textbox below.

Time-varying retail tariffs, which include TOU, RTP and CPP rates can be characterized as *"price-based" demand response.* In these tariff options, the price of electricity fluctuates (to varying degrees) in accordance with variations in the underlying costs of electricity production. Time-varying tariffs may be offered as an optional alternative to a

[12] Excessive market power has been measured in several electricity markets in the U.S. and attributed, among other reasons, to insufficient price-responsive load (Borenstein et al. 2000, ISO-NE 2005a, PJM Interconnection 2005a).
[13] Utilities (and now ISOs/RTOs) have developed several program designs that induce customers to reveal their private values/information on outage costs. One approach, based on demand subscription, allows customers to specify a firm service level (FSL) below which they cannot be curtailed and are priced at a higher rate than applies to any residual load, which is curtailable (Woo 1990, Spulber 1992). The customer agrees to curtail this interruptible load during a system emergency.

Demand Response Options

Policymakers have several tariff and program options for eliciting demand response. The most commonly implemented options are described below.

Tariff Options
("price-based" demand response)

- *Time-of-use (TOU):* a rate with different unit prices for usage during different blocks of time, usually defined for a 24-hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. TOU rates often vary by time of day (e.g., peak vs. off-peak period), and by season and are typically pre-determined for a period of several months or years. Time-of-use rates are in widespread use for large commercial and industrial (C/I) customers and require meters that register cumulative usage during the different time blocks.
- *Real-time pricing (RTP):* a rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. RTP prices are typically known to customers on a day-ahead or hour-ahead basis.
- *Critical Peak Pricing (CPP):* CPP rates include a pre-specified high rate for usage designated by the utility to be a critical peak period. CPP events may be triggered by system contingencies or high prices faced by the utility in procuring power in the wholesale market, depending on the program design. CPP rates may be super-imposed on either a TOU or time-invariant rate and are called on relatively short notice for a limited number of days and/or hours per year. CPP customers typically receive a price discount during non-CPP periods. CPP rates are not yet common, but have been tested in pilots for large and small customers in several states (e.g., Florida, California, and North and South Carolina).

Program Options
("incentive-based" demand response)

- *Direct load control:* a program in which the utility or system operator remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice to address system or local reliability contingencies. Customers often receive a participation payment, usually in the form of an electricity bill credit. A few programs provide customers with the option to override or opt-out of the control action. However, these actions almost always reduce customer incentive payments. Direct load control programs are primarily offered to residential and small commercial customers.
- *Interruptible/curtailable (I/C) service:* programs integrated with the customer tariff that provide a rate discount or bill credit for agreeing to reduce load, typically to a pre-specified firm service level (FSL), during system contingencies. Customers that do not reduce load typically pay penalties in the form of very high electricity prices that come into effect during contingency events or may be removed from the program. Interruptible programs have traditionally been offered only to the largest industrial (or commercial) customers.
- *Demand Bidding/Buyback Programs:* programs that (1) encourage large customers to bid into a wholesale electricity market and offer to provide load reductions at a price at which they are willing to be curtailed, or (2) encourage customers to identify how much load they would be willing to curtail at a utility-posted price. Customers whose load reduction offers are accepted must either reduce load as contracted (or face a penalty).
- *Emergency Demand Response Programs:* programs that provide incentive payments to customers for measured load reductions during reliability-triggered events; emergency demand response programs may or may not levy penalties when enrolled customers do not respond.
- *Capacity Market Programs:* these programs are typically offered to customers that can commit to providing pre-specified load reductions when system contingencies arise. Customers typically receive day-of notice of events. Incentives usually consist of up-front reservation payments, determined by capacity market prices, and additional energy payments for reductions during events (in some programs). Capacity programs typically entail significant penalties for customers that do not respond when called.
- *Ancillary Services Market Programs:* these programs allow customers to bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.

regular fixed electricity rate or as the regular, default rate itself.[14] Customers on these rates can reduce their electricity bills if they respond by adjusting the timing of their electricity usage to take advantage of lower-priced periods and/or avoid consuming when prices are higher. Customer response is typically driven by an internal economic decision-making process and any load modifications are entirely voluntary.

Incentive-based demand response programs represent contractual arrangements designed by policymakers, grid operators, load-serving entities (utilities and retail electricity suppliers) to elicit demand reductions from customers at critical times called program "events".[15] These programs give participating customers incentives to reduce load that are separate from, or additional to, those customers' retail electricity rate, which may be fixed (based on average costs) or time-varying. The incentives may be in the form of explicit bill credits or payments for pre-contracted or measured load reductions. Customer enrollment and response are voluntary, although some demand response programs levy penalties on customers that enroll but fail to respond or fulfill contractual commitments when events are declared.[16] In order to determine the magnitude of the demand reductions for which consumers will be paid, demand response programs typically specify a method for establishing customers' baseline energy consumption (or firm service) level against which their demand reductions are measured.

Current U.S. Demand Response Capability

Limited demand response capability exists in the U.S. at present.

Limited demand response capability exists in the United States at present. The Energy Information Administration (EIA) has collected annual information on demand-side management (i.e., energy efficiency and load management) from industry participants since the early 1990s. Industry participants (mostly utilities) provide the following information on company-administered load management programs: potential peak reduction, actual peak reductions, and program costs. Potential peak reductions reflect the installed load reduction capability, in megawatts (MW), of program participants during the time of system peak, while actual peak reduction reflects the changes in the demand for electricity resulting from a load management program that is in effect at the same time that the utility experiences its annual peak load. Program costs include direct and indirect utility expenses (e.g., program administration, payments to participants, marketing).[17] Prior to 1997, utilities reported information on a more disaggregated basis based on type

[14] TOU rates are in common use as the default service for large commercial and industrial customers throughout the U.S. RTP has been offered as an optional rate for large customers at 40-50 utilities in the U.S., and has been adopted or is under consideration as the default electricity service for large customers in several states where customers can choose their retail supplier (e.g., New Jersey, Maryland, Pennsylvania, New York).

[15] Events may be in response to high wholesale electricity market prices or contingencies that threaten electric system reliability, which can occur at any time of the year.

[16] These performance-based requirements are intended to increase system operators' confidence that demand reductions will materialize when needed.

[17] Costs reported to EIA do not include those incurred directly by participating customers.

of demand response program, which included categories for direct load control (DLC) and interruptible/curtailable (I/C) rate programs.

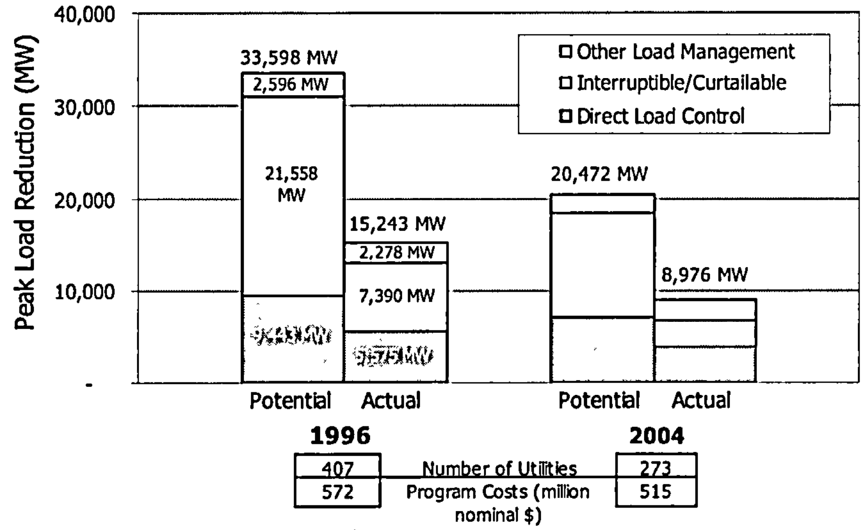

Figure 2-1. Existing U.S. Demand Response Potential

Figure 2-1 summarizes information on potential and actual peak reductions and program costs for 1996 and 2004.[18] Several trends are worth noting:

- Demand response potential in 2004 was about 20,500 MW, 3% of total U.S. peak demand. Actual delivered peak demand reduction was about 9,000 MW, about 1.3% of total peak (NERC 2005).
- Total potential load management capability has fallen by 32% since 1996. Factors affecting this trend include fewer utilities offering load management services (407 utilities in 1996 to 273 in 2004), declining enrollment in existing programs, the changing role and responsibility of utilities, and the increase in installed capacity The DSM information reported by industry participants to EIA does not fully reflect current demand response activity levels.[19]
- Actual peak reductions are affected by the available installed load reduction capability (i.e., the demand response potential), whether utilities or ISOs/RTOs called program events, and the extent to which enrolled participants respond during events.

[18] 1996 is both the year with the highest potential load reduction capability and the last year for which disaggregated information on demand response program type is available; 2004 is the most recent year of reported data.

[19] For example, utilities do not systematically report information on customer participation in optional "price-based" demand response programs (e.g. RTP, CPP, and TOU) and competitive retailers do not report the types and mix of contracts/products provided to retail customers. It is unlikely that all industry participants enrolled in ISO demand response programs are reporting their demand response activities.

- In 2004, utilities reported spending about $515M on load management programs; this represents about a 10% decrease from the early to mid-1990s.
- Although not shown explicitly in Figure 2-1, residential and industrial customers account for the bulk of actual peak load reductions (32% and 50% respectively) in 2004.

Market Structures for Electricity Production in the U.S.

Historically, the U.S. electric power industry has relied heavily on a market structure based on vertically integrated utilities that planned and operated electric generation, transmission and distribution systems on an integrated basis. Investor-owned utilities have an obligation to provide reliable service to customers in established, franchise service territories and are subject to regulation as a monopoly by state public utility commissions that set retail rates and review major capital investments and utility operations.

During the last decade, federal legislation (e.g., Energy Policy Act of 1992) and various Federal Regulatory Energy Commission (FERC) orders have helped create more competitive wholesale power markets with mandated open transmission access. Today almost every load-serving entity in the nation purchases some portion of its supply from these wholesale power markets, whether through bilateral contracts or in an organized spot market. Organized spot markets for wholesale electricity, operated by RTOs or ISOs) exist in the Northeast, Mid-Atlantic, much of the Midwest, and in Texas and California. ISOs/RTOs are typically responsible for maintaining grid reliability by overseeing and operating the high-voltage bulk power system and coordinating electricity generation, operating bid-based markets for spot energy (e.g. real-time, day-ahead, or ancillary services), and conducting long-term regional planning to identify system upgrade and expansion needs and overseeing capacity markets (in some cases).

In those states and regions without an ISO or RTO, electricity is delivered and transacted primarily by vertically integrated utilities through self-generation and bilateral contracts with significant state regulatory oversight of resource planning and rates.

Retail competition has been established in 18 states, which give customers additional choices in the supply and pricing of electricity. In these states, there have also been significant changes in the roles and responsibility of utilities (e.g. divesting of some generation assets, separation of competitive retail service function from transmission and distribution services which remain regulated).

A significant number of customers (20-25% of U.S. electric load) are also served by rural electric cooperatives or public power (municipal or public utility district) utilities. These entities have structural characteristics that are similar to vertically integrated utilities in that they typically have an obligation to serve customers in an established franchise service territory and many own generation, transmission and distribution assets, but their governance structure differs in that they are overseen by local authorities and boards. In a few states they are also regulated at the state level. Some public power utilities and rural cooperatives purchase some or all of their power requirements from vertically integrated utilities, generation and transmission cooperatives, power marketing authorities, or through wholesale markets and in some cases have developed load management resources to a greater extent than investor-owned utilities (Kexel 2004).[20]

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[20] For some rural cooperatives, the primary reason for implementing load management programs was to reduce billed demand charges to the member cooperatives themselves and to reduce the capacity requirements of their Generation and Transmission cooperatives (Kexel 2004).

The Role of Demand Response in Electric Power Systems

In assessing the benefits of demand response, it is important for policymakers to be cognizant of the physical infrastructure and operational requirements necessary to construct and reliably operate an electric power system as well as regional differences in market structure and industry organization (see the previous textbox).

In all market structures, the management of electric power systems is largely shaped by two important physical properties of electricity production. First, electricity is not economically storable, and this in turn requires maintaining the supply/demand balance at the system level in real time. Mismatches in supply and demand can threaten the integrity of the electrical grid over extremely large areas within seconds. Second, the electric power industry is very capital intensive. Generation and transmission system investments are large, complex projects with expected economic lifetimes of several decades that often take many years to develop, site and construct.

These features of electric power systems necessitate management of electricity on a range of timescales, from years (or even decades) for generation and transmission planning and construction, to seconds for balancing power delivery against fluctuations in demand (see Figure 2-2). Decisions are made at several junctures along this timeframe. Generally speaking, the amount of load committed at each juncture declines as the time horizon approaches power delivery. For example, 70-80% of supplied load is often committed through forward energy contracts, months or even years before it is delivered. The amount of power arranged on a day-ahead basis varies, but is typically 10-25% of total requirements. In most cases, less than 5% of supply is committed in the last two hours before its delivery.

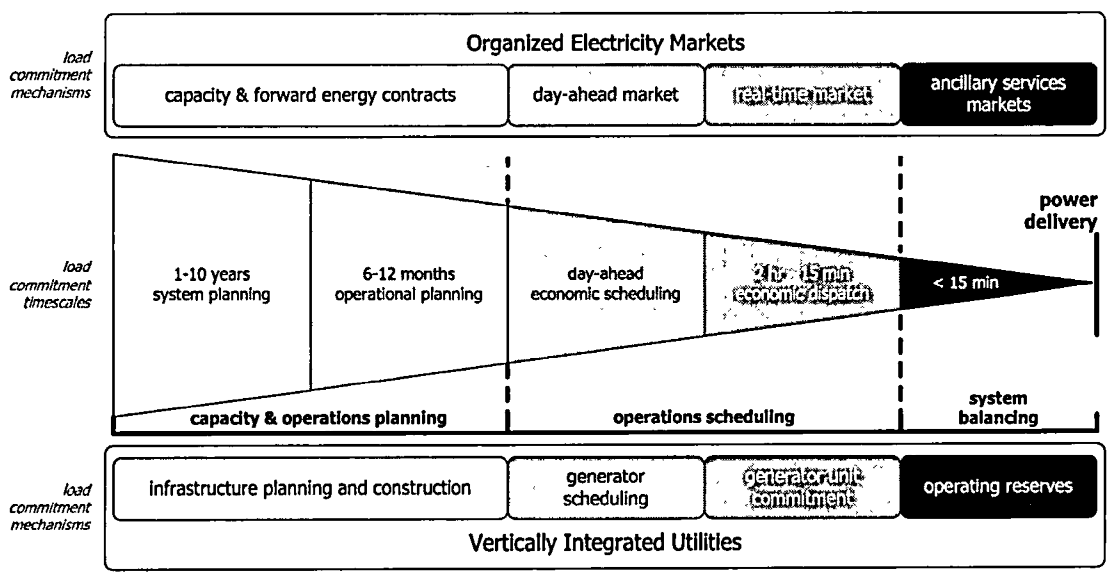

Figure 2-2. Electric System Planning and Scheduling: Timescales and Decision Mechanisms

The major infrastructure planning and operational power delivery decision timeframes are similar in regions with organized wholesale markets and in vertically integrated systems, although the mechanisms for committing energy supply responsibilities differ (see Figure 2-2). In states with retail competition, default service providers and competitive retailers often have a much shorter horizon for acquiring resources than a vertically integrated utility in a state without retail competition.

- *Capacity and operations planning* includes long-term investment and planning decisions. Capacity, or system, planning involves assessing the need for and investing in new generation, transmission and distribution system infrastructure over a multi-year time horizon. Operations planning involves scheduling available resources to meet expected seasonal demand and spans a period of months. In vertically integrated utility systems, these investments are typically evaluated in a utility resource planning process, subject to state regulatory review. In regions with organized wholesale markets, responsibility for these activities is more diffuse. An ISO or RTO engages in a long-term transmission planning process, while distribution utilities retain responsibility for distribution system planning and operations. ISO-administered energy and capacity markets (in some areas) determine the scheduling and operation of available resources to meet daily and seasonal needs and also provide price signals for investments in new generation plants. Utilities and competitive retail suppliers, collectively referred to as load-serving entities (LSEs), contract with generators to meet forward energy requirements.
- *Operations scheduling* refers to the process of determining which generators operate to meet expected near-term demand. This typically involves making day-ahead commitments based on the next day's forecasted demand, with adjustments made in a period of hours down to 15 minutes to account for discrepancies in day-ahead and day-of demand forecasts as well as to account for any unexpected generation plant outages or transmission line problems. Day-ahead and real-time markets administered by ISOs or RTOs fulfill these responsibilities in regions with organized wholesale markets, using generator (or demand resource) offers as the mechanism for scheduling resources for dispatch. Vertically integrated utilities evaluate and schedule generation plants on a merit order basis ranked according to their variable operating costs.
- *System balancing* refers to adjusting resources to meet last-minute fluctuations in power requirements. In regions with organized wholesale markets, resources offer to provide various ancillary services, such as reactive supply and voltage control, frequency-responsive spinning reserves, regulation, and system black-start capability that are necessary to support electrical grid operation.[21] Vertically integrated utilities typically provide ancillary services as part of their integrated operation of the power system.

Ultimately, supply resources are valued according to the timescale of their *commitment* or *dispatch*. Yet because electricity is not storable, its *delivery* to consumers—the goal

[21] Reserves are a type of ancillary service for which ISO/RTO markets have been established in regions with organized wholesale markets. Generators (and loads) bid their availability to supply backup power with varying degrees of notice (usually from 30 minutes down to 10 minutes). Other types of ancillary services are typically contracted for directly by ISOs or RTOs.

around which power systems are constructed and managed—occurs in real-time, regardless of when it was committed and priced.

Demand response options can be deployed at all time scales of electricity system management.

Demand response options can be deployed at all timescales of electricity system management (see Figure 2-3) and can be coordinated with the pricing and commitment mechanisms appropriate for the timescale of their commitment or dispatch.[22] For example, demand response programs designed to alert customers of load response opportunities on a day-ahead basis should be coordinated with either a day-ahead market or, in a vertically integrated market structure, with the utility's generator scheduling process. Like generation resources, the actual *delivery* of customer load reductions occurs in real time.

Energy efficiency is a demand-side resource that can be integrated and valued as part of the system planning process and time horizon (Figure 2-3). Though not dispatchable, energy-efficiency measures often create permanent demand-reduction impacts as well as electricity savings.

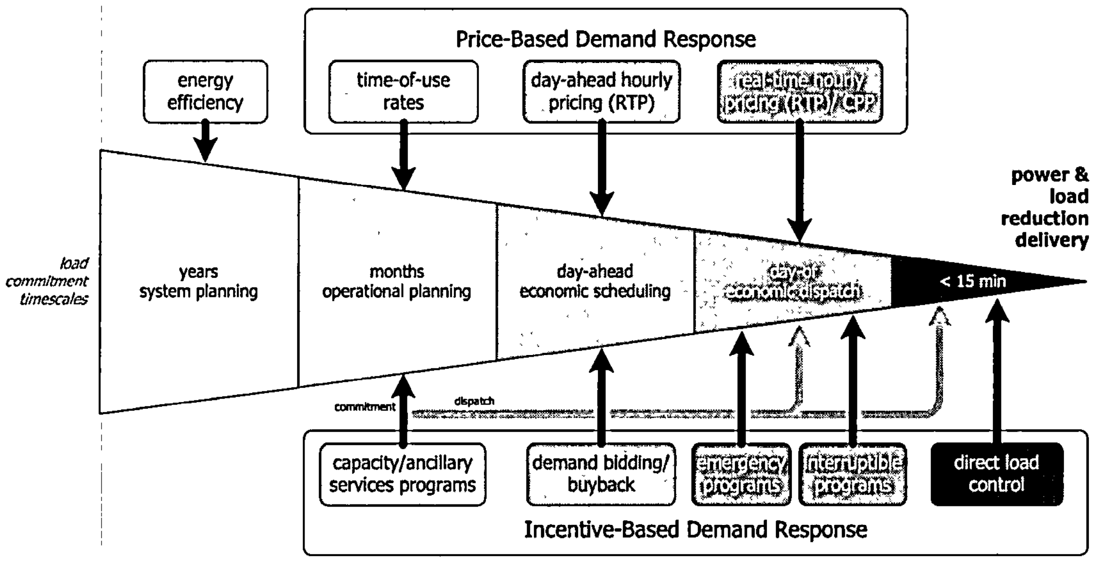

Figure 2-3. Role of Demand Response in Electric System Planning and Operations

If utility resource planners and system operators have a good sense of how their customers respond to changes in the price of electricity, price-based demand response options may be incorporated into system planning at different time scales (Figure 2-3):

[22] In some cases, demand response resources have been included in a Request for Proposals (RFP) process designed to alleviate short-term (e.g., 3-4 years), localized transmission capacity constraints. For example, ISO-NE issued an RFP for demand relief over four years in Southwest Connecticut, where construction of transmission capacity was delayed (Platts 2004), and Bonneville Power Administration issued an RFP for demand reduction, energy efficiency and distributed generation options to defer new transmission investments on a five-year timescale in 1994.

- *TOU rates*, which reflect diurnal and seasonal variations in electricity costs but are fixed months in advance, may be valued and integrated as part of operations planning.
- *RTP* provides hourly prices to customers with day-ahead or near-real-time notice, depending on the tariff design.[23] In wholesale markets with ISOs/RTOs, RTP prices are typically indexed to transparent, location-based, day-ahead or real-time hourly energy market prices; absent an organized spot market, utilities establish RTP "prices" based on the utility's marginal procurement costs.
- *CPP rates* are essentially TOU rates with the addition of a critical peak price that is called on a day-of basis.

Incentive-based demand response programs may be introduced at virtually all timescales of electric system management (Figure 2-3):

- *Capacity programs* involve load reduction commitments made ahead of time (e.g., months), which the system operator has the option to call when needed. The call option is usually exercised with two or less hours of notice, depending on the specific program design. Participants receive up-front capacity payments, linked to capacity market prices, from entities that otherwise would need to purchase comparable levels of generation to satisfy capacity reserve obligations.
- *Ancillary services programs* also involve establishing customer load commitments ahead of time. Customers whose reserve market bids are accepted must then be "on call" to provide load reductions, often with less than an hour's notice.[24]
- Load reductions from *demand buyback* or *bidding programs* are typically scheduled day-ahead, and incentive payments are valued and coordinated with day-ahead energy markets.
- *Emergency programs* are reliability-based, and payments for load reductions are often linked to real-time energy market prices (in regions with organized wholesale markets) or values that reflect customer's outage cost or the value of lost load. Program events are usually declared within 30 minutes to 2 hours of power delivery.
- *DLC programs* are typically reliability-based and can be deployed within minutes because the utility or system operator triggers the reduction directly, without waiting for a customer-induced response.[25]

[23] In some states (e.g., New Jersey, Maryland, Pennsylvania), RTP tariffs have been implemented that are indexed to real-time markets that do not communicate prices until after the fact. No studies assessing observed price response from this tariff design have been conducted. It is conceivable that customers look to near real time prices or day-ahead market prices posted by the PJM Interconnection, as a proxy and adjust their usage accordingly (Barbose et al. 2005).
[24] See Kirby (2003) and Kueck et al. (2001) for more information on customer load participation in ancillary services markets.
[25] DLC can also be used by LSEs to mitigate the impact of high wholesale market prices or manage system-demand related charges.

How Do Customers Accomplish Demand Response?

There are significant challenges in matching customers' preferences for demand response program features to system characteristics that drive value. From the customer perspective, investments in demand response and energy efficiency are both DSM strategies that can be used to manage energy costs. Participation in DSM programs (or making DSM investments) involves a series of decisions (see Figure 2-4).

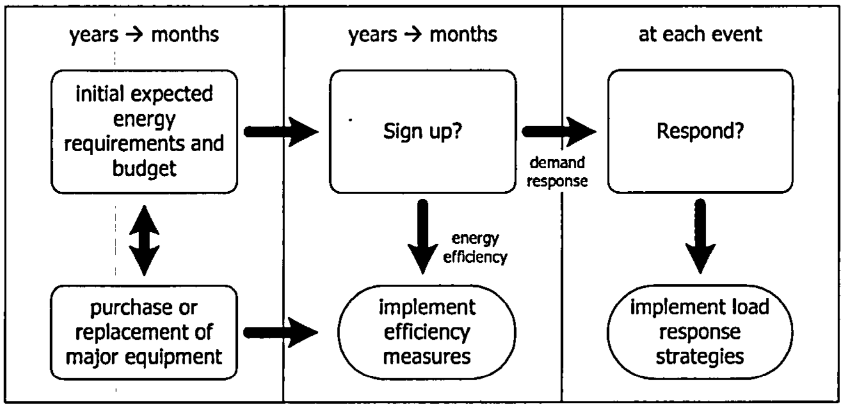

Figure 2-4. Customer Decisions for Demand-Side Management

First, customers implicitly or explicitly determine an initial energy budget based on their expectations of current and future average electricity prices and their household or facility energy needs (see Figure 2-5). The timeframe for this decision (or expectation) is typically monthly or annual, and decisions about purchasing or replacing major energy-using equipment may be made at the same time (see Figure 2-4). The decision-making process may be somewhat different for residential and small commercial customers, who may have a less formalized notion of their usage needs and budget than for large commercial or industrial facilities that may include energy costs as part of a specific operating budget.[26] Larger demand-metered customers are also more likely to be concerned with managing their peak demand in response to demand charges, which are typically included in their electricity tariffs.

Customer participation in demand response options involves *two* important decisions: whether or not to sign up for a voluntary program or tariff (or remain on the option in the case of a default tariff) and, subsequently, whether or not to respond to program events or adjust usage in response to prices as they occur (see Figure 2-4). This is in contrast to traditional energy-efficiency programs, in which customers invest in high-efficiency equipment in response to an existing program offered by a utility, state agency, or public benefits administrator that provides information, technical assistance and/or financial incentives.[27] In most cases energy-efficiency measures, once installed, continue to reduce

[26] This characterization of the customer decision process is more applicable to large, sophisticated, customers. There is a portion of the customer base, particularly many residential and small business customers that have limited understanding of their energy usage patterns and existing tariffs.
[27] Many customers also decide to invest in high efficiency equipment or measures based solely on their own internal economic decision criteria, apart from publicly funded programs.

energy usage over a multi-year economic lifetime, usually without much ongoing customer attention.[28] Compared to the initial usage and budget decision, which is relatively simple and familiar to customers, customers' decisions to enroll in demand response programs and to respond during events can be quite complex.

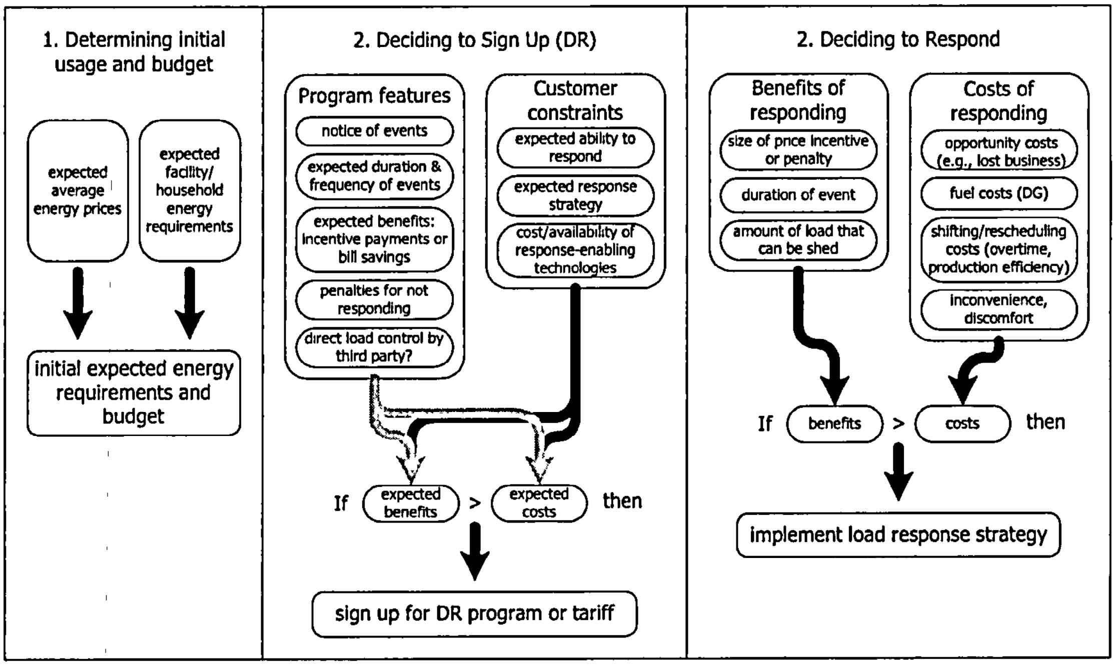

Figure 2-5. Factors Affecting Customer Decisions About Demand Response

The decision to sign up for demand response options involves evaluating offered program or tariff features and weighing the *expected* costs and benefits (see Figure 2-5). A demand response program may specify key parameters of interest to customers (e.g., maximum number of emergency events, payment if event is called), although there is significant uncertainty about the probability and timing of emergency events for the customer.

Ultimately, uncertainties in the costs and benefits of program participation represent risks to customers that may pose significant barriers to their signing up. For example, under RTP, future hourly prices are uncertain, making the benefits of participation difficult to predict.[29]

[28] Some energy-efficient equipment does require ongoing commissioning or maintenance to ensure energy savings continue to be realized over time, or savings may be affected by changes in customer usage of the equipment. Nonetheless, most energy-efficiency investments produce at least some level of savings over a period of years without further customer attention.

[29] However, the most popular form of RTP, two-part RTP, provides some financial protection against unexpectedly high prices, and the primary driver of participation is likely the expectation of *lower* average prices than under a standard tariff. Experience at successful programs (e.g., Georgia Power and Duke Power Company) has shown that some customers reduce load substantially during hours of high prices. Thus, RTP customers have the possibility of achieving bill savings from both lower prices overall, and from responding to high prices when they occur.

> *The relative certainty of a benefit stream may be as important to customers as the benefits themselves.*

Potential participants in emergency demand response programs also face uncertainty about the number of demand response events in which they will be able to achieve benefits, and the payments they will receive when the events occur. Only in capacity-related demand response programs are up-front payments typically provided, in return for which customers agree to curtail on short notice when notified. The relative *certainty* of a benefit stream may be as important as the incentive payments themselves. While certain up-front investments, such as programmable thermostats, energy management systems or onsite generation equipment, may make responding easier, uncertainties about the benefits of responding can make these investment decisions difficult to justify.

Once enrolled, customers must decide whether or not to respond as events arise (see Figure 2-5). The benefits of responding are dependent on the actual financial incentive payment that applies to the given event (including the penalty for not responding), the number of hours that the event extends for, the amount of load the customer can shed, and may also include such considerations as the desire to help others by keeping the electric system secure.[30]

Customers may adopt one or more of three basic load response strategies (see the textbox below) and will assess the actual costs of responding in a specific situation. Their costs of responding depend in part on the type of response strategy undertaken. For example, customers who forego usage without making it up later incur costs due to lost productivity or foregone amenity. Customers that shift or reschedule their energy usage may incur costs from labor rescheduling, overtime pay or productivity losses from adjustments to their production process. If onsite generation is used to respond, fuel and maintenance costs are incurred. For any response strategy, inconvenience or discomfort to building occupants or tenants are likely to be important considerations and may be an important part of the cost-benefit decision, even if they are not directly monetized.

[30] Note that customers in DLC programs often do not have the choice about whether or not to respond during emergency events. Rather, their choices are focused on the decision to enroll or continue to participate in the program.

Types of Customer Load Response

Customers participating in demand response options may respond to high prices or program events in three possible ways:

- *Foregoing:* involves reducing usage at times of high prices or demand response program events without making it up later. For example, a residential customer might turn off lights or turn up the thermostat on an air conditioner during an event, or a commercial facility might turn off office equipment. In both cases, a temporary loss of amenity or comfort results.
- *Shifting:* involves rescheduling usage away from times of high prices or demand response program events to other times. For example, a residential customer might put off running a dishwasher until later in the day, or an industrial facility might reschedule a batch production process to the prior evening hours or the next day. The lost amenity or service is made up either prior to or at a subsequent time.
- *Onsite generation:* some customers may respond by turning on an onsite or backup emergency generator to supply some or all of their electricity needs. Although the customer may have little or no interruption to their electrical usage, their net load and requirements on the power system is reduced.

Load response strategies may be enhanced with technologies and techniques that allow for fully automated demand response. Pilot projects have demonstrated this potential (Piette et al. 2005), although few customers have yet adopted fully automated demand response.

SECTION 3. BENEFITS OF DEMAND RESPONSE

EPACT requires DOE to identify the benefits of demand response in this report. This section addresses this requirement with a conceptual discussion of the various benefits of demand response, how they are derived, to whom they accrue and how to correctly ascribe value to them. The latter is important to policymakers and utilities in determining how much and what types of time-varying rates and demand response programs to include in their resource portfolios.

The following considerations underlie this discussion of demand response benefits:

- *Customers adjust their electricity usage from typical levels in expectation of receiving benefits.* These benefits must be tangible and sufficient to compensate them for the costs they incur to provide demand response, or else they will not respond.
- *Customers and program administrators incur costs in achieving demand response.* Thus, any discussion of benefits must also define and recognize costs, and quantitative assessments should identify net benefits.
- Policymakers should consider the distributional impacts—*who bears the costs and who receives the benefits*—in designing and evaluating demand response strategies.
- *The durability of benefits must be taken into account*; short-term impacts should be distinguished from long-term impacts that provide benefits over a multi-year period.
- There are important *differences in the timing and distribution of demand response benefits* for vertically integrated utilities in states without retail competition compared to regions with organized wholesale markets and retail competition.

This section begins by identifying and discussing the costs of enabling and implementing demand response. Demand response benefits are then discussed, looking at benefits to participants, collateral benefits (which include economic and reliability benefits enjoyed by some or all market participants), and other benefits that are not easily quantifiable. Appendix B provides a more detailed discussion of collateral benefits, including a discussion of differences in the timing and flow of benefits in different market structures.

Demand Response Costs

The costs of realizing demand response can be distinguished as *participant* and *system* costs (see Table 3-1). Individual customers that curtail usage incur participant costs. Demand response program administrators incur system costs to create the infrastructure required to launch and support demand response, including providing incentive payments to customers. System costs may be recovered from ratepayers (either all ratepayers or designated classes of customers) or, in some cases, through "public benefits" charges on their electric bills. Cost recovery decisions are typically made with oversight from state regulatory agencies.

Table 3-1. Costs of Demand Response

Type of Cost		Cost	Responsibility/ Recovery Mechanism
Participant costs	Initial costs	Enabling technology investments	Customer pays; incentives may be available from public benefit or utility demand response programs to offset portion of costs
		Establishing response plan or strategy	Customer pays; technical assistance may be available from public benefits or utility demand response programs
	Event-specific costs	Comfort/inconvenience costs	Customer bears "opportunity costs" of foregone electricity use
		Reduced amenity/lost business	
		Rescheduling costs (e.g., overtime pay)	
		Onsite generator fuel and maintenance costs	
System costs	Initial costs	Metering/communications system upgrades	Level of costs and cost responsibility vary according to the scope of the upgrade (e.g., large customers vs. mass market), the utility business case for advanced metering system or upgrades, and state legislation/policies
		Utility equipment or software costs, billing system upgrades	Utility typically passes cost through to customers in rates
		Customer education	Ratepayers, public benefits funds
	Ongoing program costs[1]	Program administration/management	Costs are incurred by the administering utility, LSE or ISO/RTO and are recovered from ratepayers
		Marketing/recruitment	
		Payments to participating customers	
		Program evaluation	
		Metering/communication[2]	

[1] Ongoing program costs apply for incentive-based demand response programs and optional price-based programs only. For default-service time-varying pricing, ongoing costs are equivalent to any other default-service tariff offering.
[2] Metering/communications costs can include dedicated wire or wireless lines leased from a third-party telecommunications provider and costs to communicate pricing or curtailment information to customers or their energy services suppliers.

Customers undertaking load reductions may incur *initial* as well as *ongoing* costs to respond (see Table 3-1):

- *Initial costs* are incurred before a particular demand response behavior or action can be undertaken. They include devising a load response strategy that takes costs and benefits into account, and investing in enabling technologies to assist with load response. Enabling technologies include devices, such as "smart" thermostats, peak load controls, energy management control or information systems fully integrated into a business customer's operations, and onsite generators deployed as backup to network service. Policymakers may find it appropriate to invest in customer education and/or technology rebate programs, using ratepayer or public benefits funds, to defray some of participating customers' initial costs, especially if they are barriers to the achievement of demand response potential.

- *Ongoing costs* are incurred by customers when they respond to high prices or demand response program events. These costs may be measurable financial costs (e.g., lost business activity, rescheduling costs such as employee overtime pay, fuel and maintenance costs from operating onsite generation) or more abstract measures of the value of electricity (e.g., the inconvenience or discomfort associated with load reductions).

Various system-wide costs are incurred in implementing demand response, which should be considered in assessing cost-effectiveness.

A variety of *system-wide costs*, which may be passed through to ratepayers or borne by utility or LSE shareholders, are associated with implementing demand response and require consideration in evaluating benefits. These include *initial costs* as well as *ongoing costs* for certain demand response options (see Table 3-1).

Initial costs can be organized into several functional categories, as follows:

Metering and communication system upgrade costs can present a significant barrier to widespread implementation of price-based DR.

- *Metering/communication system upgrade costs.* Customer retail rates typically charge only for the monthly volume of energy consumed, and for larger customers for maximum monthly demand. Time-varying tariffs (e.g., RTP, CPP) requires chronological measurement of energy usage or demand. This is typically accomplished by installing advanced metering systems (AMS) that measure and store energy usage at intervals of one hour or less and include communication links that allow the utility to remotely retrieve current usage information whenever need.[31] Metering and communications system upgrade costs depend on the existing technology as well as the applicable customer classes. Because the aggregate costs may be substantial, they can present a significant barrier to widespread implementation of time-varying tariffs especially for small and medium-sized customers and often raise cost responsibility and recovery issues. Advanced metering issues are discussed in the textbox below.

- *Utility billing system* upgrades may be necessary for some demand response options (e.g., RTP, CPP) because most legacy systems are not equipped to handle time-varying costs or usage. Pricing hourly (RTP), or having provision to price some hours differently (CPP), requires changing the way metered data are collected, processed, and stored.[32]

[31] Note that for some pricing applications (e.g., TOU rates) only usage by daily pricing period (peak and off-peak) needs to be recorded.
[32] RTP (and/or CPP) rates significantly increase the amount of usage data that must be collected (i.e., from two to four observations of customer demand and energy usage per month to at least 720 observations).

Advanced Metering to Support Price-Based Demand Response

Advanced metering is a key technology that enables many utility and customer functions. This textbox addresses four key questions regarding the role and cost of advanced metering.[33]

What is the relationship between price-based demand response and advanced metering? Price-based demand response (e.g., RTP or CPP) requires a tariff that links what the customer pays to the hourly wholesale costs of power. Advanced metering provides utilities with the capability to collect hourly interval or more frequent usage data, which is necessary to support RTP or CPP tariffs.

What is advanced metering? There are three basic types or classes of meters.

- *Conventional "kilowatt-hour" (kWh) meters* account for more than 90% of the current meter population. They record cumulative energy usage and are usually read once each month during an on-site visit by a utility employee.
- *Automated meter reading systems (AMR)* add a low power transceiver, a communication link, to a conventional kWh meter. The transceiver allows the meter to be read from a utility vehicle that drives by the customer site. These meter systems are usually limited by communication capability to collecting a single cumulative kWh reading. AMR speeds up the metering reading function and reduces utility personnel costs.
- *Advanced metering systems (AMS)*, also referred to as *advanced metering infrastructure (AMI)*, provide two features that distinguish them from conventional and AMR systems: (1) the capability to measure and store energy usage at intervals of one hour or less and, (2) a communication link that allows the utility to remotely retrieve current usage information to support customer billing and other utility operational functions.

Aren't advanced meters expensive? Advancements in communications and solid-state technology have reduced the cost of AMI to about $100 per meter if deployed system-wide. Costs to enhance and/or upgrade utility customer information and billing systems are extra. Several recent studies suggest that per-meter hardware and installation costs for advanced metering systems may be comparable to the cost of a new AMR system (King 2004).

What factors should be considered when evaluating the costs and benefits of advanced meters? Advanced metering (AMI) evaluations should consider three major categories of cost and benefit impacts:

- *Utility Operational Impacts:* AMI is first and foremost a technology for automating and improving basic utility operations. Interval metered customer usage data is essential to support billing, outage management, complaint resolution, forecasting, real-time dispatch, rate design and other utility functions. Benefits such as reductions in theft that do not impact utility revenue requirements also need to be addressed. Operational savings alone economically justified all 13 major AMI installations undertaken in North America through 2005. Utility business case analyses should account for the net impact of forecasted operational savings in estimating changes in the utility's revenue requirement from AMI deployment.
- *Demand Response Impacts:* AMI enables RTP, CPP and other forms of performance-based demand response.
- *Societal Impacts:* Societal impacts include improved customer service, environmental, equity and other benefits from more efficient utility operation.

Billing invoices must also be expanded to provide detailed, hour-by-hour accounting. Some utilities and load serving entities can accommodate these new pricing schemes at moderate cost if their existing billing systems are compatible with detailed usage accounting, while others may need to completely revamp or replace their entire billing systems (depending on the number of customers eligible for RTP or CPP).
[33]For more information on Advanced Metering Infrastructure, see http://www.energetics.com/madri/toolbox/.

- *Customer education* about the time-varying nature of electricity costs, potential load response strategies, and available retail market choices is often included in the rollout of demand response options.

Ongoing costs, including program administration and operation, marketing, evaluation, and customer recruitment costs, apply to incentive-based demand response programs and optional pricing tariff options that are offered in addition to customers' standard electricity tariff. For incentive-based demand response programs, additional costs also include payments to participating customers. For most default-service price-based options, there are no incremental ongoing costs relative to any other default-service tariff. However, depending on the type of metering/communication infrastructure used, ongoing equipment operation or leasing costs may apply.

Benefits of Demand Response

The benefits of demand response can be classified into three functional categories: *direct*, *collateral* and *other* benefits (see Table 3-2). Direct benefits accrue to consumers that undertake demand response actions, and collateral and other benefits are enjoyed by some or all groups of electricity consumers. Direct and collateral benefits can be quantified in monetary terms. Other benefits are more difficult to quantify and monetize.

<u>Participant Benefits</u>

Customers who adjust their electricity usage in response to prices or demand response program incentives do so primarily to realize *financial* benefits. In addition, they may be motivated by implicit *reliability* benefits (see Table 3-2).

- *Financial benefits* include cost savings on customers' electric bills from using less energy when prices are high, or from shifting usage to lower-priced hours, as well as any explicit financial payments the customer receives for agreeing to or actually curtailing usage in a demand response program.
- *Reliability benefits* refer to the reduced risk of losing service in a blackout. This benefit may be associated with an internalized benefit, in cases where the customer perceives (and monetized) benefits from the reduced likelihood of being involuntarily curtailed and incurring even higher costs, or societal, in which the customer derives satisfaction from helping to avoid widespread contingencies. Both are difficult to quantify but may nonetheless be important motivations for some customers.

The level of direct benefits received by participating customers depends on their ability to shift or curtail load and the incentives afforded by time-varying electricity prices and any additional program incentives that are offered.

<u>Collateral Benefits</u>

Demand response, through its impacts on supply costs and system reliability, produces *collateral benefits* that are realized by most or all consumers (see Table 3-2). It is these collateral benefits, which have system-wide impacts, that provide the primary motivation for policymakers' interest in demand response.

Table 3-2. Benefits of Demand Response

Type of Benefit	Recipient(s)	Benefit		Description/ Source
Direct benefits	Customers undertaking demand response actions	Financial benefits		• Bill savings • Incentive payments (incentive-based demand response)
		Reliability benefits		• Reduced exposure to forced outages • Opportunity to assist in reducing risk of system outages
Collateral benefits	Some or all consumers	Market impacts	Short-term	• Cost-effectively reduced marginal costs/prices during events • Cascading impacts on short-term capacity requirements and LSE contract prices
			Long-term	• Avoided (or deferred) capacity costs • Avoided (or deferred) T&D infrastructure upgrades • Reduced need for market interventions (e.g., price caps) through restrained market power
		Reliability benefits		• Reduced likelihood and consequences of forced outages • Diversified resources available to maintain system reliability
Other benefits	• Some or all consumers • ISO/RTO • LSE	More robust retail markets		• Market-based options provide opportunities for innovation in competitive retail markets
		Improved choice		• Customers and LSE can choose desired degree of hedging • Options for customers to manage their electricity costs, even where retail competition is prohibited
		Market performance benefits		• Elastic demand reduces capacity for market power • Prospective demand response deters market power
		Possible environmental benefits		• Reduced emissions in systems with high-polluting peaking plants
		Energy independence/ security		• Local resources within states or regions reduce dependence on outside supply

Collateral benefits can be categorized functionally as *short-term* and *long-term market impacts* as well as *reliability* benefits:

- *Short-term market impacts* are the most immediate and easily measured source of financial benefits from demand response. Broadly speaking, they are savings in variable supply costs brought about by more efficient use of the electricity system, given available infrastructure. More efficient resource use, enabled by building better linkages between retail rates and marginal supply costs, translates to short-term bill savings to consumers from avoided energy and, in some cases, capacity costs. Where customers are served by vertically integrated utilities, short-term benefits are limited to avoided variable supply costs. In areas with organized spot markets, demand response also reduces wholesale market prices for all energy traded in the applicable market. Reductions in usage during high-priced peak periods result in a lower wholesale spot market clearing price. The amount of savings from lowered wholesale market prices depends on the amount of energy traded in spot markets, rather than being committed in forward contracts.[34]

- *Long-term market impacts* hinge on the ability of demand response to reduce system or local peak demand, thereby displacing the need to build additional generation, transmission or distribution capacity infrastructure. Because the electricity sector is extremely capital-intensive, avoided capacity investments can be a significant source of savings. However, for demand response resources to reduce capacity costs, it must be available and perform reliably at high-demand periods throughout the year because it is displacing other capacity resources.

Demand response also provides reliability benefits, reducing the probability and severity of forced outages.

- *Reliability benefits* refer to reducing the probability and severity of forced outages when system reserves fall below desired levels.[35] By reducing electricity demand at critical times (e.g., when a generator or a transmission line unexpectedly fails), demand response that is dispatched by the system operator on short notice can help return electric system (or localized) reserves to pre-contingency levels.[36] These reliability benefits can be valued according to the amount of load that demand response load reductions removed from the risk of being disconnected and the value that consumers place on reliable service (the "value of lost load").

Appendix B provides a more detailed discussion of the collateral benefits of demand response to assist policymakers' understanding of economic efficiency gains, avoided capacity benefits and capacity program design and valuation issues, the impact of different market structures on the timing and distribution of short-term and long-term demand response benefits, and the identification and valuation of reliability benefits.

[34] Many load-serving entities currently purchase a substantial portion of their electricity in ISO-administered spot energy markets. In New York, a state with organized wholesale markets and retail competition, over 50% of electricity is traded in day-ahead and real-time spot markets, with the rest settled in forward contracts. In New England, about 40% of the electricity volume is traded in ISO-NE's spot markets, with about 60% committed in forward contracts.

[35] At times, system dispatchers are faced with either shutting off load to parts of the system, or risk an outage that affects many more customers and load. The loads that are shut off depend on exigent circumstances. Demand response reduces load and thereby lowers the likelihood of the need to impose forced outages. It also reduces the amenity impact of a given level of load shedding because it is distributed among customers according to their willingness and ability to curtail (given appropriate incentives) rather than, for example, cutting off all customers and all load served by a given substation.

[36] Dispatchable demand response resources include direct load control programs, interruptible/curtailable rates and emergency demand response programs. Reliability benefits derive from curtailments undertaken when all available generation has been exhausted and only load reductions can serve to restore system reliability to acceptable levels.

Other Benefits

Demand response can provide several *other benefits* that accrue to some or all market participants but are not easily quantified or monetized:

- *More robust retail markets.* In competitive retail markets, default-service RTP can stimulate innovation by retail suppliers (Barbose et al. 2005), and ISO/RTO-administered demand response programs can provide value-added opportunities for marketers (Neenan et al. 2003).
- *Improved choice.* Demand response can provide expanded choices for customers in varying retail market structures (e.g. states with or without retail competition) through additional options to manage their electricity costs.

Demand response can reduce the potential for generators to exert market power by withholding supply.

- *Market performance benefits.* Demand response can also play an important role in mitigating the potential for generators to exert market power in wholesale electricity markets by withholding supply in order to cause prices to increase. Price-responsive demand mitigates this potential because demand reductions in response to high prices increase suppliers' risk of being priced out of the market. Demand response can provide this "market performance" benefit even if it is rarely exercised because the *prospect* of demand response may be a sufficient deterrent to prevent generators from attempting market manipulation.
- *Possible environmental benefits.* Demand response may provide environmental benefits by reducing the emissions of generation plants during peak periods. It may also provide overall conservation effects, both directly from demand response load reductions (that are not made up at another time) and indirectly from increased customer awareness of their energy usage and costs (King and Delurey 2005). However, policymakers should exercise caution in attributing environmental gains to demand response, because they are dependent on the emissions profiles and marginal operating costs of the generation plants in specific regions.[37] Emission reductions during peak periods need to be balanced against possible increases in emissions during off-peak hours as well as from increased use of onsite generation.

[37] See Holland and Mansur (2004) for an analysis of regional differences in the impacts of load response on net power plant emissions, and Keith et al. (2003) for an analysis of impacts of demand response resources on net power sector emissions in New England.

SECTION 4. QUANTIFYING DEMAND RESPONSE BENEFITS

Quantifying the potential nation-wide benefits of demand response, as EPACT charges DOE to accomplish, is a large and complex undertaking and involves several functional aspects:

- *Demand Response Options*—the types of time-varying rates and demand response programs that are currently offered (or potentially available);
- *Customer Participation*—the likelihood that a customer will choose to take part in the program;
- *Response*—documenting and quantifying participants' current energy usage patterns, and determining how participants adjust that usage in response to changes in prices or incentive payments;
- *Financial Benefits*—developing methods to quantify the level and distribution of short-and long-term resource savings of load response under varying market structures;
- *Other Benefits*—identifying and quantifying any additional benefits provided by demand response resources (e.g., improved reliability); and
- *Costs*—establishing the costs associated with achieving demand response.

Given differences in market structure among states, the lack of a uniform method to measure demand response benefits and significant data limitations and gaps, which could not be overcome in the time allotted for completion of this report, DOE has chosen to take a different approach to meet its mandate.[38]

> *DOE's approach in meeting its EPACT mandate is to summarize and compare the results of recent studies that quantified demand response benefits.*

DOE's approach is to summarize and compare the results of a number of recent studies that have attempted to quantify demand response benefits under a variety of contexts and scopes and for different regions or markets. Results are used as a basis for recommendations that can guide future efforts to quantify demand response benefits at the regional market level.

This section begins by summarizing the results of recent studies of the intensity of customer response to time-varying pricing and other demand response programs to establish the extent to which participants adjust their usage in response to price changes or incentive payments. Then, ten selected studies of demand response benefits are reviewed to assess and compare the impact of varying demand response mechanisms, study methodologies, and wholesale and retail market structure. The estimates of demand response benefits are normalized to provide insight into the importance of some factors in

[38] A comprehensive study quantifying the national benefits of demand response would have to account for different types of demand response (e.g., time-varying tariffs, incentive-based demand response programs).

determining the level of benefits attributed to demand response. Finally, recommendations on practices, protocols, and standards for improving estimates of the benefits of demand response are summarized.

Intensity of Customer Demand Response

To quantify demand response benefits in aggregate, two key inputs are: (1) measures of customer acceptance and participation rates in dynamic pricing and demand response programs, and (2) measures of the extent to which individual customers curtail load in response to either time-varying prices or demand response program incentive payments i.e. intensity).

With respect to the first input, a number of studies have characterized drivers to customer participation as part of evaluations of demand response programs or pilot tariffs. Important factors in the customer's decision to enroll and participate include the level and type of incentives offered, program requirements and conditions (e.g., notice, duration, and frequency of curtailments), customer assessment of risks and value proposition (e.g., financial consequences for failure to curtail loads), and effectiveness of program design and implementation (e.g., marketing, customer education and information, technical assistance).

With respect to the second input, a relatively large number of studies characterize the extent to which customers respond to dynamic prices and demand response programs. Results are typically reported in terms of two measures (or indicators): 1) price elasticity or 2) absolute or relative load impact (e.g., kilowatt [kW] or percent load reduction).

Customer Response to Time-Varying Prices

> *Price elasticity is a normalized measure of the intensity of customers' load response to prices.*

A price elasticity provides a normalized measure of the intensity of customers' load changes in response to price circumstances especially for time-varying rates or demand response programs that induce load modifications directly in response to price changes. It is defined as the percentage change in usage for a one-percent change in price, and takes on values of zero and above, in absolute terms.[39] For example, if a customer's price elasticity is 0.15, then a doubling (100% change) of price results in a 15% reduction in electricity usage, other things equal. Higher elasticity values

[39] This definition is for own-price elasticity, which is always *negative*; usage goes down as price goes up. There are several variations on the concept of price elasticity that relate to different aspects of the full consequences of the change in usage. For example, a cross-price elasticity measures the consequences of reduced electricity usage on other goods. If a customer buys less electricity, then it has more money to spend on other goods and services. A substitution elasticity characterizes how a customer shifts the use of electricity in one period of the day to another (e.g. peak versus off-peak) in response to price differences between the two periods. A substitution elasticity can have a *positive* value (or zero). The discussion in this section reports elasticity values on an absolute basis, with the sign always positive, to emphasize the differences in results among studies. Appendix C provides a more complete and technically accurate characterization of the study results.

translate into increased price response by customers. Price elasticity is a useful measure because it allows for comparison of the load response of customers facing different prices.

Figure 4-1 summarizes the results of studies that estimated the price response exhibited by customers that participated in voluntary programs that involved time-varying prices (see Appendix C for more detailed information):

- several existing RTP programs available to larger industrial and commercial customers that have been operating for many years;
- an ongoing residential real-time-pricing (RTP) pilot;
- the California CPP pilot conducted in 2003-4; and
- pooled results of five residential TOU pilots conducted in the late 1970s.[40]

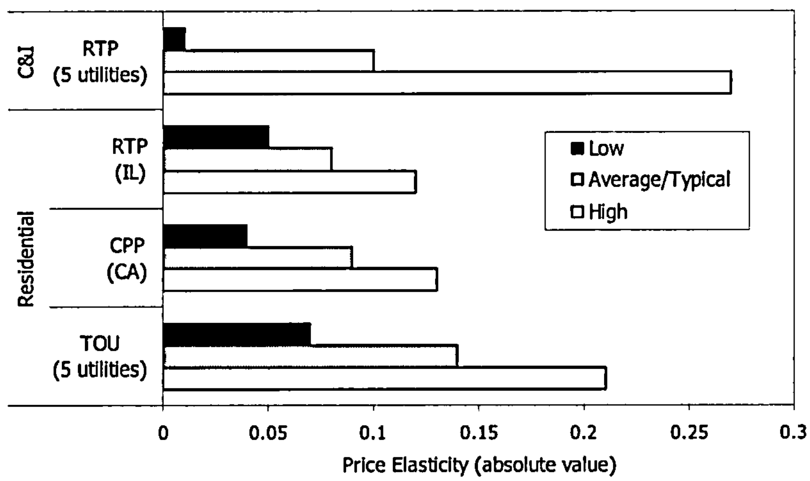

Figure 4-1. Customer Response to Time-Varying Prices: Price Elasticity Estimates

For each study, the low, average (or typical), and high estimates of price response are illustrated, although the interpretation of the low to high range values varies somewhat across studies. For example, the range in price elasticity values for a residential RTP pilot in Illinois are attributed to demographic differences within the pilot group, while for a pilot CPP program in California, the range in elasticity values primarily reflects climatic differences and saturation of air conditioning equipment among participant groups. For the residential TOU studies, the range of elasticity values reflects results across the five pilots.

Average price elasticities among the studies are fairly similar, ranging from 0.08 to 0.14 (in absolute value). The average elasticity value for RTP for large industrial and commercial customers (0.10) represents a typical value reported by several studies. The low and high elasticity values for commercial and industrial RTP customers exhibit the largest variation (i.e., 0.01 to 0.27) and reflect differences in the price responsiveness of

[40] See Appendix C for a more in-depth description of these studies and their results.

various market segments. Studies of large customers' response to RTP consistently find large differences in price elasticity across business categories. For example, a recent study of about 150 customers on RTP at Niagara Mohawk reported average elasticities of 0.16 for manufacturing customers, 0.10 for government/education customers, 0.06 for commercial/retail and 0.04 for healthcare facilities (Goldman et al. 2005).

The Residential RTP study (Illinois) reported similar price elasticities as the California residential CPP study (i.e., 0.08 to 0.09); both studies were conducted during a comparable time period (2004) but in different markets. Studies of residential customer response to time-varying prices often report that price elasticity is driven in part by the number of electricity devices present in the home. Climate also has a discernable affect, as do occupant characteristics and circumstances that affect when they are home and likely to be able to shut off devices or reduce usage.

Customer Response to Load Control Programs

Over one hundred U.S. utilities report that they currently offer residential or small commercial DLC programs that primarily target customers with air conditioning or domestic water heating load-control devices (EIA 2004).[41] A number of these programs have conducted relatively recent measurement and evaluation studies with results that are publicly available.

> *In some demand response programs (e.g., where customers do not directly respond to prices), their response is typically measured by the amount of load reduced.*

For DLC programs and other types of demand response programs where customers are not directly responding to a price, the intensity of customers' response is typically measured in terms of an absolute or relative load impact (e.g., kW of load curtailed or percent of the customer's total load that is curtailed, either through equipment cycling or shedding).

Figure 4-2 summarizes reported load reduction estimates for large groups of customers with water heating load controls and various types of control strategies for air conditioning equipment (e.g., cycling the device on and off at a specified time interval, shutting the device off for a period of time, or resetting a thermostat set point) [see Appendix C for more detailed information].[42] Residential water heating DLC programs have typically yielded load reductions in the range of 0.3 to 0.6 kW per house; the magnitude and timing of the load impact depends on household and equipment size, ground water temperature and household usage patterns. DLC programs targeting residential air conditioning (A/C) have reported load reductions ranging from approximately 0.4 to 1.5 kW per customer over the course of an event. The magnitude of the load reduction per customer can strongly depend on climate, the control strategy deployed (e.g. 100% shed, duty cycling, thermostat reset) and the customer's air

[41] Demand-side management efforts include energy efficiency and/or load management programs.
[42] The results indicate the range of possible load impacts, although the values across studies are not readily comparable because of differences in program design features, cycling strategies, and climate.

conditioning usage levels absent load control. This is illustrated in Figure 4-2 by several studies that reported low and high load reduction values based on testing different cycling strategies at various temperature levels.

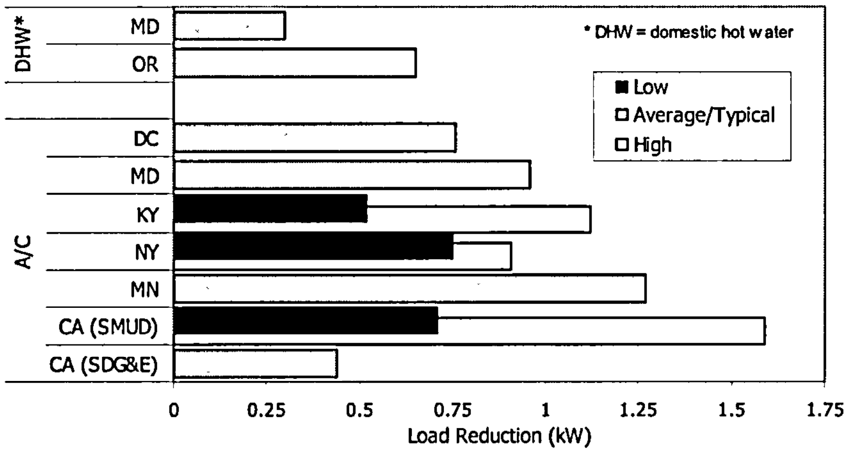

Figure 4-2. Estimated Load Impacts from Direct Load Control Programs

Impact of Enabling Technologies on Price Response

> *Studies of pilot programs combining pricing with enabling technologies provide important insights on the technical potential for demand response.*

Some utilities have offered pilot programs targeted to mass-market customers that integrate CPP with enabling technology, specifically load control devices that receive price signals and can be programmed by customers to reduce A/C or other loads during critical peak periods (see Figure 4-3 and Appendix C). Several of these programs have obtained promising results. For example, in Florida, Gulf Power reported average load reductions of 40% during critical peak periods for groups of customers that could control multiple loads (e.g. A/C, water heating, pool pumps) (Levy Associates 1994). In California, a recent Statewide Pricing Pilot (SPP) sought to quantify the impact of "smart thermostats" with critical peak prices. The average load reduction of 220 residential customers with smart thermostats during critical peak days was approximately 0.64 kW, a 27% reduction during peak periods, approximately two-thirds of which was attributed to use of the smart thermostat. Among the 235 small business customers in the California SPP, the average peak period load reduction was about 14%, although the relative impact of the enabling technology was even more pronounced. These studies may reveal the technical potential for demand response in certain market segments when time-varying pricing is combined with enabling technology.

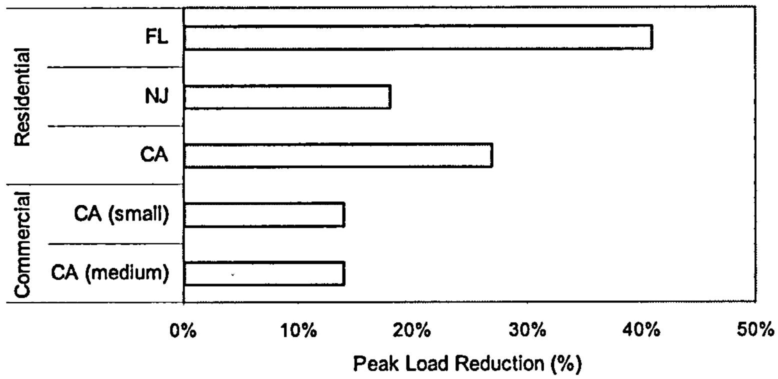

Figure 4-3. Load Response from Critical Peak Pricing and Demand Response Enabling Technologies

<u>Summary</u>

The following key findings and lessons can be drawn from this review of studies that examine customer response to time-varying prices and different types of demand response programs:

- Many initiatives have been undertaken that quantify the price-to-quantity relationship for various types of dynamic pricing and demand response programs. These data are critical because policymakers require price elasticity and load impact estimates as an input in estimating the benefit of specific demand response programs.
- Based on several of the more comprehensive studies, it is reasonable to assume that a group of large customers participating in well-designed RTP tariffs respond with a substitution elasticity of around 0.10 on average, which means that when peak prices rise by 50%, these customers will lower or shift their load to other times of the day by 5%.[43]
- Elasticities for groups of residential customers enrolled in TOU rates with significant differentials in peak to off-peak prices (e.g. factor of three) are also about 0.10—0.15.
- A small number of studies of residential customers on CPP rates, with very high critical peak prices ($.50/kWh or higher) report that that customers reduce load by an even greater amount than is reported in other studies for TOU. The recent California pilot, where the two designs were tested side-by-side, reports that the difference is almost a factor of two. However, the difference may be due to the large price differences between the two rate offerings.[44]

[43] The ability of customers enrolled in RTP tariffs to respond to prices is varied. Several studies report that 65-75% of the total measured price response is provided by about 20% of the customers on RTP rates.

[44] Two customers with identical price response capability (price elasticity) may exhibit different levels of load response if they face vastly different prices. This is because the nature of the response may increase with the nominal level of prices. The price elasticities estimated for TOU rates may be smaller than for CPP rates, because the customers never faced the higher CPP prices.

- Studies of customer response to time-varying prices should be construed as representing short-term price response. Relatively few participants on RTP or CPP tariffs automate their response behaviors and actions, either because they do not have the necessary equipment or because they do not have the technical expertise, time, or sufficient incentive to implement such changes. As a result, customers tend to rely on manual actions to shut down equipment or curtail usage. This surely constrains the frequency and extent to which loads can be reduced. As demand response becomes more widespread and time-varying prices become the default (or standard) service, some customers can be expected to make cost-effective investments in enabling technology to improve their marginal ability to respond, and thereby increase the price elasticity (or the percentage of load reduced).
- Some jurisdictions have enrolled large numbers of customers in direct load control programs. For mature load management strategies (e.g. cycling of residential air conditioners, water heaters), there are well-developed models, based on actual field studies and program evaluations, that can predict per-unit load impacts reasonably accurately and allow characterization of factors that influence the intensity of customers' response (e.g. household size, income, equipment characteristics, schedule, weather).
- There has been relatively little emphasis on measuring and verifying the impacts of interruptible rates. The response of some customer market segments (e.g., small and medium-size business customers) has also received little research attention.
- Areas that warrant additional evaluation include: quantifying the impact of information and/or enabling technologies in customer decisions to participate in demand response options and the intensity of their response in specific market segments, understanding customer participation and response in markets that offer dynamic pricing and demand response (and energy efficiency) programs in order to assess potential synergies.

Quantifying the Value of Demand Response

Initial attempts to quantify the benefits of demand response arose after the passage of the Public Utilities Regulatory Policy Act (PURPA) in the early 1980s. PURPA set in motion initiatives to promote load management programs, using both pricing and load control mechanisms. Utilities needed to establish that paying loads to curtail was cost-effective; thus load management programs were justified on the specific cost savings they produced. The benefits were defined by the avoided capital and operating costs; utilities used available planning methods to establish how dispatched curtailments reduced the use of generation units.[45] Utilities evaluated these load management programs using an equivalence standard: load management had to produce service equivalent to the displaced generation but at a lower cost.

[45] Utility planning methods ranged from simple what-if calculations to in-depth and complex studies of the impacts on system operation.

During the 1980s, integrated resource planning initiatives further refined the process and tools used by utility planners to evaluate investments in load management and energy efficiency in lieu of constructing generation plant. Standardized cost-effectiveness tests were developed that specified both the scope of and methods to estimate the benefits, expressed in terms of avoided costs. The standardized tests were used to facilitate screening of programs and help establish a threshold criterion for program spending. Load management programs were also offered in states that did not require utilities to develop and file formal IRP plans. Utilities had to show that load management programs would reduce supply costs relative to an all-generation solution. In all states, program costs were ultimately allocated to consumers, as new generation would have been.

In the 1990s, as problems arose with the introduction of competition in wholesale (and retail) markets, demand response was seen as a critical feature of competitive wholesale markets. However, a measure of the benefits was needed to justify expenditures to achieve greater demand response. Efforts to estimate the benefits of demand response have proceeded on three parallel tracks.

First, studies were undertaken to demonstrate the benefits of demand response by comparing the operation of markets with and without adequate levels of customer response to hourly prices (Borenstein 2002). Theorists argued that demand response should be fostered as a matter of principle, because any market where customers are not exposed to changes in the costs of supplying power is by definition inefficient and not robustly competitive. Experimental trials in economic laboratories contributed to verifying these contentions (Smith and Kiesling 2005, Adilov et al. 2004).

Second, studies commissioned to assess the benefits of organized, competitive wholesale markets specifically quantified the benefits that might be attributable to demand response (ICF Consulting 2002, DOE 2003). Others sought to verify the extent of financial benefits by conducting simulations to link specific levels of demand response to decreases in market prices, some of which indicated that the benefits might be quite significant, in the billions of dollars even in regional markets (Braithwait and Faruqui 2001, Caves et al. 2000). The push to identify the role and value of demand response also found its way into regions that largely retained the vertically integrated structure. IRP studies began to look more closely at how demand response creates cost savings (NPPC 2005, Orans et al. 2004, Violette et al. 2006).

Third, as programs were introduced in organized markets to foster demand response, analytical methods were needed to determine the value of those load curtailments. Policymakers and market participants wanted assurances that the programs produced net benefits and were interested in the distribution of the benefits (e.g. reduced energy market prices and reliability impacts) among market participants (Boisvert and Neenan 2003).

There has been no coordinated effort to compare and synthesize contemporary methods of quantifying demand response benefits.

In summary, there have been a number of efforts to quantify the benefits of demand response in a variety of market settings and conditions. However, to date there has been no coordinated effort to determine whether this body of work allows us to estimate these benefits at the national level or provides detailed methods to quantify those benefits. EPACT places that obligation upon DOE.

Benefits of Demand Response: Review of Existing Studies

A literature review was undertaken to identify the body of information available to estimate the national benefits of demand response. Ten studies were selected to provide insight into how demand response benefits are quantified to analyze the methods used and to assess their impact on the results (see Table 4-1). They encompass most recent empirical studies of demand response benefits and can be classified into three categories:

- *Illustrative analyses* demonstrate the potential importance and/or quantify the economic impacts of demand response in a proposed market structure or hypothetical market circumstance. All four examples examined the potential for demand response benefits in organized wholesale markets. The approach taken is to create a base case reflecting the current market structure and conditions, estimate impacts of the proposed market structure changes (in the Standard Market Design [SMD] examples in Table 4-1), project how the electricity market would evolve with and without a specified amount of demand response, and then compare the results. In these studies, the benefits are hypothetical and speculative. The means for accomplishing demand response is often not explicitly addressed—it is presumed that demand response either occurs naturally in response to hourly prices or is induced through demand response programs—and the accuracy of the results depends on how well actual circumstances match assumptions used in the analysis.
- *Integrated Resource Planning* (IRP) studies assess whether and how much demand response resources ought to be acquired in a long-term resource plan based on avoided supply costs. They are typically undertaken by utilities in markets without retail competition. Demand response programs or dynamic pricing initiatives found to avoid capital and operating costs in excess of their implementation costs may be included in a utility's resource plan. Because vertically integrated utilities are responsible for securing additional capacity to meet anticipated customer loads, as well as administering proposed demand response programs or pricing initiatives, they have the ability to defer or eliminate other potential capacity additions to realize the avoided capacity (and energy) benefits. Three IRP studies are included in this analysis.
- *Program performance analyses* measure actual outcomes of demand response programs and provide an estimate of delivered value, rather than a forecast of benefits. The three program performance studies were conducted in states or regions with organized wholesale markets administered by ISOs/RTOs. These

studies estimate the impacts of load curtailments on market prices, quantify the level and distribution of benefits, and explicitly account for reliability benefits.

Demand Response Benefit Case Studies: Comparison of Key Features

The ten studies were assessed and compared along several key features that contextualize results and provide insight into issues that must be addressed to ensure more consistent, standardized approaches for valuing the benefits of demand response going forward. The following discussion refers to Table 4-1.

Market Character. The selected studies include examples from both organized spot markets and vertically integrated systems. The four illustrative analyses focus primarily on organized markets. Two of them (B and C in Table 4-1) look at nation-wide demand response impacts, because they were commissioned to quantify the benefits of the adoption of FERC's proposed standard market design (SMD). These studies included scenarios that examined the benefits of demand response over and above what the SMD was expected to deliver. The third study (D) provides a regional New England perspective, and the fourth focused on the California electricity market (A). Conversely, the three IRP studies (E, F and G) reflect a vertically integrated utility perspective, in which utilities define alternative strategies and assess their relative merits over a long planning horizon as a basis for up-front planning decisions. The three program performance studies (H, I and J) were conducted in regions where an ISO or RTO administers organized spot markets; they draw heavily on transparent market prices to measure actual performance benefits.

Market Analyzed. The selected studies vary considerably in their spatial scope and include national, regional, state, and individual utility system assessments. However, results from studies in more geographically focused settings (e.g., a utility, state or region) are sufficiently general that the results may apply elsewhere, after adjusting for program design features.

Peak Demand. The system peak demand of the market described in each study indicates market size. System peak load also serves as the denominator used to normalize reported gross benefits across studies; this helps reveal factors that affect reported demand response benefits.

Demand Response Mechanism. Eight of the studies either modeled or reported demand response benefits for specific types of demand response mechanisms. Four (A, D, E and F) estimated benefits for either RTP or CPP. Another four (C, H, I and J) estimated benefits for emergency demand response programs offered by utilities or ISOs. Six of these studies (C, F, G, H, I and J) also estimated benefits for demand bidding programs in which customers participate in day-ahead or real-time energy markets. Two studies (C and F) reported aggregated benefits for more than one demand response option. Aggregated benefit estimates for individual demand response programs were developed

Table 4-1. Benefits of Demand Response: Review of Selected Studies

		Illustrative Analyses				Integrated Resource Planning			Program Performance Analyses		
		Market Equilibrium DR[1]	FERC SMD[2]	DOE SMD[3]	Default RTP[4]	Mass Market DR[5]	IEA/DRR[6]	NPCC[7]	NYISO[8]	ISO-NE[9]	PJM[10]
1	Study	A	B	C	D	E	F	G	H	I	J
2	Market Character	Organized Wholesale Markets				Vertically Integrated Utility			Organized Wholesale Market		
3	Market Analyzed	CA	U.S.	U.S.	New England States	Midwest Utility	Sub-set of the MAAC Region	Northwest States	NY State	New England States	Mid-Atlantic States
4	Peak Demand (MW)	46,000	700,000	700,000	26,000	7,500	30,000	30,000	31,000	26,000	53,000
5	DR Mechanism	RTP	Price response only	DA-LBAR, EDR	Default Service RTP	CPP	DLC, DA-LBAR, CPP	DA-LBAR	DA-LBAR, EDR	DA-LBAR, EDR	DA-LBAR, EDR
6	Time Horizon (start)	Equilibrium	17 years (2004)	one year (2003)	5 yrs (2006)	20 years (2002)	20 years(2004)	20 years (2006)	Results for 2001-2004		
7	Participating Load	33% or more of load, no segment distinction	50% of customers in all regions	2% of load in economic, 2.5% in reliability	about 2% of system load	About 900,000 residential customers (100% participation)	15% penetration top-end	6% of peak demand (in 2020)	Participants in 1) emergency, 2) ICAP, or 3) energy DR programs Subscribed load reduction from participating customers for all classes, ranging from 1 to 6%of system load		
8	Implementation Costs	Not reported	Not reported	Not reported	Implementation cost estimated (~10% of gross benefits)	Implementation and incentive costs estimated (~25% of gross benefits)	Implementation and incentive costs estimated (90% of gross benefits)	Implementation and incentive costs estimated (~53% of gross benefits)	Report B/C ratio by program for incentives-all exceed 1; separately report Implem. cost	Report B/C ratio by program for incentives-all exceed 1.	Report B/C based on incentives. Separately report implementation costs
9	Analysis Method	Simulated dispatch and capacity adjustments	Simulated market equilibrium	Simulated dispatch	Simulated LMP adjustments to RTP	Simulation of market impacts	Simulated optimal capacity expansion plan and corresponding energy dispatch: stochastic market characterization		Simulated LMP and Reliability adjustments to demand response		Redispatch LMP change
10	Gross Benefits (Million $)	$302	$52,236	$362	$350	$1,000	$1,476	$718	$7	$1	$15
11	Gross Benefits ($/kW yr)	$6.57	$4.39	$0.52	$2.69	$6.67	$2.46	$1.20	$0.22	$0.04	$0.29
12	Normalized Gross Benefits ($/kW-yr.)	$1.99	$0.88	$2.07	$1.35	$2.02	$1.64	$1.99	$0.45	$0.30	$0.66

References:
[1] Borenstein 2005
[2] ICF Consulting 2002
[3] DOE 2003
[4] Neenan et al. 2005
[5] Faruqui and George 2002
[6] Violette et al. 2006
[7] NPCC 2005
[8] NYISO 2004
[9] RLW Analytics and Neenan Associates 2004
[10] PJM Interconnection 2004

Abbreviations:

DLC	Direct Load Control
DA-LBAR	Day-ahead Load Bidding as a Resource (demand bidding)
EDR	Emergency Demand Response
CPP	Critical Peak Pricing
RTP	Real-time Pricing
LMP	Locational Marginal Price

from the ISO/RTO program performance studies (H, I and J). Two studies (B and G) did not specify the type of demand response mechanism studied.

The ten reviewed studies' time horizons vary considerably, from one to twenty years.

Time Horizon. The studies' time horizons vary considerably, ranging from one to 20 years. These differences are driven by differing study contexts, analysis methods, and market structure. Prospective studies tend to span a multi-year period. For example, the FERC SMD study (B) assesses cumulative impacts over a 17-year period because its primary focus was on the long-term benefits of SMD. In a somewhat different approach, the DOE SMD analysis (C) reports annualized estimates of demand response benefits for the 20-year study time horizon. IRP studies are by definition long-term planning exercises and all three examples (E, F and G) cover approximately 20 years. In contrast, the three ISO/RTO program performance studies (H, I and J) are retrospective evaluations that measure the actual benefits of demand response; all of these studies examine the benefits of programs that have operated over several years.

The types of customers targeted and assumed (or actual) market penetration rates varied significantly among the ten studies.

Participating Load. There are significant differences in the targeted population and the assumed or actual demand response market penetration rates among the ten studies. Two of the illustrative analysis studies (A, B) assume high market penetration rates; this contributes to relatively high estimates of gross savings (row 11 in Table 4-1). Participation rates are affected to a great extent by the assumed tariff design. For example, the mass market demand response study (E) evaluates the benefits arising from placing the subject utility's entire residential customer group on CPP to assess the impacts of a mandatory tariff. In contrast, the Default RTP study (D) estimates the potential benefits of implementing RTP as the default service for large industrial and commercial customers (with peak demand greater than 1 MW) in the New England states that have adopted retail choice (although customers can opt out in favor of alternative supply products that may offer fixed rates).

Forecasting levels of customer acceptance, participation and load response is critical to evaluating the impacts of voluntary demand response programs.

Forecasting levels of customer acceptance, participation, and load response are critical variables in voluntary demand response programs. The NPCC study (G) assumes that demand response will constitute about 6% of the resources used to meet the Pacific Northwest system peak after a 20-year ramp-up. The IEA/DRR study (F) assumes that demand response resources from three demand response programs and a dynamic pricing tariff will comprise about 15% of system peak demand after 20 years. The three ISO/RTO program performance studies draw on actual experience in enrolling customers in voluntary programs, rather than forecasts. However, estimating participation rates is complicated by difficulties in defining the eligible population.[46] In this analysis, subscribed load reductions as a fraction of system peak load are used to estimate participation rates; the results range from 1% to 6%.

Three out of ten studies did not report costs; cost reporting was inconsistent or incomplete among several other studies.

Implementation Costs. Practices for reporting participant and system costs necessary to achieve demand response vary significantly among the ten studies (see Table 3-1 for demand response cost reporting categories). Three of the illustrative analyses (A, B and C) did not report costs at all. Among studies that included costs, demand response costs were not reported uniformly or were incomplete. Four studies included *estimates* of costs (D, E, F and G). In two of them, both IRP studies (F and G), demand response was modeled as a generation resource by specifying its product characteristics (availability period, capacity, number and duration of event calls) and cost. The costs to the utility system of acquiring this "resource" (e.g., initial costs, on-going program administration, and payments to participating customers) were well characterized. Initial participant costs were partially accounted for through incentives to subsidize their initial equipment or other costs, but event-specific costs were not (see Table 4-1). The two studies that focused on pricing options (D and E) estimated incremental metering and billing costs. Study E also included customers' investments in enabling technologies.

The three ISO/RTO program performance studies (H, I and J) reported *actual* implementation costs to varying degrees. These studies highlight some of the issues involved in reporting and accounting for costs. All three reported direct incentive payments made to customers for curtailing load. Some ISOs/RTOs reported their program administration costs. Most participant costs were not reported, including event-specific costs incurred by participating customers (NYISO 2004, PJM Interconnection 2004).[47]

Analysis Methods. All of the studies used simulation techniques to derive estimates of demand response benefits.[48] Simulation involves characterizing how the market works in a base-case scenario through cause and effect relationships. Demand is modeled as a function of prevailing economic conditions, the presence of electricity-using devices, and the prices consumers pay. Other factors, such as weather, can have predictable influences, but only under known (after-the-fact) or hypothesized conditions. The modeling of

[46] To be eligible for ISO emergency demand response programs, customers must be able to shed 100 kW of load, although aggregations of small customers are typically allowed. As a result, the eligible population could be defined as: all customers, all customers over a certain size range (this requires assumptions about the percent of load that can be shed), or customers that can shed 100 kW. As a practical matter, larger industrial, institutional and commercial customers account for most of the subscribed load in ISO demand response programs.

[47] It can be challenging for ISOs to collect information on participant costs because they often do not interact directly with customers. Instead load aggregators enroll customers in ISO programs. Collecting participant cost information would require placing additional reporting requirements on load aggregators.

[48] Study E utilized a Total Resource Cost (TRC) test to determine the cost-effectiveness of implementing mass-market demand response.

energy supply costs is influenced by market structure and incorporates information on available generation units and their performance characteristics and fuel costs.

The illustrative analyses, all targeted to organized markets, focus on whether energy and (where applicable) capacity market prices would be sufficient to attract enough capacity to meet reliability standards at least cost. The goal of such simulations is to explore the conditions under which competitive market equilibrium is reached (as in study A) or to simulate market transactions within different market designs and measure key performance indicators such as capacity investment and market-clearing prices. The focus is on minimizing the resulting market prices.

The IRP planning studies were undertaken to answer the question of how much capacity to add, at what time, and to what extent energy efficiency or demand response resources should be implemented to meet capacity needs. The IRP simulations (F and G) explored the cost implications of alternative supply strategies over an extended period and analyzed major uncertainties (e.g. load growth, weather, capability of generation units, fuel prices) using probabilistic techniques to identify a risk-constrained, least-cost strategy.

The program performance studies (H, I and J) analyzed the extent to which wholesale market prices were influenced by customer load curtailments in response to program events and estimated the direct and collateral benefits of these lower prices (see Table 3-2 for a typology of demand response benefits). This involved simulating price formation at a sufficient degree of detail to estimate reductions in market prices. Reliability benefits were also simulated for the program performance studies using assumptions about the value of lost load (VOLL) to customers and the impact of emergency demand response program curtailments in restoring system reserves.[49]

Gross Benefits. The gross benefits reported are the total estimated dollar benefits from each study, without any offset for the costs associated with achieving the hypothesized or measured level of demand response. It is important to note that many individual studies reported a range of benefits, although there were differences in how these ranges were developed. For example, in several of the illustrative analyses and IRP studies, the range of reported demand response benefits were derived from scenarios based on differences in assumed price elasticities, participation rates, or the set of demand response programs offered. In contrast, in the program performance analyses, the ranges of benefits were primarily based on differences in the assumed value of lost load or expected un-served energy in emergency programs.

In Table 4-1, a single representative value for gross benefits is reported for each study, rather than the complete ranges. The choice of values was intended to place the studies on as comparable a basis as possible. For example, for illustrative analysis and IRP studies, the reported benefits estimates correspond to scenarios that most closely approximate a

[49] Reliability benefits are discussed in section 3 and Appendix B.

price elasticity of 0.10 for dynamic pricing options—a typical level of response based on the results of demand response impact studies discussed above.[50]

The ISO/RTO program performance studies present a different type of challenge for reporting gross benefits because these studies report actual customer response, and the programs have only been in existence for several years. Unlike the other studies, these estimated benefits reflect actual program outcomes, not an average of those expected over many years, which the other studies report (see the textbox below).

Estimating Normalized Demand Response Benefits from Program Performance Studies

- In Table 4-1, the demand response benefits reported for the NYISO study involve two components: (1) the weighted average of the annual reliability benefits for 2001-2004, where the weights represent market circumstances relative to expectations over a ten-year period, and (2) benefits from price reductions from scheduled day-ahead load curtailments. The majority of the reported benefits derive from reliability impacts, primarily from the 2003 Northeast blackout events.
- ISO-NE reported reliability benefits from its emergency demand response program for 2003 and 2005, but declared no events in 2004. The benefits reported are from 2003, which are approximately equal to the preliminary values for 2005.
- PJM attributes virtually all of its benefits to reduced real-time prices from customer self-scheduled curtailments that are paid the real-time market price. The reported benefits are averaged for 2003 and 2004.

Demand Response Benefit Case Studies: Discussion of Results

Gross benefits estimates vary widely, from $1 million to $52 billion.

The gross demand response benefits estimated by the ten studies span a very large range, from $1 million (M) to $52 billon (B) (see Table 4-1). Even among studies of similar scope, the estimates differ substantially. For the two national studies (B and C), annual gross benefits vary by a factor of eight (estimated at $3B and $360M). Differences in market scope and size, time horizon, analytic methods, the type and number of demand response resources represented, and assumed market penetration and customer responsiveness all affect the differing gross benefit estimates.

Normalization can make comparison of these results more informative. Accordingly, a gross benefit metric was devised to normalize the study results, incorporating and adjusting for several factors: market size, time horizon, and the assumed level of customer participation in a demand response program or pricing initiative. The gross benefits value (row 10 in Table 4-1) was first divided by the market's peak demand in

[50] Some studies included a scenario with that exact price elasticity assumption. In illustrative analysis studies where price elasticity was not an explicit variable included in the sensitivity analysis, a judgment was made as to the most comparable scenario in terms of customer price responsiveness.

2004 (row 4).[51] This removes some of the scale bias. However, there are also significant differences in the time horizon over which demand response benefits were calculated and the assumed level of participation in demand response programs that were simulated. To address these factors, the size-adjusted gross benefits were divided by the number of years in the study and then by a factor that normalized each study to an equivalent demand response participation rate of 10%.

Gross benefits of demand response reported in each study were normalized to adjust for differences in time horizon, level of customer participation, and market size to facilitate comparing different studies' estimates.

The resulting estimates of normalized gross benefits, measured in \$/kW-year, provide a more comparable basis for understanding the methodological and market structure factors that influence the estimates of demand response benefits (see row 12 of Table 4-1). This metric, which gives an estimate of dollar value per kW of *system peak load* is different from avoided capacity costs, which are measured in the same units but represent a dollar value per kW of *avoided capacity* (see the textbox, below). These two metrics should not be directly compared.

Avoided-Cost Benefits of Demand Response vs. Normalized Gross Benefits

Some demand response programs (e.g., direct load control) have traditionally been regarded and analyzed as an effective capacity equivalent of generation in which the primary source of benefits is the avoided capacity cost from displacing a generation resource. Often, demand response programs are evaluated against an avoided cost standard: the costs of a demand response program are compared to a capacity alternative on the basis of their costs per kW-year. For example, if a peaking unit requires revenues to cover investment costs of \$75/kW-year, which can be interpreted as the utility's avoided capacity costs. If a demand response program costs \$50/kW-year, then the net benefits are about \$25/kW-year. In this example, the annualized benefits of demand response are expressed in terms of net benefits (\$) per *unit of avoided capacity* (kW); this is how the industry typically quantifies the value or cost of demand response.

Although the *units* are the same, it is important not to confuse the industry approach described above with the *normalized gross benefits* estimated for the ten studies included in this report. This metric expresses the studies' annual gross benefits in terms of dollars per unit of system peak load. It is calculated by dividing estimated benefits by the number of years covered by the study and the peak demand (kW) of the target market. The meaning and interpretation of this metric is different from avoided-cost benefits. Because normalized gross benefits are divided by the peak demand *of the entire market*, the values estimated for these ten studies (\$0.30-2.00/kW-year) are much lower than the avoided capacity benefits of demand response, and they should not be compared with the value or cost of demand response used in conventional analyses of capacity or supply costs. Rather, this indicator was constructed solely to facilitate a comparative review of these demand response benefit studies.

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[51] This adjustment approach, using system peak demand as a proxy for market size, may produce some bias across studies, particularly for studies that cover 20 years because peak system demand is likely to increase over that period. However, given data availability constraints, peak demand in 2004 was adopted for forward-looking studies with long time horizons and peak demand at the time of study completion was used for other studies.

The normalized gross benefits are plotted for the ten studies in Figure 4-4, and the average and range of values for each type of study are shown in Figure 4-5.

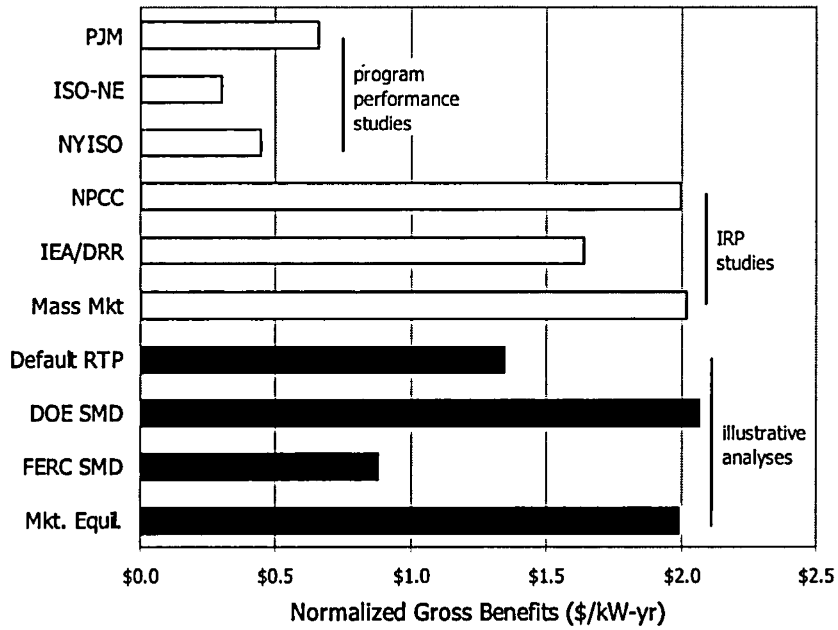

Figure 4-4. Normalized Gross Demand Response Benefits: Estimates of Ten Selected Studies

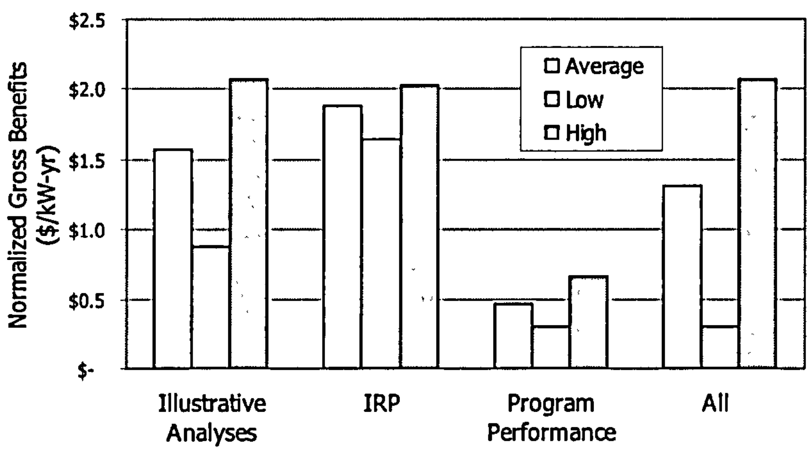

Figure 4-5. Normalized Gross Demand Response Benefits by Type of Study

DOE highlights the following key findings and observations based on this comparative review and analysis of these benefit studies.

There is a noticeable difference in the normalized demand response benefits of program performance analysis studies in organized markets relative to those of the illustrative and IRP studies (see Figure 4-4). This is largely attributable to differences in analytic methods.

The demand response benefit values estimated by program performance analyses, in normalized gross savings ($0.30 to 0.65/kW-year), are 70-75% lower than the average values for the other two types of studies (see Figure 4-4 and Figure 4-5), even after adjusting for differences in participation rates. This is largely attributable to the analytic methodology employed, which looks backward at limited, observable demand response program results. The illustrative and IRP studies typically estimate the *forward* market value of demand response over many years with assumed perfect foresight about demand response penetration and impact. These studies conduct market simulations over the full distribution of possible electricity market conditions in which demand response is deployed, during years when its value is small and others with extreme conditions where demand response provides significant value. In IRP studies, the long planning horizon in conjunction with the explicit treatment of key uncertainties allows demand response resources to be deployed during low probability but high consequence events (NPPC 2004; Violette et al. 2006).

In contrast, the program performance studies reflect market conditions over a very short time period, with only one instance of an extreme condition (the 2003 blackout, captured in the NYISO study only). These studies do not fully reflect the distribution of market circumstances likely to be encountered over a 20-year period, so they represent market conditions that are on average less favorable for demand response.

Lower estimated benefits for ISO programs illustrate the challenge of fostering demand response without a way to fully recognize its potential long-term value to the electricity system under the full range of market circumstances and conditions.

The difference between the average values reported in the three ISO/RTO program studies and the other two types of studies does not mean that demand response is less valuable in organized regional markets, but only demonstrates the challenge of fostering demand response absent the ability to recognize and reward the full forward value of demand response over a long planning horizon.

Under current practices, the market-impact value attributed to demand response is significantly affected by market structure (e.g. organized market vs. vertically integrated systems (Figure 4-4).

The market-impacts value of a demand response mechanism in a vertically integrated utility system may be different—perhaps significantly—from its valuation in an organized market with a similar customer base, resource mix, and supply/demand balance. In vertically integrated systems, demand response is valued largely according to avoided capacity costs, determined by the amortization of a peaking capacity unit ($70-100/kW-year), with some incremental savings (typically 5-15%) attributable to avoided short-term energy production costs. Moreover, qualified demand response resources are essentially deemed to achieve the pre-established avoided capacity benefits, or some portion thereof, for several years in the future.[52]

[52] Updated avoided cost methods for the Standard Practice Manual tests traditionally used for energy efficiency and some load management programs have incorporated market prices for time periods that they

In organized wholesale markets administered by an ISO or RTO, demand response is typically valued over the short term, based on prevailing market prices or reliability circumstances at the time of an event. For example, in some organized markets, customers can offer curtailable load as capacity resources (e.g., through capacity-based demand response programs). Capacity market prices, which are an indication of the value of these resources, have recently been much lower than the reference cost of a new peaking unit in most ISOs and RTOs (ISO-NE 2005b, PJM Interconnection 2005c). At times, the value of capacity, as reflected in capacity or energy market prices, may be substantially higher in regions with organized markets than in vertically integrated systems, although currently the reverse is true; this is reflected in the three ISO/RTO program performance studies.

Assumptions about customer acceptance and participation rates significantly affect estimated gross demand response benefits.

Among studies that examined impacts of demand response pricing strategies (A, D and E), gross savings estimates (row 11 in Table 4-1) are much higher in those studies that assumed higher market penetration rates (i.e., percent of customers facing dynamic prices compared to overall system loads). Studies A and E, which assumed either mandatory CPP or high customer acceptance of RTP, exhibited higher gross savings than study D, which did not.

The reporting and accounting of participant and utility/ISO/RTO system demand response costs are inconsistent.

Evaluations of existing ISO/RTO demand response programs report system costs, but not participant costs. Utility experience evaluating energy efficiency programs demonstrates that it is possible to collect and report information on initial participant costs (e.g., investments in enabling technologies or energy audits).[53] On-going (event-specific) participant costs are unlikely to be explicitly included in future analyses. As a practical matter, customers quantify these types of costs and indicate their acceptance of the participation costs when they enroll in a voluntary demand response program or optional pricing tariff and respond during events.[54] It is probably most feasible to reflect these costs in estimating participation rates and the aggregate price elasticity of program participants, rather than directly in benefit/cost tests.

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are available (e.g. observable forward prices) and use costs of an existing peaking plant for periods prior to the need to construct a new peaking unit (Orans et al. 2004).

[53] However, in contrast to a utility-sponsored program, it is often more difficult for the ISO to communicate directly with customers to establish their costs. Customers typically enroll through a utility, competitive retailer or a demand responses service provider. The ISOs can request that these entities collect customer data, but are hard-pressed to make it a condition of participation.

[54] Violette et al (2005) suggests that it can be assumed that the upfront and ongoing payments to customers for participating in a demand response program fully account for the value of foregone electricity consumption and any costs incurred by the customer related to the demand response event or curtailment call. Otherwise the customer would not have decided to enroll and participate.

The ten studies reviewed also differed significantly in their treatment and estimates of advanced metering costs. This is partly attributable to differences in the availability of advanced metering systems among utilities, and the target markets and types of demand response mechanisms assumed in the studies. For example, among IRP analyses, Study E assumed relatively low incremental meter reading and data management costs to support dynamic pricing among residential customers because the subject utility already had a fixed network, automated meter reading system in place. Study F included costs of metering and incremental data management for business customers only, while Study G did not appear to have explicitly accounted for these costs at all.

Given the lack of standardized or generally accepted techniques and frameworks to estimate demand response benefits and report program costs, it is not particularly useful to report net benefits for our sample of ten studies (several of which included no cost estimates).

Quantitative assessments should estimate and report ***net*** *demand response benefits.*

Quantitative assessments should ideally estimate *net* demand response benefits; this is not possible given the information provided by existing studies. Three studies did not account for costs at all. The three IRP studies and one of the illustrative analyses provided ranges of estimated benefits and compared them to ranges in estimated costs. While they draw general conclusions about the relative merits of including specific demand response pricing or program options in the modeled systems, these studies are not framed in terms of achieving specific levels of benefits. As a result, they do not provide any direct insights for DOE to use in recommending specific levels of demand response benefits as directed by Section 1252 of EPACT.

Establishing Protocols and Practices for Estimating Demand Response Benefits

Fostering demand response is an industry responsibility and obligation. Doing so requires that stakeholders make informed decisions on the financial and non-financial implications of introducing (or mandating) time-varying rates (i.e., price-based demand response) and programs to acquire demand response under specific circumstances (i.e., incentive-based demand response). To do this, policymakers need reliable and consistent methods for estimating the implications of the alternatives available to them. Current practices and protocols for valuing demand response provide a foundation for developing these methods, but are ill adapted to valuing demand response in several important ways. There is still work to be done to develop appropriate valuations tools and standard practices for evaluating demand response options.

It is premature to focus on setting national demand response goals or specific achievement targets.

Based on the findings of this study it is premature to focus on setting national demand response goals or specific achievement targets as EPACT instructs DOE to do. Nonetheless, demand response can and should be fostered in all market structures because it plays a vital role in achieving efficient market operation.

An immediate goal should be refining analytic methods and practices to recognize the full benefits of demand response.

Thus, one immediate goal should be refining analytic methods and practices to recognize the full benefits of demand response. Improvements in methods used to quantify and report the benefits and costs of demand response are needed and achievable. These improved analytic methods and practices will provide policymakers and market participants with tools to establish program performance standards, measure progress, and assess the performance and value of demand response initiatives.

Drawing from the body of literature on demand response valuation and the findings of this report, DOE offers the following recommendations for establishing standardized methods and protocols that enhance practices for estimating the benefits of demand response (see Appendix D for more detailed discussion):

1. DOE recommends that stakeholders collaborate to adopt conventions and protocols for estimating the benefits of demand response and, where appropriate, develop standardized tests that evaluate demand response program potential and performance.

2. DOE recommends that these protocols: (1) clarify the relationships and potential overlap among categories of benefits attributed to demand response to minimize double counting, (2) quantify various types of benefits to the extent possible, and (3) establish qualitative or ranking indices for benefits that are found to be too difficult to quantify.

3. DOE recommends that FERC and state regulatory agencies work with interested ISOs/RTOs, utilities, other market participants, and customer groups to examine how much demand response is needed to improve the efficiency and reliability of wholesale and retail markets.[55]

4. DOE recommends that regional planning initiatives examine how demand response resources are characterized in supply planning models and how the benefits are quantified. More accurate characterization of certain types of demand response resources may require modifications to existing models or development of new tools.

5. DOE recommends that, in regions with organized wholesale markets, ISOs and RTOs should work with regional state committees to undertake studies that assess the benefits of demand response *under foreseeable future circumstances* as part of their regional transmission expansion plans as well as under current market conditions.

[55] Issues to consider in this assessment include ability of demand response to obviate the need for active market mitigation, and potential impact of demand response on supplier market power and system reliability.

SECTION 5. RECOMMENDATIONS FOR ACHIEVING THE BENEFITS OF DEMAND RESPONSE

Section 1252(d) of EPACT requires DOE to submit a report that (1) "identifies and quantifies the national benefits of demand response," and (2) "makes a recommendation on achieving specific levels of such benefits by January 1, 2007."

Sections 3 and 4 of this report identify and quantify demand response benefits. Based on the findings of this study, DOE has determined that it is not appropriate to develop recommendations on achieving specific levels of demand response benefits by January 1, 2007. The eleven months between submission of this report and January 2007 do not allow time for meaningful recommendations to be successfully implemented. Instead, DOE offers a set of recommendations for consideration by state, regional and federal agencies, electric utilities and consumers to enhance demand response in a manner consistent with state and regional conditions.

The recommendations are organized as follows:

- *Fostering Price-Based Demand Response*—by making available time-varying pricing plans that let customers take control of their electricity costs;
- *Improving Incentive-Based Demand Response*—to broaden the ways in which load management contributes to the reliable, efficient operation of electric systems;
- *Strengthening Demand Response Analysis and Valuation*—so that program designers, policymakers and customers can anticipate how demand response delivers benefits;
- *Integrating Demand Response into Resource Planning*—so that the full impacts of demand response are recognized, and the maximum level of resources benefits are realized;
- *Adopting Enabling Technologies*—to realize the full potential for managing usage on an ongoing basis; and
- *Enhancing Federal Demand Response Actions*—to take advantage of existing channels for disseminating information and forming public-private collaboratives.

DOE developed these recommendations after a public input process in which interested parties were asked to provide suggestions in response to a web survey for "how to advance demand response in all markets." DOE considered the recommendations from the 40 organizations that submitted responses,[56] looked at other recent demand response studies,[57] and developed its own views. The recommendations reflect DOE's best judgment of the actions needed to advance demand response across the nation.

[56] Appendix A identifies the contributing organizations.
[57] These are listed in the References.

The primary audiences for the recommendations include:

- regional entities and market stakeholders (such as ISOs, RTOs, and multi-state entities involved in the electricity sector);
- Federal and State legislative and regulatory authorities (including FERC, public utility commissions, public service commissions, and state utilities boards);[58]
- electric utilities (such as those regulated by the states, as well as electric cooperatives, municipal utilities, and public utility districts) and load serving entities;
- electricity customers; and
- other stakeholders such as consumer and environmental groups, curtailment service providers, energy services companies, and equipment manufacturers.

Fostering Price-Based Demand Response

Retail electricity prices that are linked to contemporaneous supply costs or prices are one of the principal mechanisms for accomplishing demand response. Since the passage of the Public Utilities Regulatory Policy Act of 1978 (Public Law 95-617) there has been interest in and support for efforts to implement retail rates that reflect the marginal costs of providing electricity. The aim is to provide time-varying price signals that encourage customers to reduce demand when the costs of providing electricity are relatively high. Section 1252 of EPACT (under Subtitle E—Amendments to PURPA) directs State regulatory authorities to decide whether their utilities should offer customers time-based rate schedules (i.e., RTP, CPP and TOU rates) and advanced metering and communications.

Large Customers

RTP is an effective means of facilitating demand response for large commercial and industrial customers.[59] Default service RTP tariffs that index hourly prices to day-ahead markets support demand response and retail market development by giving customers more notice and certainty of the financial consequences of their response. RTP tariff designs that offer customers a fairly predictable financial benefit, and allow them to financially hedge their exposure to price risks (e.g., through a two-part RTP with a consumer baseline and/or financial risk management products), are effective in vertically integrated systems.

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[58] A recent study by the Government Accountability Office (GAO 2004) concluded that a majority of the actions to address demand response involve retail markets and thus come under the jurisdiction of the states, based on provisions of the Federal Power Act. In EPACT, Congress did not require the states to do demand response but instead required them to consider and investigate demand response and time-based metering based on changes to the Public Utility Regulatory Policies Act of 1978. Congress also authorized DOE and FERC to encourage demand response through information and education on benefits, barriers, and technologies as well as technical assistance. Absent additional legislative changes from Congress, actions of Federal [regulatory] agencies that affect demand response are limited to wholesale markets.

[59] See Barbose et al. (2004 and 2005) and Goldman et al. (2005).

- *In states that allow retail competition, state regulatory authorities and electric utilities should consider adopting RTP as their default service option for large customers.*

- *In states that do not allow retail competition, state regulatory authorities and electric utilities should consider offering RTP to large customers as an optional service for large customers.*

Customers on RTP need to understand their electricity consumption patterns in substantial detail and also need to be aware of their capabilities to curtail or shift discretionary usage. For example, facility audits can help identify and assess operational strategies and/or technologies for responding to hourly prices. Financial incentives for energy management control systems, distributed energy systems, or automated controls may, in certain cases, be warranted.

Customer Sizes

There is no standard classification of customer size. The following classifications are adopted for this report:

Large customers are those with electric demand **exceeding 1,000 kilowatts** and generally include manufacturing plants, office and large hospital complexes, skyscrapers, and university campuses.

Medium business customers are those with electric demand of **100-1,000 kilowatts** and generally include many types of commercial buildings such as 'big box" retail stores and office buildings, warehouses, and light industrial facilities.

Small business customers are those with electric demand **below 100 kilowatts** and generally include small commercial buildings, retail stores, and restaurants.

Residential customers are a subset of small customers and include single-family homes, town houses, and apartments, most of which have electric demand below **10 kilowatts**.

- *Regional entities and collaborative processes, state regulatory authorities, and electric utilities should provide education, outreach, and technical assistance to customers to maximize the effectiveness of RTP tariffs.*

Medium and Small Business Customers

Medium and small business customers comprise a highly diverse mix of businesses and types of buildings. These customers are not typically targeted for price-based demand response to the same extent as large commercial and industrial customers. As a result, the experience base about what does and does not work is much less developed, and this lack is a deterrent to the implementation of price-based or other demand response mechanisms.

The diversity of medium and small business customers makes it relatively difficult to design pricing approaches that can elicit predictable and cost-effective demand response across diverse customer circumstances, (e.g., schools, grocery stores, "big box" retail outlets, private sector office buildings, government facilities, warehouses, and restaurants). Each of these has different decision-making processes, patterns of demand, and types of equipment. A library of case studies about customer and utility experiences with price-based demand response would help customers see how demand response can work in their business by seeing how it works in comparable businesses.

- *State regulatory authorities and electric utilities should investigate new strategies for segmenting medium and small business customers to identify relatively homogeneous sub-sectors that might make them better candidates for price-based demand response approaches.*

There is evidence that RTP could be suitable for medium-sized businesses, particularly among the larger customers in this group (e.g., those with demand above 300-500 kW).[60] CPP may also provide an effective means for introducing demand response to medium and small businesses, particularly those served by vertically integrated systems. There may be circumstances where policy or business cases can be made for offering RTP or CPP as the standard rate (vertically integrated systems) or as the default service (competitive retail markets).

- *State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for medium and small business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis.*

- *State regulatory authorities and electric utilities should consider conducting policy or business case analysis of RTP for medium business customers. Results from existing pilot programs should be carefully evaluated and included in the analysis.*

<u>Residential Customers</u>

Several electric utilities have conducted large-scale CPP pilots that included residential customers and found encouraging results, including high acceptance and demand reduction in certain customer segments.[61]

- *State regulatory authorities and electric utilities should consider conducting business case analysis of CPP for residential customers. Results from existing pilot programs should be carefully evaluated and included in the analysis.*

Residential (and small business) customers represent a special challenge for price-based demand response. Most residences (and small businesses) lack information on their electricity-using appliances and equipment and are not familiar with demand response enabling technologies that can facilitate effective energy management.

- *State regulatory authorities and electric utilities should investigate the cost-effectiveness of offering technical and/or financial assistance to small business*

[60] See Barbose et al. (2005).
[61] See Charles River Associates (2005).

and residential customers to enable their participation in CPP or TOU tariffs and enhance their abilities to reduce demand in response to higher prices.

Improving Incentive-Based Demand Response

Experience has shown that the effectiveness of incentive-based demand response programs is closely correlated to how programs are designed and offered to customers.[62] Program design considerations include eligibility criteria, curtailment terms and conditions (e.g., notice, duration, and frequency of events), incentive payments, cost recovery, and procedures to measure and verify demand reductions.

- *Traditional load management (LM) programs such as direct load control of residential and small commercial equipment and appliances (e.g., air conditioners, water heaters, and pool pumps) with an established track record of providing cost-effective demand response should be maintained or expanded.*

In some cases, these LM programs must be adapted to new market structures or circumstances, which involves rethinking program design features related to triggering events (e.g., only system emergencies or other economic and emergency criteria), linking payments to actual performance, considering improvements or enhancements to control technologies, improving system communications, or enhancing monitoring/verification capabilities to allow LM programs to participate in various wholesale electricity markets (e.g., capacity, reserves). When adapting LM from vertically integrated systems to other market structures (e.g. markets with retail competition and vertical de-integration), a key issue to address is the fact that with the proliferation of market actors (e.g. competitive retailers, "wires-only" utilities), no single entity has the incentive to pursue the full benefits of demand response.

- *State regulatory authorities and electric utilities should consider offering existing and new participants in these LM programs "pay-for-performance" incentive designs, similar to those implemented by ISOs/RTOs and some utilities, which include a certain level of payment to customers who successfully reduce demand when called upon to do so during events.*

Some emergency demand response programs have been able to provide reliability benefits to regional entities, electric utilities, and customers in a cost-effective manner. Certain program design features have been particularly effective in achieving both consumer enrollment and performance during times of system need.

- *Regional entities, state regulatory authorities, and electric utilities should consider including the following emergency demand response program features:*
    - *Payments that are linked to the higher of real-time market prices or an administratively-determined floor payment that exceeds customers' transaction costs;*

[62] Policymakers need to recognize that it takes at least six months and often up to several years to build demand response capability, depending on the type of program adopted.

- o *"Pay-for-performance" approaches that include methods to measure and verify demand reductions;*
- o *Low entry barriers for demand response providers, and in vertically integrated systems, procedures to ensure that customers have access to these programs; and*
- o *Multi-year commitments from regional entities for emergency demand response programs so that customers and aggregators can make decisions about committing time and resources.*

Electric utilities that own and operate distribution systems only may have limited interest in implementing demand response programs for customers that remain on default service, especially in cases where supply for those customers is contracted out to another entity.

- *State regulatory authorities should investigate whether it would be cost-effective for default service providers to implement demand response. They should also provide cost recovery for demand response investments undertaken by distribution utilities.*

Strengthening Demand Response Analysis and Valuation

Additional work is needed to standardize reporting of demand response costs, benefits, and valuation methods before it will be possible to establish appropriate levels of demand response benefits. A stronger analytical infrastructure for demand response will help electric utilities, customers, retail suppliers, ISOs/RTOs, and state, regional, and federal agencies to properly assess demand response capabilities, business cases, and resource plans.

- *A voluntary and coordinated effort should be undertaken to strengthen demand response analysis capabilities. This effort should include participation from regional entities, state regulatory authorities, electric utilities, trade associations, demand response equipment manufacturers and providers, customers, environmental and public interest groups, and technical experts. The goal should be to establish universally applicable methods and practices for quantifying the benefits of demand response.*

Public-private partnerships of this type have been successful in addressing similar challenges by fostering better information exchange and helping to build consensus. DOE can help to facilitate the formation of such a partnership, but the objectives, work plans, experts, and resources need to come from the members. Appendix D of this report contains additional information on needed demand response analysis and valuation information, tools, and techniques. Key needed activities include:

- Developing standardized methods to evaluate demand response potential and performance and identify appropriate tests for foreseeable programs and circumstances;

- Clarifying the different categories of demand response benefits, developing methods to quantify those benefits that can be quantified and qualitative or ranking indices for those that are difficult to quantify;
- Developing methods to estimate demand response impacts on wholesale electricity costs and reliability, and the benefits and savings that are passed through to retail customers, thus clarifying the link that demand response provides between wholesale and retail markets;
- Documenting the impact of price-based demand response on wholesale electric market prices and costs based on actual demand response program results; and
- Establishing a database of existing demand response programs to (1) document a track record of program performance with respect to reliability protection, (2) gain insight into the factors that influence performance, and (3) identify ways to use demand response most effectively to deal with reliability challenges.

Integrating Demand Response into Resource Planning

Electric resource adequacy is paramount to ensuring reliable, secure, and affordable electric market operations. It is appropriate for regional entities, state regulatory authorities, and electric utilities to ask how much demand response is needed (and is enough) for ensuring resource adequacy, given market structures and system conditions.

Existing studies confirm the view that even low levels of demand response can improve resource adequacy and the efficiency of market operations. However, existing studies do not address, nor provide methods for, establishing optimal levels or target goals for demand response in specific market settings.

- *FERC and state regulatory agencies should work with interested ISOs/RTOs, utilities, other market participants and customer groups to examine how much demand response is needed to improve the efficiency and reliability of their wholesale and retail markets.*[63]

Current resource planning methods often fail to characterize demand response resources properly. For example, RTP is often evaluated as a resource that can be dispatched to serve demand, rather than as reductions in the timing and level of demand. Also, the flexibility of being able to add, or limit, certain types of demand response resources, from one year to the next, based on system needs, is often not fully reflected in resource plans.

- *Resource planning initiatives should review existing demand response characterization methods and improve existing planning models to better incorporate different types of demand response as resource options.*

[63] Issues to consider in this examination include the ability of demand response to obviate the need for active market mitigation, the impact of demand response on supplier market power, and the ability of demand response to enhance reliability.

In wholesale markets where ISOs/RTOs administer organized spot markets, the primary focus is on short-term demand response impacts and benefits. More effort should be devoted to characterizing long-term impacts and potential benefits. In the absence of forward markets for demand response, and the potential for a stream of benefits, demand response value will depend primarily on current market conditions.

- *ISOs and RTOs, in conjunction with other stakeholders, should conduct studies to understand demand response benefits under foreseeable future circumstances as part of regional transmission planning and under current market conditions in their demand response performance studies.*

Adopting Enabling Technologies

Recent advances in information and communication technologies have expanded metering functionality, and increased the potential for lower metering costs. DOE believes these enabling technologies have the potential to produce demand response offerings that are more attractive and cost-effective for electric utilities and customers.

Advanced metering systems are one of the most important demand response enabling technologies, particularly for mass-market customers.[64] They can also improve regional grid operators and electric utilities' grid management and operations capabilities because they enable access to real-time and disaggregated information on demand conditions in local areas. While a number of U.S. utilities have committed to system-scale deployment of advanced metering systems, in many of those cases the business case focused primarily on the utility's operational and business benefits (e.g., reduced meter reading costs, outage and tamper detection, and energy profiling).

- *State regulatory authorities and electric utilities should assure that utility consideration of advanced metering systems includes evaluation of their ability to support price-based and reliability-driven demand response, and that the business case analysis includes the potential impacts and benefits of expanded demand response along with the operational benefits to utilities.*

There are other key demand-response enabling technologies, including advanced HVAC and lighting controls, "grid friendly" appliances,[65] smart thermostats, and distributed

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[64] Advanced metering systems encompass a range of solid-state devices that are capable of measuring electricity consumption for whatever time interval is desired (e.g., minute-by-minute, hourly, or for specified "critical peak periods"). They often include equipment and software for communicating consumption and other relevant customer information to utilities automatically, thus eliminating the need for meter readers. The infrastructure that is needed to support advanced metering systems can be extensive and typically includes the meter manufacturers, distributors, and services providers; software developers; communications equipment and services providers (e.g., radio, cable, telephone, and power lines); and electric utilities.

[65] The grid-friendly appliance is a concept that includes refrigerators and other home appliances which contain special computer chips that enable utilities and/or demand response providers, with the use of wide-area data acquisition and control systems, to determine the operational status of home appliances and provide the ability to control its electricity consumption during times of system need.

energy devices such as advanced turbines and micro-turbines, high efficiency engines, thermal and electric energy storage, thermally-activated heating and cooling equipment, fuel cells, photovoltaic arrays, and small-scale combined heat and power (CHP) systems. In addition, advanced designs for integrating and configuring these devices for "whole building," or multi-building applications need to be evaluated, particularly those that can be optimized for energy, economic, and environmental performance. These include building automation systems and concepts such as "zero-energy homes," "low-peak communities," "district CHP systems," "GridWise™," "Intelligrid," and "microgrids."

- *State regulatory authorities and electric utilities should evaluate enabling technologies that can enhance the attractiveness and effectiveness of demand response to customers and/or electric utilities, particularly when they can be deployed to leverage advanced metering, communications, and control technologies for maximum value and impact.*

- *State legislatures should consider adopting new codes and standards that do not discourage deployment of cost-effective demand response and enabling technologies in new residential and commercial buildings and multi-building complexes.*

Enhancing Federal Actions

Sections 1252 (d), (e), and (f) of EPACT contain provisions for DOE, FERC, and other federal agencies to encourage demand response. DOE has been encouraging demand response through information exchange, technical assistance, and technology development and transfer activities. In wholesale markets, FERC has been encouraging the increased use of demand response. For example, FERC and the ISOs/RTOs have been addressing the integration and use of demand response in regions with organized spot markets, and the potential impact of demand response on the market power of suppliers.

- *DOE, to the extent annual appropriations allow, should continue to provide technical assistance on demand response to states, regions, electric utilities, and the public including activities with stakeholders to enhance information exchange so that lessons learned, best practices, new technologies, barriers, and ways to mitigate the barriers can be identified and discussed.*[66]

- *DOE and FERC should continue to coordinate their respective demand response and related activities.*

[66] Information exchange topics include, for example, how the states are addressing the Section 1252 provisions of EPACT for advanced metering and demand response, how demand response potentially affects utility revenues and profits, and how utility ratemaking and incentive mechanisms potentially affect demand response adoption and program success.

- *FERC should continue to encourage demand response in the wholesale markets it oversees.*[67]

Section 103 of EPACT includes a provision whereby all federal facilities are to have metering capabilities—and to the extent practical, advanced meters or advanced metering devices—by October 1, 2012.

- *DOE, through its Federal Energy Management Program, should explore the possibility of conducting demand response audits at Federal facilities.*

Although not always the case, in certain circumstances it is possible for demand response programs and pricing approaches to have a favorable impact on energy efficiency and the environment.

- *DOE and the Environmental Protection Agency should explore efforts to include appropriate demand response programs and pricing approaches, where appropriate, in the ENERGY STAR® and other voluntary programs.*

[67] Examples of this include: encouraging expanded efforts by the ISOs and RTOs to (1) find ways for customers to participate in spot, day-ahead, and ancillary service markets; (2) determine whether current or proposed reliability rules need to be changed to accommodate demand response; and (3) support even greater levels of information exchange and collaboration on demand response across regions of the country.

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APPENDIX A. ORGANIZATIONS THAT PROVIDED INPUT ON RECOMMENDATIONS

American Council for an Energy-Efficient Economy
American Public Power Association
Apogee Interactive, Inc.
Arkansas Public Service Commission
Battelle-Pacific Northwest National Laboratory
BP Solar
California Department of Water Resources State Water Project
California Energy Commission
California Public Utilities Commission
Constellation Energy
Consumer Energy Council of America
Cornell University
Demand Response and Advanced Metering Coalition
Distributed Energy Financial Group
Duke Power
East Kentucky Power Cooperative
Edison Electric Institute
Energy Connect Inc.
Grid Services, Inc.
Hunt Technologies, Inc.
Idaho Public Utilities Commission
Invensys Controls
ISO New England, Inc.
Itron
Louisville Gas and Electric
M.Cubed
National Rural Electric Cooperative Association
New York State Department of Public Service
PJM Interconnection, LLC
San Francisco Community Power Cooperative
Solar Turbines, Inc.
Southern California Edison Company
Steel Manufacturers Association
SUEZ Energy NA
The Cool Solutions Company
The Stella Group, Ltd.
U.S. Department of Energy—Building Technologies Program
United States Demand Response Coordinating Committee
Utilipoint International, Inc.
Utility Economic Engineers

APPENDIX B. ECONOMIC AND RELIABILITY BENEFITS OF DEMAND RESPONSE

This Appendix provides a more detailed conceptual discussion of the economic and reliability benefits of demand response than was included in Section 3. First, short-term market impacts are described, drawing on economic theory to show how demand response can result in improved economic efficiency, and distinguishing how these benefits are manifested under different market structures. Next, long-term economic benefits from avoided capacity investments are discussed along with issues in designing and implementing programs designed with this goal in mind. Differences in how short-term and long-term economic benefits are realized and passed on to consumers are then described for vertically integrated utilities and regions with ISO/RTO spot markets. Finally, reliability benefits are described along with concepts used to value them.

Short-Term Market Impacts: Supply Costs and Market Prices

This section provides a detailed discussion of how customer load reductions lower energy supply costs in the short term. First, the basic source of short-term market benefits—improved economic efficiency brought about by allowing consumers to make electricity usage decisions based on marginal, rather than average, supply costs—is described. Differences in how these benefits are manifested in regions with differing market structures are then discussed.

Societal Benefits

In evaluating policies or structural changes that impact how markets work, economists distinguish between societal gains, which benefit everyone, and financial flows that involve gains by some at the expense of others, called transfers. In the absence of a way to weigh the relative impact on individuals of gains and losses (i.e., a change in utility), economists argue that policies should primarily be judged on their net outcome, which is defined by the level of societal benefits (see the textbox below).

Demand response produces societal benefits, which are resource savings, by reducing the gap between time-varying marginal supply costs and retail electricity rates based on average costs. Economic theory asserts that the most efficient use of resources occurs when consumption decisions are based on prices that reflect the marginal cost of supply. In a competitive market, this is defined by the intersection of a good's supply and demand curves (see Figure B-1). In electricity markets, the marginal electricity supply curve is constructed by ordering generators from lowest to highest operating costs (often referred to as "merit order").[68] Due to the technical characteristics of electricity generation equipment, the supply curve—the upward curving line in Figure B-1—tends

[68] Certain generators may be required to run, regardless of their marginal operating costs, to maintain reliability in areas with constrained generating and/or transmission capacity, which limits the ability of least-cost resources to serve local demand.

to increase very steeply at its upper end.[69] This means that when demand approaches the industry's installed capacity, each additional increment of demand imposes increasingly more cost than the previous one. In other words, the marginal cost of electricity becomes most sensitive to changes in demand when demand is already high.[70]

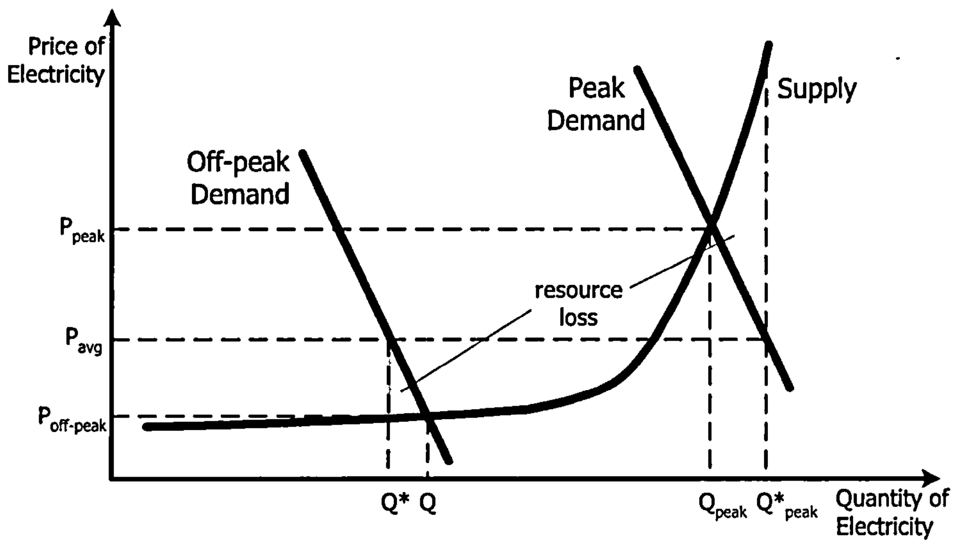

Figure B-1. Inefficiencies of Average-Cost Pricing

Like most goods, the demand for electricity exhibits declining marginal value (i.e., the marginal value of additional consumption declines as consumption increases). Electricity demand is characterized by a downward-sloping line, regardless of how electricity is priced. But, if the price that consumers pay never varies, demand appears to be perfectly inelastic, and is characterized by a vertical line. Moreover, consumers' demand for electricity also depends on the time of day, with more usage typically occurring during the "peak" afternoon and early evening hours and less at other times. This phenomenon is driven by the economic activity of businesses and residential customer lifestyles and usage patterns, but is also influenced by electricity rates that are the same throughout the day. For simplicity, the two lines labeled "peak" and "off-peak" in Figure B-1 represent consumer demand.

The most efficient pricing and usage of electricity is determined by the intersection of the supply and demand curves in Figure B-1. In other words, during off-peak periods, the efficient price of electricity should equal $P_{off\text{-}peak}$ and consumers would use an amount of

[69] The long, flat portion of the electricity supply curve represents "base-load" power plants, such as nuclear, hydroelectricity and coal plants that have very low operating costs and are run most hours of the year. Base-load plants are typically large with similar characteristics. The steeply inclining portion of the supply curve represents "peaking" plants that are used to meet peak demand needs and may be run only a few hours per year. These plants are typically natural gas- or oil-fired combustion turbines that are less expensive to build than most base-load technologies but have higher operating costs. Peaking plants are typically smaller units with varied operating characteristics.

[70] High demands do not always lead to high prices. If the entire portfolio of capacity is available, then the marginal unit may be relatively low cost. The steepest part of the supply curve is encountered when demands are especially high (e.g. a heat wave) or generation is short due to forced outages, or both.

electricity equal to Q, and during peak hours, the efficient price should equal P_{peak} and consumers would use Q_{peak} units of electricity. However, most consumers currently pay electricity tariffs that reflect average, rather than marginal, electricity supply costs; this is represented by P_{avg} in Figure B-1. Actual usage therefore reflects the intersection of the demand curves with this average price, resulting in less than the social optimal usage in off-peak periods (Q*) and more than the social optimal usage in peak periods (Q^*_{peak}) relative to the optimally efficient system.

Distinguishing Societal Benefits from Rent Transfers

Economists make a distinction between *transfers*—the benefits of a policy initiative that amount to gains for some at the expense of others—and *social welfare gains* that inure to society as a whole. Social welfare gains are desirable because they derive from efficiency improvements that benefit all market participants. These benefits provide a strong rationale for policymakers to invest consumers' money in initiatives to realize such gains. Transfers result in some market participants being better off than others. In the case of demand response, lower market prices reduce revenue to suppliers and lower costs to consumers. The economists' task is to quantify the relative marginal gains and losses to the individuals involved.

Some economists caution that treating market price reductions as benefits is misleading, and may result in policies that undermine, rather than enhance, market efficiency (Ruff 2002). Specifically, they contend that using the bill savings from price reductions, which largely amount to transfers, to justify demand response incentive payments to customers actually raises electricity prices in the long term. They contend that merchant generators count on the profits (called scarcity rents) realized when prices are high to recoup their capital costs and achieve the rate of return their investors require. If these profits are reduced because policymakers use them to justify customer curtailment incentives, then investors will become more skeptical and require higher returns, which, the argument concludes, results in higher prices in the long run.

This is the basis for many of the objections to allowing customers to bid load curtailments as resources into ISO/RTO spot markets, called "demand bidding as a resource." However, other economists contend that if demand response moves the wholesale market to greater economic efficiency and the result is a more appropriate supply and demand balance, then the elimination of those artificial rents to generators corrects a market distortion and prevents investments that are not needed based on how customers value electricity.

Another objection to demand bidding raised by some economists is their claim that customers on default service have no right to the energy, since the utility rates require that it be served, but do not give the customer any contractual rights to that supply. This could be corrected by requiring that in order to bid curtailments into spot energy markets, the customer would have to demonstrate that it has contractual rights to that power. As an alternative, these critics propose "self-financing" demand response whereby the inherent savings from avoiding paying high market prices is the inducement for customers to curtail, and no payment has to be made to achieve that result (Braithwait 2003).

These arguments have only been raised for demand response programs that allow customers to offer curtailments as resources in centrally organized spot markets. Yet, substantially the same transactions characterize demand bidding and CPP programs run by vertically integrated utilities.

Economists refer to the inefficiencies that arise when retail prices do not reflect marginal supply costs as "dead-weight losses" or resource losses (i.e., the loss of societal welfare when resources are not used optimally). The resource losses from average cost pricing are illustrated by the shaded triangles in Figure B-1. In the off-peak period, electricity that would have value to consumers if it were priced according to its marginal supply cost is not consumed—this represents a loss to society in economic activity that would have occurred but did not. In the peak period, consumers that do not pay the full marginal cost of power consume excessive amounts of electricity at a cost in excess of the value it provides them. Because this occurs at the steeply inclining portion of the electricity supply curve, these costs can be substantial.[71]

The short-term market-impacts benefit of demand response lies in reducing or eliminating this resource loss, thereby improving net social welfare. The combined resource loss from all peak and off-peak hours—and thus the potential for short-term demand response benefits—depends on how widely average and marginal electricity costs vary. For example, in a tightly constrained market, where peak demand is often very close to supply limits, the potential short-term efficiency benefit from implementing demand response can be substantial.

<u>Supply Cost and Market Price Impacts in Regions with Differing Market Structures</u>

Short-term market impacts are illustrated for vertically integrated utilities in Figure B-2. The supply curve typically reflects the utility's supply costs, including its own generation plants and any incremental wholesale power purchases. If demand is forecast to be Q, then a demand reduction that moves consumption to Q_{DR} results in an avoided utility supply cost equal to the shaded area in Figure B-2.

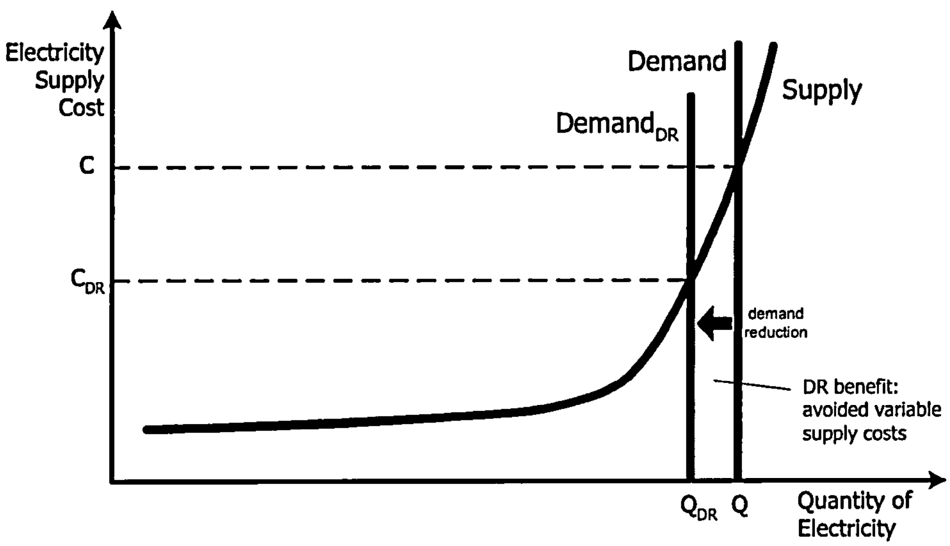

Figure B-2. Impact of Demand Response on Vertically Integrated Utility Supply Costs

The same load reduction produces more extensive impacts in regions with organized wholesale markets because of the way these wholesale markets are designed. The supply curve is developed by arranging generators' offer bids in merit order from lowest to

[71] Electricity pricing that does not reflect supply costs results in societal losses both when costs are high, and when they are low. However, the extent of these losses is greater at elevated supply costs, and therefore correcting prices in these periods has captured the attention of policymakers and market designers.

highest. Because of competition among generators, generators' offer bids reflect their marginal operating and maintenance costs and in some circumstances additional margins to recover fixed costs. LSEs also bid their expected load requirements into the market, producing a demand curve.[72] The bid price of last generator needed to serve the LSE's purchases sets the market clearing price for the whole market. This means that a demand reduction from Q to Q_{DR} not only provides the avoided variable cost savings observed for vertically integrated utilities (the shaded area to the right in Figure B-3), but it also lowers the price of all other energy purchased in the market. This second market impact, represented by the shaded rectangle in Figure B-3, is dependent on the level of price reduction—the difference between P and the new price P_{DR}—and the amount of energy bought in the applicable market. LSEs typically commit their expected energy requirements with a mix of bilateral forward contracts with generators and purchases in day-ahead and real-time markets. This is represented by the dotted line in Figure B-3. The extent of customer savings from price reductions thus depends on how much energy is purchased in spot markets.[73]

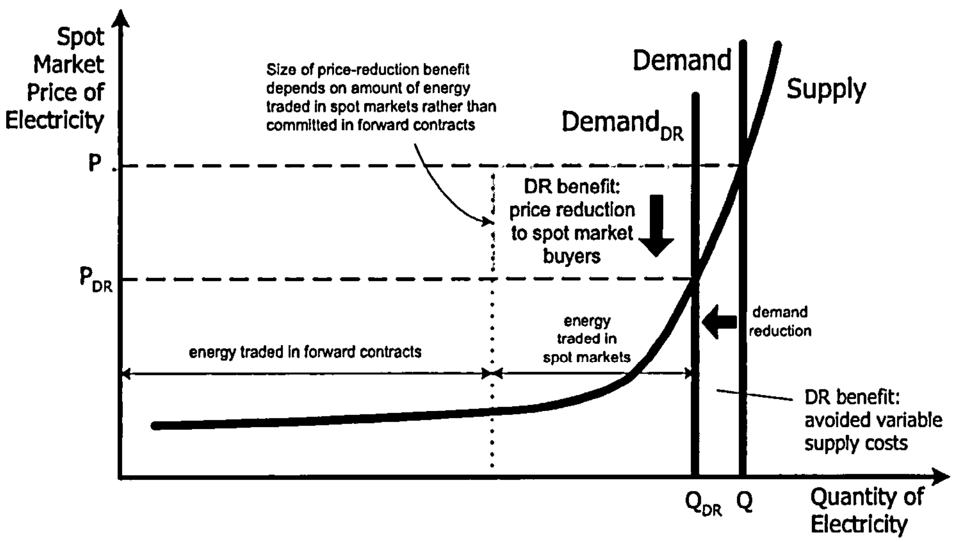

Figure B-3. Impact of Demand Response in Regions with Organized Wholesale Markets

In regions with organized wholesale markets, if, over time, customers routinely respond to high prices by curtailing or shifting loads, then additional, longer-term savings will result. Thus, if demand response consistently reduces market prices and volatility, bilateral contract prices will also drop over time, as reduced price risk in day-ahead and real-time markets pushes longer-term contract prices down. This is because LSEs may be willing to pay less for hedged forward contracts and will buy instead from the spot market if generators do not offer lower forward contract prices. In this way, lower energy

[72] In this example, demand is represented by a vertical line for simplicity (i.e., it is presumed to be fixed). Currently, most LSEs bid fixed quantities of electricity in spot markets, so this characterization is appropriate.
[73] In New York, a state with organized wholesale markets and retail competition, over 50% of electricity is traded in day-ahead and real-time spot markets, with the rest settled in forward contracts. In New England, about 40% of the electricity volume is traded in ISO-NE's spot markets, with about 60% committed in forward contracts.

prices resulting from short-term demand response market impacts can eventually extend to the entire market.[74]

Long-term Market Impacts: Capacity Benefits

The long-term market impacts of demand response hinge on reducing the *system peak demand*—the highest instantaneous usage by consumers in a particular market. Reducing system peak demand can avoid or defer the need to construct new generating, transmission and distribution capacity, resulting in savings to consumers. This applies for both vertically integrated utilities and organized wholesale markets, although capacity costs are allocated differently. This benefit can be specifically elicited from customers through capacity-based demand response programs (e.g., DLC, I/C rates or ISO/RTO capacity based programs) or may result from consistent load reductions from price-based demand response options (e.g., RTP). For example, in a capacity-based demand response program, load reductions timed to reduce load from a level that otherwise would have established the system maximum demand can yield large benefits for all consumers. Historical system maximum demand, adjusted for planned reserves, establishes ongoing generating capacity requirements, usually on an annual or semi-annual basis. For example, if the maximum demand served in a control area during the past summer was 5,000 MW, then that demand would serve as the basic capacity target for the next summer, to which an additional reserve margin (e.g., 18%) would be added.[75] If the existing infrastructure were insufficient to serve the resulting 5,900 MW capacity requirement, additional capacity would be necessary. Since generating capacity is expensive, ranging from about $50,000 to over $100,000 per MW-year (depending on the type and location of generating units), demand response that displaces the need for new infrastructure can produce substantial avoided cost savings.

Demand response programs designed to reduce capacity needs are valued according to the marginal cost of capacity. By convention, marginal capacity is assumed to be a "peaking unit", a generator specifically added to run in relatively few hours per year to meet peak system demand. Currently, peaking units are typically natural gas turbines with annualized capital costs on the order of $75/kilowatt-year (kW-year) (Orans et al. 2004, Stoft 2004). Thus, if demand response programs avoid 100 MW of generating capacity, the avoided capacity cost savings would be $7.5 million per year in this example. If the total program costs were $50/kW-year, including incentive payments to participating customers, then other customers realize the rest as savings (e.g., $2.5 million per year in this example), which may eventually be reflected in lower rates and bills. As long as there is some sharing of benefits, all customers benefit from others' participation in a capacity demand response program.

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[74] Whether or not savings from short-term market price impacts and reduced forward contract prices brought about by incentive-based demand response programs should be treated as societal benefits is a subject of controversy (see the textbox on "Distinguishing Societal Benefits from Rent Transfers", earlier in this Appendix).

[75] Reserve margins vary in electricity markets across the U.S., but are typically 15-18%.

Transmission and distribution system capacity investments are also capital-intensive, and demand response that reduces local maximum demand in areas nearing infrastructure capacity can also provide significant avoided cost savings.

Realizing Capacity Benefits: Establishing and Reducing System Peak Demand

Capacity-based demand response programs are designed to replace generation investments and participants receive up-front capacity payments tied to this avoided cost. To realize this benefit and justify making the capacity payments, system operators must be able to dispatch curtailments that actually avoid building new capacity. This is accomplished in one of two ways: (1) predicting when system peak demand will exceed historic levels and dispatching load reductions accordingly or (2) dispatching curtailments when a designated peaking generation unit would otherwise be in service.

Dispatching demand response to avoid increasing system peak demand involves predicting when peak demand is likely to exceed historic levels absent any curtailments. Electric systems are generally either winter or summer peaking, meaning that annual demand is seasonal. However, demand can exceed historic peak levels several times during the peak season, which may span several months. To ensure that a capacity program truly does reduce peak demand, operators may need to dispatch the program several times during the peak season to account for forecast error. For participating customers, multiple curtailment obligations can be burdensome. To improve the attractiveness of capacity programs to customers, limits are sometimes are placed on how many curtailments can be called in a particular season.

The alternative method is to dispatch capacity-based demand response programs when an existing plant designated to meet peak demand would be needed to serve expected demand, absent any curtailments. This practice is somewhat more straightforward in regions with organized wholesale markets because transparent market rules direct dispatch operations. However, vertically integrated utilities have similar unit dispatch rules that could be used. Here too, limits may be placed on how frequently curtailments are called for.

Both methods of dispatching demand response to realize capacity value require provisions for periodic testing of customer response as well as penalties for non-performance. Testing is necessary to certify that customers truly have the capability to deliver the contracted curtailments on an on-going basis. Penalties serve to reinforce their obligation to be available and deliver load reductions when called. However, establishing appropriate penalty levels can be challenging. Increased penalty levels make demand response commitments more reliable and more valuable to the system operator, but are likely to reduce the amount of demand response committed by customers.[76] Program designers must balance the attractiveness of the program to customers against the potential consequences of forced outages that affect a large number of customers at costs well in excess of the avoided cost payment participating customers receive.

Because the avoided capacity cost savings calculation is prospective, so is the value of a capacity-based demand response program. This raises issues in forecasting the timing of system peak demand, or the highest 10-30 load hours of the year, so that calls for demand reductions actually moderate system maximum demand as designed. Since forecasting involves errors, program administrators/sponsors must make provisions to ensure the

[76] One useful strategy may be to recruit larger numbers of customer participants by dropping or reducing penalties for non-performance. Even though each customer is a less reliable source of demand response in the absence of penalties, the larger number of participants could increase the total expected demand response. The adoption of such a strategy would require evaluation of accumulated experience on the effect of various levels of penalties on customer performance.

demand response program is called often enough to effectively lower the forecast of system peak demand (see the textbox above).

Timing and Distribution of Market Impacts of Demand Response

Differences in market structure influence the timing and distribution of short-term and long-term market impacts of demand response in important ways. These differences are illustrated in this section by tracing the market impacts and resulting benefits of demand response in two types of market structure: 1) "vertically integrated systems", in which a vertically integrated utility with a retail monopoly franchise engages in some wholesale market transactions but operates in a region without an ISO or RTO, and 2) regions with organized wholesale markets in which ISOs/RTOs administer spot markets and retail competition is enabled at the state level. These illustrative combinations of retail and wholesale market structures reflect the current situation in many states or regions, although other retail/wholesale market structures are prevalent in the U.S.[77]

In this section, the examples suggest that the market impacts of demand response within organized spot markets produce benefits in a *shorter* timeframe than those for a vertically integrated, monopoly utility.

Market Impacts of Demand Response for Vertically Integrated Utilities

Vertically integrated utilities are responsible for making capacity investment decisions (whether to build new generation itself or to purchase supply contracts from other sources such as independent power producers), subject to regulatory oversight and approval, and for planning and operating the electricity grid and ensuring reliability. Retail rates are determined administratively, based on the average cost of supplying all three major facets of electricity production and delivery—production, transmission and distribution—and expected sales volumes. Embedded in retail rates are marginal costs to supply power, such as fuel, operating and maintenance costs, as well as a return on investment for un-depreciated utility-owned generation.

The economic impacts of demand response for a vertically integrated utility operating with a retail monopoly franchise are depicted in Figure B-4. Short-term demand response benefits may be traced as follows:

- Depending on the timing and type of demand response option, customers' load changes may be integrated into the utility's scheduling and dispatch decisions on a day-ahead or near-real-time basis.
- Changes in load (e.g., reductions in usage during high-priced peak periods) offset a portion of usage that otherwise would have been met by production from high-

[77] For example, utilities in some states are still vertically integrated and retain a retail monopoly franchise but are part of an organized regional wholesale market administered by an ISO or RTO (e.g., some parts of MISO, Vermont).

operating-cost power plants or purchases during the load response event (see Figure B-2).[78]

- This lowers the average variable electricity cost, which should be manifested eventually as customer bill savings through lower regulated electricity rates.

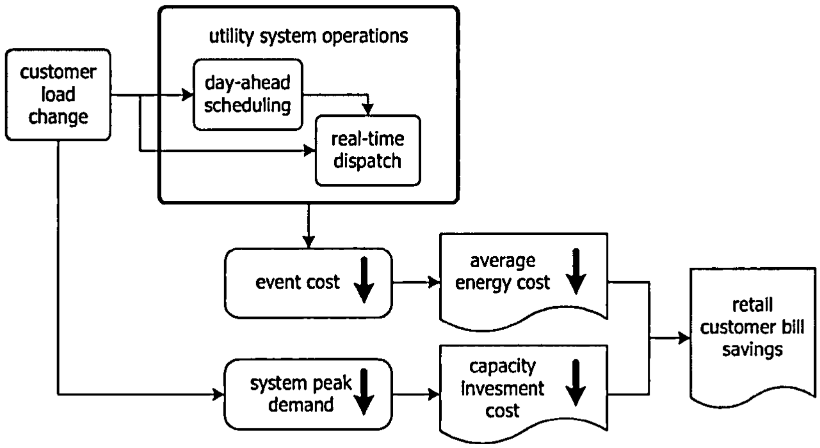

Figure B-4. Market Impacts of Demand Response for Vertically Integrated Utilities

The utility's return on capacity investments is recovered separately from its marginal costs to produce or purchase electricity and operate the electric grid. Thus, in vertically integrated systems, in the absence of a mechanism to reveal marginal capacity or reliability costs in unit operating costs, the short-term market impacts of demand response are limited to efficiency improvements in operating costs (including energy production and purchase costs) alone.[79]

In the long term, demand response that reduces peak demand growth directly averts the need for utilities to build more power plants, power lines and other capacity-driven infrastructure or to buy new capacity and energy from other suppliers (see Figure B-4). Because capacity investments are usually fully recovered—along with a pre-established return on investment—through higher retail electricity rates, these long-term benefits are realized over a multi-year period and can result in significant savings to consumers.

In vertically integrated, stand-alone utility systems, demand response is most useful to improve generation and transmission asset usage, avoid new capacity construction or purchases, and create more flexibility to assure reliable system operations. This influences the types of demand response programs preferred by vertically integrated utilities, as well as how they value and compensate demand response program participants.

[78] The converse is true for increases in load at times when the marginal cost of electricity is lower than the average retail price.
[79] Some utilities quantify the marginal value of reliability in their RTP tariffs quoting hourly prices to participants for changes in their usage from an established base amount; those hourly prices contain an explicit ($/kWh) marginal reliability (outage cost) element to reflect exigent reserve conditions (Barbose et al. 2004)

Market Impacts of Demand Response in Regions with Organized Wholesale Markets

About 60% of U.S. load is served by utilities or load serving entities that operate in regions with wholesale markets administered by ISOs/RTOs. Retail competition is also allowed in many of the states in these regions. These last-price wholesale electric commodity markets pay all competitively dispatched load a price determined by the last successful bid, which also sets the market clearing price. The market clearing price covers operating or production costs for the dispatched load (if each generator bids at least its marginal supply cost). If supply is very tight relative to demand, spot market energy prices will rise as more expensive units set the market clearing price. As a result, all units get the higher price, which includes creating "scarcity rents" for suppliers with costs below that of the marginal, price-setting unit.[80] Accordingly, spot energy prices serve as signals about whether additional supply- or demand-side capacity investments are needed, and what level of return to expect.

Three organized markets (NYISO, PJM, and ISO-NE) have established capacity payment mechanisms to create an additional stream of revenues for generators to recoup their investment costs. LSEs are required to purchase capacity in these markets to meet the expected peak demand of the customers they serve.

The impacts of demand response in an organized wholesale spot market are depicted in Figure B-5.[81]

The short-term market impacts of specific demand response events can be traced as follows:

- Depending on the timing and type of demand response option, customers' load changes may be integrated into day-ahead or real-time energy markets [as indicated by the arrows at the top of Figure B-5).
- Reductions in load during high-priced peak periods move marginal usage down the electricity supply curve (see Figure B-3), lowering market clearing prices during the demand response event (the event price in Figure B-5).
- This lowers LSEs' purchasing costs in the applicable wholesale market during the event. These savings may be captured by the LSE initially, but ultimately a significant share should be passed on to their customers (LSE event energy cost in Figure B-5).[82]

[80] This argument assumes that generators must recovery all of their revenue requirements and variable running costs, from energy sales at spot market prices. Some markets impose capacity requirements on LSEs that constitute a form of investment cost recovery for generators selling in those markets.
[81] The Midwest ISO (MISO), ERCOT and the California ISO (CAISO) all do not operate capacity markets.
[82] In some states, public utility commissions have adopted tariffs that specify the percent of savings that a regulated LSE providing default service must pass on to their customers. Eventually, competitive pressures should motivate LSEs to pass a significant portion of purchase cost savings to their customers.

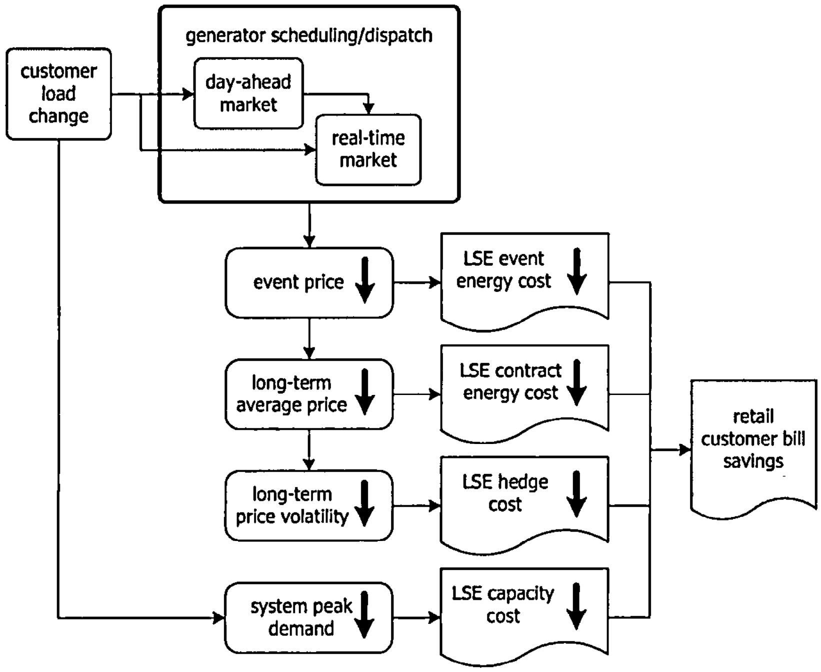

Figure B-5. Market Impacts of Demand Response in Regions with Organized Wholesale Markets

In regions with organized spot markets, demand response can produce cascading positive market impacts in the medium or long-term, realized over months or years (see Figure B-5):

- Reduced average market clearing prices can reduce forward contract costs for LSEs; these savings are then passed on to their customers (LSE contract energy cost in Figure B-5)
- Reduced volatility in market clearing prices puts downward pressure on risk premiums incorporated into hedged pricing products offered by competitive LSEs (LSE hedge cost in Figure B-5) and may lower transaction prices
- Lower forecast peak demand, resulting from demand response, also reduces LSEs' capacity acquisition requirements (LSE capacity cost in Figure B-5).

Long-term market impacts are less clear in organized wholesale and competitive retail markets compared to a vertically integrated utility system. A vertically integrated utility is allowed to directly pass through its capacity investment to customers in rates and likely most of its purchased energy and capacity costs as well; savings realized from demand response that avoids "uneconomic" investments or expenditures for peaking capacity are a direct source of cost savings to customers. In contrast, in organized spot markets, investment risk for new resources is assumed by the private sector. The combination of lower market clearing prices and reduced capacity requirements will dampen capacity investment signals, which should reduce construction of unneeded new power plants.

In summary, because organized spot markets use energy market clearing prices to pay generators for operating, but often only a fraction of the committed capacity costs, the long-term capacity savings benefits of demand response may not be fully monetized and paid to demand response providers. Because the spot market valuation of demand response is linked to wholesale market clearing prices (for energy and capacity) rather than avoided capacity costs, this creates different payment streams and priorities between the two market structures. Policymakers need to recognize these differences in designing demand response options and evaluating benefits derived from market impacts under these different market structures.

Reliability Benefits

In addition to improving the efficiency of electricity markets, demand response can provide value in responding to system contingencies that compromise the dispatcher's ability to sustain system-level reliability, and increase the likelihood and extent of forced outages. Electric systems in the U.S. conduct long-term planning exercises to specify the level of resources required to serve the system's anticipated maximum load reliably in the long term. Typically, planning reserve margins are 15-18% of historic maximum system demand.

System operators arrange for some of the available generation resources to serve as reserves to cover real-time load-serving requirements and avoid outages; operating reserves of 5-7% of forecast demand must be maintained at all times. The system operator typically uses standby generators, ready to be run in less than 30 minutes, to deal with abrupt changes in load or unexpected loss of generator or transmission availability. Demand-response based load reductions can be used to replace some of this stand-by generation to rebalance load and supply.

Demand response can supplement system reliability by providing load curtailments that help restore reserves, providing incremental reliability benefits to the system.[83] Customers participating in emergency demand response programs receive incentive payments for reducing load when called upon by the system operator. They receive no up-front capacity payments in some program designs because they are not counted on as system resources for planning purposes. Instead, they are supplemental resources, the need for which is not foreseeable, or even likely, but possible. They represent an additional resource for reliability assurance, distinct from capacity-based demand response programs (see the textbox below).

[83] The capacity they provide can be particularly valuable if located in what operators call "load pockets", localized areas with a shortage of available resources to serve load when a generator is out of service.

Roles of Capacity and Emergency Demand Response Programs

Emergency demand response programs provide benefits distinct from capacity-based demand response programs. In capacity programs, customers are paid incentives based on the avoided cost of new generation capacity and are counted among planned reserves. As such, they become part of the overall portfolio of resources assembled to meet system reserve requirements. Capacity-based demand response does not provide incremental system reliability—it supplants conventional resources in meeting established reliability goals, simply replacing what a generator that was not built would have provided.

In contrast, emergency demand response programs provide incremental reliability benefits at times of unexpected shortfalls in reserves. When all available resources, including capacity demand response programs, have been deployed and reserve margins still cannot be maintained, curtailments under an emergency demand response program reduce the likelihood and extent of forced outages. Load curtailments under emergency demand response programs are therefore valued according to their impact on system reliability.[84]

System operators generally dispatch emergency demand response programs only after exhausting all available capacity and operating reserves. When operating reserves are called upon to go from standby status to actually producing energy to serve load, the level of remaining operating reserves drops if additional replacement resources are not available. This is analogous to a consumer drawing down savings to pay an unexpected bill, leaving them more vulnerable to consequences from further unanticipated expenses.

System operators can reduce this vulnerability by asking emergency program participants to curtail load, thereby reducing system demand and operating reserve requirements. This means that some generating resources can revert to their standby status and be ready for another contingency event, and can be likened to a cash infusion to restore savings in the consumer analogy. The curtailment allows the operator to maintain reliability at prescribed or target levels (Kueck et al. 2001). At the margin, this form of demand response provides value, although it is not priced in any market.

Figure B-6 illustrates this impact, and provides a way to estimate these reliability benefits. The portrayed system has been scheduled to provide D_1 units of energy (including required reserves) at a price of P_1 at a specific time.[85] As the delivery time approaches, a system contingency arises that effectively pushes the supply curve to the left (e.g., a generator outage) or customer demand to the right (e.g., an unexpected surge in demand, as portrayed in the figure by the move from D_1 to D_2), so that supply and demand no longer intersect. This reserve shortfall is represented by the demand curve D_2. Activating an incentive-based demand response program initiates customer demand reductions that bring system demand back to D_1, thereby eliminating the reserve shortfall.

[84] It is possible that an emergency demand response program, while not explicitly designed to fulfill capacity requirements , may nonetheless be capable of providing some level of capacity benefits as well.
[85] In this example, customer demand is represented by a vertical line, because in a reliability event, which occurs within minutes or seconds of power delivery, demand may be viewed as fixed.

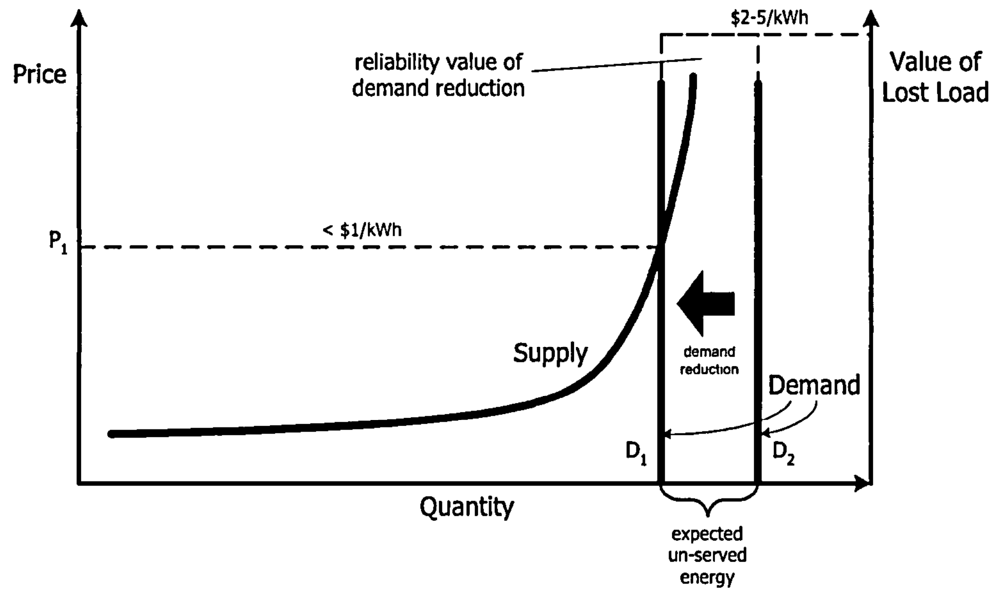

Figure B-6. Valuing the Reliability Benefits of Demand Response

While the price of served energy is determined by market conditions (P_1 in Figure B-6), the value of the demand reduction is defined by the decreased likelihood of a forced outage. Economists define the concept of *value of lost load* (VOLL) as the proper measure of improved reliability, since it reflects customer's marginal value for electricity under these circumstances. The product of VOLL and the *expected un-served energy* (EUE), the load that otherwise would not have been served, monetizes the value of the load curtailments (see the textbox below). This is represented by the shaded rectangle in Figure B-6 in the case where the curtailed load corresponds exactly to the amount of expected un-served energy.

Emergency demand response programs can provide low-cost, incremental resources to preserve reliability in various market structures; at present, the most prominent examples are implemented by the Northeast ISOs.

Value of Lost Load and Expected Un-Served Energy

"Value of lost load" (VOLL) is a measure of how customers value electric reliability, or what they would be willing to pay to avoid a loss of service. It varies among customers but is almost always greater than the retail price of electricity because customers incur costs from being disconnected without notice. Customer values factored into VOLL include inconvenience or discomfort, loss of sales or productivity (e.g., at retail premises or factories), large cleanup and restart costs (e.g., at pharmaceutical companies), and overtime costs to make up for lost production. Given the wide range of customer circumstances and difficulties in predicting which customers will be affected by a particular outage, the accepted industry practice is to adopt a VOLL of $2-5/kilowatt-hour (kWh), which represents an average value across the entire market.

"Expected un-served energy" (EUE) is a measure of the magnitude of a reserve shortfall. It takes into account the change in the likelihood of a curtailment and the consequences of such an event: how much load would have been forced off-line by dispatchers in such circumstances if the curtailments had not been undertaken. NYISO concluded that during the service restoration effort following the 2003 northeast blackout, demand response curtailments reduced forced outages kWh for kWh, because they enabled smoother service restoration. However, under other, less extreme conditions, curtailments were found to produce less than proportional reductions in EUE (NYISO 2003).

APPENDIX C. INTENSITY OF CUSTOMER DEMAND RESPONSE

This Appendix summarizes DOE's review of selected studies that have attempted to quantify the intensity of customer response to time-varying prices and demand response programs. First, different types of price elasticity used to measure demand response intensity are introduced. Next, the results of studies that estimated price elasticities for large and small customers exposed to time-varying rates are summarized. Some studies have examined the demand response intensity of programs targeting demand response-enabling technologies; these results are compared next. Finally, the results of studies that estimated load impacts from direct load control programs are summarized.

Indicators of Demand Response Intensity

For rate options and demand response programs that elicit load modifications directly in response to price changes, the intensity of customers' demand response is typically expressed in terms of their *price elasticity* (see the textbox below). Price elasticity provides a normalized measure of the intensity of customers' load changes in response to price circumstances. In analyzing price response, it is important to not confuse reported own-price and elasticity of substitution values. *Own-price elasticity* is defined as the percentage reduction in electricity usage in response to a one percent increase in the price of electricity. In analyzing price response among large industrial and commercial customers, it is common instead to estimate the *elasticity of substitution*, which measures the propensity of customers to shift electricity usage from peak to off-peak periods in response to changes in relative peak and off-peak prices. The substitution elasticity is defined as the percentage change in the ratio of peak to off-peak electricity usage in response to a one percent change in the ratio of off-peak to peak electricity prices. Various factors may influence customers' price elasticity, including the nominal level of prices. For example, some customers may be relatively unresponsive when prices are low but find it worthwhile to reduce load at very high prices. This characteristic of price elasticity has important implications for the design and evaluation of time-varying pricing and demand response programs.[86]

For DLC programs or other types of demand response programs where customers are not directly responding to a price, the intensity of customers' response is typically measured in terms of an absolute or relative load impact (e.g., kW or percent load reduction).

[86] If price response increases with relative prices, then it is important to account for this factor when estimating how customers will respond to prices or to a demand response program incentive. A specific price threshold may be necessary to obtain a significant response among a group of customers.

Price Elasticity: Insights and Sources of Confusion

Price elasticity is a normalized (for the relative price change) measure of the intensity of how usage of a good (in this case electricity) changes when its price changes by one percent. It facilitates a comparison of the intensity of load changes among customers since the price change has been factored out; the price elasticity is a relative measure of response. For example, Customer A, with an elasticity of 0.25, responds to the same relative price change much more than Customer B, who has an elasticity of 0.05 (i.e., five times more relative to the customer's usage level). But, not five times greater than another customer in absolute terms, unless they have exactly the same load. This highlights the relative comparison of intensity that a price elasticity response provides; the basis is each customer's load. Consequently, some studies prefer to report and compare customers' actual percentage changes in load. This is insightful, as long as the load changes were in response to the same change in prices.

A potential source of confusion comes from differences in how price elasticity is reported. Some analysts report the *own-price elasticity*, which is expected to be negative, since a one percent increase in price would be expected to cause usage to go down, all other things equal. It is a useful measure of how customers adjust to increases in the price of electricity by adjusting the consumption of other goods. This is especially useful when evaluating longer-term adjustments to changes in electricity price. Other analysts report the *substitution elasticity*, which takes on only positive values. The substitution elasticity focuses on how consumers substitute one good for another, or goods in different time periods for one another, when relative prices change. Specifically, if the price of electricity varies substantially from one time period to another, and customers can shift usage among those periods, then the appropriate measure of price response is how relative usage changes in those periods. The substitution elasticity is therefore defined as the relative change in usage in the two periods (e.g., the ratio of the peak to off-peak usage) for a one percent change in the relative prices in those periods (the ratio of the off-peak to peak price). Note that the price term uses the inverse price ratio, which is why substitution elasticities are positive (e.g., a higher peak price decreases the off-peak to peak price ratio, causing peak load to be reduced and therefore the peak to off-peak load ratio to decline).

On an absolute value basis, ignoring the sign, own-price and substitution elasticities are similar in that they both measure relative changes, so a value of zero corresponds to no change in usage regardless of the change in price (i.e., perfectly price inelastic), and absolute values progressively greater than zero indicate relatively higher price response. They are roughly similar measures of intensity on a nominal basis—a substitution or an own-price elasticity of 0.50 both indicate relatively high changes in load in response to price changes. But because these two elasticity values measure a different characterization of how usage is adjusted to price changes (i.e., price in one period vs. relative prices in two periods), there is no simple way to cross-map reported values. They should be used in the appropriate context: the own-price elasticity when the circumstances involve reduced electricity usage and the substitution when shifting from one time to another characterizes price response.

In this report, substitution elasticities are always reported as a positive number and own-price elasticities as a negative number.

Price Elasticity Estimates

For mass-market (residential and small commercial) customers, there is an extensive price elasticity literature examining the load impacts from TOU rates. Not surprisingly, the estimates produced by these various studies span a wide range, reflecting both methodological differences and situational factors (e.g., related to customer characteristics or program design). Caves et al. (1984) pooled data from five residential TOU pilots implemented in the U.S. in the latter half of the 1970s (see Table C-1). The average elasticity of substitution derived from this pooled data set was 0.14, but elasticities varied by a factor of three, from 0.07 to 0.21, depending on the household's electric appliance holdings (Faruqui and George 2002). King and Chatterjee (2003) reviewed price elasticity estimates from 35 studies of residential and small commercial customers published between 1980 and 2003. They report an average own-price elasticity of –0.3 among this group of studies, with most studies ranging between –0.1 and –0.4. Several studies have also examined the intensity of residential (and small business) customers' response to CPP and RTP tariffs and isolated the affect of various factors and customer circumstances. A recent study at Commonwealth Edison in Illinois of the first residential RTP pilot in the U.S. found notably lower demand response intensity than has been observed for small customers; own-price elasticities were –0.04 in 2003 and –0.08 in 2004 (Summit Blue Consulting 2005). However, the weather during these two summers was unseasonably cool and A/C usage and hourly prices were correspondingly low, which suggests that the price response may be higher under more extreme conditions.

An evaluation of a recent residential CPP pilot in California estimated a statewide average elasticity of substitution of 0.09 on critical peak days occurring between July and September and reported that the average statewide reduction in peak period energy use on critical peak days was about 13% (Faruqui and George 2005).[87] However, the elasticity varied by more than a factor of three across five climate zones, reflecting regional trends in temperature and A/C saturation (which varies from 7% to 73% of households). The study also found substantial differences between customers' price elasticities during the hotter summer months (July—September) and during the shoulder months of May, June and October—also indicative of differences in A/C usage.

Information on the price elasticity of large commercial and industrial (C&I) customers is based primarily on studies that examined customers' response to RTP. These studies have employed several types of demand models producing different types of price elasticity measures and have examined variations with time of day, price level, and customer characteristics (e.g., business type, presence of onsite generation, number of years on RTP).

[87] Impacts varied across climate zones, from 7.6% in the relatively cool coastal climate zone (e.g. which includes San Francisco) to 15.8% in inland, hot climates of California (Faruqui and George 2005).

Table C-1. Demand Response Program and Pricing Studies: Estimated Price Elasticity of Demand

Type of Program	Target Market	Region (Utility)	Demand Response Impact (average per customer)	Comments
TOU	Residential	U.S (utilities in five states)	Elasticity of Substitution **0.14** average; **0.07** to **0.21** range depending on electric appliance holdings	Pooled results from five residential TOU pilots in the late 1970s. Sources: Caves *et al.* (1984) and Faruqui and George (2002).
TOU/ CPP	Residential and Small Commercial	U.S. and International (various utilities)	Own-Price Elasticity **-0.3** (average of 35 studies); **-0.1** to **-0.8** range across the studies	The authors calculated the simple average of own-price elasticity estimates from 35 studies of TOU or CPP. Source: King and Chatterjee (2003)
CPP	Residential	California (PGE, SCE, SDG&E)	Elasticity of Substitution **0.09** average (July-Sept.); **0.04** to **0.13** range across climate zones	Population of about 1,000 residential customers, including control groups, in 2003/4 California Statewide Pricing Pilot. Elasticity range across climate zones attributed to differences in A/C saturation (7-73%). Source: Charles River Associates (2005)
Day ahead RTP	Residential	Illinois (Com Ed, Community Energy Cooperative)	Own-Price Elasticity **-0.04** average (2003); **-0.08** average (2004); **-0.05** to **-0.12** range across customer segments (2004).	Population of about 1,000 customers in 2004; $0.12/kWh maximum hourly price. Own-price elasticities were reported for six different customer segments defined in terms of housing type (single- or multi-family) and A/C equipment type (window, central, or none). Source: Summit Blue Consulting (2005)
	Med./Large C&I (>200 kW)	Georgia (Georgia Power)	Own-Price Elasticity **-0.01** to **-0.28** range across customer segments and hourly price levels	Population of about 1,600 customers. Elasticities were estimated for seven different customer segments at four different price levels, ranging from $0.15 to $1.00/kWh. Source: Braithwait and O'Sheasy (2002)
	Med./Large C&I (>100 kW)	U.K. (Midlands Electric)	Hourly Own-Price Elasticity **-0.01** to **-0.27** range in maximum hourly elasticities, across customer segments	Population of about 500 customers, most with peak demand >1 MW. Hourly own-price and substitution elasticities were calculated for each of five different industry classifications. Source: Patrick and Wolak (2001)
	Large C&I (>1 MW)	North and South Carolina (Duke Power)	Average Peak-Period Own-Price Elasticity **< -0.01** to **-0.38** range across customers	Population of about 50 customers, some with 8 years experience on RTP. Hourly own-price were calculated for each customer, and averaged over the peak period (2:00-9:00 p.m.). Source: Taylor *et al.* (2005)
	Large C&I (>1 MW)	Southwest U.S. (Central and Southwest Services)	Elasticity of Substitution **0.10 to 0.27** range across customer segments and definitions of the peak period	Population of 54 customers, segmented into two groups, with firm day-ahead hour-ahead notice of hourly prices. Elasticities estimated for each group and for different definitions of the peak period. Source: Boisvert *et al.* (2004)
	Large C&I (>2 MW)	New York (Niagara Mohawk)	Elasticity of Substitution **0.11** (average); **0.02** to **0.16** range across customer segments	Population of about 150 customers. Individual customer elasticities vary substantially within sectors: e.g., most manufacturing customers are either highly responsive or not at all. Source: Goldman *et al.* (2005)

Note: Elasticity values are the averages of all participants' elasticity at all price levels, unless otherwise noted. Elasticity of substitution values are for intraday substitution between peak and off-peak periods, while own-price elasticities are the average value, unless noted as hourly.

Braithwait and O'Sheasy (2002) analyzed data from participants in Georgia Power's RTP program, the largest in the country. The authors estimated own-price elasticities for seven different business customer segments and examined differences across hourly price levels. Most customer segments exhibited larger price elasticities at higher prices. The most responsive customer segment was a group of very large industrial customers (peak demand > 5 MW) who, in exchange for slightly lower base rates, had opted to receive notification of hourly prices on an hour-ahead (rather than day-ahead) basis. This group exhibited a price elasticity of –0.18 to –0.28 across the range of reported prices ($0.15/kWh to $1.00/kWh), which was double the elasticity of any other group. The least responsive customer segments, consisting of smaller C&I customers that neither had onsite generation nor had previously participated in the utility's curtailable rate, exhibited price elasticities of –0.06 or lower at all price levels.

A study of about 150 large customers at Niagara Mohawk estimated an average substitution elasticity of 0.11 among those that faced day-ahead hourly prices (Goldman et al. 2005). However, the average elasticity varied substantially across business categories (e.g., average elasticities were 0.16 for manufacturing customers, 0.10 for government/education customers, and 0.02 for health care facilities) and even more within them (e.g., half of the industrial customers were very inelastic, and half were relatively elastic).

Studies of the large C&I RTP programs offered by Duke Power and Midlands Electric (in the U.K.) estimated average hourly own-price and substitution elasticities (Taylor et al. 2005, Patrick and Wolak 2001). Both studies found a substantial range in own-price elasticity values over the course of the day and among customers. Among the 50 or so participants in Duke's program, the average hourly price elasticity during peak period hours ranged from less than –0.01 to –0.38. This study also concluded that many large C&I customers exhibit complementary electricity usage across blocks of afternoon hours. That is, high prices in one hour result in reduced usage in that hour as well as in adjacent hours. This is consistent with industrial batch process loads that, once started, must continue for a specified period, and with other business practices that exhibit similar relationships (e.g., rescheduling of labor shifts). Usage in many other hours of the day was found to be a substitute to the afternoon hours. The study of Midlands Electric's customers also found substantial variation in the magnitude and hourly pattern of price elasticity among different industrial classifications. Customers in the water supply industry were the most price-responsive, with a maximum hourly own-price elasticity of –0.27, while all of the other industrial classifications in the participant population exhibited price elasticities of less than –0.05 in all hours.

Impact of Enabling Technologies on Price Response

A small number of utilities have offered pilot programs targeted at mass market customers that integrate CPP with enabling technology, specifically load control devices that receive price signals and can be programmed by customers to reduce A/C or other loads during critical peak periods (see Table C-2).

Table C-2. Load Response from Enabling Technologies in Combination with CPP

Enabling Technology	Target Market	Region (Utility)	Demand Response Impact (average per customer)	Comments
Thermostat reset	Residential	California (SDG&E)	**0.64 kW (27%)** average peak period load reduction on critical peak days; **0.4 kW** attributed to enabling technology.	2003/2004 pilot program with about 220 residential customers and about 235 C&I customers, including control groups. Customers had "smart thermostats" that could be programmed to raise the temperature set point during critical peak periods. Analysis distinguished between enabling technology and behavioral components of price response. Peak period prices on critical peak days averaged $0.65/kWh for residential customers, $0.87/kWh for customers with <20 kW peak demand and $0.71/kWh for larger C&I customers. Source: Charles River Associates (2005)
	Small/Med. C&I (<200 kW)	California (SCE)	Customers with <20 kW peak demand: **0.95 kW (14%)** average peak period load reduction on critical peak days; attributed entirely to enabling technology. Customers with 20-200 kW peak demand: **3.1 kW (14%)** average peak period load reduction on critical peak days; **2.5 kW** attributed to enabling technology.	
Control of multiple loads (A/C, heat pump, water heater, pool pump, and/or appliances)	Residential	New Jersey (GPU)	Elasticity of Substitution 0.3 (average)	Pilot program results from summer 1997. Critical peak price was $0.50/kWh. Source: Braithwait (2000)
	Residential	Florida (Gulf Power)	**2.7 kW (41%)** average load reduction during critical peak periods	Estimated response from current *GoodCents Select* program. Source: Borenstein *et al.* (2002).
	Residential	Upper Midwest (AEP)	Winter: **3.5-6.6 kW** Summer: **1.5-2.0 kW**	Pilots conducted at three AEP utilities in the early 1990s with about 600 customers, including control groups. Critical peak price ranged from $0.15-$0.29/kWh among the three utilities. Source: Levy Associates (1994)

An evaluation of the recent Statewide Pricing Pilot in California sought to quantify the incremental impact of this type of technology on customers' demand response. Groups of residential and small commercial participants in this pilot faced CPP and had "smart thermostats," which customers could pre-program to automatically raise their temperature settings by a specified number of degrees during critical peak periods. The statistical model used in the evaluation decomposed these customers' total load reduction during critical peak periods into a "technology component" (i.e., the portion of the load reduction attributable to use of the smart thermostat) and a "price component" (i.e., the portion attributable to manually-implemented actions). The average load reduction by residential customers with smart thermostats during critical peak days was approximately 0.64 kW, approximately two-thirds of which was attributed to use of the smart thermostat. Among small business customers, the relative impact of the enabling technology was even more pronounced.

A handful of utilities elsewhere in the U.S. have implemented residential CPP pilots in which participants were provided with thermostats that they could program to control their A/C and other appliances (pool pumps, heat pumps, and electric water heaters) during critical peak periods. Studies of these programs have typically found that participants exhibited a relatively high intensity of demand response. For example, an analysis of GPU's pilot (in New Jersey) measured a substitution elasticity of 0.3, which is higher than most elasticity of substitution values estimated from residential TOU pilots (Braithwait 2000). Studies at Gulf Power and American Electric Power (AEP) where multiple loads could be controlled in response to critical peak prices reported that average load reductions among a sample of customers were in the 35-40% range (Levy Associates 1994).

Load Impacts from Direct Load Control

Approximately 180 U.S. utilities (out of the 1,118 investor-owned, municipal, and rural cooperative utilities that reported demand-side management efforts) report that they currently offer residential DLC programs that primarily target specific appliances, such as air conditioners or water heaters, of mass market customers (EIA 2004).[88] Various control strategies (e.g., cycling the device on and off at a specified frequency, shutting the device off, or resetting a thermostat set-point) are utilized during prescribed conditions depending on end use, control equipment vintage, and program design.[89] Several of these programs have conducted relatively recent measurement and evaluation studies with results that are publicly available. In DLC programs, because the utility controls the switch, the customer cannot be said to exhibit price response, per se, although the change in the customer's load is measurable. The most appropriate measure of demand response impact for this program type is simply the average or expected load reduction (in absolute or percentage terms), rather than the price elasticity.

Table C-3 summarizes the measured impact from selected evaluations of DLC programs that targeted customers with air conditioning or water heating load control devices. The results indicate the range of possible load impacts, although the individual values are not readily comparable because of the differences in program design features, cycling strategies, and climate. DLC programs targeting residential A/C have reported load reductions ranging from approximately 0.4 to 1.5 kW per customer over the course of an event. The magnitude of the load reduction per customer can strongly depend on climate, the corresponding level of A/C usage that would occur absent load control, and the control strategy deployed (e.g. 100% shed, duty cycling). Furthermore, when customers have the ability to over-ride the curtailment via their thermostat, the average response per customer has generally been found to decline (sometimes substantially) over the course of each event. Residential water heating DLC programs have yielded load reductions in the range of 0.2 to 0.6 kW per house. The magnitude and timing of the load impact depends on equipment size, ground water temperature and household size and operating use patterns.

[88] Demand-side management efforts include energy efficiency and/or load management programs.
[89] In newer DLC programs, particularly those that use thermostat-based controls, customers can typically over-ride curtailments on an event-by-event basis, either by pushing an "over-ride" button on their thermostat, logging onto a program website, or calling the utility. If they do over-ride a curtailment event, customers typically forfeit a portion of their incentive payment or are charged a penalty.

Table C-3. Direct Load Control Programs: Estimated Load Impacts

Type of Program	Target Market	Region (Utility)	Demand Response Impact (average per customer)	Comments
A/C temp. reset (with over-ride option)	Residential	SDG&E	**0.44 kW** (average); **0.10-0.81 kW** (range over 12 events)	Sample of about 100 customers (including control group) with 12 test events in summer 2004. Source: KEMA-Xenergy (2004)
A/C cycling (with over-ride option)	Residential and Small Commercial	New York (LIPA)	**0.75-0.91 kW** (residential) **1.01-1.43 kW** (small commercial)	Ranges in average hourly load reductions over a single event day with 50% cycling. Based on 12,000 residential customers and 2,000 commercial customers. Source: Lopes (2004)
A/C cycling (no over-ride option)	Residential	Minnesota (Xcel Energy)	**1.27 kW**	Based on interval metering at large number of customer sites; 50% cycling frequency. Source: Xcel Energy (2004)
A/C cycling (no over-ride option)	Residential	California (SMUD)	**0.71-1.59 kW**	Pilot program results from summer 2002. The lower bound corresponds to a cycling frequency of 33% and outdoor temperature of 96-100° F; the upper bound corresponds to a cycling frequency of 66% and an outdoor temperature of >100° F. Source: Violette and Ozog (2003).
A/C cycling (no over-ride option)	Residential	Kentucky (LG&E, KU)	**0.52-1.12 kW**	Interval metering measurements at 20 customer sites. The lower bound corresponds to a cycling frequency of 33% and outdoor temperature of 90-95° F; the upper bound corresponds to a cycling frequency of 66% and an outdoor temperature of >95° F. Source: Violette and Ozog (2003).
A/C cycling (no over-ride option)	Residential	Maryland and D.C. (Pepco)	**0.96 kW** (MD) **0.76 kW** (DC)	Measured impact for hour ending 17:00, based on 20-year average system peak day weather; 43% cycling off strategy. Source: Horowitz (2002)
Electric water heater cycling	Residential	Oregon (PGE)	**0.65 kW**	Load reductions measured at 0800. Source: PGE (2004)
Electric water heater cycling	Residential	Maryland (BGE)	**0.2 kW** (at 5 PM) **0.3 kW** (at 7 PM)	Load reductions measured at 1700 and 1900. Source: BGE (2002, 2003)

APPENDIX D. STANDARDS, PROTOCOLS AND PRACTICES FOR ESTIMATING THE BENEFITS OF DEMAND RESPONSE

In Section 4 of this report, DOE offers several recommendations on establishing standardized methods and protocols and enhancing practices for estimating the benefits of demand response. This Appendix provides further discussion that supports these recommendations.

> *1. DOE recommends that stakeholders collaborate to adopt conventions and protocols for estimating the benefits of demand response and, where appropriate, develop standardized tests that evaluate demand response program potential and performance.*

Policymakers and industry participants should develop standardized tests that are applicable and appropriate for the evaluation and cost-effectiveness screening of demand response resources. Standard Practice Manual (SPM) tests are widely used among state regulatory commissions and utilities to evaluate and screen energy efficiency programs (CPUC 2001).[90] Historically, a number of states and utilities have also used these tests for cost-effectiveness screening of load management programs and, recently, there have been some efforts to modify the SPM tests to enhance their usefulness for evaluating demand response resources in the context of competitive wholesale markets (CPUC 2003; Violette et al. 2006, Orans et al. 2004). However, there is general consensus that a more comprehensive evaluation framework is needed to fully capture the benefits of demand response (PIER DRRC, 2005).

Some of the challenges in developing standardized tests appropriate for demand response are revealed by comparing energy efficiency and demand response resources. While it is relatively straightforward to identify and estimate the peak demand and energy reduction impacts of energy efficiency, this is much more difficult for most demand response options. Because most demand response options are relatively new, our ability to predict program participation rates and assess how specific program designs and dynamic pricing affect customer behavior is still rudimentary.[91] Moreover, many forms of demand response turn on behaviors that are price- or incentive-driven, and may change in response to changing market circumstances. Uncertainties in estimating demand response impacts over a multi-year period mean that demand response benefit (and cost) estimates are equally uncertain.

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[90] The SPM describes several tests that evaluating demand-side management programs from various perspectives: Participant Test, Ratepayer Impact Measure (RIM) Test, Total Resource Cost (TRC) Test, and Program Administrator (formerly Utility) Test.

[91] Load reduction impacts are well characterized for residential DLC programs that have operated for many years, although there have been issues in determining the extent to which customers remove load control switches or over-ride load curtailments. For interruptible/curtailable programs, little information exists from which long-term performance can be predicted. For thermostat-based programs, limited information gathered through several large pilots is available to shed light on customer behavior. For optional RTP tariffs, substantial evidence shows that customer attrition can be a significant problem when major price shocks occur.

In contrast, 15-20 years of implementation experience and tens of millions of dollars spent evaluating energy efficiency programs has produced well-developed methods for forecasting market penetration and estimating first-year energy savings, expected economic lifetime and the persistence of savings for most energy-efficiency measures and programs. This task is further eased because most energy efficiency measures produce savings that are not dependent upon customer behavior.

The SPM tests, which use avoided costs to characterize benefits, have shortcomings in the way in which they characterize the value of demand response to the electric system and customers. Despite recent advances, these tests are not well suited to estimating the value of dispatchable demand response resources. For example, SPM tests have limited ability to reflect the value of capacity in critical peak hours, and the potential of demand response to mitigate episodic, high spot market prices is therefore undervalued. Other aspects of demand response benefits, such as quick ramp-up (relative to constructing new generation resources), and reliability benefits, are also not captured by SPM tests. A more comprehensive analytic framework is needed to fully evaluate and assess the benefits of demand response. At present, summarizing the benefits and costs for some types of demand response resources by means of a standardized test may be premature.

> *2. DOE recommends that these protocols: (1) clarify the relationships and potential overlap among categories of benefits attributed to demand response to minimize double counting, (2) quantify various types of benefits to the extent possible, and (3) establish qualitative or ranking indices for benefits that are found to be too difficult to quantify.*

Policymakers and analysts assessing the merits of demand response mechanisms need to clarify the relative importance of benefits that are difficult to quantify.

Some demand response advocates allude to benefits, such as market power deterrence, risk mitigation and avoided pollutant emissions—that are not quantified but are presumed to be substantial (PLMA 2002; NEDRI 2003; Violette et al. 2006).[92] Not only are such benefits difficult to quantify, but care must be taken to avoid double-counting benefits from other sources (e.g., market-power reduction benefits must be disentangled from other market price impacts). Parties seeking to justify greater expenditures on demand response often assert the existence of such benefits. Policymakers, however, are often wary of including these benefits as criteria for designing policies to foster demand response. Research to determine the magnitude of these impacts and to develop methods for quantifying or incorporating them into benefit/cost analyses, without double counting, is needed.

> *3. DOE recommends that FERC and state regulatory agencies work with interested ISOs/RTOs, utilities, other market participants, and customer groups to examine*

[92] These non-quantified demand-response benefits are discussed in more detail in section 3 (see *Other Benefits*).

> *how much demand response is needed to improve the efficiency and reliability of wholesale and retail markets.*

It is appropriate for state and regional policymakers to ask how much demand response is sufficient for their specific market structure and system conditions. A number of demand response studies confirm that a little demand response can go a long way towards improving the efficiency and operations of electricity markets, both in theory and practice. However, existing studies do not address how to identify optimal, or target, levels of demand response in specific market settings. Initiatives should be launched at the appropriate market level (e.g. state or region) to establish relevant goals and appropriate targets for demand response.

As part of the process of determining how much demand response is needed, it is also important to address the appropriate mix of different types of demand response options (e.g. emergency demand response programs, direct load control, time-varying pricing) and any timing issues related to demand response resource deployment and ramp-up (Violette et al. 2006). Although this is not a problem today given the low participation rates in dynamic pricing and demand response programs, it is important to acknowledge that there may be a potential for diminishing returns in the value of demand response beyond certain levels of saturation. For example, the level of price-based demand response is somewhat self-limiting—if at some point demand response becomes widespread, customers may find that their savings from load response actions deteriorate as the impact of their collective response on market prices grows.

> *4. DOE recommends that regional planning initiatives examine how demand response resources are characterized in supply planning models and how the benefits are quantified. More accurate characterization of certain types of demand response resources may require modifications to existing models or development of new tools.*

Resource planning methods currently used to characterize demand response resources are too constraining and rigid to capture the full benefits of all types of demand response resources. In vertically integrated systems, long-term resource planning models characterize demand response as a way to avoid generation (and in some cases transmission and distribution) investment costs. Demand response is typically portrayed as a generation unit, which can either be dispatched indiscriminately or with some restrictions on the total frequency or hours of service. This characterization does not fully describe the differences between generation and demand response resources.

Certain types of demand response resources provide benefits that generation cannot. For example, capacity-based demand response programs can provide equivalent capacity to generation investments but with greater flexibility. This is because some types of demand response resources can be implemented more quickly than a power plant can be sited and built, and customers often prefer or are willing to accept a shorter time commitment than is necessary to amortize a power plant.[93] These flexibility benefits are particularly important from a system cost perspective that includes and explicitly accounts for the uncertainties in demand growth or generation unit retirement schedules and costs. Resource planners' avoided cost studies should explore the implications and value of flexible demand response program options as both long-term and short-term operational resources to deal with generation load balance and transmission and distribution adequacy challenges.

Moreover, long-term resource planning models often do not fully recognize or represent the benefits of price-based options such as RTP. RTP ties hourly retail prices to prevailing wholesale market supply costs. To fully account for its potential benefits, RTP should be portrayed as a change in demand in response to prices, not as a resource dispatched to serve demand. Moreover, the RTP prices in tariffs offered by vertically integrated utilities often reflect both marginal supply costs and reliability value of load curtailments. These hour-by-hour impacts, which are carefully measured in ISO/RTO demand response program performance studies, can get overlooked in a long-term resource planning exercise.[94]

On the other hand, peaking generation resources have some characteristics that are more desirable to resource planners than demand response resources. For example, system operators have high confidence that generation resources will come online when needed, whereas customers may decide not to respond when a demand response resource is called. This makes it more difficult to predict the precise amount of available resources on a given day. Another advantage of supply resources is that they can provide certain ancillary services, such as voltage support and re-starting the electrical grid after a blackout, that demand response resources cannot. These considerations should also be incorporated into planning models to appropriately characterize and assess available resources.

> *5. DOE recommends that, in regions with organized wholesale markets, ISOs and RTOs should work with regional state committees to undertake studies that characterize the benefits of demand response under foreseeable future circumstances as part of their regional transmission expansion plans as well as under current market conditions in their demand response program performance studies.*

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[93] The capacity programs implemented by several ISOs do not involve long-term customer commitments (customers may participate for only a few months if they wish). These programs have demonstrated reasonably predictable and stable performance without putting "iron in the ground"—generation assets whose costs must be recovered over 20 years or more (NYISO 2003). Emergency programs that require no commitment on the customer's part have attracted substantial participation by customers that delivered curtailments on a pay-for-performance basis, and are a potentially cost-effective way to increase system reliability.

[94] Moreover, RTP may result in increased usage during off-peak periods when prices are lower. Increased unit utilization lowers the overall average cost of capital, another important source of benefits that may not be adequately reflected in current study practices.

In regions with organized spot markets, analytic methods focus primarily on assessing the short-term impacts of ISO/RTO demand response programs; more work is needed to assess the potential long-term benefits of demand response resources. ISOs/RTOs that offer demand response programs provide annual performance assessments to FERC that focus primarily on realized, short-term impacts. These assessments provide policymakers, market participants, and customers with information on both the level and distribution of demand response benefits and resource costs.[95] However, in the absence of a forward electricity market that would create a steady stream of guaranteed annual benefits, the value of demand response necessarily depends primarily on current market conditions.

However, ISOs and RTOs can and should provide information on the future value of demand response within their regional markets. Most ISOs and RTOs conduct or coordinate long-range planning studies that focus on developing coordinated system expansion plans that identify projects that can ensure electric system reliability, reduce congestion and also provide market signals for planning and running generation and transmission systems and demand-side management projects (ISO-NE 2005b; PJM Interconnection 2005b). One goal of the studies is to use forecasts of regional load/resource balance to identify needed investments to forestall potential supply shortfalls that could lead to high price volatility. The extent to which demand response is considered in these regional transmission expansion plans is evolving over time. ISOs, RTOs and regional state committees are well positioned to recognize the long-term benefits of demand response and incorporate demand response into their long-term system plans.[96] Another option would be to facilitate a forward market in demand response, as PJM has proposed (PJM Interconnection 2005c).

[95] Because benefits can vary from year to year and opportunities to participate are not always available, it is important that load aggregators and customers are made aware of how benefits and costs (i.e., incentive payments) may vary with market circumstances.

[96] Efforts are already beginning in this area. A recent pilot study by ISO-NE that compared the value of RTP and other types of demand response programs under alternative market circumstances was intended to facilitate discussions of this issue among policymakers, ISOs, load serving entities, and customer groups (Neenan Associates 2005).

Journal of Regulatory Economics; 27:3 235–262, 2005

24/7 Hourly Response to Electricity Real-Time Pricing with up to Eight Summers of Experience*

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Abstract
This paper provides hourly own and cross price elasticities for industrial customers with up to 8 years of experience on Duke Power optional real-time rates. We include the effects of customer characteristics and temperature conditions. Aggregated results show larger own elasticities than have previous studies, complementarity within the potential peak hours and substitution in the late evening. As customers gain experience with hourly pricing, they show larger load reductions during higher priced hours. As compared to a TOU rate, net benefits are $14,000 per customer per month, approximately 4% of the average customer's bill, and much greater than metering costs.

Key words: real-time pricing, hourly elasticities, industrial response

JEL Classification: L51, L94, D00

* We wish to acknowledge helpful comments from Herb Thompson and Steve Braithwait. We also wish to thank Colin Loxley and other participants at the Rutgers Advanced Workshop in Regulation and Competition, Lake Tahoe, CA, June 2002, as well as participants at the Second World Congress of Environmental Economics in Monterey, CA, June 2002, for comments on a preliminary version of this paper. Finally, we thank two anonymous referees for helping to improve this paper.

1. Introduction

Energy crises are repeatedly in the news. Several years ago it was California's disastrous foray into electricity deregulation. Then it was the Northeast blackout. More recently, it was record oil prices. If the market is allowed to respond, marginal-cost based prices will spur more efficient energy use, and in turn help to mitigate these episodes. A number of electric utilities have introduced real-time pricing (RTP) to their retail customers. Price incentives can reduce short-term demand when capacity is tight, increase use when capacity is available, and moderate the long-term need for electric infrastructure. The purpose of this study is to provide hourly response by customers who have up to 8 years of experience on the Duke Energy Hourly Pricing (HP) program, which provides day-ahead notice of the next day's hourly prices.

To better gauge demand during potential peak hours, utilities need to understand patterns of substitution and complementarity as well as own elasticities.[1] The influence of hourly pricing on demand during the hours of potential system peak is of particular importance in determining resource requirements. For many utilities, peak demands occur during the afternoon hours of hot summer days. While own price effects of hourly pricing may lead customers to reduce consumption at times of system peak, the cross price effects could shift the peak to adjacent hours leaving the utility no better off than with time-of-use (TOU) or even flat rates. With day-ahead prices, the possibility of a shifting peak can arise because rates cannot be adjusted between the time when prices are announced and real-time consumption. With 24 elasticities for each hour, it is possible to determine if high real time prices lead to reduced consumption during typical peak demand hours, and if substitution takes place in adjacent hours, or outside the range of the typical peak demand period.

The analysis considers aspects of customer production processes that facilitate response to hourly prices. Applications that involve the customer's ability to self-generate or the use of discrete production processes such as arc furnaces are of particular interest. Temperature conditions are also included. If RTP is to reduce customer load when it is most needed, it is important that customers respond when temperatures are high. The preponderance of existing RTP studies use a constant elasticity of substitution (CES) specification that yields a single hourly elasticity rather than 24 separate elasticities. In addition, the CES does not provide cross elasticities to capture the effect of price in a given hour on quantity in another hour. Consequently, the CES does not allow the determination of whether

1 Utilities must provide capacity to meet the peak demand on the system. Peak shifting may be experienced if customer response to hourly prices creates new peak demands in hours other than those when peaks typically occur.

consumption in a given hour is a substitute or complement for consumption in any other hour.

In order to obtain hourly elasticities and cross elasticities, it is desirable to use a flexible functional form that satisfies the global curvature restrictions implied by economic theory, while being able to capture substitutability and complementarity within inputs. The Generalized McFadden (GM), developed by Diewert and Wales (1987), is such a function.[2] Patrick and Wolak (PW), in an NBER report (2001), apply the GM to analyze five industries on an RTP tariff offered by the Midlands Power Company of Great Britain.[3]

Our study uses the GM to provide estimates of own and cross price elasticities of demand for individual customers, by hour, for each year the customer was in the program. In contrast to PW, the focus is on individual customers. Earlier CES studies such as Schwarz et al. (STBD 2002) found considerable heterogeneity even within industries.[4] Estimation at the customer level reveals who is most and least responsive to hourly prices.[5] In addition, our implementation of the GM, as compared to that of PW, appears to allow for a greater range of possibilities in the pattern of substitute and complementary hours.[6]

The current paper contains an examination of how hourly elasticity and demand changes with experience. Such information is useful for long-term planning. Both STBD (2002) and Taylor and Schwarz (1990) found that response increases with experience. Using GM results, we again find that response increases with experience.

This study also includes a Social Welfare Analysis (SWA) of the potential gain if customers can transfer from TOU pricing to RTP. Most of the customers who opted for RTP had previously been on a TOU rate. The SWA shows net benefits from RTP that are on the order of $14,000 per month per customer, approximately four percent of the average customer's bill, and much larger than utility

2 The complexity of estimating the GM does require some sacrifice. As indicated, our Social Welfare Analysis (SWA) does not include inter-day substitution, unlike some CES studies. With the large number of intra-day parameters provided by the GM, it is unwieldy to expand estimation across days.

3 A doctoral dissertation by Kim (1998) distinguishes short run and long run. While the theory is carefully developed, the empirical work uses a Cobb-Douglas production function. The Generalized McFadden (GM) is a flexible functional form that is generally regarded as preferable to the CES or Cobb-Douglas on theoretical grounds, as well as allowing the estimation of own- and cross elasticities. The GM functional form was developed by Diewert and Wales (1987) and its properties were compared to other functional forms in a doctoral dissertation by Feger (2000).

4 Goldman et al. (2004) use a CES to estimate real-time response for Niagara Mohawk customers. They group together subsets of hours so as to get separate hourly elasticities. However, they are not able to estimate cross price elasticities.

5 STBD also included price thresholds, where some customers respond only above a particular hourly price. We are currently investigating making this modification to the GM.

6 We provide further details in the model formulation and footnote 15.

costs associated with real-time metering.[7] It is likely that benefits would be larger if RTP were offered to customers currently paying prices that do not vary at all by hour. In addition, the analysis does not include substitution across days. Benefits would increase, for example, if customers decide to meet a weekly quota by running plants more on cooler days and less on hot days.

The Duke HP rate is voluntary for customers. It would be necessary to adjust for self-selection bias in order to draw inferences for mandatory rates. Such a correction requires data on a control group, which is not available.[8] For this reason, these results should not be extended to the claim that mandatory RTP has benefits that exceed costs.[9]

2. Model and Estimation

After presenting the model, we develop and estimate own and cross price elasticities for each customer, for every hour in our data set. While estimation is at the customer level, results are aggregated to determine price effects for the total system.

2.1. Methodology

A set of demand equations derived from a GM cost function is as follows:[10]

$$E_{idyk} = \left[\frac{1}{PZ_{my}} \sum_{j=1}^{24} c_{ijyk} P_{jdyk} + b_{idyk} \right] Y_{dyk} + a_{idyk} + d_{iyk} T_{idy} + U_{idyk} \qquad (1)$$

Variables are defined as

E_{idyk} is the demand in mW (megawatts) for hour i, day d, year y, customer k;

PZ_{my}, the producer price index for month m, year y;

7 This benefit is well in excess of costs identified at Duke Power for metering and administering the hourly pricing program.

8 Aigner and Ghazi (1989) provide a relevant approach directed at TOU experiments. Ham et al. (1997) also provide a correction to self-selection bias in TOU experiments. Nor is the Duke rate experimental. We do not intend for our results to be used to make a case for mandatory real-time rates. As pointed out by Woo et al. (1996), optional rates are a Pareto improvement given reasonable assumptions. Mandatory RTP will face much resistance from potential losers. Almost all RTP programs that we are aware of in the United States are optional.

9 Brennan (2004) makes a case against subsidizing real-time metering. If universal real-time metering cannot be justified, than mandatory RTP cannot be imposed.

10 This equation is identical to PW (1997), 4–12, equation (7), except for additional subscripts in our equation to reflect estimation at the individual customer level. PW show that this demand equation is obtained by application of Shepard's Lemma to the GM expected variable cost function.

P_{jdyk}, the price in \$/mWh (megawatthour) for hour j, day d, year y, customer k;[11]
T_{idy}, the temperature in degrees F for hour i, day d, and year y;
Y_{dyk}, the daily output on day d, year y for customer k;
U_{idyk}, the unobserved random vector with mean 0 and covariance matrix Ω;
where $i = 1, \ldots, 24$ (1 = hour ending at 1 AM, 24 = hour ending at midnight); $d = 1, \ldots, 122$ (June 1 = 1,..., September 30 = 122); $y = 1, \ldots, 8(1 = 1994, \ldots, 8 = 2001)$; $k = 1, \ldots, 51$.

Hourly energy use (E_{idyk}) is in units of mW; however, results are in kW to be consistent with units generally applied in retail markets. The producer price index (PZ_{my}) is available quarterly, so it takes on one value for June, and a second value for July, August and September for each summer.[12] Hourly temperature (T_{idy}) is the average temperature from three weather stations located over the Duke Energy system. The constant term, a_{idyk} and also b_{idyk}, the coefficient of Y_{dyk}, are unique to each observation. This generality is obtained by specifying each of these terms as Fourier series across hours of the summer. This approach was used by PW (1997). Values for these terms, as well as c_{ijyk}, are obtained by estimating the parameters of the Fourier specification as described in Appendix 1.

The expression in brackets describes hourly electricity demand as a linear function of prices for each hour of the day with a constant term. Theoretical rigor calls for the inclusion of the firm's output (Y_{dyk}) in the equation for derived demand for

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11 The price used for estimation is the hourly price of the Duke tariff. For customers served from the high voltage transmission system, the average price over the full 8 years was \$0.035 per kWh and the maximum was \$0.33 per kWh. Beginning in 1995, some customers served from the distribution system began participation. Their prices reflect a higher cost to serve with an average of \$0.041 per kWh and a maximum of \$0.43 per kWh. In 2001, two customers opted for a new design of the rate in which the reliability component of the hourly price is applied differently. The average price for the new design was \$0.026 per mWh with a maximum of \$0.42 per mWh.
Duke Power's HP rate is a standard two-part tariff. It contains a customer baseline with charges for consumption above the baseline assessed at the hourly price and reductions below the baseline credited at the hourly price is provided on a day ahead basis.
There are two charges that are applied ex post. An "Incentive Margin" of \$0.005 per kWh is assessed to "Net New Load". Net new load is the amount by which the total of hourly consumption above the baseline exceeds the total of hourly consumption below the baseline. If net new load is negative, the incentive margin does not apply. For simplicity, we added the incentive margin directly to hourly proces. The great majority of customers in the Duke population have net new load greater than zero and even for those with negative net new load, adding the incentive margin does not change relative prices across hours of the day.
In addition to the margin, the Duke tariff assesses an ex post "Incremental Demand Charge" of some \$0.25 per kW to the amount by which maximum demand charges of Duke's standard rates which are on the order of \$10 to \$13 per kW. We examined bills for a typical month drawn from our population and found the share accounted for by this change to be just over 0.5% on average. At its greatest, the share was just over 2.5%. Given such a small influence on customer bills, we did not incorporate the demand charge in our analysis.

12 As pointed out by a referee, costs may vary by industry, which would not be reflected in a single producer price index. This problem would be more serious if data were pooled over customers and years. However, because estimates are obtained for each customer by year separately, and with just two values for the PPI, the gains to an industry-specific PPI would be likely to be small.

an input such as electricity. In this study, however, as in many studies of industrial energy use, output is unavailable.[13] As a proxy for output, there are dummy variables for days of the week, weekends, and holidays, along with weeks of the year, and year. It is reasonable to expect that output may vary across such day types. While these variables do not yield a precise specification of output for the firm, they do provide a control for variation in relative levels of output across these day types.[14]

Implicit in this GM formulation is that daily output and labor usage are determined at the beginning of each year, and cannot be altered on a real-time or day-ahead basis. However, the firm can alter electricity usage and other inputs once it knows hourly electricity prices and temperatures. Thus, the model allows for intraday substitution. The advantage of the GM as compared to the CES is its ability to give 24 elasticities (own and cross) for each of the 24 h of the day. The large number of parameters in the GM, as compared to the CES, makes an expansion to interday substitution unwieldy.

Diewert and Wales (1987) show that global concavity is ensured by estimating the c_{ijyk} in equation (1) as $C = -MM'$, where M' is an upper triangular matrix. This approach is implemented by specifying $M = D + G + H$ where D is a diagonal matrix, and G is lower triangular with zeros on the diagonal. The matrix H, which is lower triangular with zeros on the diagonal, is included in order to avoid constraints on the signs of cross elasticities.[15]

Equation (1) is estimated jointly for each of the 24 h of the day. Estimates are by year, for each customer that was in Duke's hourly pricing program in 2001, the last year of data for this analysis. A year is made up of summer months only: June, July, August, and September. The program began in 1994, and 51 customers remained on the program as of 2001. Six were on the program for its entire duration of 8 years. In total, there are 243 separate customer-year estimates of equation (1).

The use of Fourier Series to estimate c, b, and a reduces the computational burden of estimation. The number of parameters used to specify the Fourier series

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13 For competitive reasons, firms consider this information confidential. Even if it were available, it is unclear how to measure output outside of manufacturing industries, such as, for example, a university.

14 Woo et al. (1996) found no difference in weekday patterns, in which case our four dummy variables to cover five weekdays would be insignificant. Nevertheless, weekday dummies are included so as to allow for any sources of variation in unobserved output. Details are in Appendix A.

15 We initially estimated the specification employed by PW that is, $C = -LD^2L$ with D as a diagonal matrix and L as a lower triangular matrix with ones on the diagonal. However, for our data this specification results in problems with multicollinearity. We also discovered that this specification constrains the 24×24 matrix of own and cross elasticities to patterns containing "bands" of complements and substitutes. There are $2^{n(n-1)/2}$ possible patterns of substitutes and complements. The P & W specification permits only 2^{2n-3} of those patterns. Our specification allows for all possible patterns. For a 24×24 matrix the number of patterns possible is 2^{276} and the number permitted by the P & W specification is 2^{45}. (These calculations assume that all off-diagonal elements will be non-zero.)

is much smaller than the total number that must otherwise be directly estimated. Details are in Appendix 1.

The data is organized as a time series containing 2928 observations per customer for each year. The error specified as AR(m)-EGARCH(p, q) and accounts for both intra- and inter-day autoregression as well as heteroskedasticity. A sequential approach first determines the autoregressive process across days, then transforms the data accordingly and determines the autoregressive process across hours within the day. When the data transformation is complete, final estimates are from non-linear OLS and Seemingly Unrelated Regression.[16]

2.2. Results

Many of the findings are in the form of price elasticities. From the expression for customer demand in equation (1), the elasticity of demand for customer k in hour i with respect to price in hour j on day d of year y is:[17]

$$\varepsilon_{ijdyk} = c_{ijyk}\left(\frac{Y_{dyk}}{PZ_{my}}\right)\left(\frac{P_{jdyk}}{E_{idyk}}\right) \tag{2}$$

Table 1 shows own and cross price elasticities aggregated over all customers and all years to reflect price responsiveness for the total population averaged over the entire period. Own elasticities are along the diagonal. The formula for aggregating all elasticities to the level of the total population is in Appendix 2, equation (B11).

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16 It is generally desirable to correct error terms for any hetereoskedasticity and autocorrelation. See, for example, STBD, Table 9. We found these conditions to be present and corrected them as follows.

First we fit the model using non-linear OLS. With these residuals, we determine values for m, p, and q. A Generalized Durbin Watson test (GDW) is employed to ascertain m. For the across day process, we look at each hour separately and sort the data by month and day. (Recall that estimates are obtained for each customer for each summer.)

Then, for each hour, we set m equal to the first significant lag as determined by the GDW but do not allow the lag to exceed 30. Values for q and p are determined in a similar manner utilizing the Engle Lagrange Multiplier Test for q and the Portmanteau Test for p. Once m, p, and q are determined, we estimate the associated parameters of the AR and EGARCH error structure. In this step, we also develop a set of weights equal to the inverse of the square root of the conditional variance to correct for heteroskedasticity. We then utilize these estimated parameters and weights to transform the data and fit the model using non-linear OLS.

Next we look at the autoregressive process across hours. To do this, we take the residuals from the previous step and sort by month, day and hour. We then determine m, p, and q using the same approach as for the across day estimation, except that the lag for m is not allowed to exceed 23. The data is again transformed with this new set of parameters, and an additional set of weights equal to the inverse of the square root of the conditional variance is calculated and incorporated to further correct for heteroskedasticity.

17 Note that even though C is symmetric, the matrix of elasticities is not necessarily symmetric. It will be symmetric if P_{jdyk}/E_{idyk} is equal to P_{idyk}/E_{jdyk} for all i and j.

Table 1: Own-and Cross-Price Weighted Elasticities: All Customers

Price

Demand

Hour	Hour 01	Hour 02	Hour 03	Hour 04	Hour 05	Hour 06	Hour 07	Hour 08	Hour 09	Hour 10	Hour 11	Hour 12	Hour 13	Hour 14	Hour 15	Hour 16	Hour 17	Hour 18	Hour 19	Hour 20	Hour 21	Hour 22	Hour 23	Hour 24
1	-0.0562	0.0022	0.0029	0.0037	0.0034	0.0040	0.0048	0.0045	0.0038	0.0030	0.0023	0.0017	0.0011	0.0006	-0.0001	-0.0008	-0.0009	-0.0004	0.0002	0.0007	0.0009	0.0008	0.0005	0.0004
2	0.0022	-0.0696	0.0002	0.0015	0.0030	0.0042	0.0049	0.0050	0.0045	0.0035	0.0026	0.0018	0.0010	0.0005	0.0002	-0.0002	-0.0005	-0.0003	0.0002	0.0007	0.0007	0.0001	-0.0006	-0.0012
3	0.0030	0.0003	-0.0532	-0.0022	-0.0003	0.0017	0.0031	0.0037	0.0033	0.0025	0.0016	0.0011	0.0010	0.0013	0.0011	0.0001	-0.0013	-0.0020	-0.0013	-0.0003	0.0002	-0.0001	-0.0012	-0.0025
4	0.0038	0.0016	-0.0023	-0.0521	-0.0026	0.0001	0.0020	0.0028	0.0024	0.0013	0.0005	0.0003	0.0010	0.0020	0.0022	0.0008	-0.0019	-0.0031	-0.0021	-0.0002	0.0012	0.0012	-0.0002	-0.0023
5	0.0047	0.0031	-0.0003	-0.0028	-0.0517	-0.0010	0.0014	0.0028	0.0022	0.0020	0.0009	0.0000	0.0000	0.0010	0.0019	0.0016	0.0000	-0.0014	-0.0013	0.0001	0.0013	0.0016	0.0007	-0.0011
6	0.0050	0.0043	0.0017	0.0001	-0.0010	-0.0604	-0.0043	-0.0015	0.0010	0.0020	0.0016	0.0001	-0.0014	-0.0017	0.0000	0.0028	0.0038	0.0029	0.0007	-0.0009	-0.0011	-0.0005	0.0003	0.0005
7	0.0050	0.0050	0.0030	0.0020	0.0014	-0.0041	-0.0797	-0.0102	-0.0054	-0.0015	0.0006	0.0008	-0.0002	-0.0008	0.0039	0.0048	0.0074	0.0065	0.0025	-0.0012	-0.0026	-0.0016	0.0009	[illegible]
8	0.0045	0.0050	0.0035	0.0027	0.0028	-0.0013	-0.0098	-0.0758	-0.0136	-0.0086	-0.0040	-0.0004	0.0015	0.0024	0.0033	0.0043	[illegible]	[illegible]	0.0015	-0.0008	-0.0009	0.0007	0.0032	[illegible]
9	0.0039	0.0042	0.0030	0.0022	0.0029	0.0009	-0.0062	-0.0132	-0.0660	-0.0125	-0.0077	-0.0023	0.0020	0.0044	0.0050	0.0033	0.0011	-0.0002	0.0000	0.0011	[illegible]	[illegible]	[illegible]	[illegible]
10	0.0027	0.0031	0.0021	0.0012	0.0018	0.0017	-0.0016	-0.0080	-0.0119	-0.0769	-0.0085	-0.0041	0.0007	0.0046	0.0061	0.0045	0.0014	-0.0006	-0.0002	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
11	0.0019	0.0020	0.0013	0.0004	0.0005	0.0011	0.0003	-0.0035	-0.0068	-0.0079	-0.0687	-0.0072	-0.0034	0.0010	0.0030	0.0035	0.0009	-0.0014	-0.0014	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
12	0.0012	0.0012	[illegible]	0.0001	-0.0003	-0.0002	0.0004	-0.0005	-0.0019	-0.0034	-0.0064	[illegible]	-0.0073	-0.0055	-0.0040	-0.0038	-0.0042	-0.0038	-0.0015	0.0017	[illegible]	[illegible]	[illegible]	[illegible]
13	0.0006	0.0008	[illegible]	0.0003	-0.0004	-0.0011	-0.0002	0.0010	0.0015	0.0006	-0.0026	-0.0063	-0.1548	-0.0119	-0.0151	-0.0153	-0.0112	-0.0044	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
14	0.0001	0.0003	[illegible]	[illegible]	-0.0001	-0.0013	-0.0005	0.0015	0.0031	0.0030	0.0006	-0.0043	-0.0105	-0.2571	-0.0254	-0.0276	-0.0205	-0.0075	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
15	-0.0003	0.0001	0.0004	0.0007	0.0004	-0.0006	0.0000	0.0015	[illegible]	0.0032	0.0022	-0.0028	-0.0116	-0.0223	-0.1509	-0.0357	-0.0286	-0.0136	0.0010	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
16	-0.0005	-0.0001	0.0000	0.0001	0.0005	[illegible]	0.0013	0.0013	0.0010	0.0017	0.0011	-0.0022	-0.0106	-0.0223	-0.0329	-0.0919	-0.0258	-0.0117	0.0015	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
17	-0.0006	-0.0002	-0.0005	-0.0006	0.0002	0.0013	0.0023	0.0011	-0.0006	-0.0003	0.0003	-0.0021	-0.0075	-0.0163	-0.0259	-0.0252	-0.1748	-0.0104	0.0016	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
18	-0.0003	-0.0001	-0.0008	-0.0012	-0.0002	0.0013	0.0022	0.0006	-0.0014	-0.0014	-0.0010	-0.0018	-0.0027	-0.0061	-0.0128	-0.0117	-0.0107	-0.1353	-0.0101	0.0024	[illegible]	[illegible]	[illegible]	0.0035
19	0.0001	0.0001	-0.0008	-0.0010	-0.0003	[illegible]	0.0011	0.0001	-0.0009	-0.0009	-0.0010	-0.0005	[illegible]	[illegible]	0.0019	0.0029	0.0027	-0.0113	-0.1331	-0.0054	[illegible]	0.0072	[illegible]	0.0014
20	0.0005	0.0003	-0.0004	-0.0003	0.0001	-0.0001	-0.0003	-0.0003	[illegible]	0.0010	[illegible]	[illegible]	[illegible]	0.0134	0.0130	0.0133	[illegible]	[illegible]	-0.0061	-0.1375	-0.0049	-0.0017	0.0000	-0.0004
21	[illegible]	[illegible]	-0.0001	0.0005	0.0008	-0.0004	-0.0011	0.0000	[illegible]	0.0034	[illegible]	0.0033	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-0.0048	-0.0941	-0.0145	-0.0101	-0.0056
22	[illegible]	0.0001	-0.0003	0.0007	0.0011	-0.0001	-0.0005	0.0012	[illegible]	[illegible]	[illegible]	0.0052	0.0112	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-0.0008	-0.0153	-0.0576	-0.0195	-0.0131
23	0.0004	-0.0005	-0.0010	-0.0002	0.0006	0.0005	0.0011	0.0030	[illegible]	0.0063	[illegible]	0.0070	0.0107	0.0135	0.0115	0.0100	0.0122	0.0134	[illegible]	[illegible]	-0.0113	-0.0213	-0.0553	-0.0200
24	0.0004	-0.0011	-0.0022	-0.0019	-0.0009	0.0005	[illegible]	[illegible]	[illegible]	0.0062	[illegible]	0.0059	[illegible]	0.0115	[illegible]	[illegible]	[illegible]	[illegible]	0.0024	0.0010	-0.0060	-0.0156	-0.0225	-0.0636

Legend

-0.1	Cross-Price Elasticity, Different from Zero, Negative
0.1	Cross-Price Elasticity, Different from Zero, Positive
-0.1	Own-Price Elasticity, Different from Zero, Negative
0.1	Not Different From Zero

The boxed hours of 14–21 (2 PM–9 PM) are considered potential system peak hours for the summer months. The greatest response of the boxed hours is −0.26 in hour 14 (2 PM), which is also the largest own elasticity for any of the 24 h. While even this elasticity may appear small, it suggests a large quantity response given that price changes can be very large. For example, average price in hour 14 is on the order of \$0.05 per kWh, but may rise to \$0.10 on days of higher demand and \$0.20 or more on days of peak demand. Given the elasticity of −0.26, a doubling of price would reduce hourly demand by one-fourth, while a fourfold price increase would cut demand in half.

Hours 14–18 (hour ending at 2 PM– hour ending at 6 PM) show statistically significant negative cross elasticities across adjacent hours, indicating complementarity.[18] A higher price in any of these hours reduces demand in all of these hours. In general, there is a pattern of complementarity immediately adjacent to the diagonal while substitution behavior is present in the more distant hours. The magnitude of the elasticities suggests that the late afternoon and evening hours are relatively strong substitutes for the boxed hours of potential system peak. Magnitudes generally decrease as the hours become further apart, indicating weakening substitution.

These effects are illustrated with an example in Figure 1. The figure shows average system load for year 2001 and how a price increase in three consecutive afternoon hours would cause this load pattern to change. Note the complementary effects in hours adjacent to the price increase and the substitution effects later in the evening.

The findings suggest that firms vary their use in blocks of hours, rather than treating each hour as a separate decision. The hours 12–18 are complements while substitution takes place in hours 20–24. The hour 18 corresponds approximately to the end of the day shift, suggesting that some production is substituted to the night shift.

One concern about TOU prices that should be alleviated by RTP is the possibility of a shifting peak. Customers paying TOU rates could shift use from the high priced period to an adjacent hour with lower prices, resulting in a new peak. With real-time rates, prices would rise during these adjacent hours, so that load would be transferred to a more distant hour where aggregate demand is lower. However, the Duke HP rate is among hourly tariffs where rates are set on the previous business day, so if the utility cannot fully anticipate customer substitution patterns a day ahead, there would still be the potential for shifting peaks.[19]

These results indicate that there is little risk that high prices during potential system peak hours will lead to a shifting peak. The pattern of complementarity

18 Appendix 2 contains an explanation of the method used to calculate statistical significance for the elasticities.

19 See Taylor and Schwarz (2000) for a model and simulation of how customer response to RTP changes with the amount of advance notice of prices.

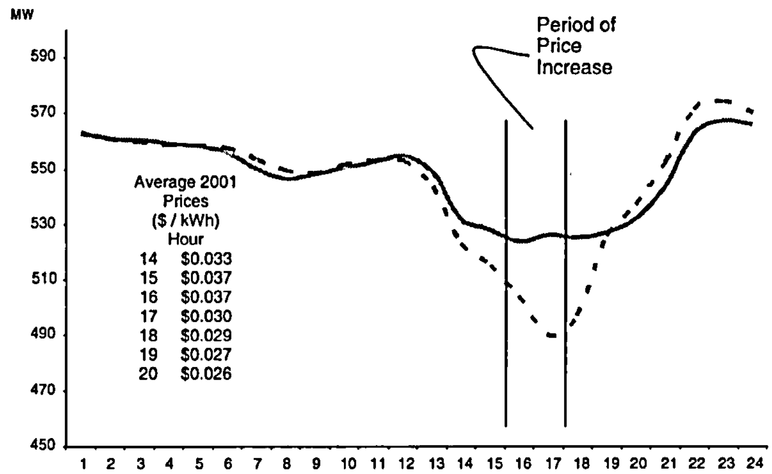

Figure 1. Change in pattern of consumption with increase in price of $0.01/kwh in hours 16, 17, and 18.

that we observe during periods of high prices and high demand tends to suppress loads in adjacent hours. With substitution during the evening hours, load would not increase until later in the day. In contrast, PW found substitution across adjacent periods for their most responsive industry, water supply. In that case, a higher price during a peak hour could shift use to a nearby hour, creating a new peak.

Next, consider response to hourly prices by individual customers. There are estimates of own and cross elasticities by customer for each of the 24 hours per day and 122 days per summer, for every summer that the customer is on the hourly pricing rate, nearly 17 million elasticities in all. To reduce the burden of providing these results, we condense the effects of the own and cross elasticities into an "hourly" elasticity.[20] This elasticity sums all own and cross effects for the hour and describes how demand in a given hour changes for a given change in the average price for the day:

$$\varepsilon_{i,\overline{P}} = \sum_{j=1}^{24} w_j \varepsilon_{ij}, \tag{3}$$

where

$$w_j = (dP_j/P_j)/(d\overline{P}/\overline{P}).$$

20 The following derivation applies to demand for a single customer in a given year, day and hour.

We assume for simplicity that the weight for each hour is unity. That is, the percentage change in price is the same for each hour and is equal to the percentage change in the average price for the day. The change in the hourly price profile implied by this approach yields greater absolute changes in the high priced hours as compared with the lower priced hours. Such a relationship is typically observed on those days when the overall price level increases.

Table 2 shows individual customer hourly elasticities for selected hours arranged in order of price responsiveness.[21]

This ranking is based on the average of hourly elasticities for the potential peak hours of 14–21.[22] Customers with self-generation generally show a sizable response. Of ten customers with self-generation, seven are among the top twelve responders. Two of the top responders who do not have self-generation – steel and electrodes – have arc furnaces. This production process is compatible with curtailing operations in response to high prices.

Based on individual customers, we find some individual customers with larger elasticities than PW found using industry groupings. In their study, the largest average hourly elasticity was 0.20 and largest single hour elasticity was 0.27 for the water supply industry. Seven of 51 customers exceed 0.20 based on the average of hours 14–21, and the largest individual hourly value is 0.775.

Aggregate elasticities for various groupings are in table 3.

Two groups well represented in the customer sample are customers with self-generation and textile customers.[23] Customers who possess self-generation

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Subscripts denoting customer, year, and day are suppressed for clarity. Assume demand in each hour (E_i) is a function of prices in all hours:

$$E_i = E_i(P_1, \ldots, P_i, \ldots, P_{24})$$

The change in E_i with respect to the change in average price level $\bar{P}$ may be written as

$$dE_i/d\overline{P} = (dE_i/dP_1)(dP_1/d\overline{P}) + (dE_i/dP_2)(dP_2/d\overline{P}) + \cdots + (dE_i/dP_{24})(dP_{24}/d\overline{P})$$

Expressing this relationship as an elasticity and summing:

$$(dE_i/d\overline{P})(\overline{P}/E_i) = \sum_{j=1}^{24}(dE_i/dP_j)(P_j/E_i)[(dP_j/P_j)/(d\overline{P}/\overline{P})]$$

or

$$\varepsilon_{i,\overline{P}} = \sum_{j=1}^{24}\varepsilon_{ij}[(dP_j/P_j)/(d\overline{P}/\overline{P})]$$

which yields equation (3) in the text. This logic is followed in Appendix 2 to derive the hourly elasticity of equation (B.10).

21 The elasticities of Table 2 are load weighted averages of the hourly elasticity of equation (3). The formula is in Appendix 2, equation (B.10) as evaluated for each customer k.

22 This ranking is similar to the ranking of STBD (2002), table 4, p. 604. That study used Duke Power data through the year 2000, when there were as many as 100 customers on the HP rate.

23 Our data reflects purchases from the utility. So for customers who can self-generate, we analyze price response only for the part of their load that is purchased from the utility.

Table 2. Hourly own-price total elasticities: individual customer

	Average Elasticities					Selected Hourly Elasticities				
Industry	Generator	Hour 14 to 21	Hour 14	Hour 15	Hour 16	Hour 17	Hour 18	Hour 19	Hour 20	Hour 21
University	Y	−0.376***	−0.349***	−0.285***	−0.319***	−0.416***	−0.519***	−0.465***	−0.369***	−0.291***
Textiles	N	−0.353*	−0.405*	−0.386*	−0.372*	−0.354*	−0.339*	−0.328*	−0.334*	−0.304*
Paper	Y	−0.352***	−0.775***	−0.536***	−0.335***	−0.541***	−0.340***	−0.218***	−0.119***	0.046***
Textiles	Y	−0.333***	−0.332***	−0.346***	−0.352***	−0.385***	−0.353***	−0.315***	−0.313***	−0.265***
Glass Tempering	N	−0.316***	−0.069***	−0.247***	−0.319***	−0.524***	−0.513***	−0.375***	−0.390***	−0.088***
Steel	N	−0.299***	−0.426***	−0.438***	−0.353***	−0.353***	−0.302***	−0.224***	−0.206***	−0.091***
Electrodes	N	−0.208***	−0.355***	−0.241***	−0.225***	−0.261***	−0.215***	−0.208***	−0.138***	−0.022***
Laboratory	Y	−0.168***	−0.111***	−0.188***	−0.172***	−0.154***	−0.225***	−0.207***	−0.156***	−0.135***
University	Y	−0.163***	−0.104***	−0.095***	−0.098***	−0.159***	−0.270***	−0.249***	−0.177***	−0.156***
Chemical Fiber	Y	−0.106***	−0.110***	−0.118***	−0.126***	−0.120***	−0.120***	−0.115***	−0.080***	−0.058***
Plactics	N	−0.091***	−0.035***	0.005*	−0.041***	−0.127***	−0.167***	−0.136***	−0.124***	−0.105***
Brewery	Y	−0.068***	−0.055***	−0.120***	−0.107***	−0.046***	−0.090***	−0.078***	−0.033***	−0.014***
Textiles	N	−0.061***	0.022***	−0.001*	−0.030***	−0.061***	−0.095***	−0.102***	−0.105***	−0.118***
Textiles	N	−0.058***	−0.048***	−0.057***	−0.044***	−0.050***	−0.064***	−0.057***	−0.078***	−0.066***
Textiles	N	−0.053***	−0.036***	−0.042***	−0.038***	−0.045***	−0.044***	−0.066***	−0.094***	−0.063***
Nat Gas Storage	N	−0.051***	−0.039***	−0.069***	−0.076***	−0.018***	−0.037***	−0.067***	−0.051***	−0.051***
Textiles	N	−0.050***	−0.036***	−0.040***	−0.043***	−0.038***	−0.046***	−0.047***	−0.065***	−0.086***
Textiles	N	−0.050***	0.007***	−0.018***	−0.021***	−0.040***	−0.082***	−0.088***	−0.079***	−0.076***
Plactics	N	−0.049***	−0.037***	−0.038***	−0.057***	−0.047***	−0.052***	−0.075***	−0.043***	−0.042***
Textiles	N	−0.046***	−0.040***	−0.034***	−0.060***	−0.048***	−0.040***	−0.052***	−0.053***	−0.043***
Textiles	N	−0.045***	−0.070***	−0.020***	−0.031***	−0.052***	−0.051***	−0.043***	−0.065***	−0.027***
Food Product	Y	−0.044***	−0.045***	−0.051***	−0.048***	−0.040***	−0.044***	−0.042***	−0.040***	−0.037***
Textiles	N	−0.038***	−0.036***	−0.040***	−0.043***	−0.042***	−0.038***	−0.037***	−0.035***	−0.031***
Computer Mfg	N	−0.036***	0.006***	−0.018***	−0.021***	−0.032***	−0.054***	−0.047***	−0.053***	−0.072***
Textiles	N	−0.035***	0.010***	0.008***	−0.010***	−0.043***	−0.060***	−0.043***	−0.056***	−0.087***
Machinery	N	−0.031***	−0.010***	0.004***	0.004***	−0.005***	−0.021***	−0.057***	−0.106***	−0.056***
Computer Mfg	N	−0.029***	0.010***	−0.006***	−0.018***	−0.027***	−0.022***	−0.040***	−0.073***	−0.055***
Pipeline	N	−0.026***	−0.025***	−0.027***	−0.027***	−0.030***	−0.025***	−0.025***	−0.026***	−0.025***
Tobacco	N	−0.026***	−0.011***	−0.026***	−0.057***	−0.029***	−0.012***	−0.018***	−0.025***	−0.031***

Table 2. (continued)

	Average Elasticities		Selected Hourly Elasticities							
Industry	Generator	Hour 14 to 21	Hour 14	Hour 15	Hour 16	Hour 17	Hour 18	Hour 19	Hour 20	Hour 21
Textiles	N	−0.025***	−0.019***	−0.031***	−0.028***	−0.021***	−0.029***	−0.022***	−0.042***	−0.010***
Textiles	N	−0.023***	−0.022***	−0.016***	−0.019***	−0.029***	−0.025***	−0.022***	−0.031***	−0.022***
Textiles	N	−0.023***	−0.022***	−0.013***	−0.020***	−0.030***	−0.025***	−0.026***	−0.026***	−0.024***
Textiles	N	−0.021***	−0.022***	−0.032***	−0.034***	−0.027***	−0.019***	−0.011***	−0.010***	−0.014***
Battery Mfg	N	−0.019***	−0.024***	−0.025***	−0.019***	−0.016***	−0.023***	−0.015***	−0.019***	−0.011***
Auto Mfg	Y	−0.016***	−0.058***	−0.045***	−0.018***	−0.016***	0.004***	−0.003*	−0.006***	0.017***
Textiles	N	−0.015***	−0.021***	−0.013***	−0.016***	−0.014***	−0.015***	−0.019***	−0.013***	−0.011***
Textiles	N	−0.014***	−0.014***	−0.009***	−0.013***	−0.004***	−0.001	−0.011***	−0.019***	−0.043***
Plactics	N	−0.013***	−0.009***	−0.010***	−0.005***	−0.012***	−0.016***	−0.028***	−0.021***	−0.004***
Textiles	N	−0.013***	−0.014***	−0.011***	−0.013***	−0.014***	−0.013***	−0.015***	−0.014***	−0.010***
Textiles	N	−0.013***	−0.016***	−0.017***	−0.012***	−0.011***	−0.016***	−0.011***	−0.011***	−0.007***
Textiles	N	−0.013***	−0.014***	−0.014***	−0.011***	−0.011***	−0.014***	−0.014***	−0.013***	−0.010***
Chemical	N	−0.012***	−0.007***	−0.005***	−0.008***	−0.013***	−0.015***	−0.018***	−0.016***	−0.011***
Chemical Fiber	N	−0.012***	−0.008***	−0.012***	−0.006***	0.000	0.005***	−0.001*	−0.021***	−0.049***
Paper Products	N	−0.010***	−0.011***	−0.011***	−0.009***	−0.010***	−0.010***	−0.008***	−0.013***	−0.011***
Textiles	N	−0.010***	−0.006***	−0.006***	−0.005***	−0.008***	−0.016***	−0.019***	−0.016***	−0.006***
Textiles	N	−0.009***	−0.012***	−0.008***	−0.007***	−0.008***	−0.008***	−0.010***	−0.011***	−0.011***
Paper	N	−0.009***	−0.009***	−0.013***	−0.027***	−0.000	−0.003**	−0.008***	−0.007***	−0.003***
Chemical	Y	−0.009***	−0.013***	−0.020***	−0.011***	−0.005***	−0.005***	−0.005***	−0.004***	−0.005***
Textiles	N	−0.008***	−0.007***	−0.007***	−0.005***	−0.006***	−0.012***	−0.009***	−0.008***	−0.009***
Fiber Cable	N	−0.006**	−0.006***	−0.003*	−0.003*	−0.003*	−0.004**	−0.009***	−0.011***	−0.008***
Chemical Fiber	N	−0.002***	−0.003***	−0.001***	0.000***	−0.001***	−0.003***	−0.004***	−0.004***	−0.003***

Note: This table contains the elasticity for the change in demand in a single hour given a 1% increase in price for all 24 h of the day. Elasticities are weighted averages across all days of available data for each customer as described in Appendix B, equation (B.10). The column Average Elasticity is the simple average of the table entries for hours 14 to 21. The level of significance is indicated by the asterisks. Three asterisks indicate the estimate is three or more times greater than its standard error. Two asterisks indicate the estimate is greater than or equal to two but less than three times its standard error. One asterisk indicates the estimate is greater than or equal to one, but less than two times its standard error. If there is no asterisk, the estimate is less than its standard error.

Table 3. Average of hourly elasticities for hours 14 to 21 for selected customer groups

Customer group	Elasticity Complete group	Generator	Arc furnace	No generator or Arc furnace
All customers	−0.155 (51)	−0.269 (10)	−0.269 (2)	−0.029 (39)
Textiles	−0.212 (23)	−0.333 (1)	n.a. (0)	−0.038 (22)

Notes. The entry in the second line of each Customer group represents the number in that group. Note that there is only one Textile customer with a generator. Elasticities are weighted averages of customers in each group, weighted by level of KWH consumption.

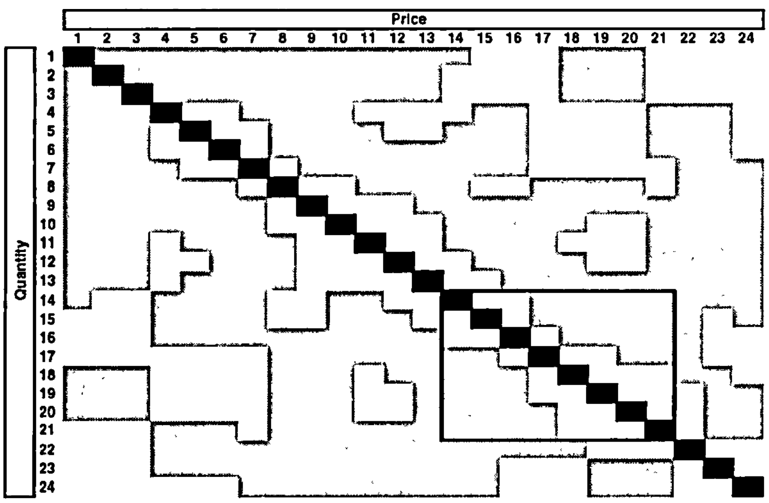

Figure 2. Signs of cross-elasticities for textile customers. ▭ – Cross-Price Elasticity, Negative, ▭ – Cross-Price Elasticity, Positive, ■ – Own-Price Elasticity.

have elasticities of −0.27 while textile customers (omitting one who has self-generation) have an elasticity of −0.04. These are again average elasticities for the hours from 14 to 21. The production process for textiles is continuous, and any interruption would substantially impair product quality.

Figures 2 and 3 indicate the signs of cross elasticities on high price days.[24] Both groups exhibit complementarity in hours adjacent to the diagonal. During

24 These results are developed from load weighted averages of individual customers in each group for days in 2000 when the maximum price exceeded $0.20 per kwh. The pattern of cross effects for each individual customer is symmetric; however, this symmetry is not preserved in the calculation of the weighted average for the group.

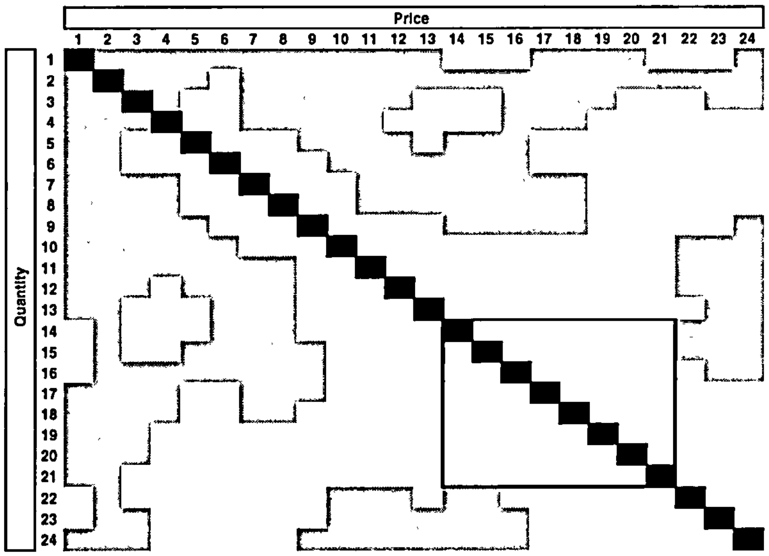

Figure 3. Signs of elasticities for customers with generators. ☐ – Cross-Price Elasticity, Negative, ☐ – Cross-Price Elasticity, Positive, ■ – Own-Price Elasticity.

the hours of the afternoon when prices are high, customers with generators appear to demonstrate more complementary behavior than textiles possibly implying that there is limited flexibility to adjust generation on an hour to hour basis.

Customers with generators show more substitution than textiles in the early morning hours. This behavior is consistent with a scenario that has the generators coming on and staying on during the period of the highest prices of the day. Textile customers might be adjusting smaller discretionary loads such as lighting and office air conditioning that are not associated with the manufacturing process.

These results can be compared to the most responsive industry in PW, the water supply industry. Based on cross elasticity, that industry displays substitutability across adjacent load periods. The authors attribute this response to the ability of the industry to shift daily pumping and storage operations. In our study, the textile industry displays this pattern. In PW, the steel tubes industry shows complementarity in adjacent hours, which is hypothesized to be consistent with little ability to shut down production. There is substitution in more distant hours and the patterns of complementary and substitute hours suggest that production is transferred to the next labor shift. In our study, we find complementarity for customers with self-generation. We attribute that finding to the fact that it only makes sense to use self-generation for at least several consecutive hours.

2.2.1. Changes in Customer Response with Experience

Economic theory predicts that customer response, as measured by hourly elasticity and demand, increases with the length of time that the customer has been

Table 4. Regression results for hourly elasticity

Hour	YearOnHP		TempD		PriceSmr	
	Estimate	Significance	Estimate	Significance	Estimate	Significance
1	0.019	0.10	−0.005		−0.443	
2	0.027	0.10	−0.009	0.05	0.065	0.10
3	0.008		−0.006	0.10	0.150	
4	−0.003		−0.005		0.116	0.10
5	0.017		−0.009	0.05	0.335	
6	0.002		−0.003		0.976	0.01
7	−0.006		−0.007		0.780	0.01
8	−0.012		−0.015		1.270	
9	0.072		−0.042		0.442	
10	0.045		−0.053	0.10	0.566	
11	0.034		−0.049		−0.199	
12	0.039		−0.072	0.01	−1.221	
13	0.037		−0.071	0.05	−5.485	
14	−0.081		−0.072	0.01	−10.692	
15	−0.313	0.01	−0.093	0.01	−8.698	
16	−0.132	0.10	−0.084	0.01	−5.145	
17	−0.139	0.05	−0.068	0.01	−6.644	
18	−0.099		−0.075	0.01	−6.045	0.05
19	−0.072		−0.074	0.01	−3.054	
20	−0.195	0.01	−0.091	0.01	−2.518	0.10
21	−0.044		−0.049	0.01	2.600	
22	−0.008		−0.041	0.01	3.133	
23	−0.049		−0.045	0.01	3.232	
24	−0.018		−0.027	0.05	1.791	

Notes. Estimates are from equation (4) in text.

on the hourly pricing rate. The hourly elasticity, $\varepsilon_{i,\overline{p}}$, in equation (3) is obtained for each customer for each hour in the data set and is the dependent variable in a regression analysis that incorporates the length of time that the customer has been on the hourly pricing rate.[25]

The following specification is estimated for each hour of the day, developing an hourly profile of customer response across the day:

25 There are approximately 29,000 observations for each of the 24 h of the daily profile. This number varies slightly from hour to hour due to some missing data. The Glass Tempering customer of Table 1 is omitted from this analysis. This customer is very small and demonstrates extreme volatility in its load pattern. Including this customer in the analysis appears to substantially distort our results.

$$\varepsilon_{i,\overline{p}} = \sum_i a_i \text{ Customer}_i + b_1 \text{ YearOnHP} + b_2 \text{ TempD} + b_3 \text{ Wkend} + b_4 \text{ Holiday} + \sum_{m=1}^{3} c_n \text{ Month}_m + b_5 \text{ PriceSmr} \quad (4)$$

Variables are defined as
ε_{ij} is the predicted hourly elasticity in equation (3) for each customer (i) for the hour(j),
Customer$_i$ the binary variable (1 or 0) designating the individual customer (i),
YearOnHP the the number of years the customer has been on Duke's Hourly Pricing Rate at hour (j),[26]
TempD the average temperature for the day (Degrees F),
Wkend the binary variable designating weekends,
Holiday the binary variable designating holidays.
Month the binary variables designating the months of July, August, and Sept, and
PriceSmr the average level of prices for the summer (June to Sept) (\$/mWh),

Including the price and monthly binary variables as well as variables reflecting average temperature for the day controls for the influence that each may have on price responsiveness over time. As a result, it is possible to isolate the effect of customer experience on price responsiveness by using the YearOnHP variable.[27]

Results for YearOnHp, PriceSmr, and TempD are in table 4. Parameter estimates for YearOnHP are negative for all of the potential peak hours of 14–21, with statistical significance ranging from 0.10 to 0.01 for four of the seven hours. Two of the remaining 3 hours approach statistical significance. A negative sign indicates that the elasticity increases (in absolute value) with experience. Such a finding is consistent with the notion that customers find new ways to adjust behavior, or possibly install capital equipment in order to increase their price responsiveness over time.

The variable PriceSmr, has negative but generally non-significant coefficients during the afternoon indicating that an increase in the overall summer price level does not significantly influence price responsiveness during potential peak hours. There are, however, positive and significant coefficients for several of the early

26 A customer who has been on the HP rate for the full eight years would have a value of 1 for YearOnHP for the first year of data (1994), a value of 2 for the second year (1995), and so on up to a value of 8 for the final year (2001).

27 STDB (2002) provide a full discussion of the issues considered in developing the specification of equation (10). We began by estimating the same specification as that reported in STDB. OLS estimates were found to be subject to heteroskedasticity and autocorrelation. Heteroskedasticity was resolved by incorporating binary variables to designate each individual customer. As a result, the need for variables to denote the presence of a generator or arc furnace, and customer size (variables STBD include) was obviated. We also replaced their variable for average summer temperature with one for daily temperature. The resulting specification was corrected for autocorrelation by incorporating all significant autoregressive parameters up to 24 lags.

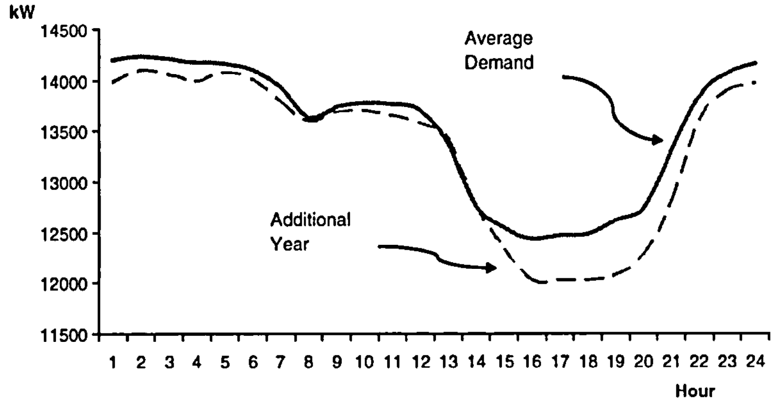

Figure 4. Change in average demand per customer with additional year experience on hourly pricing.

morning hours. Such a finding is consistent with the notion that higher summer prices may encourage customers to substitute consumption during morning hours for consumption during other hours of the day.

Increases in average daily temperature as measured by TempD lead to an increase in price responsiveness for all hours. This effect is significant at the 0.01 level for hours 12–23, which includes the potential peak hours. So, in contrast to the earlier work in STBD, we do find some significance associated with temperature. The temperature finding indicates that RTP is most effective when it is most needed, peak hours on days of highest temperatures.

It is possible that customer response could increase over time without affecting elasticity, to the extent that customer substitutions are inframarginal, and the observed response is at the margin.[28] To focus on additional changes, average hourly energy use for the customer sample is regressed on years on the HP rate. Independent variables are the same as in the elasticity equation, except average summer price is replaced with variables for each of the 24 hourly prices.

Figure 4 shows the predicted change in hourly demand associated with one additional year of experience.[29] The solid line shows demand predicted at the average

28 We thank an anonymous referee for pointing out the possibility of inframarginal effects.

29 Predictions for hourly demand are obtained from a regression approach similar to that utilized to predict hourly elasticities in equation (4). Customer hourly consumption (kwh) is the dependent variable and the same independent variables as in equation (4) are incorporated with the exception that the 24 hourly prices are included in the place of the PriceSmr variable. The model is:

$$mwh_{i,\bar{p}} = \sum_i a_i \text{ Customer}_i + b_1 \text{ YearOnHP} + b_2 \text{ TempD} + b_3 \text{ Wkend} + b_4 \text{ Holiday} + \sum_{m=1}^{3} c_n \text{ Month}_n + \sum_{n=1}^{24} d_n \text{ Price}_n$$

value of all independent variables. The dashed line increments the value of the YearOnHp variable by 1. These results support the findings presented in table 4 that the longer customers are on the hourly pricing rate, the more they reduce load during the higher priced hours of the afternoon.

3. Social Welfare Analysis

Social welfare is approximated as the net benefit of hourly pricing over standard TOU rates for the hourly pricing population. Net benefit is defined as the difference between net value received when billed on hourly pricing less net value received on the standard rate. Net value received is consumer surplus less any under-recovered cost of supply plus any over-recovered cost of supply. Marginal cost is assumed to be constant at the level of the hourly price in each hour. There may be over- or under-recovery of cost with the standard fixed rate. However, with the hourly pricing rate, there is no over- or under-recovery of cost since prices are presumed equal to marginal cost, including capital recovery cost. Over- or under-recovery of cost on the standard rate may alternatively be viewed as increases or decreases in producer surplus.

Net benefit is calculated for each customer for every hour that the customer was billed on the hourly pricing rate. This net benefit is found to exceed metering and other costs to administer the program.[30] As an indicator of the benefits associated with hourly pricing, this estimate is conservative because some price response is likely to be realized with the TOU rate.

Figures 5 and 6 illustrate how consumption would change if the customers billed on Duke's hourly pricing rate were instead billed on Duke's standard TOU rate.[31] Figure 5 is typical of the great majority of days when hourly prices are relatively low. It is notable that the TOU rate provides an incentive for customers to reduce load, even though there may be plenty of capacity available as evidenced by the low prices of the marginal-cost based hourly rate.

Consumer surplus is given by the line integral of demand evaluated between the price paid in each hour and the price that yields zero consumption for all hours.[32]

30 We are unable to observe customer adjustment costs; however, it is presumed that customer benefits exceed such costs because the program is voluntary and customers have chosen to remain on the hourly pricing rate.

31 Predicted consumption for the TOU rate is obtained by utilizing the elasticities developed for the hourly pricing customers. The percentage difference in the marginal prices of the HP rate and the TOU rate is multiplied by the estimated elasticity and this product is then multiplied by the predicted consumption for customers on the HP rate to obtain the change in consumption brought about by the difference in HP and TOU marginal prices.

32 Pressman (1970) points out that line integrals should be used when more than one price changes and there are own and cross effects. The result is independent of the path taken between points 1 and 2. The proof is available upon request.

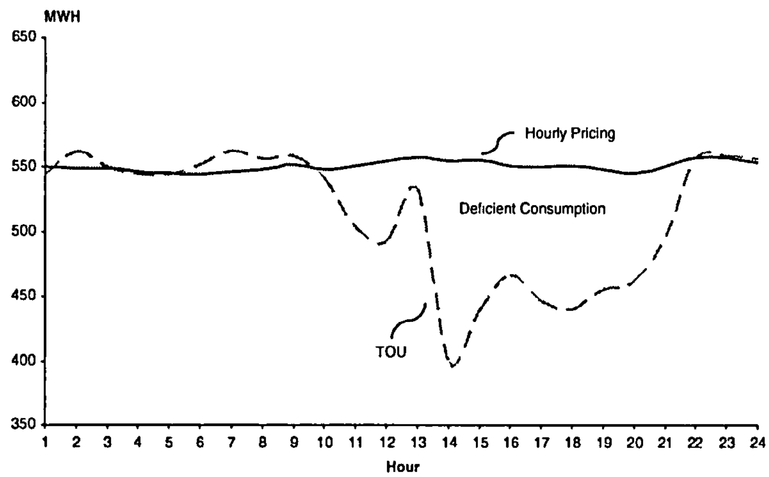

Figure 5. Predicted consumption on the TOU and hourly pricing rates for a low price day, August 23, 2000.

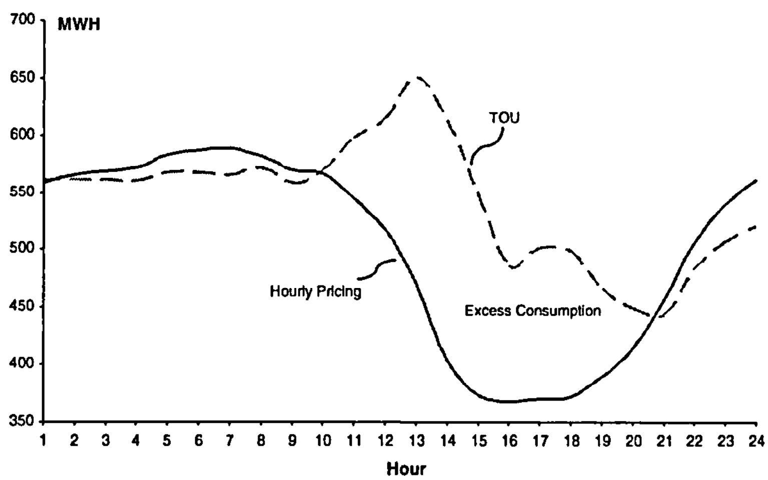

Figure 6. Predicted consumption on the TOU and hourly pricing rates for a high price day, August 9, 2000.

The line integral of demand is:

$$\oint \sum_{i=1}^{24} E_{idyk} d P_{idyk} = \oint \sum_{i=1}^{24} (\frac{Y_{dyk}}{PZ_{my}} \sum_{j=1}^{24} c_{ijyk} P_{jdyk} + k_{idyk}) d P_{idyk}.$$

Evaluated to yield consumer surplus:

$$CS_{dyk}|_a^b = [\frac{1}{2}\frac{Y_{dyk}}{PZ_{my}}\sum_{i=1}^{24}\sum_{j=1}^{24} c_{ijyk}P_{idyk}P_{jdyk} + \sum_{i=1}^{24} k_{idyk}P_{idyk}]|_a^b.$$

In terms of own and cross elasticities, this function is

$$CS_{dyk}|_a^b = [(1/2)\sum_{i=1}^{24} P_{idyk}E_{idyk}\sum_{j=1}^{24}\varepsilon_{ijyk} + \sum_{i=1}^{24} k_{idyk}P_{idyk}]|_a^b, \tag{5}$$

where

P_{idyk} is the price in hour i, day d, year y for customer k; E_{idyk} is the demand in hour i, day d, year y for customer k; ε_{ijyk} is the elasticity of E_{idyk} with respect to P_{jdyk}, and k_{idyk} represents the non-price terms.

Points a and b are prices over which consumer surplus is evaluated. For the HP rate, point b represents, for each hour of the summation, the hourly price of the HP rate. Point a is the price that yields zero consumption in all hours. For the TOU rate, point b represents hourly marginal prices associated with the TOU rate while point a is the same as for the HP rate.

The net benefit to society is calculated as

$$NB = \sum_{y=1}^{N_y}\sum_{k=1}^{n_{dy}}\sum_{d=1}^{D_y}(CS_{dyk}(P_{dyk}^{TOU}) - CS_{dyk}(P_{dyk}^{H}) - \sum_{i=1}^{24} E_{idyk}^{TOU}(P_{idyk}^{TOU} - P_{idyk}^{H})). \tag{6}$$

The first expression in parenthesis with the superscript TOU denotes equation (5) evaluated at the marginal price of the TOU rate. The second with superscript H denotes equation (5) evaluated at the hourly price. Because point 'a' of equation (5) cancels out of the expression in (6), it is not necessary to evaluate equation (5) at the price that yields zero consumption.

Using equation (6), the net benefit, in nominal terms, is in table 5. Net benefit by year ranges from under $1 million to almost $3.5 million, for a total of $13.7 million. To provide some perspective for this number, there are 243 customer summers in this study and, with four months per summer, 972 customer months. Net benefit averages over $14,000 per customer per month. The average monthly bill for customers on hourly pricing was $348,000 over the period of our analysis, so net benefit averages just over four percent of the customer's bill. Duke Power estimates that it costs no more than $300 per customer per month for the administrative support and equipment necessary to provide hourly pricing. Net benefit of this program greatly exceeds this cost.

For the data in this analysis, customers gained by switching from TOU to HP rates in 6 of the 8 years. Correspondingly, the utility would have gained producer surplus had these customers remained on TOU during these years. Customer losses occur in 2 years, and are largest in the year 2000. Not surprisingly, a large number

Table 5. Welfare analysis of the gain to hourly pricing compared To Duke Power Company's Standard TOU rate

	Amount of change Consumer surplus	Unrecovered cost	Net benefit
1994	4472	−2620	1852
1995	5548	−4378	1170
1996	7232	−5973	1259
1997	5865	−4978	888
1998	4869	−3499	1370
1999	−5922	9328	3406
2000	−12,743	15,544	2801
2001	19,112	−18,130	982
Total	28,433	−14,705	13,728

Note. Net benefit is the sum of consumer surplus and under or over recovered cost of supply (producer surplus). This comparison is for the population of customers in our analysis. Consumption on the two rates is predicted using the elasticities estimated in our analysis. Table entries are in thousands of dollars.

of customers dropped off the rate after the summer of 2000. For customers who remained, net benefits jumped to their largest value in 2001.[33]

Duke's marginal cost hourly pricing rate gives price signals that lead to efficient consumption. Because the TOU rate tends to achieve some of these benefits as an approximation to marginal cost pricing, our results understate the full benefits of marginal-cost based price signals for customers whose rates do not vary at all with time of use, such as was the case for customers in the California energy crisis whose rates were frozen while wholesale rates gyrated in real time.

As noted earlier, customer participation in the Duke program is voluntary. Most real time pricing programs in the U.S. are voluntary in nature. It would not be appropriate to ascribe the level of net benefit for Duke's voluntary program to programs in which participation is mandatory.

4. Conclusions and Future Research

RTP has the potential to reduce customer demands. Our results show greater potential than previous studies, with own price elasticities as large as 0.26 in absolute value for the aggregate of our population. Cross price effects also contribute to response in a given hour. The pattern of cross elasticities shows complementarity within the potential peak hours of 14 to 18 (the hour ending at 2 PM through

33 For the Southeast region served by Duke Power, Summer 2000 was a relatively warm summer and hourly prices reached all time highs. Prices in Summer 2001 were much lower reflecting a return to cooler temperatures.

the hour ending at 6 PM), as well as the preceding hours of 12 and 13 (the hours ending at 12 noon and 1 PM). These results indicate that RTP will not cause a shifting peak to an adjacent hour. The aggregate results show substitution beginning at hour 20 to hour 24 for the potential peak hours of 14–18.

Customers with generators and arc furnaces are highly responsive. Of the 12 most responsive customers, seven have self-generation and an additional two have arc furnaces. Customers with generators show complementarity near the high-priced hours, while textile customers, with a continuous production process and no self-generation, show substitutability near the high-priced hours.

We find evidence that load reductions deepen during potential peak hours of the afternoon as customers gain experience with the hourly pricing rate. We also find a highly significant increase in price responsiveness when there is an increase in average daily temperature.

Comparing the hourly pricing rate to Duke's standard TOU rate, the net benefit to society of hourly pricing for the 8 years of the study is \$13.7 million. This figure of some \$14,000 per customer per month averages four percent of customer bills, and is well in excess of the administrative and equipment cost necessary to provide hourly pricing.

There are several topics that have promise for future research. Previous work indicates that customers may have price thresholds above which response becomes significant.[34] Incorporating price thresholds into the elasticity estimates presented in this work should improve our understanding of customer response. Another area that will benefit from additional research is the SWA. This paper focuses on a comparison of consumer surplus under hourly pricing and Duke's time-of-use rate. It will be useful to compare the welfare effects of hourly pricing with other rate types, such as a flat rate. Finally, it is worth examining the different motivations for customers who signed up for the rates, given the limited response of customers with continuous production processes and no self-generation, as well as differences between customers who stay on RTP and customers who drop off. In the year 2000, there were approximately 100 customers on the rate. There were large losses in consumer surplus during the summer of 2000, and approximately half of these customers dropped off the rate. It is worth comparing these two groups in future work.

Appendix 1. Variable Specification and Formulation of the C_{ij} Matrix

We estimate the c_{ijyk} in equation (1) as $C = -MM'$, where M' is an upper triangular matrix defined as

$$M = D + G + H \tag{A.1}$$

34 STBD (2002) show results indicating that customers with self-generation and arc furnaces show a significant response above a price point.

Matrix D is diagonal and G is lower triangular with zeros on the diagonal. The matrix H is lower triangular with zeros on the diagonal.
Because of the large number of parameters to be estimated, we assume that the elements of D, G, and H can be represented by Fourier series. The number of parameters used to specify the Fourier series is much smaller than the number of elements in the C matrix.[35]

$$D_{ii} = \Delta_{00} + \sum_{j=1}^{N\Delta}(\Delta_j * \cos(i * 2\pi * j/24) + \Delta_{j+N\Delta} * \sin(i * 2\pi * j/24)), \quad (A.2)$$

$$G_{ij} = G_i * G_j, \; i > j, \; 0 \text{ else}, \quad (A.3)$$

where

$$G_k = \Gamma_{00} + \sum_{l=1}^{N\Gamma}(\Gamma_l * \cos(k * 2\pi * l/24) + \Gamma_{l+N\Gamma} * \sin(k * 2\pi * l/24)), \quad \text{for } k = i \text{ or } j,$$

and

$$H_{i,j} = H_{00} + \sum_{k=1}^{NH}(H_k * \cos(X_{i,j} * 2\pi * k/276) + H_{k+NH} * \sin(X_{i,j} * 2\pi * k/276)), \quad (A.4)$$
$$i > j, \; 0 \text{ else, where } X_{i,j} = 47 * j/2 - 24 - j^2/2 + i.$$

We choose $N_\Delta = 5$, $N_\Gamma = 3$, and $N_H = 3$, where N is the number of parameters in the Fourier series, for our estimation.

Estimates are obtained for each customer for each year. We have no independent information on the level of output Y_{dyk}. Our approach is to assume that output varies in a regular pattern by specifying binary variables for day of the week, week of the summer, and two holidays, July 4 and Labor Day. Our formulation is:

$$Y_{dyk} = \text{DOW}_{dyk} * \text{Week}_{dyk} * \text{Holiday}_{dyk}, \quad (A.5)$$

where each component is of the general form:

$$\text{DOW} = 1 + a_1 * \text{Sunday} + a_2 * \text{Monday} + \cdots + a_6 * \text{Saturday},$$
$$\text{Week} = 1 + b_1 * \text{Week1} + b_2 * \text{Week2} + \cdots + b_x * \text{Week(X)},$$
$$\text{Holiday} = 1 + c_1 * \text{July4} + c_2 * \text{Labor Day}.$$

Note that it is necessary to omit one weekday binary and one week binary to avoid over-specifying those components. Thus, if the number of summer weeks is 19, X is 18. We also restrict each parameter (a_i, b_i, c_i) to be greater than (-1) so that our index for Y_{dyk} is positive, thus avoiding the possibility of positive own price elasticities as derived from equation (1).

35 See section 4 of PW (1997) regarding the use of Fourier series.

To provide generality in estimation of the constant term, a_{idyk} and also b_{idyk}, the coefficient of Y_{dyk} in equation (1), we specify these terms as Fourier series.

$$b_{idyk} = \beta_{00yk} + \sum_{j=1}^{N_\beta}(\beta_{jyk} * \cos(h * 2\pi * j/2928) + \beta_{j+N_\beta yk} * \sin(h * 2\pi * j/2928)), \quad (A.6)$$

$$a_{idyk} = \alpha_{00yk} + \sum_{j=1}^{N_\alpha}(\alpha_{jyk} * \cos(h * 2\pi * j/2928) + \alpha_{j+N_\alpha yk} * \sin(h * 2\pi * j/2928)) \quad (A.7)$$

where

$$h = (d-1) * 24 + i.$$

We choose $N_\beta = 5$ and $N_\alpha = 5$, where N is the number of parameters in the Fourier series. With this approach, we are able to predict values of b_{idyk} and a_{idyk} for each observation using only 11 parameter estimates respectively.

The index h represents the hour of the summer such that for the hour ending one a.m. on June 1, h takes the value one, for the next hour it takes the value two and so on until the hour ending at midnight on September 30, for which h takes the value 2928. This approach allows the values of the unobserved variables to be unique for each hour.

Appendix 2. First Stage Elasticities

From text equation (2), the elasticity of demand for customer k in hour i with respect to the price in hour j on day d of year y is:

$$\varepsilon_{ijdyk} = (Y_{dyk}/PZ_{my}) * C_{ijyk} * P_{jdyk}/E_{idyk}. \quad (B.1)$$

The elasticities are non-linear functions of the estimated parameters so the variances and covariances are calculated using a linear Taylor's expansion. There are 24 elasticities for each hour in the data and 705,456 hours in our analysis which means there are nearly 17,000,000 elasticities. Clearly this is too much data to be presented.

Our approach is to present results at various levels of aggregation. The following analysis describes how weighted average elasticities are computed for the data in our population. We begin with average system load for hour i, expressed as

$$E_i = (1/N_y) * \sum_{y=1}^{N_y}(1/D_y) * \sum_{d=1}^{D_y}\sum_{k=1}^{n_{dy}}(\frac{Y_{dyk}}{PZ_{my}}\sum_{j=1}^{24} C_{ijyk}P_{jdyk} + \sum_{i=1}^{24} X_{idyk}), \quad (B.2)$$

where

N_y is the number of years in the analysis, D_y is the number of days in year y, n_{dy} is the number of customers present on day d of year y, and X_{idyk} is all the non-price terms in equation (1) in the text.

Define the weighted average price as

$$Pbar = (1/\sum_{i=1}^{24} E_i) * \sum_{y=1}^{N_y}\sum_{d=1}^{D_y}\sum_{k=1}^{n_{dy}}\sum_{i=1}^{24} E_{idyk} * P_{jdyk}. \tag{B.3}$$

Next, take the differential of equation (B.2), set the changes in all variables except price and quantity to zero, and divide by E_i. This gives the percent change in E_i:

$$dE_i/E_i = (1/E_i) * (1/N_y) * \sum_{y=1}^{N_y}(1/D_y) * \sum_{d=1}^{D_y}\sum_{k=1}^{n_{dy}}\sum_{j=1}^{24} \frac{Y_{dyk}}{PZ_{my}} C_{ijyk} dP_{jdyk}. \tag{B.4}$$

Express this equation as a function of our elasticities by multiplying and dividing the term inside the rightmost summation sign by the quantity P_{jdyk}/E_{idyk}:

$$dE_i/E_i = (1/E_i) * (1/N_y) * \sum_{y=1}^{N_y}(1/D_y) * \sum_{d=1}^{D_y}\sum_{k=1}^{n_{dy}} E_{idyk} * \sum_{j=1}^{24} \varepsilon_{ijyk} dP_{jdyk}/P_{jdyk}. \tag{B.5}$$

Now calculate the percent change in Pbar, holding quantity constant:

$$dPbar/Pbar = (1/Pbar) * (1/\sum_{i=1}^{24} E_i) * \sum_{y=1}^{N_y}\sum_{d=1}^{D_y}\sum_{k=1}^{n_{dy}}\sum_{i=1}^{24} E_{idyk} * dP_{jdyk}. \tag{B.6}$$

This equation can be simplified to

$$dPbar/Pbar = (\sum_{y=1}^{N_y}\sum_{d=1}^{D_y}\sum_{k=1}^{n_{dy}}\sum_{i=1}^{24} E_{idyk} * P_{jdyk} * dP_{jdyk}/P_{jdyk})/ \sum_{y=1}^{N_y}\sum_{d=1}^{D_y}\sum_{k=1}^{n_{dy}}\sum_{i=1}^{24} E_{idyk} * P_{jdyk}. \tag{B.7}$$

The total hourly elasticity for demand in hour i with respect to all prices is the ratio of equation (B.5) to equation (B.7). If we make the simplifying assumption that all prices change by the same percentage then equation (B.5) becomes:

$$dE_i/E_i = \Delta * (1/E_i) * (1/N_y) * \sum_{y=1}^{N_y}(1/D_y) * \sum_{d=1}^{D_y}\sum_{k=1}^{n_{dy}}\sum_{i=1}^{24} E_{idyk} * \varepsilon_{ijyk}, \tag{B.8}$$

where Δ is the percentage change in prices, and equation (B.7) reduces to

$$dPbar/Pbar = \Delta * \sum_{y=1}^{N_y}\sum_{d=1}^{D_y}\sum_{k=1}^{n_{dy}}\sum_{j=1}^{24} E_{idyk} * P_{jdyk}/ \sum_{y=1}^{N_y}\sum_{d=1}^{D_y}\sum_{k=1}^{n_{dy}}\sum_{j=1}^{24} E_{idyk} * P_{jdyk} = \Delta. \tag{B.9}$$

Thus the total hourly elasticity for demand in hour i with respect to weighted average price, when all prices are changed by the same percentage, is

$$\varepsilon bar_i = (1/E_i) * (1/N_y) * \sum_{y=1}^{N_y} (1/D_y) * \sum_{d=1}^{D_y} \sum_{k=1}^{n_{dy}} \sum_{i=1}^{24} E_{idyk} * \varepsilon_{ijyk}. \tag{B.10}$$

If instead of the total hourly elasticity we want to look the individual own and cross elasticities for that hour the equation becomes:

$$\varepsilon bar_{ij} = (1/E_i) * (1/N_y) * \sum_{y=1}^{N_y} (1/D_y) * \sum_{d=1}^{D_y} \sum_{k=1}^{n_{dy}} E_{idyk} * \varepsilon_{ijyk}. \tag{B.11}$$

The variance for the total hourly elasticity for a given customer, hour, day, and year is calculated using the Taylor's expansion method. The elasticities in equations (B.10) and (B.11) are linear functions of the elasticities for each customer, hour, day, and year so we can easily calculate their variances as a combination of linear terms. To do so, we simply multiply the appropriate variances by the squares of the terms that multiply the elasticities and then sum these values over the same ranges that we are summing the elasticities. This method provides estimates of the standard errors used to construct confidence limits.

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2012 Carbon Dioxide Price Forecast

October 4, 2012

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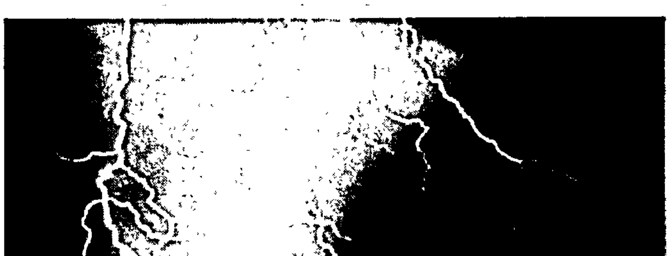

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1. Executive Summary

Electric utilities and others should use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. Estimating this price can be difficult because, despite several attempts, the federal government has not come to consensus on a policy (or a set of policies) to reduce greenhouse gas (GHG) emissions in the U.S.

Although this lack of a defined policy certainly creates challenges, a "zero" price for the long-run cost of carbon emissions is not a reasonable estimate. The need for a comprehensive effort in the U.S. to reduce GHG emissions has become increasingly clear, and it is certain that any policy requiring, or leading to, these reductions will result in a cost associated with emitting CO_2 over some portion of the life of long-lived electricity resources. Prudent planning requires a reasonable effort to forecast CO_2 prices despite the considerable uncertainty with regard to specific regulatory details.

This 2012 forecast seeks to define a reasonable range of CO_2 price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. This forecast updates Synapse's 2011 CO_2 price forecast, which was published in February of 2011. Our 2012 forecast incorporates new data that has become available since 2011, and extends the study period end-date to 2040 in order to provide recommended CO_2 price estimates for utilities planning 30 years out into the future.

A. Key assumptions

Synapse's 2012 CO_2 price forecast reflects our expectation that cap-and-trade legislation will be passed by Congress in the next five years, and the resultant allowance trading program will take effect in or around 2020. These assumptions are based on the following reasoning:

- We believe that a federal cap-and-trade program for GHGs is a key component of the most likely policy outcome, as it enables the reduction of significant amounts of GHGs while allowing those reductions to come from sources that can mitigate their emissions at the least cost.
- We believe that federal legislation is likely by the end of the session in 2017 (with implementation by about 2020) prompted by one or more of the following factors:
    - technological opportunity
    - a patchwork of state policies to achieve state emission targets for 2020 spurring industry demands for federal action
    - a Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies
    - increasingly compelling evidence of climate change

Given the interest and initiatives on climate change policies in states throughout the nation, a lack of federal action will result in a hodgepodge of state policies. This scenario is a challenge for any company that seeks to make investments in existing, modified, or new power plants. It would also lead to inefficient emissions decisions that are driven by inconsistent policies rather than economics. Historically, this pattern of states and regions initiating policies that are eventually superseded at a national level has been common for energy and environmental regulation in the U.S. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

In addition to the assumptions regarding a federal GHG program described above, we anticipate that regional and state policies will lead to costs associated with GHGs in the near-term (i.e., prior to 2020). Prudent planning requires that utilities take these costs into account when engaging in resource planning.

B. Study approach

To develop its 2012 CO_2 price forecast, Synapse reviewed more than 40 carbon price estimates and related analyses, including:

- McKinsey & Company's 2010 analyses of the marginal abatement costs and abatement potential of GHG mitigation technologies
- Analyses of the CO_2 allowance prices that would result from the major climate change bills introduced in Congress over the past several years, including analyses by the Energy Information Association (EIA) and the Environmental Protection Agency (EPA)
- The U.S. Interagency Working Group's estimates for the social cost of carbon
- Analyses of the factors that affect projections of allowance prices, including analyses by the EIA and Resources for the Future
- CO_2 price estimates used by utilities in a wide range of publicly available utility Integrated Resource Plans

Because we expect that a federal cap and allowance trading program will ultimately be adopted, analyses of the various Congressional proposals to date using this approach offer some of the most relevant estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. It is not possible to compare the results of all of these analyses directly, however, because the specific models and the key assumptions vary.

Synapse also considered the impact on CO_2 prices of regulatory measures outside of a cap-and-trade program—such as a federal Renewable Portfolio Standard—that could simultaneously help to achieve the emission-reduction goals of cap-and-trade. These "complementary policies" result in lower CO_2 allowance prices, since they would reduce the demand for CO_2 emissions allowances under cap-and-trade.

C. Synapse's 2012 CO_2 price forecast

Based on analyses of the sources described above, and relying on its own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2020 to 2040. These cases represent different appetites for reducing carbon, as described below.

- The Low case forecast starts at $15/ton in 2020, and increases to approximately $35/ton in 2040.[1] This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly—for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility. This price forecast could also be realized through a series of complementary policies, such as an aggressive federal Renewable Portfolio Standard, substantial energy efficiency investment, and/or more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario).
- The Mid case forecast starts at $20/ton in 2020, and increases to approximately $65/ton in 2040. This forecast represents a scenario in which a federal cap-and-trade program is implemented with significant but reasonably achievable goals, likely in combination with some level of complementary policies to give some flexibility in meeting the reduction goals. Also assumed in the Mid case is some degree of technological learning, i.e. assuming that prices for emissions reductions technologies will decline as greater efficiencies are realized in their design and manufacture and as new technologies become available.
- The High case forecast starts at $30/ton in 2020, and increases to approximately $90/ton in 2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets (nationally or internationally); restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; or higher baseline emissions.

Table ES-1 presents Synapse's Low, Mid, and High case price projections for each year of the study period, as well as the levelized cost for each case.

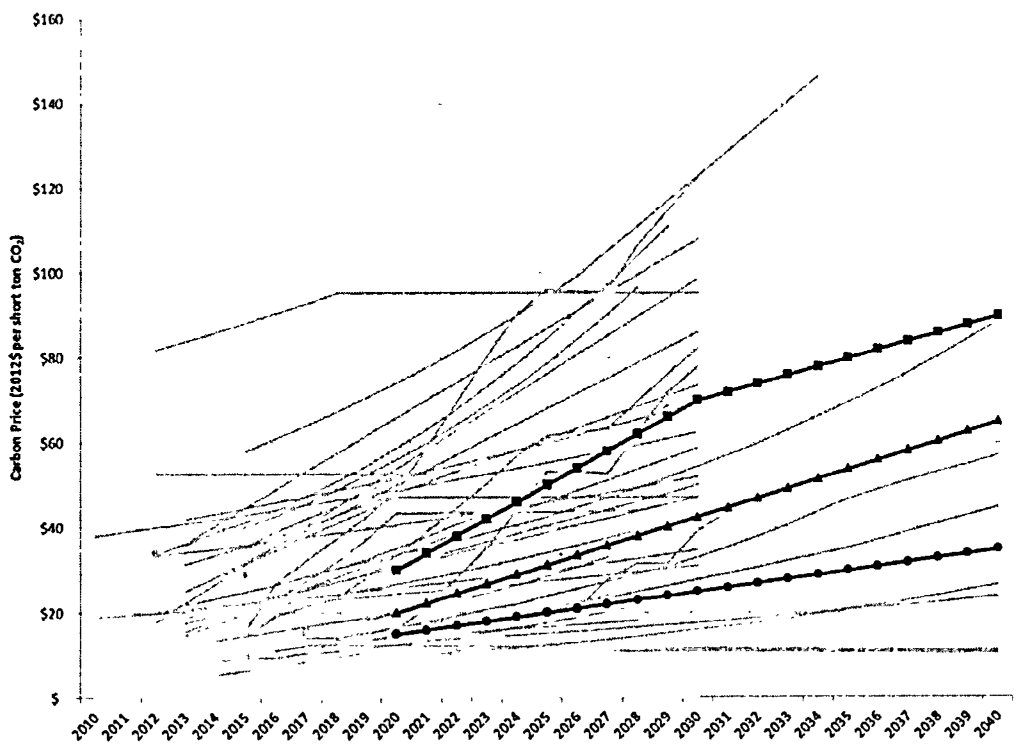
Figure ES-1 presents Synapse's Low, Mid, and High case forecasts as compared to a broad range of CO_2 allowance prices used by utilities in resource planning over the past three years. Synapse forecasts are represented by black lines, while utility forecasts are represented by grey.

[1] Throughout this report, CO_2 allowance prices are presented in $2012 per short ton CO_2, except in reference to a few original sources, where alternate units are clearly labeled. Results from other modeling analyses were converted to 2012 dollars using price deflators taken from the US Bureau of Economic Analysis. Because data were not available for 2012 in its entirety, values used for conversion were taken from Q2 of each year. Results originally provided in metric tonnes were converted to short tons by multiplying by a factor of 1.1.

Table ES-1: Synapse 2012 CO_2 allowance price projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$30.00
2021	$16.00	$22.25	$34.00
2022	$17.00	$24.50	$38.00
2023	$18.00	$26.75	$42.00
2024	$19.00	$29.00	$46.00
2025	$20.00	$31.25	$50.00
2026	$21.00	$33.50	$54.00
2027	$22.00	$35.75	$58.00
2028	$23.00	$38.00	$62.00
2029	$24.00	$40.25	$66.00
2030	$25.00	$42.50	$70.00
2031	$26.00	$44.75	$72.00
2032	$27.00	$47.00	$74.00
2033	$28.00	$49.25	$76.00
2034	$29.00	$51.50	$78.00
2035	$30.00	$53.75	$80.00
2036	$31.00	$56.00	$82.00
2037	$32.00	$58.25	$84.00
2038	$33.00	$60.50	$86.00
2039	$34.00	$62.75	$88.00
2040	$35.00	$65.00	$90.00
Levelized	$23.24	$38.54	$59.38

Figure ES-1: Synapse forecasts compared to a range of utility forecasts



2. Structure of this Paper

This paper presents Synapse's assumptions, data sources, and estimates of reasonable future CO_2 prices for use in resource planning analyses. The report is structured as follows:

- Section 3 discusses the key assumptions behind Synapse's estimates
- Sections 4 through 8 present data from the sources reviewed by Synapse in developing its estimates of the future price of CO_2 emissions
- Section 9 presents Synapse's 2012 Low, Mid, and High CO_2 price forecasts, and compares these projections to a range of utility forecasts
- Appendix A provides a more detailed discussion of state and regional GHG initiatives. Collectively, these initiatives suggest that momentum is building toward federal GHG action

3. Discussion of Key Assumptions

A. Federal GHG legislation is increasingly likely

Congressional action in the form of cap-and-trade or clean energy standards is only one avenue in an increasingly dynamic and complex web of activities that could result in internalizing a portion of the costs associated with emissions of greenhouse gases from the electric sector. The states, the federal courts, and federal agencies are also grappling with the complex issues associated with climate change. Many of these efforts are proceeding simultaneously.

Nonetheless, we believe that a federal cap-and-trade program for GHGs is the most likely policy outcome, as it enables the reduction of significant amounts of GHGs while allowing those reductions to come from sources that can mitigate their emissions at the least cost. Several cap-and-trade proposals have been taken up by Congress in the past few years, though none yet have been passed by both houses. (More discussion of this topic is provided in Section 5 of this report.)

We further believe that federal action will occur in the near-term. This 2012 CO_2 price forecast assumes that cap-and-trade legislation will be passed by Congress in the next five years, and the resultant allowance trading program will take effect in 2020, prompted by one or more of the following factors:

- technological opportunity
- a patchwork of state policies to achieve state emission targets for 2020 spurring industry demands for federal action
- a Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies
- increasingly compelling evidence of climate change

Given the interest and initiatives on climate change policies in states throughout the nation, a lack of federal action will result in a hodgepodge of state policies. This scenario is a challenge for any company that seeks to make investments in existing, modified, or new power plants. It would also lead to inefficient emissions decisions driven by inconsistent policies rather than economics. Historically, this pattern of states and regions initiating policies that are eventually superseded at a national level has been common for energy and environmental regulation in the U.S. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

B. State and regional initiatives building toward federal action

The states—individually and coordinating within regions—are leading the nation's policies to respond to the threat of climate change. In fact, several states, unwilling to wait for federal action, are already pursuing policies on their own or in regional groups. These policies are described below, and are discussed in more detail in Appendix A of this report.

Cap-and-trade programs

The Northeast/Mid-Atlantic region and the state of California have developed, or are in the last stages of developing, greenhouse gas caps and allowance trading.[2]

Under the Regional Greenhouse Gas Initiative (RGGI), ten Northeast and Mid-Atlantic states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten percent reduction in these emissions from levels at the start of the program by 2018.

Meanwhile, California's Global Warming Solutions Act (AB 32) has created the world's second largest carbon market, after the European Union's Emissions Trading System (EU ETS). The first compliance period for California's cap-and-trade program will begin on January 1, 2013, and will cover electricity generators, carbon dioxide suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 25,000 metric tons of CO_2e[3] per year. The initial cap is set at 162.8 million metric tons of CO_2e and decreases by 2% annually through 2015.

State GHG reduction laws

Massachusetts: In 2008, the Massachusetts Global Warming Solutions Act was signed into law. In addition to the commitments to power sector emissions reductions associated with RGGI, this law committed Massachusetts to reduce statewide emissions to 10-25% below 1990 levels by 2020 and 80% below 1990 levels by 2050. Following the development of a comprehensive plan on steps to meet these goals, the 2020 target was set at 25% below 1990 levels.[4] Rather than put a price on carbon in the years before 2020, this plan will achieve a 25% reduction through a combination of federal, regional, and state-level regulations applying to buildings, energy supply, transportation, and non-energy emissions.

Minnesota: In 2008, the Next Generation Energy Act was signed to reduce Minnesota emissions by 15% by 2015, 30% by 2025, and 80% by 2050.[5] While the law called for the development of an action plan that would make recommendations on a cap-and-trade system to meet these goals, the near-term goals will be met by a combination of an aggressive renewable portfolio standard and energy efficiency.

Connecticut: Also in 2008, the state of Connecticut passed its own Global Warming Solutions Act, establishing state level targets 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In December 2010, the state released a report on mitigation options focused on regulatory mechanisms in addition to strengthening RGGI and reductions of non-CO_2 greenhouse gases.[6]

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[2] The Midwest Greenhouse Gas Reduction Accord was developed in 2007. Though the agreement has not been formally suspended, the participating states are no longer pursuing it.
[3] CO2e refers to carbon dioxide equivalent, a measure that includes both carbon dioxide and other greenhouse gases converted to an equivalent amount of carbon dioxide based on their global warming potential.
[4] Massachusetts Clean Energy and Climate Plan for 2020, Available at: http://www.mass.gov/green/cleanenergyclimateplan
[5] Minnesota Statutes 2008 § 216B.241
[6] See http://www.ctclimatechange.com for further details on CT plans for emissions mitigation.

Renewable portfolio standards and other initiatives

A renewable portfolio standard (RPS) or renewable goal specifies that a minimum proportion of a utility's resource mix must be derived from renewable resources. The standards range from modest to ambitious, and qualifying energy sources vary by state.

Currently, 29 U.S. states have renewable portfolio standards. Eight others have renewable portfolio goals. In addition, many states are pursuing other policy actions relating to reductions of GHGs. These policies include, but are not limited to: greenhouse gas inventories, greenhouse gas registries, climate action plans, greenhouse gas emissions targets, and emissions performance standards.

In the absence of a clear and comprehensive federal policy, many states have developed a broad array of emissions and energy related policies. For example, Massachusetts has a RPS of 15% in 2020 (rising to 25% in 2030), belongs to RGGI (requiring specific emissions reductions from power plants in the state), and has set in place aggressive energy efficiency targets through the 2008 Green Communities Act.

4. Marginal Abatement Costs and Technologies

This chapter presents key data related to marginal abatement costs for CO_2, which were reviewed by Synapse in developing its estimates of the future price of CO_2 emissions.

The long-run marginal abatement cost for CO_2 represents the cost of the control technologies necessary for the last (or most expensive) unit of emissions reduction required to comply with regulations. This cost depends on emission reduction goals: lower emissions reduction targets can be met by lower-cost technologies, while more stringent targets will require additional reduction technologies that are implemented at higher costs. The Copenhagen Agreement, drafted at the 15th session of the Conference of the Parties to the United Nations Framework Convention on Climate Change in 2009, recognizes the scientific view that in order to prevent the more drastic effects of climate change, the increase in global temperature should be limited to no more than 2° Celsius. Atmospheric concentrations of CO_2 would need to be stabilized at 450 ppm in order to limit the global temperature increase to no more than 2°C.[7]

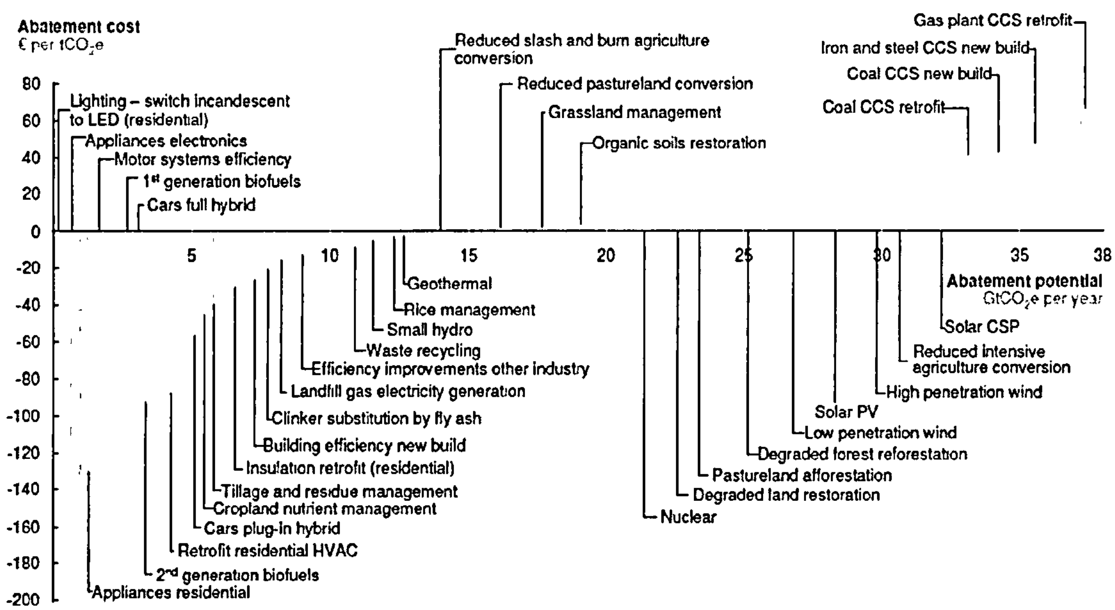
In recent years, there have been several analyses of technologies that would contribute to emission reductions consistent with an increase in temperature of no more than 2°C. McKinsey & Company examined these technologies in a 2010 report entitled *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*. The CO_2 mitigation options identified by McKinsey and the costs of those options are shown in Figure 1. Global mitigation options are ordered from least expensive to most expensive, and the width of each bar represents the amount of mitigation likely at these costs. The chart represents a marginal abatement cost price curve, where cost of abatement is shown on the y-axis and cumulative metric tonnes of GHG reductions are shown on the x-axis. It is likely that the lowest cost reductions will be implemented first, but as reduction targets become more stringent and low-cost options are saturated, the cost of the marginal abatement technology is likely to increase.

The chart below, from the McKinsey report, provides a useful reference to the types of options and technologies that might be employed at specific CO_2 prices.

[7] IPCC, 2007: Summary for Policymakers. In: *Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [B. Metz, O.R. Davidson, P.R. Bosch, R. Dave, L.A. Meyer (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Figure 1: McKinsey & Company marginal abatement technologies and associated costs for the year 2030[8]

V2.1 Global GHG abatement cost curve beyond BAU – 2030



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €80 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.
Source: Global GHG Abatement Cost Curve v2.1

As shown in Figure 1, technologies for carbon mitigation that are available to the electric sector include those related to energy efficiency, nuclear power, renewable energy, and carbon capture and storage (CCS) for fossil-fired generating resources. McKinsey estimates CCS technologies to cost 50-60 €/metric tonne (2005€). Converted into current dollars, this is equivalent to \$65 to \$85/ton (\$71.5 to \$93.5/metric tonne, 2012\$). According to the International Energy Agency (IEA), "in order to reach the goal of stabilizing global emissions at 450 ppm by 2050, CCS will be necessary."[9] If this is true, it is reasonable to expect that a CO_2 allowance price will rise to \$65/ton or higher under a GHG policy designed to limit the global temperature increase to no more than 2°C. However, if significant reductions could be accomplished with CCS at the high \$65 to \$85/ton CO_2 range, we would not expect CO_2 mitigation prices to significantly exceed the top of that range.

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[8] McKinsey & Company. *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve.* 2010. Page 8.
[9] International Energy Agency. *Technology Roadmap: Carbon Capture and Storage.* 2009. Page 4.

5. Analyses of Major Climate Change Bills

This chapter presents key data related to analyses of major climate change bills proposed in Congress over the past few years, which were reviewed by Synapse in developing its estimates of the future price of CO_2 emissions. Because we expect that a federal cap and allowance trading program will ultimately be adopted, analyses of these proposals offer some of the most relevant estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. It is not possible to compare the results of all of these analyses directly, however, because the specific models and the key assumptions vary.

A. Cap-and-trade proposals

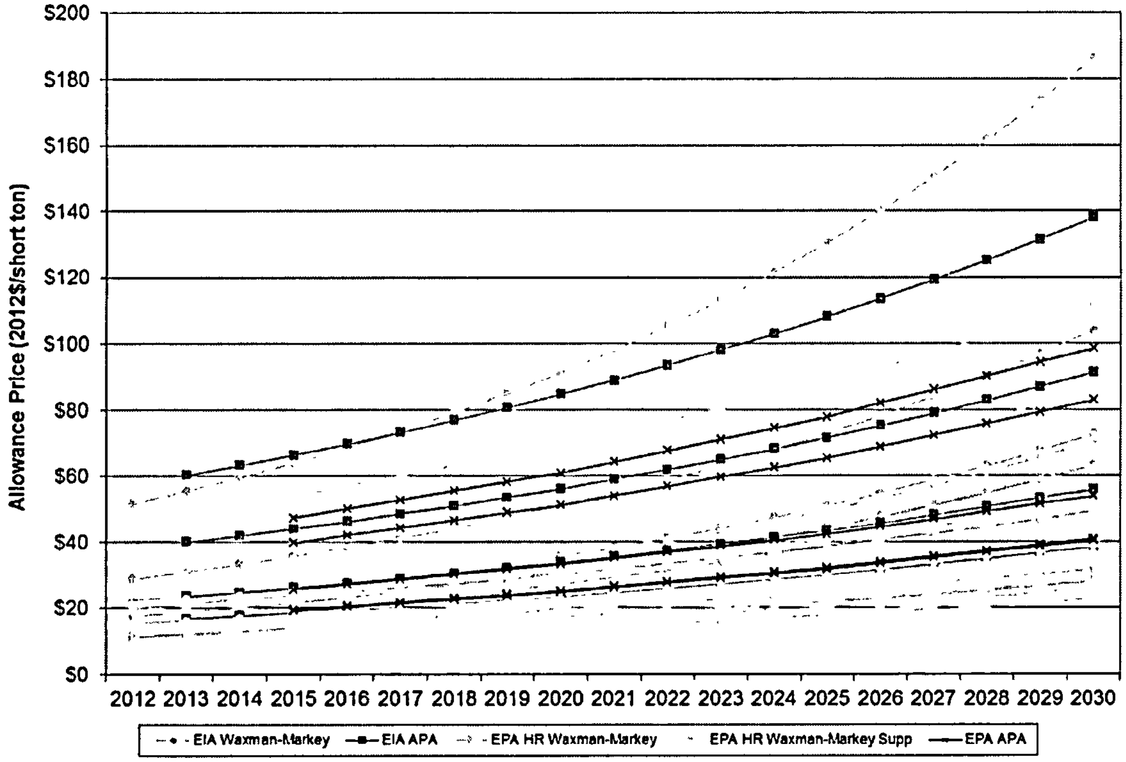
In the past decade, the expectation has been that action on climate change policy will occur at the Congressional level. Legislative proposals have largely taken the form of cap-and-trade programs, which would reduce greenhouse gas emissions through a federal cap, and would allow trading of allowances to promote reductions in GHG emissions where they are most economic. Legislative proposals and President Obama's stated target aim to reduce emissions by up to 80% from current levels by 2050.

Comprehensive climate legislation was passed in the House in the 111th Congress in the form of the American Clean Energy and Security Act of 2009 (ACES, also known as Waxman-Markey and HR 2454); however, the Senate ultimately did not take up climate legislation in that session. HR 2454 was a cap-and-trade program that would have required a 17% reduction in emissions from 2005 levels by 2020, and an 83% reduction by 2050. It was approved by the House of Representatives in June, 2009, but the Senate bill, known as the American Power Act of 2010 (APA, also known as Kerry-Lieberman), never came to a vote.

Figure 2 shows the results of EIA and EPA analyses of HR 2454 and APA. The chart shows the forecasted allowance prices in the central scenarios, as well as a range of sensitivities. Figure 3 shows these values as levelized prices for the time period 2015 to 2030.[10]

[10] Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

Figure 2: Greenhouse gas allowance price projections for HR 2454 and APA 2010[11]



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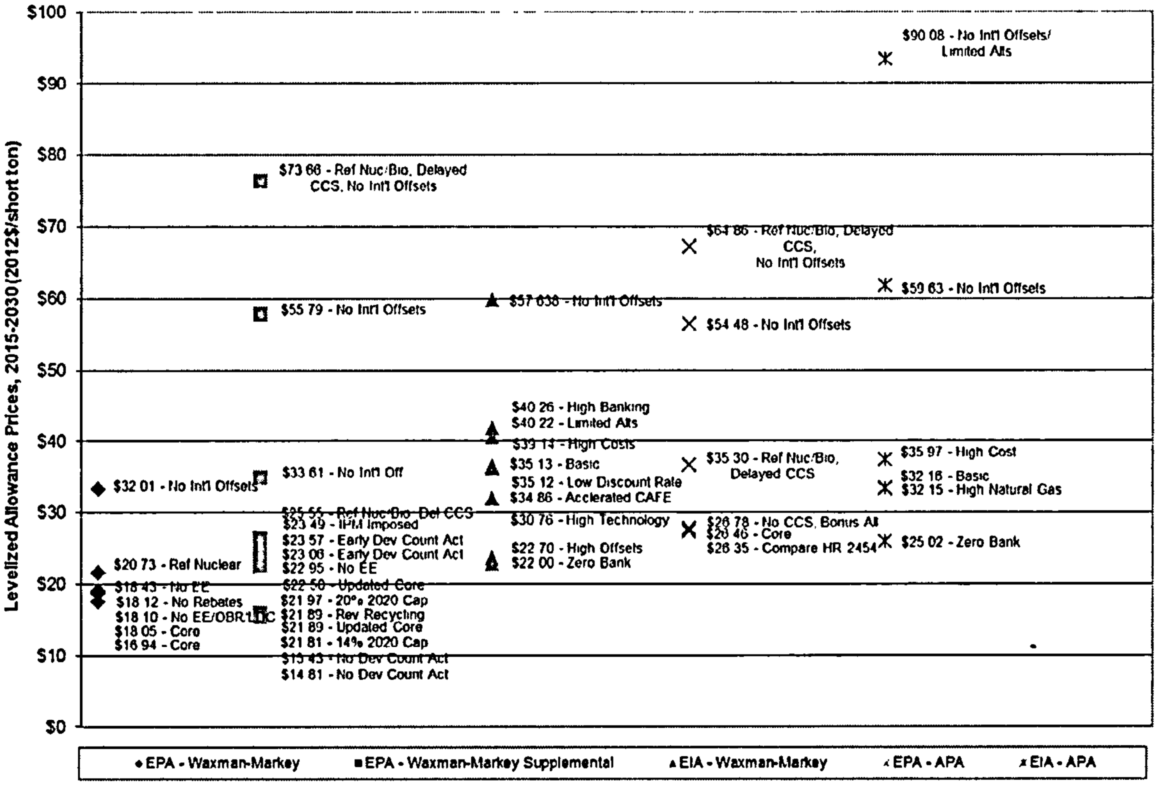
[11] Sources for Figure 2 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html
U.S. Environmental Protection Agency ("EPA"); *Analysis of the American Power Act of 2010 in the 111th Congress* (June 2010). Available at http://www.epa.gov/climatechange/Downloads/EPAactivities/EPA_APA_Analysis_6-14-10.pdf
EPA; *Supplemental EPA Analysis of the American Clean Energy and Security Act of 2009 (H.R. 2454)* (January 2010). Available at: Available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_SupplementalAnalysis.pdf
EPA; *Analysis of the American Clean Energy and Security Act of 2009 (H.R. 2454)* (June 2009). Available at: http://www.epa.gov/climatechange/Downloads/EPAactivities/HR2454_Analysis.pdf

Figure 3: GHG allowance price projections for HR 2454 and APA 2010 - levelized 2015-2030



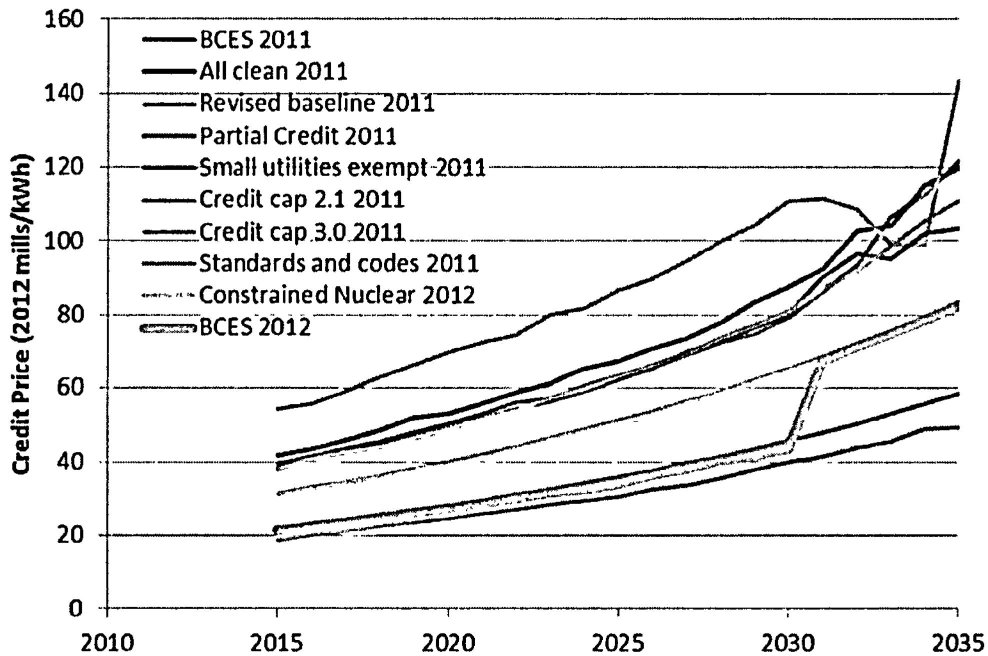
B. Clean Energy Standard

The 112th Congress chose not to revisit legislation establishing an economy-wide emissions cap, and instead focused on policies aimed at fostering technology innovation and developing renewable energy or clean energy standards. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S.2146), under which larger utilities would be required to meet a percentage of their sales with electric generation from sources that produce fewer greenhouse gas emissions than a conventional coal-fired power plant. All generation from wind, solar, geothermal, biomass, municipal solid waste, and landfill gas would earn a full CES credit, as would hydroelectric and nuclear facilities. Lower-carbon fossil facilities, such as natural gas and coal with carbon capture, would earn partial credits based on their CO_2 emissions. Generation owners would be required to hold credits equivalent to 24% of their sales beginning in 2015, and the CES requirement rises over time to 84% by 2035, creating demand for renewable energy and low-emissions technologies. The credits generated by these clean technologies would be tradable and have a value that would change depending on how costly the policy is to achieve. The Clean Energy Standard would apply to utilities with sales greater than 2 million MWh, and expand to include those with sales greater than 1 million MWh by 2025.

The EIA conducted analyses of a potential Clean Energy Standard in both 2011 and 2012.[12,13] All of these cases result in some level of increase in nuclear, gas, and renewable generation, typically at the expense of coal. The exact generation mix, as well as the resulting reduction in emissions, is highly dependent on both the technology costs and policy design. The resulting CES credit prices (Figure 4) vary widely, from 25 to 70 mills/kWh in 2020,[14] rising to 47 to 138 mills/kWh in 2035. The credit cap cases show a smaller rise in credit prices. When credit prices are capped at a specific value, clean energy deployment and emissions abatement is reduced.

An effective CO_2 allowance price can be calculated based on the fact that this policy gives existing gas combined cycle units 0.48 credits and existing coal units zero credits, and the emissions from an average gas unit are about 0.57 tCO_2/MWh and from an average coal unit 1.125 tCO_2/MWh.[15] For the BCES 2012 case, for example, this conversion would result in effective allowance prices of \$18.4/tCO_2 in 2015 and \$71.4/tCO_2 in 2035.

Figure 4: CES credit prices in EIA analyses of a U.S. Clean Energy Standard



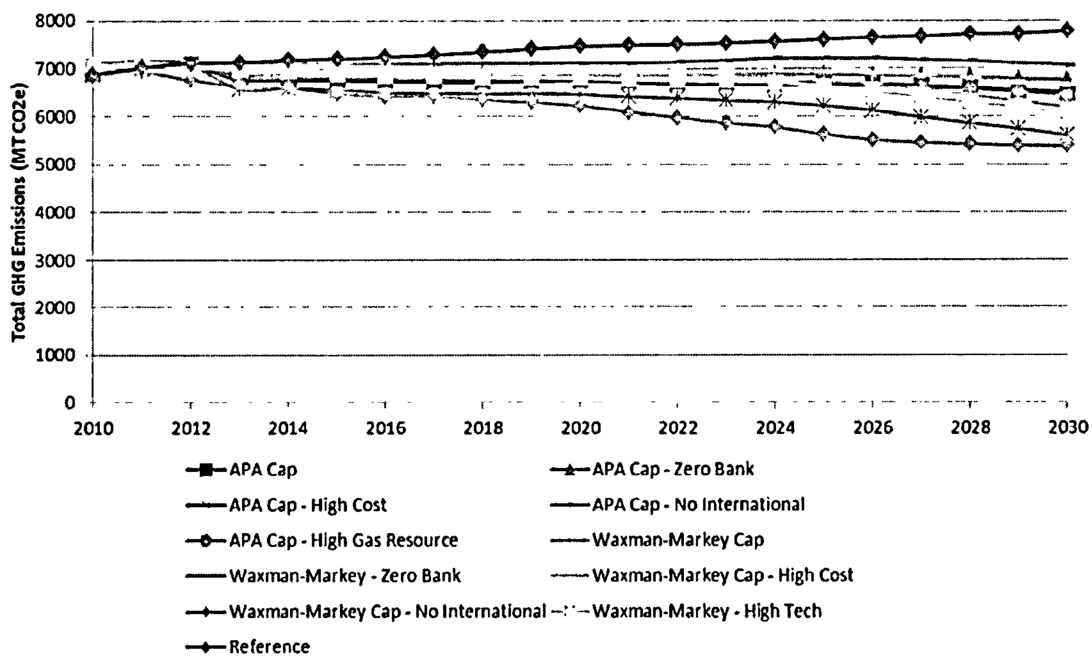
[12] US EIA. 2011. Analysis of Impacts of a Clean Energy Standard as requested by Chairman Bingaman. http://www.eia.gov/analysis/requests/ces_bingaman/.
[13] US EIA. 2012. Analysis of the Clean Energy Standard Act of 2012. http://www.eia.gov/analysis/requests/bces12/.
[14] A mill is one one-hundredth of a cent. Therefore, these CES prices in 2020 represent costs of 0.25 to 0.70 ¢/kWh, or \$2.5 to \$7/MWh.
[15] EPA Air Emissions Overview, Available at: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.htm

6. Key Factors Affecting Allowance Price Projections

Dozens of analyses over the past several years have shown that there are a number of factors that affect projections of allowance prices under federal greenhouse gas regulation. Some of these factors derive from the details of policy design, while others pertain to the context in which a policy would be implemented.

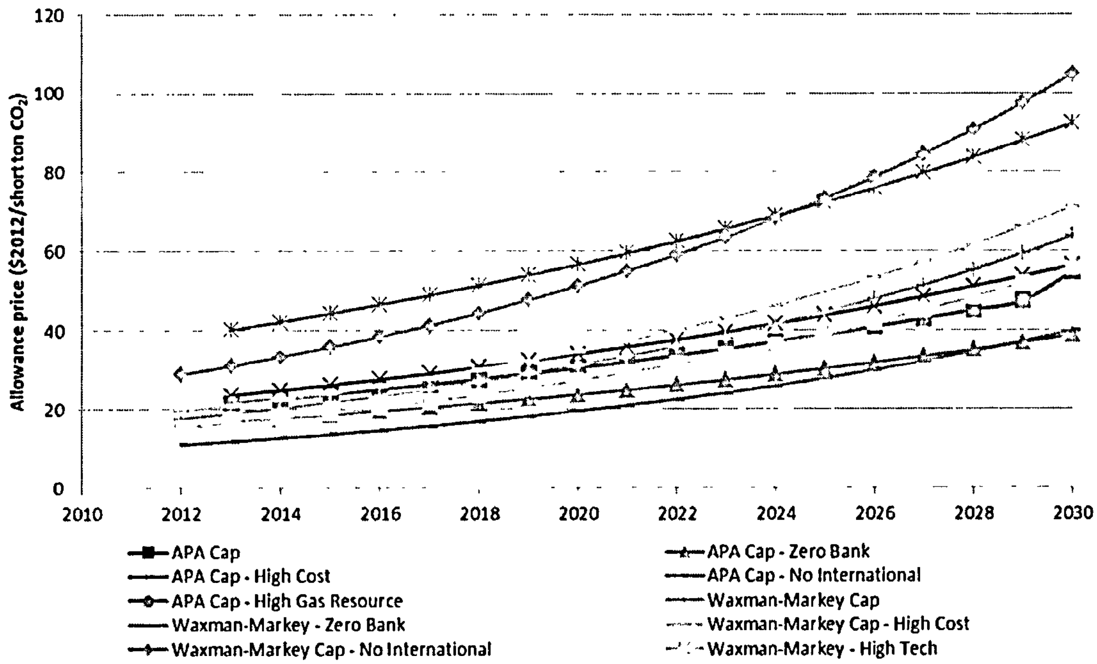
Factors in a forecast include: the base case emissions forecast; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps including international offsets) and allowance banking; assumptions about technological progress; the presence or absence of a "safety valve" price; and treatment of emissions co-benefits. Figures 5 and 6 show the very significant ranges in emissions and allowance prices for the Waxman-Markey and APA federal cap-and-trade policies, as well as several associated sensitivities, including assumptions on banking, international offsets, technology cost and progress, and gas supply.

Figure 5: GHG Emissions in Waxman-Markey and APA policies and sensitivities[16]



[16] Sources for Figure 5 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html

Figure 6: Allowance prices in ACES and APA policies and sensitivities[17]



A. Assessing the potential impact of a natural gas supply increase

The recent shale gas boom has put substantial downward pressure on natural gas prices. Several factors could influence future gas prices, including the estimated ultimate recovery per well and regulations addressing the environmental impacts of hydraulic fracturing.[18] The impact of higher or lower gas prices on carbon prices is uncertain. In the near term, lower natural gas prices are likely to make emissions mitigation in the electric sector less expensive, as gas power plants can displace coal plants at lower cost. Conversely, as marginal electricity prices are frequently set by natural gas plants, lower gas prices will contribute to lower electricity prices, potentially increasing electricity consumption and associated emissions. Lower electricity prices also make it more difficult for renewable technologies with even lower emissions than gas to compete in electricity markets.

In 2010, Resources for the Future (RFF) used a version of the EIA's National Energy Modeling System (NEMS) energy model to test effects of increased gas supply from shale gas on the economics of energy policy. Under a moderate climate policy, the high gas scenario decreased the 2030 allowance price by less than 1%, from $61.1 to $60.8 per ton of CO_2.[19] The EIA showed

[17] Sources for Figure 6 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html
[18] EIA (2012) "Projected natural gas prices depend on shale gas resource economics" http://www.eia.gov/todayinenergy/detail.cfm?id=7710
[19] Brown et al (2010). "Abundant Shale Gas Resources: Some Implications for Energy Policy". Available at: http://www.rff.org/RFF/Documents/RFF-BCK-Brownetal-ShaleGas.pdf

similar results in its analysis of the American Power Act: increased gas supply decreased the 2030 allowance price by less than 0.1%, from \$49.80 to \$49.78 per ton of CO_2.[20] In the policies studied by EIA and RFF, the result of an increased gas supply amounted to an inconsequential reduction in CO_2 prices. At this point it appears that, while a large shale gas resource may change how each policy is met, it is not a significant factor in the CO_2 cost that utilities should use for planning. Ongoing studies are expected to provide further insight into this issue.[21]

[20] EIA (2010) "Energy Market and Economic Impacts of the American Power Act of 2010". Available at: http://www.eia.gov/oiaf/servicerpt/kgl/index.html

[21] The Energy Modeling Forum will evaluate carbon constraints under cases of reference and high case supply levels in the EMF 26 study, which began in late 2011 and is ongoing (see http://emf.stanford.edu/research/emf_26/)

7. The U.S. Interagency Social Cost of Carbon

In 2010, the U.S. government began to use "social cost of carbon" values in an attempt to account for the damages resulting from climate change.[22] Four values for the social cost of carbon were initially provided by the Interagency Working Group on the Social Cost of Carbon, a group composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others. This group was tasked with the development of a consistent value for the global societal benefits of climate change abatement. These values, $5, $21, $35, and $65 per metric tonne of CO_2 in 2007 dollars ($4.9, $20.7, $34.5, and $64.0 per ton in 2012 dollars), reflected three discount rates and one estimate of the high cost tail-end of the distribution of impacts. As of May 2012, these estimates have been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[23]

The U.S. "social cost" values are the result of analysis using the DICE, PAGE, and FUND integrated assessment models. The combination of complex climate and economic systems with these reduced-form integrated assessment models leads to substantial uncertainties. In a 2012 paper, Ackerman and Stanton[24] explored the impact of specific assumptions used by the Interagency Working Group, and found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater. Despite limitations in the calculations for the social cost of carbon stemming from the choice of socio-economic scenarios, modeling of the physical climate system, and quantifying damages around the globe for hundreds of years into the future, this multi-agency effort represents an important initial attempt at incorporating consistent values for the benefits associated with CO_2 abatement in federal policy.

[22] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

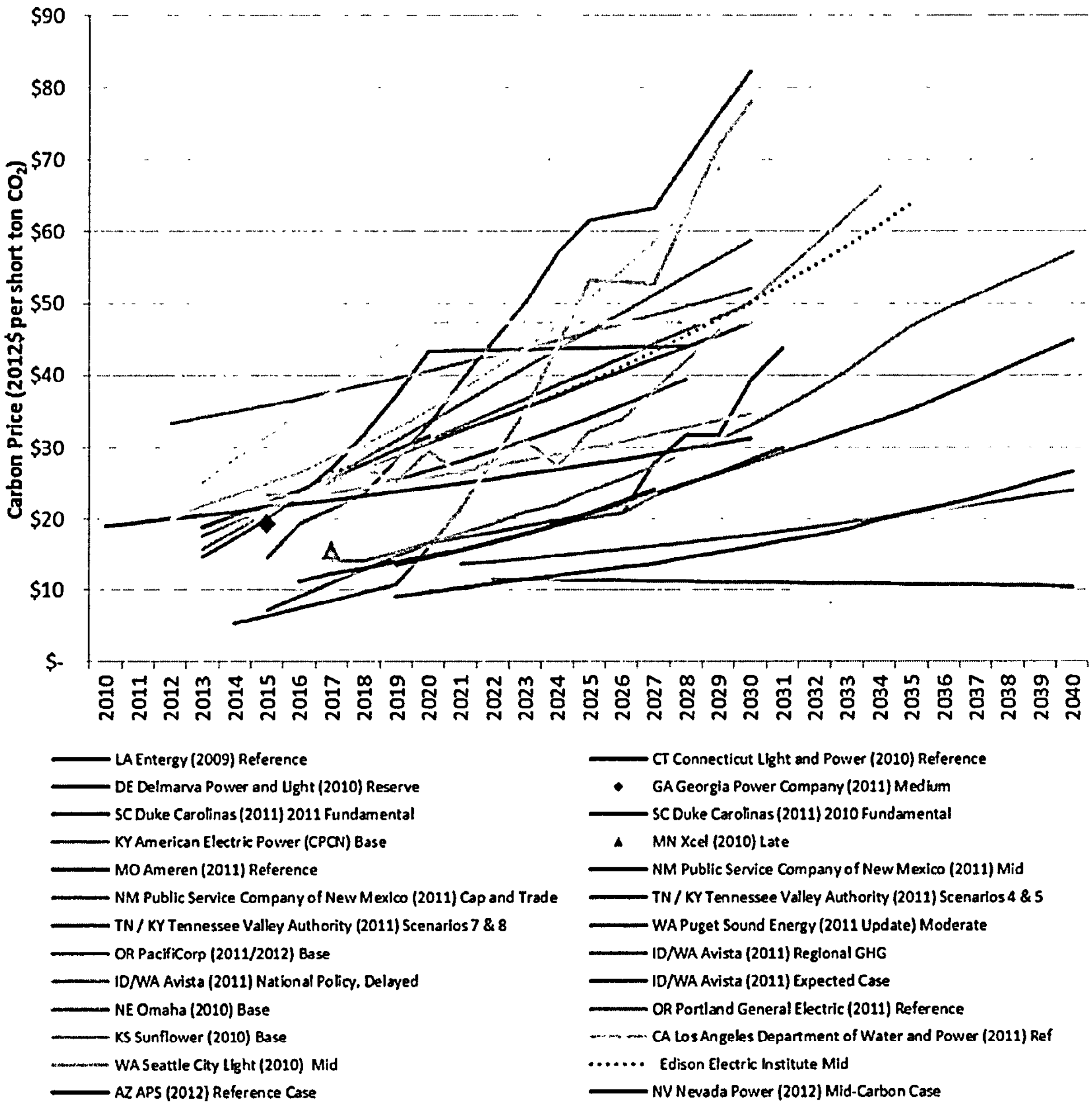
[23] Robert E. Kopp and Bryan K. Mignone (2012). The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15

[24] Frank Ackerman and Elizabeth A. Stanton (2012). Climate Risks and Carbon Prices: Revising the Social Cost of Carbon. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10

8. CO_2 Price Forecasts in Utility IRPs

A number of electric companies have included projections of costs associated with greenhouse gas emissions in their resource planning procedures. Figure 7 presents the mid-case values of publicly available forecasts used by utilities in resource planning over the past three years.

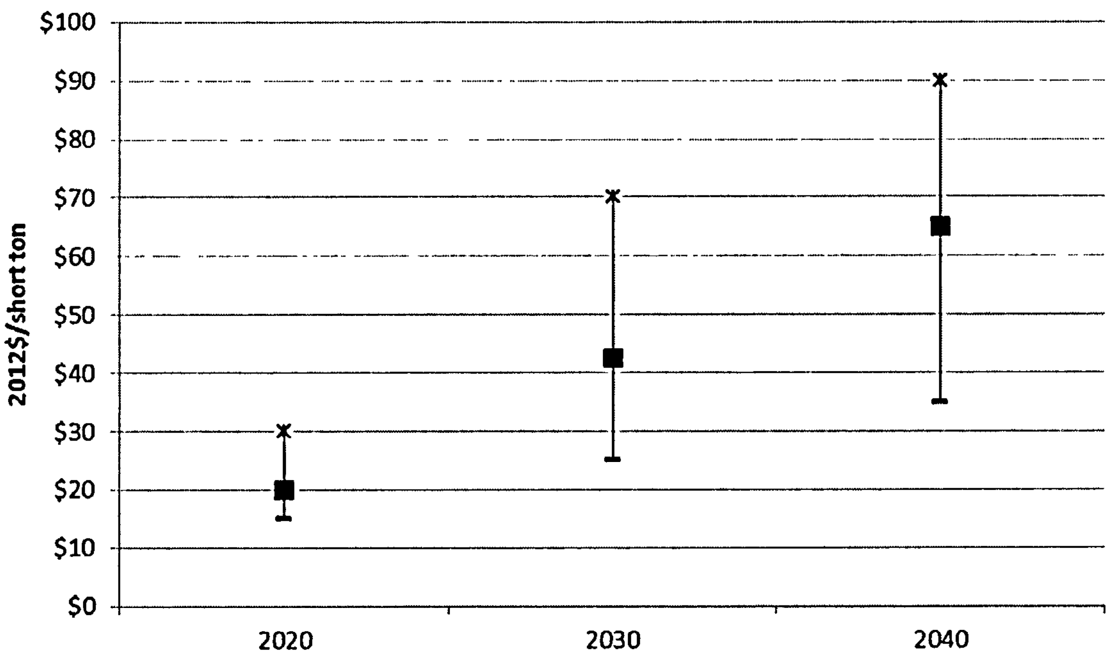
Figure 7: Utility Mid Case CO_2 Price Forecasts



9. Recommended 2012 CO_2 Price Forecast

Based on analyses of the sources described in Sections 4 through 8, and relying on our own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2020 to 2040. Figure 8 shows the range covered by the Synapse forecasts in three years: 2020, 2030, and 2040. These forecasts share the common assumption that a federal cap-and-trade policy will be passed sometime within the next five years, and will go into effect in 2020. All annual allowance prices and levelized values are reported in 2012 dollars per ton of carbon dioxide.[25]

Figure 8: Synapse 2012 Forecast Values



Each of the forecasts shown in Figure 8 represents a different appetite for reducing carbon, as described below.

- The Low case forecast starts at $15/ton in 2020, and increases to approximately $35/ton in 2040, representing a $23/ton levelized price over the period 2020-2040. This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly—for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility. This price forecast could also be realized through a series of complementary policies, such as an aggressive federal Renewable Portfolio Standard, substantial energy efficiency investment, and/or more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario). Such complementary policies would

[25] All values in the Synapse Forecast are presented in 2012 dollars. Results from EIA and EPA modeling analyses were converted to 2012 dollars using price deflators taken from the US Bureau of Economic Analysis, and available at: http://www.bea.gov/national/nipaweb/SelectTable.asp Because data were not available for 2012 in its entirety, values used for conversion were taken from Q2 of each year. Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

lead directly to a reduction in CO_2 emissions independent of federal cap-and-trade, and would thus lower the expected allowance prices associated with the achievement of any particular federally mandated goal.

- The Mid case forecast starts at $20/ton in 2020, and increases to approximately $65/ton in 2040, representing a $39/ton levelized price over the period 2020-2040. This forecast represents a scenario in which a federal cap-and-trade program is implemented with significant but reasonably achievable goals, likely in combination with some level of complementary policies to give some flexibility in meeting the reduction goals. These complementary policies would include renewables, energy efficiency, and transportation standards, as well as some level of allowance banking and offsets. Also assumed in the Mid case is some degree of technological learning, i.e. assuming that prices for emissions reductions technologies will decline as greater efficiencies are realized in their design and manufacture and as new technologies become available.
- The High case forecast starts at $30/ton in 2020, and increases to approximately $90/ton in 2040, representing a $59/ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

Synapse's Low, Mid, and High case price projections for each year of the study period are presented in graphic and tabular form, below.

Figure 9: Synapse 2012 CO_2 Price Trajectories

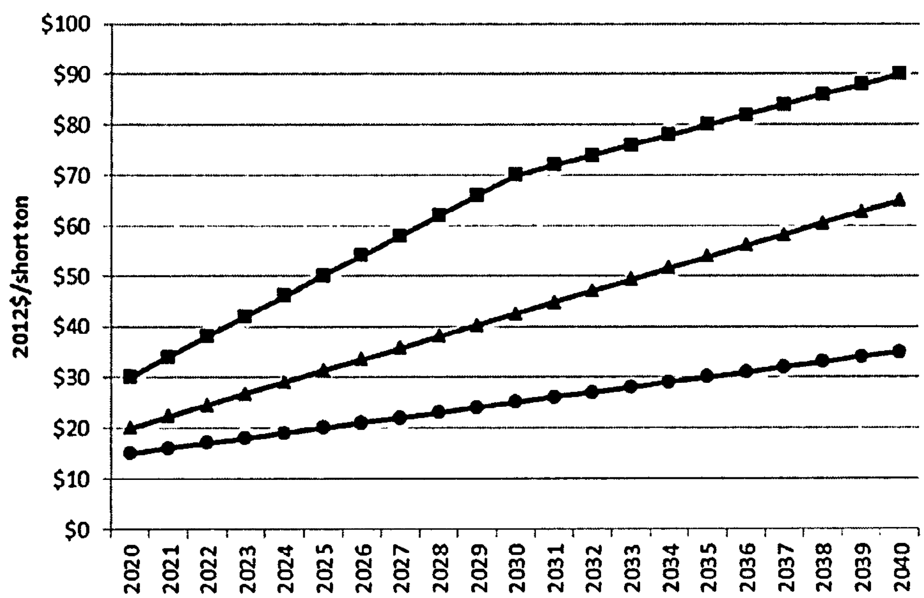


Table 1: Synapse 2012 CO_2 Allowance Price Projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$30.00
2021	$16.00	$22.25	$34.00
2022	$17.00	$24.50	$38.00
2023	$18.00	$26.75	$42.00
2024	$19.00	$29.00	$46.00
2025	$20.00	$31.25	$50.00
2026	$21.00	$33.50	$54.00
2027	$22.00	$35.75	$58.00
2028	$23.00	$38.00	$62.00
2029	$24.00	$40.25	$66.00
2030	$25.00	$42.50	$70.00
2031	$26.00	$44.75	$72.00
2032	$27.00	$47.00	$74.00
2033	$28.00	$49.25	$76.00
2034	$29.00	$51.50	$78.00
2035	$30.00	$53.75	$80.00
2036	$31.00	$56.00	$82.00
2037	$32.00	$58.25	$84.00
2038	$33.00	$60.50	$86.00
2039	$34.00	$62.75	$88.00
2040	$35.00	$65.00	$90.00
Levelized	$23.24	$38.54	$59.38

The following charts compare the Synapse Mid, High, and Low case forecasts against various utility estimates. Data on utility estimates was collected from a wide range of available public Integrated Resource Plans (IRPs). We have excluded several IRPs with zero carbon prices or IRPs with no carbon price given, accounting for 9 of 65 collected.

Figure 10 shows 26 utility CO_2 price forecasts, with 2030 prices ranging from \$10/tCO_2 to above \$80/tCO_2. Due to the extended development period of many IRPs, some of these forecasts may not accurately reflect very recent years; a NM Public Service forecast, for example, begins in 2010, when there was no economy-wide CO_2 price. Nevertheless, IRPs do their best to represent accurate views of the future, in order to develop least-cost plans. The Synapse Mid forecast, beginning at \$20/tCO_2 and rising to \$65/tCO_2, lies well within the range of the mid-case forecasts shown here.

Figure 10: Synapse 2012 Mid forecast as compared to the Mid forecasts of various U.S. utilities (2010-2012)[26]

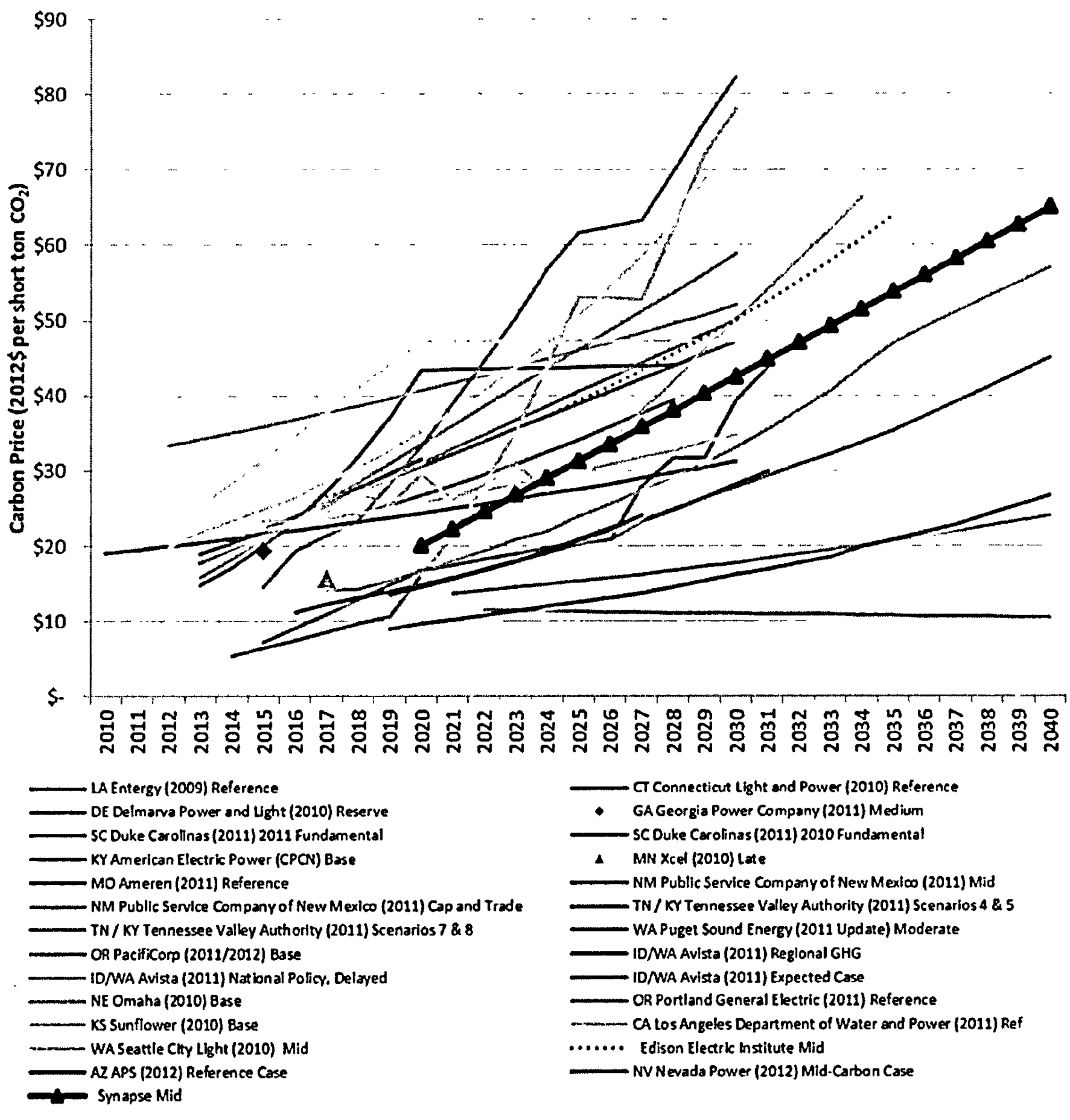


Figure 11 overlays the Synapse High case and the high case forecasts of many IRPs on top of the utility mid case forecasts shown in Figure 10 (now shaded in grey). Not all IRPs that provide mid-level forecasts also provide high forecasts. The high cases generally reflect a nearer-term policy start date, as well as a more rapid rate of increase in prices with time. The Synapse forecast starts later than most, and rises from $30/tCO_2$ in 2020 to $90/tCO_2$ in 2040.

[26] Legend given here is common to all subsequent utility price forecast charts. While scenario names may change, colors are constant for a given utility.

Figure 11: Synapse High forecast as compared to the High and Mid forecasts of various utilities (see legend in Figure 10)

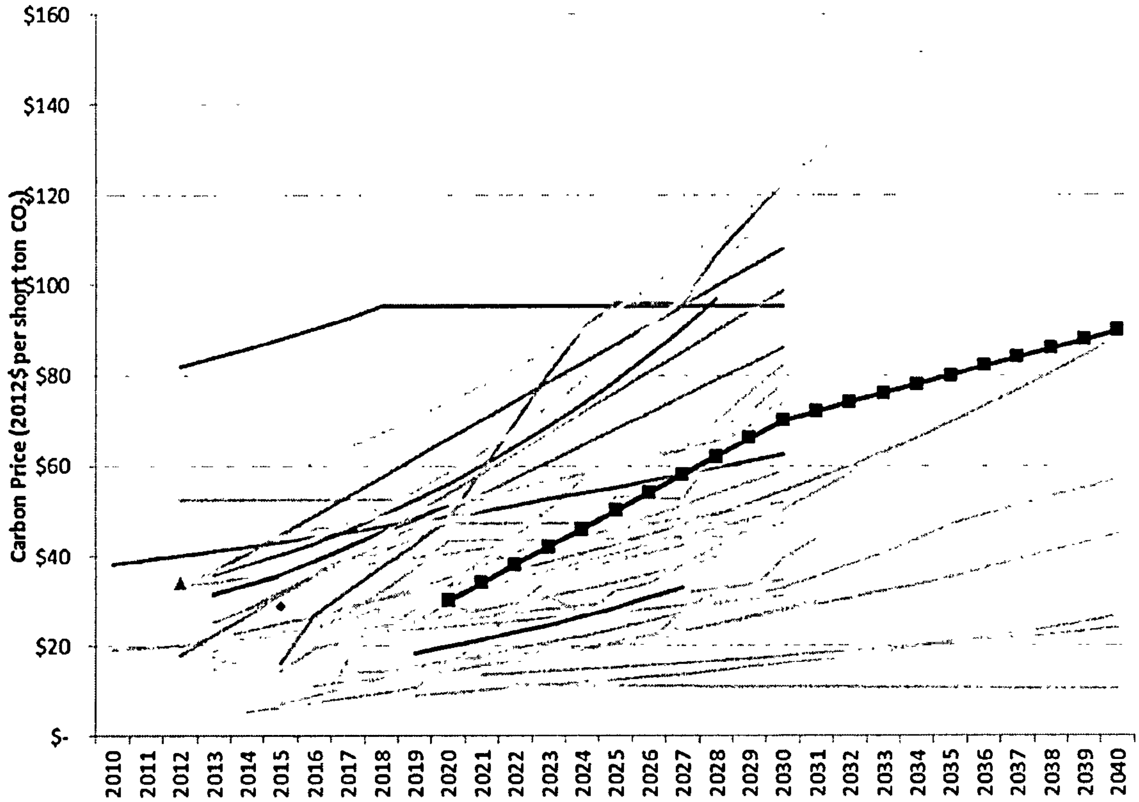


Figure 12 overlays the Synapse Low case and the low case forecasts of many IRPs on top of the utility mid case forecasts shown in Figure 10 (shaded in grey). The low case forecasts both start at substantially lower values (occasionally at zero values), and rise at slower rates. The Synapse forecast starts later than most and rises from $15/t$CO_2$ in 2020 to $35/t$CO_2$ in 2040.

Figure 12: Synapse Low forecast as compared to the Low and Mid forecasts of various utilities (see legend in Figure 10)

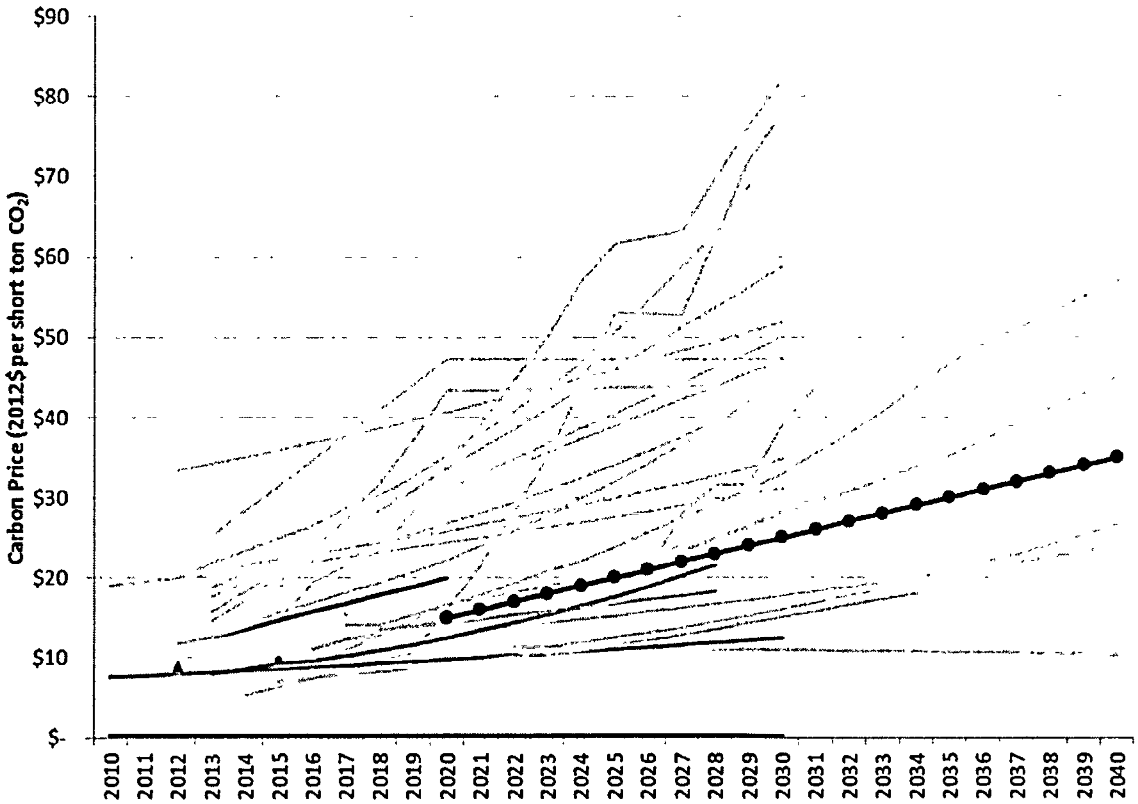


Figure 13 shows Synapse's Low, Mid, and High forecasts compared to the full range of utility forecasts shown above. The Synapse projections represent a plausible range of possible future costs. Using all three recommended price trajectories will facilitate sensitivity testing of long-term investment decisions in electric sector resource planning against likely federal climate policy scenarios.

Figure 13: Synapse forecasts compared to the range of utility forecasts

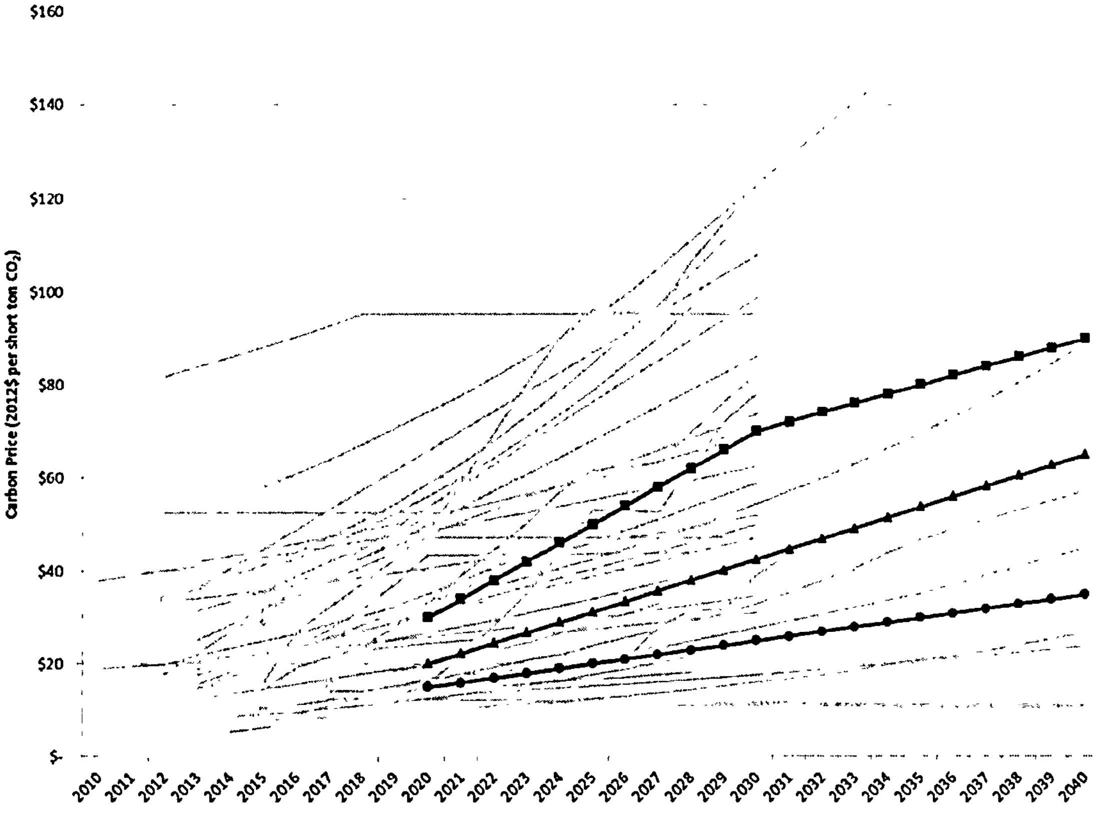
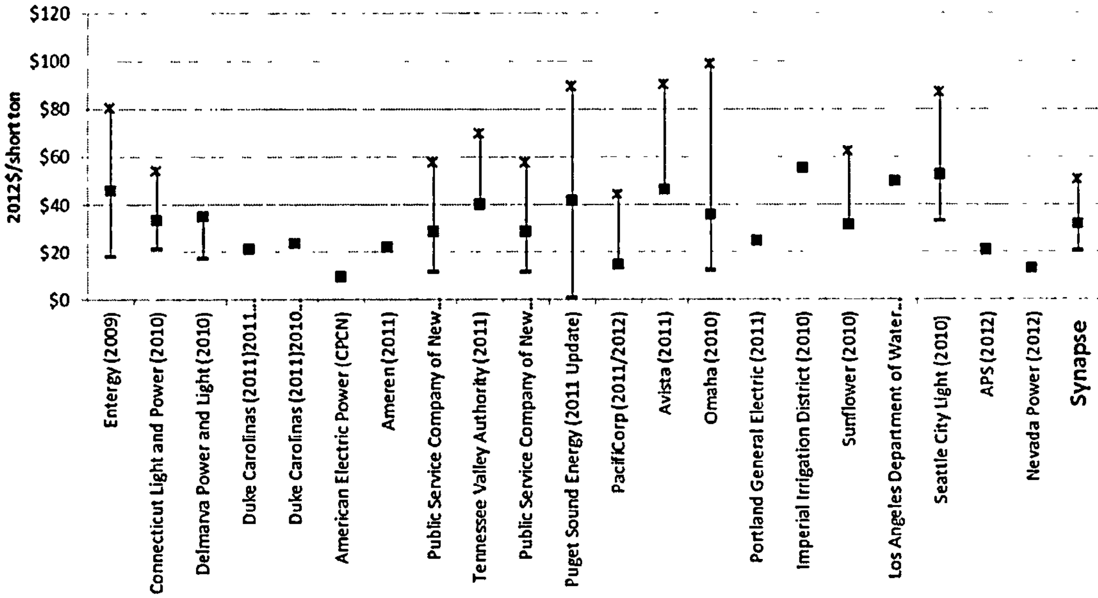


Figure 14 compares the levelized costs of Synapse's Low, Mid, and High cases to the levelized costs of utility estimates for 2020 through 2030, a period after the start and before the end of most forecasts. While levelizing between 2020 and 2030 results in different Synapse values than presented in Table 1 (where forecasts were levelized between 2020 and 2040), this approach allows for overlap and comparison with a broader range of utility estimates.

Figure 14: Levelized price of CO_2, 2020-2030, utilities and Synapse[27]



[27] All forecasts are levelized with a 5% discount rate based on CO_2 prices between 2020 and 2030. Forecasts with a price for only a single year excluded.

Appendix A: State and Regional GHG Initiatives

The states—individually and coordinating within regions—are leading the nation's policies to respond to the threat of climate change. In fact, several states, unwilling to postpone and wait for federal action, are pursuing policies specifically because of the lack of federal legislation.

This appendix provides a more thorough discussion of state and regional greenhouse gas (GHG) initiatives. Collectively, these initiatives suggest that momentum is building toward more comprehensive federal GHG action.

Cap-and-trade programs

The Northeast/Mid-Atlantic region and the state of California have developed, or are in the last stages of developing, greenhouse gas caps and allowance trading. [28]

Regional Greenhouse Gas Initiative: The Regional Greenhouse Gas Initiative (RGGI) is an effort of ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions, and is the first market-based CO_2 emissions reduction program in the United States. Participating states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten percent reduction in these emissions from levels at the start of the program by 2018.[29] This is the first mandatory carbon trading program in the nation. Recently, allowance prices have been hitting the CO_2 price floor, as actual emissions are far below the budget of 188 mtons/year.

California: In 2006, the California Legislature passed the Global Warming Solutions Act (AB 32), which requires the state to reduce emissions of GHGs to 1990 levels by 2020. The California Air Resources Board (CARB) outlined more than a dozen measures to reduce carbon emissions to target levels in its 2008 *Scoping Plan*. Those measures include a renewable portfolio standard, a low carbon fuel standard, and a cap-and-trade program. Approximately 22.5% of the emissions reductions called for by AB 32 are estimated to occur under the cap-and-trade program. California will have the world's second largest carbon market, after the European Union's Emissions Trading System (EU ETS).

The first compliance period for the program will begin on January 1, 2013, and will cover electricity generators, carbon dioxide suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 25,000 metric tons of CO_2e per year. The second compliance period will run from 2015-2017, and the third compliance period will cover 2018-2020. During these periods, the cap-and-trade program will expand to cover suppliers of natural gas, distillate fuel oil, and liquefied petroleum gas if the combustion of their products would result in 25,000 metric tons of CO_2e or more.[30] The initial cap is set at 162.8 million metric tons of CO_2e and decreases by 2% annually through 2015. When additional sources are added, the cap increases to accommodate them, but then increases the percentage reductions in emissions to 3% in 2016, rising to 2.5% in 2020. The state plans to allocate the bulk of allowances for free in 2013, but will gradually auction

[28] The Midwest Greenhouse Gas Reduction Accord was developed in 2007. Though the agreement has not been formally suspended, the participating states are no longer pursuing it.
[29] The ten states are: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Information on the RGGI program, including history, important documents, and auction results is available on the RGGI Inc website at www.rggi.org
[30] §95812 (d)(1), page 48

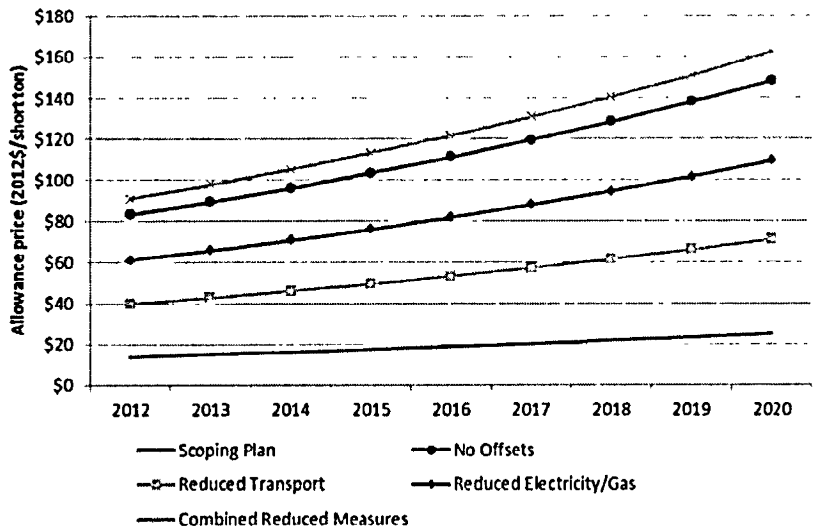
an increasing number of allowances between 2013 and 2020. Banking[31] and offsets[32] are both allowed under the California program.

The state of California has set a floor price for allowances beginning at $9.1/ton in 2013 ($10/metric tonne), and rising annually by 5% plus the rate of inflation.[33] In 2010 the Air Resources Board modeled the CO_2 allowance price trajectory that would enable reduction targets to be met under the following five cases:

1. Scoping Plan: Implements all of the measures contained in CARB's *Scoping Plan*
2. No Offsets: Does not allow offsets in the cap-and-trade program
3. Reduced Transport: Examines less effective implementation of the transportation-sector measures
4. Reduced Electricity/Gas: Examines less successful implementation of the electricity and natural gas measures
5. Combined Measures Reduced: Examines less successful implementation of transportation, electricity, and natural gas measures[34]

These five cases represent different scenarios of regulatory programs which, although different from the cap-and-trade program, can simultaneously help to achieve the goals of cap-and-trade. These regulatory measures are known as complementary policies. Figure A-1 shows the allowance price trajectories associated with those five cases.

Figure A-1: AB 32 Modeled Allowance Price Trajectories[35]



[31] §95922 (a), page 151
[32] §95973 (a)(2)(C), page 156
[33] §95911 (b)(6), page 129
[34] California Air Resources Board. *Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board.* March 24, 2010. Page ES-6.
[35] Id. Page 40.

As shown in Figure A-1, when the policies that are complementary to the cap-and-trade program are less effective, greater CO_2 reductions need to occur under the cap-and-trade program, and the allowance price is much higher. Similarly, the availability of offsets lowers the allowance price in the cap-and-trade program, as compliance with reduction targets can be met with offsets. This allows banking of allowances in the beginning of the program, which can keep allowance prices lower in later years.

California's first allowance auction is scheduled for November 14. A trial auction was completed on August 30, and more than 430 entities that will be regulated under the cap-and-trade program were invited to participate. CARB does not plan to release a settlement price, but on the date of the test auction, futures for December 2013 were trading at $14.77/ton, and forward contracts had sold for $14.77 and $14.82/ton.

State GHG reduction laws

Massachusetts: In 2008, the Massachusetts Global Warming Solutions Act was signed into law. In addition to the commitments to power sector emissions reductions associated with RGGI, this law committed Massachusetts to reduce statewide emissions to 10-25% below 1990 levels by 2020 and 80% below 1990 levels by 2050. Following the development of a comprehensive plan on steps to meet these goals, the 2020 target was set at 25% below 1990 levels.[36] Rather than put a price on carbon in the years before 2020, this plan will achieve a 25% reduction through a combination of federal, regional, and state level regulations applying to buildings, energy supply, transportation, and non-energy emissions.

Minnesota: In 2008, the Next Generation Energy Act was signed to reduce Minnesota emissions by 15% by 2015, 30% by 2025, and 80% by 2050.[37] While the law called for the development of an action plan that would make recommendations on a cap-and-trade system to meet these goals, the near-term goals will be met by a combination of an aggressive renewable portfolio standard and energy efficiency.

Connecticut: Also in 2008, the state of Connecticut passed its own Global Warming Solutions Act, establishing state level targets 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In December 2010, the state released a report on mitigation options focused on regulatory mechanisms in addition to strengthening RGGI and reductions of non-CO_2 greenhouse gases.[38]

Renewable portfolio standards and other initiatives

A renewable portfolio standard (RPS) or renewable goal specifies that a minimum proportion of a utility's resource mix must be derived from renewable resources. These policies require electric utilities and other retail electric providers to supply a specified minimum amount—usually a percentage of total load served—with electricity from eligible resources. The standards range from modest to ambitious, and qualifying energy sources vary by state.

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[36] Massachusetts Clean Energy and Climate Plan for 2020, Available at: http://www.mass.gov/green/cleanenergyclimateplan

[37] Minnesota Statutes 2008 § 216B.241

[38] See http://www.ctclimatechange.com for further details on CT plans for emissions mitigation.

In general the goal of an RPS policy is to increase the development of renewable resources by creating a market demand. Increasing demand makes these technologies more economically competitive with other less expensive, but polluting, forms of electric generation. Many other policy objectives drive the adoption of an RPS or renewable goal, including climate change mitigation, job creation, energy security, and cleaner air.

The impact of an RPS on CO_2 emissions is dependent on factors such as:

- the types of resources that are eligible to meet the standard,
- the target level set by the RPS,
- the base quantity of electricity sales upon which the standard is set,
- how renewable energy credits (RECs) or attributes are tracked or counted,
- how RECs are assigned to different resources,
- banking, trading and borrowing of RECs,
- alternative compliance options, and
- coordination with other state and federal policies.

Currently, 29 US states have renewable portfolio standards. Eight others have renewable portfolio goals.

In addition, many states are pursuing other policy actions relating to reductions of GHGs. These policies include, but are not limited to: greenhouse gas inventories; greenhouse gas registries; climate action plans, greenhouse gas emissions targets, and emissions performance standards.

In the absence of a clear and comprehensive federal policy, many states have developed a broad array of emissions and energy related policies. For example, Massachusetts has a RPS of 15% in 2020 (rising to 25% in 2030), belongs to RGGI, requiring specific emissions reductions from power plants in the state, and has set in place aggressive energy efficiency targets through the 2008 Green Communities Act.

Hawaii, while not part of a regional climate initiative, has an even more aggressive RPS, seeking to achieve 40% renewable energy by 2030, coupled with an Energy Efficiency Portfolio Standard with the goal of reducing electricity use by 4,300 GWh by 2030. After 2013, 2% of electricity revenues in Hawaii will go towards a Public Benefit Fund, an independent entity tasked with promoting and incentivizing energy efficiency measures across the state.