ORNL/CON-485

The Potential Economic Impact of Electricity Restructuring in the State of Oklahoma: Phase II Report

October 2001

Prepared by
S. W. Hadley, C. R. Hudson, D. W. Jones, D. P. Vogt
Power Systems Research Program

ORNL/CON-485

ENGINEERING SCIENCE AND TECHNOLOGY DIVISION

THE POTENTIAL ECONOMIC IMPACT OF ELECTRICITY RESTRUCTURING IN THE STATE OF OKLAHOMA

PHASE II REPORT

S. W. Hadley
C. R. Hudson
D. W. Jones
D. P. Vogt

October 2001

Sponsored by
The Oklahoma Corporation Commission
P.O. Box 52000-2000
Oklahoma City, OK 73152-2000

OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37831
managed by
UT-BATTELLE, LLC
for the
U.S. DEPARTMENT OF ENERGY
under contract No. DE-AC05-00OR22725

CONTENTS

EXECUTIVE SUMMARY

Because of the recent experiences of several states undergoing restructuring (e.g., higher prices, greater volatility, lower reliability), concerns have been raised in states currently considering restructuring as to whether their systems are equally vulnerable. Factors such as local generation costs, transmission constraints, market concentration, and market design can all play a role in the success or failure of the market. These factors along with the mix of generation capacity supplying the state will influence the relative prices paid by consumers.

The purpose of this project is to provide a model and process to evaluate the potential price and economic impacts of restructuring the Oklahoma electric industry. The Phase I report concentrated on providing an analysis of the Oklahoma system in the near-term, using only present generation resources and customer demands. This Phase II study analyzed the Oklahoma power market in 2010, incorporating the potential of new generation resources and customer responses.

Five key findings of this Phase II were made:

- Projected expansion in generating capacity exceeds by over 3,000 MW the demands within the state plus the amount that could be exported with the current transmission system.
- Even with reduced new plant construction, most new plants could lose money (although residential consumers would see lower rates) unless they have sufficient market power to raise their prices without losing significant market share (Figure S-1).
- If new plants can raise prices to stay profitable, existing low-cost coal and hydro plants will have very high profits. Average prices to customers could be 5% to 25% higher than regulated rates (Figure S-1). If the coal and hydro plants are priced at cost-based rates (through long-term contracts or continued regulation) while all other plants use market-based rates then prices are lower.
- Customer response to real-time prices can lower the peak capacity requirements by around 9%, lowering the need for new capacity and reduce prices during the peak demand.
- Changes to electric prices on the order of 5% to 20% will have only a modest effect on overall economic activity within the state.

SUPPLY AND DEMAND

The total of existing and proposed capacity equals 25,690 MW, with a large fraction of that being new combined cycle plants to be built in the next four years or so (Table S-1). Consumer demands within the state are projected to grow 26% by 2010, totaling 14,340 MW. Simple expansion of current exports would set their peak at 990 MW. Total exports could increase greatly, limited by the maximum capacity of transmission lines exiting the state at approximately 6,050 MW. This would give a total peak demand of 20,390 MW. Dividing capacity by peak demand gives a reserve margin if all plants are built of 26% in 2010 and even higher in earlier years. While some reserve is required for reliability reasons, such a high level of excess capacity is not sustainable in a restructured market.

Table S-1: Projected electricity supply and demand for Oklahoma in 2010.

Supply, MW		Demand, MW	
Existing Plants	12,170	**Residential**	7,510
New Combined Cycle	11,850	**Commercial**	3,350
New Combustion Turbine	1,670	**Industrial**	2,910
		Other	570
		Max exports	6,050
Total	25,690	**Total**	20,390

In fact, there is a growing realization that the market may be set for a bust in the near future. According to Christopher Ellinghaus, an investment banker at Williams Capital Group, power companies across the country have proposed 350,000 MW of new plants by 2004, but only 100,000 MW of this is actually expected to be built (Bannerjee, 2001). According to the New York Times article, transmission constraints and power plant economics are both playing a role in the lowering of expectations. Many of the announcements of new capacity were based on the expectation of broadly rising prices, as exemplified by California and the entire western region. With the recent decline in wholesale prices, new plant economics are not as favorable.

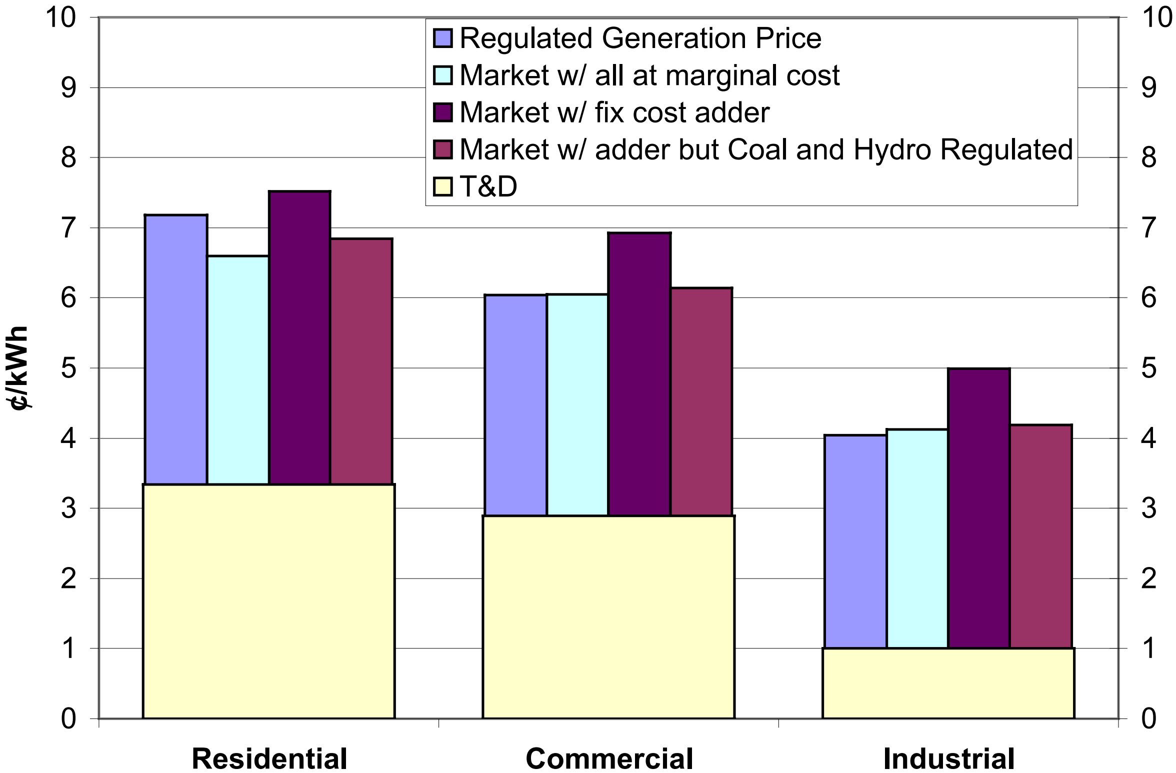
Furthermore, many of the plants are being located in states with large gas resources, such as Oklahoma, Texas, and Louisiana. However, transmission systems are not being upgraded quickly enough to be able to ship this excess capacity to states needing it. In Oklahoma, only one additional 345 kV line is planned between now and 2010. Expansion of the transmission system is more difficult to construct than new generation. Current transmission owners see little benefit to build since it dilutes the value of their existing lines and/or regulated returns are low. Owners of plants in high-cost regions may also prefer constraints that keep low-cost power out. Landowners do not see the benefit since the power is to be used by others far away. Even intervening states frequently object to new lines. For example, Connecticut recently vetoed a needed transmission line to Long Island (Behr 2001).

MARKET PRICING AND PLANT PROFITABILITY

In a purely competitive market where supply bids into a market until demand is satisfied, the optimum bid for any supplier is to price their product at its marginal cost. Prices then are set by the highest price bid that fulfills demand. The problem for the electric industry is that in an industry with a high ratio of fixed to variable costs, there is a greater likelihood that the resulting prices will not cover their fixed costs, leading to boom and bust cycles. Examples include such industries as airlines, steel, and cement. In many such industries, what happens is a shortage that boosts profits, leading to a build-up of capacity that then leads to temporary cutbacks as demand and supply constantly equilibrate. The lack of an economical electrical storage mechanism and the large sizes of plants makes this process potentially even more of a problem for the electric generation business. The inelasticity of supply and demand can lead to great volatility.

Average prices for the modeled Oklahoma market under regulated rates and with all plants pricing at the market are shown in Figure S-1. However, in this scenario most new plants lose money. If plants could raise prices by adding some of their fixed costs into their price, they become profitable but prices rise for all consumers.

Figure S-1: Consumer prices under regulation and with different market scenarios.



Plants are very reliant on the existence of higher-priced plants in order to make their profits in a spot market. Even if a large segment of the capacity raises its price, it risks being undercut by other plants unless they bid to just below the others' marginal cost. The incentive for individual plants to "cheat" and lower their bids can undermine the market power potential. Only if a substantial majority of the participants in the market, especially those with higher costs, raise their bids proportionately, do profits rise for all.

Withholding capacity can be successful in increasing profits, but only if the market is constrained so that other producers (internal or external to the state) cannot offset the capacity except at higher prices. Long-term contracts can mitigate the volatility of spot markets, with prices likely approaching the regulated rates. In the actual market, companies may choose to sell some of their generation under long-term contracts, some on the day-ahead or spot market, some as either a spinning or non-spinning reserve, as well as save some for internal use if it is a cogeneration project. All of these factors influence the final market and prices to consumers.

REGULATION OF EXISTING LOW-COST PLANTS

Among the major beneficiaries of a change to pricing using market-based prices are the existing low-cost producers, notably coal and hydro facilities. These two plant types would receive prices much higher than their average costs plus a reasonable return. It might be feasible during restructuring to mandate that they sell their power at cost plus a reasonable profit, instead of at the full market rates. There are precedents of this in other states. For example, as part of its restructuring, California required that the nuclear and hydro facilities owned by the investor-owned utilities price their production at cost. While the rest of the production in the state became very expensive this past year, the nuclear and hydro plants provided some measure of stability.

The utilities in many states undergoing restructuring have been faced with the problem of paying for power plants that were more expensive than the market would bear. Oklahoma is faced with the opposite situation; many of its existing power plants, especially the coal and hydro plants, have costs much lower than the expected market prices. It may be advisable that some or all of this difference be returned to customers in some fashion, through mechanisms such as continued cost-based pricing (as we modeled), rebates following the sale of plants, or other mechanisms. Figure S-1 shows the price impact if these plants continue to price based on their regulated costs.

RESPONSE OF CUSTOMERS TO REAL-TIME PRICES

Customer response to high peak prices lowered the peak demand by roughly 9% in our model, lessening the need for new capacity. The response of customers to real-time prices has a modest effect on average prices paid. Its larger impact is on prices paid at the peak. In the case without elasticity impacts, market prices were 120 ¢/kWh during the short time when all plants were at full capacity. In the case with elasticity this price peaked at 100 ¢/kWh. With elasticity and consequent flatter demand profile, peak prices do not have to rise as much to lower demand to available capacity.

OVERALL ECONOMIC IMPACT TO STATE

The scenario with the highest price increases raised prices an average of 12 percent, in a commodity that accounts for 2.3 percent of state production. Against this aggregate backdrop, it is not surprising that the electricity rate changes have very small impacts on the overall economy of the state. Depending on the price-change scenario, employment in the state could fall by three or four one-hundredths of one percent while other property income could rise by about one-third of one percent. The differences in impact across the scenarios also are small.

These impact projections are likely to be on the high side of actual, long-run impacts, since the assumptions of the input-output framework, as well as assumptions we adopted for this study, minimize the opportunities to substitute away from electricity in both final and intermediate demands. We did not attempt to simulate the potential for substitution away from electricity into natural gas for some energy uses, but over a five- to ten-year period, if some classes of rates stayed twenty to twenty-five percent higher, some substitutions surely would occur in specific uses such as heating, air conditioning and water heating.

LIST OF FIGURES AND TABLES

ACRONYMS

CC	Combined Cycle
CT	Combustion Turbine
DEQ	Oklahoma Department of Environmental Quality
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
NERC	North American Electric Reliability Council
O&M	Operations and Maintenance
OCC	Oklahoma Corporation Commission
ORCED	Oak Ridge Competitive Electricity Dispatch model
ORNL	Oak Ridge National Laboratory
RDI	Resource Data International
ROE	Return on Equity
SPP	Southwest Power Pool
T&D	Transmission and Distribution

1 Introduction

In April 1997, the Oklahoma legislature passed a bill to restructure the state's electric industry, requiring that the generation sector be deregulated and allowing retail competition by July 2002. Details of the market structure were to be established later. Senate Bill #220, introduced in the 2000 legislature, provided additional details on this market, but the bill did not pass. Subsequent discussions have identified the need for an objective analysis of the impact of restructuring on electricity prices and the state's economy, especially considering the experiences of other states following restructuring of their electric systems.

Because of the recent experiences of other states undergoing restructuring (e.g., higher prices, greater volatility, lower reliability), concerns have been raised in states currently considering restructuring as to whether their systems are equally vulnerable. Factors such as local generation costs, transmission constraints, market concentration, and market design can all play a role in the success or failure of the market. Energy and ancillary services markets both play a role in having a well-functioning system. Customer responsiveness to market signals can enhance the flexibility of the market.

The purpose of this project is to provide a model and process to evaluate the potential price and economic impacts of restructuring the Oklahoma electric industry. The goal is to provide sufficient objective analysis to the Oklahoma legislature that they may make a more informed decision on the timing and details of any future restructuring. It will also serve to inform other stakeholders on the economic issues surrounding restructuring. The project is being conducted in two phases. The Phase I report (Hadley 2001) concentrated on providing an analysis of the Oklahoma system in the near-term, using only present generation and transmission resources. This Phase II report looks further in the future, incorporating the potential of new generation resources. Changes in the market structure due to additional capacity, pricing mechanisms, and export markets are considered.

During the initial phase of the analysis, Oak Ridge National Laboratory (ORNL) developed a benchmark or base case based on the existing set of plants, customer demands, and regulated power prices. Generation and electric market data were gathered from the Department of Energy's Energy Information Administration (EIA), Resource Data International (RDI), the North American Electric Reliability Council (NERC), and the Oklahoma Corporation Commission (OCC). An ORNL-specialized model, the Oak Ridge Competitive Electricity Dispatch (ORCED) model, was used to evaluate the marginal-cost-based prices for the state.

In this second phase of the study, we advanced the supplies and demands amounts to model the year 2010. We considered the potential expansion of the electricity export market as constrained by the available transmission capacity. Resulting power prices were adjusted to show the impact of market power in bidding and the continued regulation of some power plants. Using the real-time prices, we adjusted customer load profiles based on their price elasticity and reevaluated the impact of restructuring on consumer prices. Lastly, we used an input/output economic simulation of the Oklahoma economy to determine the broader economic impacts of changes in prices.

2 Background

2.1 Recap of Phase I Analysis

The Phase I study provided a view of the Oklahoma electricity market if restructuring occurred in 1999. Customer demands and power plant production were found from existing reports submitted to the Federal Energy Regulatory Commission (FERC) and Energy Information Administration (EIA). Existing plants were allowed to price based on the marginal cost of the highest-cost plant operating at any one time.

The analysis identified two key issues. First, much of the existing capacity is low-cost coal. Under existing regulated pricing these plants receive revenues sufficient to pay costs plus a reasonable return on investment. In a restructured market with prices set by the marginal producer, revenues for the low-cost coal plants increased greatly. This was reflected in a general rise in electricity prices of around 1¢/kWh in the base scenario. Furthermore, market-based electricity prices are more sensitive to the price of natural gas. With an increase in gas prices of 53%, market prices rose 1.5¢/kWh while regulated prices (that average all production costs) rose 0.5¢/kWh. As a consequence, market prices became 2¢/kWh higher than regulated prices.

Sensitivities were also run on the availability of coal-fired capacity, raising it from the historical value of the existing plants to broader industry standards. The increase in low-cost production lowered both the regulated and market prices. An interesting detail was that the increased production from the coal plants actually lowered their profitability because of their effect on market prices. Other plants also suffered lower profits, threatening their continued operation. This touches on the issue of market power, which will be looked at in more detail in this paper.

2.2 Rise of Merchant Power

Generation capacity is growing throughout the country. According to the RDI NewGen database (RDI 2001b), over 390 GW of capacity are planned or under construction in the U.S. Much of this capacity is being built not by regulated utilities, but by independent power producers. These producers sell their generation either through long-term contracts to utilities or in shorter-term or spot markets. Within Oklahoma, 98% of the proposed new construction is by merchant power producers.

As part of restructuring, power plants may sell directly to end-use consumers. As with utilities, consumers may sign bilateral long-term contracts or purchase through a spot market. Small consumers may choose to aggregate their demands to better take advantage of the market. These aggregators may be existing utilities, municipalities, or even new organizations that provide this service.

Even without restructuring in all states, merchant power is a rising force within the electric power industry. Traditional utilities have been reluctant to construct new facilities, due to uncertainty of the market and potentially inadequate returns on their investment. Some utilities have created unregulated subsidiaries to control their generation assets and to build additional plants. They choose to use their expertise in owning and operating power plants by competing in the open market outside of their regulated territories. Other companies have also entered the market, building either stand-alone merchant plants or cogeneration plants within an existing industrial facility.

In some states that are undergoing restructuring, the utilities have been forced to sell some or all of their generation. This was done to avoid the utilities obtaining too much market power through combined ownership of transmission assets and a large share of the generation assets. Auctions have been held to sell the plants to multiple companies. The prices paid helped to determine the asset values and stranded costs of the utility. These plants have frequently been purchased by the unregulated subsidiaries of utilities that are located elsewhere in the country or overseas, or by independent power producers.

In Oklahoma, there have been a large number of plants proposed for construction in the coming years. The Oklahoma Department of Environmental Quality (DEQ 2001) releases a monthly report of the proposed plants that shows the air permit status, capacity, and type of plant (Table 1). Most of these plants are to be built by companies that are not the regulated utilities within the state. As such they will be able to sell their power either through contracts with existing utilities, on the wholesale spot market, or if restructuring occurs, directly to consumers.

Table 1: July 2001 listing of proposed plants for Oklahoma (DEQ 2001)

Facility	Permit Status	Fuel	Gen. Cap. MW
Base Units(Comb.Cycle)			
AECI – Chouteau	Issued	GAS	530
Cogentrix- Jenks	Issued	GAS	800
C&SW – Oologah	Issued	GAS	492
Calpine – Coweta	Issued	GAS	1,000
Duke – Newcastle	Issued	GAS	520
Energetix-Arcadia	Proposed	GAS	1,100
Energetix Thunderbird	Issued	GAS	865
Kiowa – Kiamichi	Issued	GAS	1,200
Smithcogen – Pocola	Proposed	GAS	1,200
Smithcogen. - Lawton	Tech. Rev.	GAS	600
Energetix – Webbers Falls	Tech. Rev.	GAS	825
Tenaska - Seminole	Tech. Rev.	GAS	1,200
Energetix – Great Plains	Tech. Rev.	GAS	900
Duke - Stephens	Admin Rev	GAS	620
Total Combined Cycle			11,852
Peaking Units(Simp. Cycle)			
OG&E - Horseshoe	Issued	GAS	90
OneOK - Edmond	Issued	GAS	320
KM Pwr - Pittsburg	Issued	GAS	550
WFEC – Anadarko	Issued	GAS	94
Mustang – Mustang	Draft	GAS	310
Mustang - Harrah	Admin Rev	GAS	310
Total Simple Cycle			1,674
Grand Totals			13,526

3 Oklahoma Market Data for 2010

3.1 Demand Growth within Oklahoma

According to the *Electric Power Annual 1999* (EIA 1999), total retail demand for Oklahoma in 1999 was 46,700 GWh. According to the EIA's *Annual Energy Outlook 2001* (EIA 2000), overall electric power demand in the Southwest Power Pool is expected to grow overall by 26% between 1999 and 2010, representing an annual growth rate of 2.1% (Table 2). Each sector (residential, commercial, and industrial) has different levels of growth, depending on a variety of factors such as economic development and changes in technology.

Table 2: Oklahoma electricity demand growth from 1999 to 2010

	1999 Sales GWh	Annual escalation	2010 Sales GWh	Losses	Busbar GWh	Peak MW
Residential	18,300	2.2%	23,400	8%	25,400	7,510
Commercial	12,400	2.6%	16,500	6%	17,500	3,350
Industrial	13,300	1.4%	15,500	5%	16,300	2,910
Other	2,800	2.1%	3,500	6%	3,700	570
Total	46,700	2.1%	58,900		63,000	14,340

3.2 Export of Power and Transmission Capacity

Based on the analysis in Phase I, total exports of power from Oklahoma in 1999 were 4,800 GWh, with a peak demand of 800 MW. A simple expansion of this demand using the growth rate from above through 2010 would give sales of 6,500 GWH and peak capacity of 990 MW. Consequent total demand would be 15,300 MW. However, proposed expansions of capacity greatly exceed this amount, as shown in Table 1. Since power plant capacity is projected to be much higher, the question arises as to the how much could exports increase, given transmission constraints.

There are currently seven 345 kV lines that cross Oklahoma state lines according to the Southwest Power Pool (SPP) (Figure 1).[1] An approximate line rating for conventional three-phase lines at 345 kV is 600 MW (EPRI 1982), although this value can vary greatly depending on the length and materials used for the line. These lines could therefore accommodate 4,200 MW of interstate transmission. An additional 345 kV line is planned for 2006 (Northwest to Harrington), which could provide an additional 600 MW of transmission capacity.

There is also one 230 kV line that crosses into the panhandle of Texas (Elk City to Harrington-Nichols). The estimated capacity for this line is 200 MW. In addition, several 138 kV lines cross the state border that could be used for interstate energy transfer. Using an approximate line rating for 138 kV lines of 75 MW, the estimated maximum capacity at 138 kV is 1,050 MW.

---

[1] The seven current 345 kV lines are Woodring to Wichita, Northeastern to Neosho, GRDA 1 to Flint Creek, Clark to Chambers Springs, Muskogee to Ft. Smith, Valliant to Lydia, and Lawton to Oklaunion.

As shown in Table 3 below, it appears that by 2010 Oklahoma would have a maximum interstate transmission capacity of approximately 6,000 MW. Hirst and Kirby give higher estimates of the capacity for various voltage lines, closer to 900 MW per 345 kV line (Hirst and Kirby 2001). However, their analysis was based on thermal limits for short lines, less than 100 miles. As lengths increase, the maximum transmission capability drops because of voltage or stability limits. Furthermore, actual combined capabilities can be different from simply the sum of the individual lines, and sales potentials will depend on the markets that the lines enter. A more detailed analysis of the actual transmission limits in and out of Oklahoma may be necessary to establish the potential for exports.

Figure 1: Oklahoma transmission lines with 345 kV lines highlighted (SPP 2001)

Table 3: Estimated interstate transmission capacity from Oklahoma in 2010

Line Voltage (kV)	Number of lines	Approximate line rating (MW)	Estimated maximum capacity (MW)
345	8	600	4,800
230	1	200	200
138	14	75	1,050
Total	23	-	6,050

3.3 Generation Supply

Generation capacity is growing in Oklahoma. Plans for new plants indicate a broad expansion, roughly doubling the amount of capacity available. The number of plants listed in Phase I for 1999 totaled 13,430 MW. In 2010, most of these plants are expected to still be operating, although 1,260 MW of plants were removed from the list due to either retirement or refurbishment. This left 12,170 MW of capacity from existing plants in 2010.

There were three sources of data on new plants for Oklahoma. The most complete source used was the list of new plants from the Oklahoma DEQ (Table 1). These were compared to lists of plants from Resource Data International's NewGen (RDI 2001a) and PowerDat databases (RDI 2001b) that give capacity, fuel, and expected on-line date. In some cases either the plant capacities did not match with the DEQ data, the plants did not have the same name, or on-line dates were not provided. The DEQ capacities were used, with on-line dates of 2004 for those without known dates. The total new capacity added was 11,852 MW of combined cycle (CC) and 1,674 MW of combustion turbines (CT), in line with the DEQ estimates (Table 4).

Table 4: New Generating plants from Oklahoma DEQ and RDI

Facility	Permit Status	Fuel	Gen. Cap. MW	RDI Gen. Cap. MW	RDI On-line Date
Base Units(Comb.Cycle)					
AECI – Chouteau	Issued	GAS	530	530	2004
Cogentrix- Jenks	Issued	GAS	800	800	2002
C&SW – Oologah	Issued	GAS	492	300	2001
Calpine – Coweta	Issued	GAS	1,000	1,000	2002
Duke – Newcastle	Issued	GAS	520	500	2001
Energetix-Arcadia	Proposed	GAS	1,100	1060	2003
Energetix Thunderbird	Issued	GAS	865	825	2003
Kiowa – Kiamichi	Issued	GAS	1,200	1200	2003
Smithcogen – Pocola	Proposed	GAS	1,200	600	2003
Smithcogen. - Lawton	Tech. Rev.	GAS	600	600	2003
Energetix – Webbers Falls	Tech. Rev.	GAS	825	825	–
Tenaska - Seminole	Tech. Rev.	GAS	1,200	1,200	–
Energetix – Great Plains	Tech. Rev.	GAS	900	500	2004
Duke - Stephens	Admin Rev	GAS	620	?	
Total Combined Cycle			11,852		
Peaking Units(Simp. Cycle)					
OG&E - Horseshoe	Issued	GAS	90	96	2000
OneOK - Edmond	Issued	GAS	320	300	2001
KM Pwr - Pittsburg	Issued	GAS	550	550	2003
WFEC – Anadarko	Issued	GAS	94	90	–
Mustang – Mustang	Draft	GAS	310	?	
Mustang - Harrah	Admin Rev	GAS	310	?	
Total Simple Cycle			1,674		
Grand Totals			13,526		

Because the actual efficiencies and costs for these plants are not known, we used representative values from a recent study on future energy use, *Clean Energy Futures*, written by five national laboratories including ORNL (Inter-Laboratory Working Group 2000) and from the Generating Availability Data System from NERC (NERC 1998). Heat rates, fixed and variable operations and maintenance (O&M) costs, capital costs were , and outage rates for combined cycle and combustion turbines were assigned to the plants in Table 4 based on the year they entered into service (Table 5).

Table 5: New plant cost and operating parameters

	Effici-ency	Capital Nom $/kW	Variable O&M 1999 ¢/kWh	Fixed O&M 1999 $/kW	Forced Outage Rate	Planned Outage Rate
Combined Cycle						
2001	49.7%	476	0.05	15.6	3.4%	10.3%
2002	50.1%	491	0.05	15.6	3.4%	10.3%
2003	50.5%	505	0.05	15.6	3.4%	10.3%
2004	51.0%	521	0.05	15.6	3.4%	10.3%
Combustion turbine						
2001	37.8%	354	0.01	6.4	3.0%	10.8%
2002	38.3%	365	0.01	6.4	3.0%	10.8%
2003	38.8%	376	0.01	6.4	3.0%	10.8%
2004	39.3%	387	0.01	6.4	3.0%	10.8%

Average fuel prices were raised from the 1999 values used in Phase I to 2010 values by applying the expected increase from the AEO2001 for the Oklahoma region (Table 6). (Note that coal prices are expected to increase at less than the general inflation rate so have a negative escalation rate.) In Phase I, the existing plants used fuel prices based on their reported amounts for 1999. We escalated each plant's cost by the rate shown in Table 6. The new plants used the average prices as shown in the table.

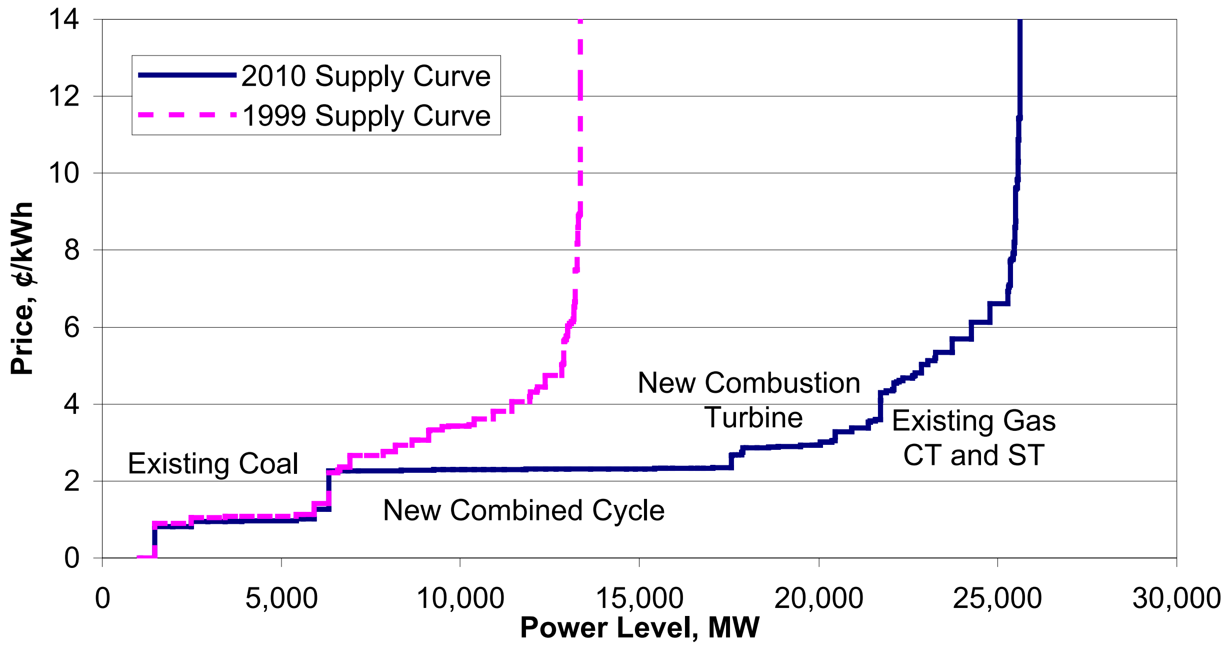
Table 6: Average fuel prices for 2010, in 1999 $/MBtu

	1999 Avg. Fuel Cost, $/MBtu	Annual Escalation Above General Inflation	2010 Avg. Fuel Cost, 1999$/MBtu
Gas	2.73	1.8%	3.34
Coal	0.94	-1.0%	0.84
Dist. Oil	2.06	1.0%	2.29

Although the plants are listed as in planning or under construction, it is not known whether all will be built. For example, three plants are proposed for construction in the Lawton, OK, area. However, according to minutes of the Lawton city council there may be water limits requiring auctioning of available water (Lawton City Council 2001). In scenarios where there was excess capacity, some plants were removed from the list, beginning with those with the latest on-line date. However, in reality, other plants may have their dates or capacities modified, or transmission capacity may be added through new lines or modifications. Also, the costs and operating parameters are likely to be different than the estimates used here. For these reasons, it is important to realize that the results from this study should not be applied to specific plants.

The plants within Oklahoma were separated into 141 units, each with its own capacity and operating parameters. When placed in order of increasing marginal cost, they create a supply curve. Figure 2 shows the supply curve for the plants in 2010, as well as the 1999 curve from the Phase I report. The large increase in capacity at essentially the same marginal price has interesting consequences for the profitability of the plants, as described later.

Figure 2: Oklahoma electricity supply curves for 1999 and 2010



4 ORCED Analysis

The Oak Ridge Competitive Electricity Dispatch (ORCED) model was developed at Oak Ridge National Laboratory to examine numerous facets of a restructured electricity market (Hadley and Hirst 1998). The model is a complex Excel spreadsheet that takes the inputs on supply and demand described above and dispatches plants to meet the defined demands for a single year of operation. Further details on the calculations involved are included in the Phase I report (Hadley et al., 2001).

Several versions of the model have been developed over the years depending on the needs of the study. For this study we used a version that models a single region without internal transmission constraints. It can handle up to 200 power plants and models two seasons, a peak and an off-peak. For the Phase II analysis the model was modified to allow individual plants to sell some or all of their power at either the market-based rate or on a contractual, fixed cost basis. Also, the calculation of the bid prices that plants use in the spot market was modified to enable varying amounts of fixed costs to be incorporated into the bid.

4.1 Determining Production scenario

In order to create a credible scenario for 2010 we must first establish the expected demand and production levels. For the initial run, we used the internal demands as shown in Table 2 and kept exports equal to 11% of internal retail demands as in 1999. This resulted in a peak demand of 15,300 MW. If all planned capacity is built, the total capacity available is 25,600 MW, resulting in a reserve margin of 67%. At such a high level, many of the plants will never be called upon to produce, which makes this scenario unlikely. Either demands must increase, supply decrease, or both.

To increase demands, we raised the amount of exports from a peak demand of 990 MW to 6,030 MW, as described in Section 3.2 above. We left the load factor the same as in 1999 so that total sales also scaled up by a factor of five as well. This makes total exports equal to 67% of retail sales, versus 11% in 1999, and raised peak demand to 20,380 MW. Even with this expansion to full capacity of the transmission lines, the reserve margin was 25.8%. Many plants were still never called upon or for only a few hours in the year.

We lastly lowered the supply capacity by removing 3,545 MW of planned combined cycle construction (the last four CC plants in Table 4). This lowered the reserve margin to 8.4%, which is slightly lower than the 10.0% in the 1999 case. While too high of a value can cause some plants to run so rarely that they are not economic, too low of a value can cause reliability concerns. For example, California declares Stage One Emergencies when the reserve margin drops below 7%. Further information on this topic can be found in the paper on generation adequacy (Hirst and Hadley 1999).

4.2 Determining price scenarios

Once supplies and demands were set, we considered the prices to customers and profitability of the plants. There are two issues concerning prices, what are the overall prices paid by customers in a restructured market compared to a regulated market, and do new plants receive sufficient revenues to justify their construction and operation. If prices are low to consumers but new plants are losing money, then this is not a viable scenario. We set the expected return on equity for the new combined cycle plants at 14% after taxes. Returns significantly below that would discourage investors from funding their construction.

4.2.1 All plants at marginal-cost based market price

First, we ran a scenario that had all plants bid their marginal prices on the spot market. This is similar to the pricing used in Phase I. This scenario provides lower prices to residential consumers than the regulated prices, although other customers pay slightly higher prices. Table 7 first shows the transmission and distribution (T&D) charge to customers, based on results from the Phase I study. These were not changed from the 1999 values because the focus of this study is not on changes in T&D prices. The next column shows the generation prices if system-wide revenue requirements are allocated between customer categories based on their energy purchases and peak demand requirements. The third column is the sum of the previous two. The restructured generation price is the average price paid by each customer category if charged based on the time-varying market price, with adjustments for plants that have prices fixed by long-term contracts. The total restructured price is the sum of the generation and T&D prices, and the difference between restructured and regulated prices are shown in the last column. The regulated and market prices are shown in Figure 3.

Table 7: Consumer regulated and market-based prices with plants bid marginal costs only

	T&D	Regulated Generation Price	Total Regulated Price	Restructured Generation Price	Total Restructured Price	Differ-ence
Residential	3.34	3.83	7.17	3.26	6.59	-0.57
Commercial	2.89	3.14	6.02	3.16	6.05	0.03
Industrial	1.00	3.03	4.03	3.13	4.13	0.10

In this scenario with all plants charging marginal costs, the new plants lost money because they could not recover their fixed costs. The combined cycle plants had a return on equity (ROE) of -2%, well below the expected value of 14%. In Table 8 the first column shows the capacity for each major plant type. Hydro includes both hydro and pumped storage facilities. The "Old" designation is for plants built prior to 2000 and "New" for plants built in 2000 or later. The capacity factor indicates the amount of generation the plant produced as compared to if the plant ran at full power 100% of the year. The percentage of time on the margin indicates for what percentage of the year each plant type was the most expensive plant operating and so setting the market-clearing price. The average price is the revenues received by each plant type divided by its production, while the average cost is the sum of its fuel, O&M, depreciation, interest charges, taxes, and a "reasonable" return on equity (shown in the last column). The ROE is the net income received by the plants (escalated to 2010 $) divided by the equity invested in the plants.

Figure 3: Customer prices under each market scenario

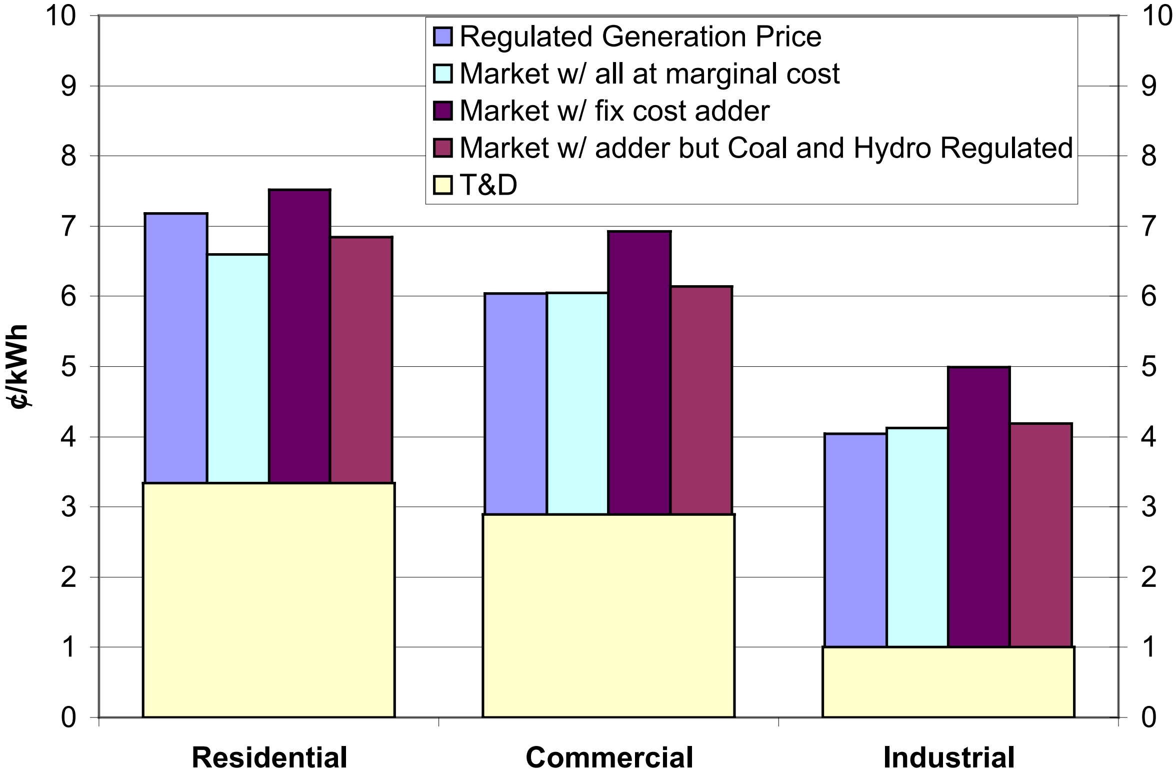


Table 8: Plant operations and financial results with prices based on marginal costs

Plant Type	Capa-city MW	Capa-city Factor %	Time on Margin %	Price Received[a] ¢/kWh	Marginal Cost[b] ¢/kWh	Total Cost[c] ¢/kWh	ROE %	Regu-lated ROE %
Coal	5156	76	0	2.77	0.97	1.45	437.3	11.9
Hydro	1035	29	0	3.45	0.37	1.52	772700	0.0
Oil	39	19	0	3.53	2.69	4.39	-598.6	11.0
Gas ST	4625	5	13	5.49	3.90	6.28	-33.9	11.0
Gas CC/Old	909	29	10	3.79	3.03	3.67	41.5	12.9
Gas CT/Old	343	6	1	4.57	3.38	7.23	-93.0	11.0
Gas CC/New	8309	79	54	2.89	2.31	3.62	-2.0	14.0
Gas CT/New	1674	22	21	3.92	2.90	6.14	-4.2	13.9

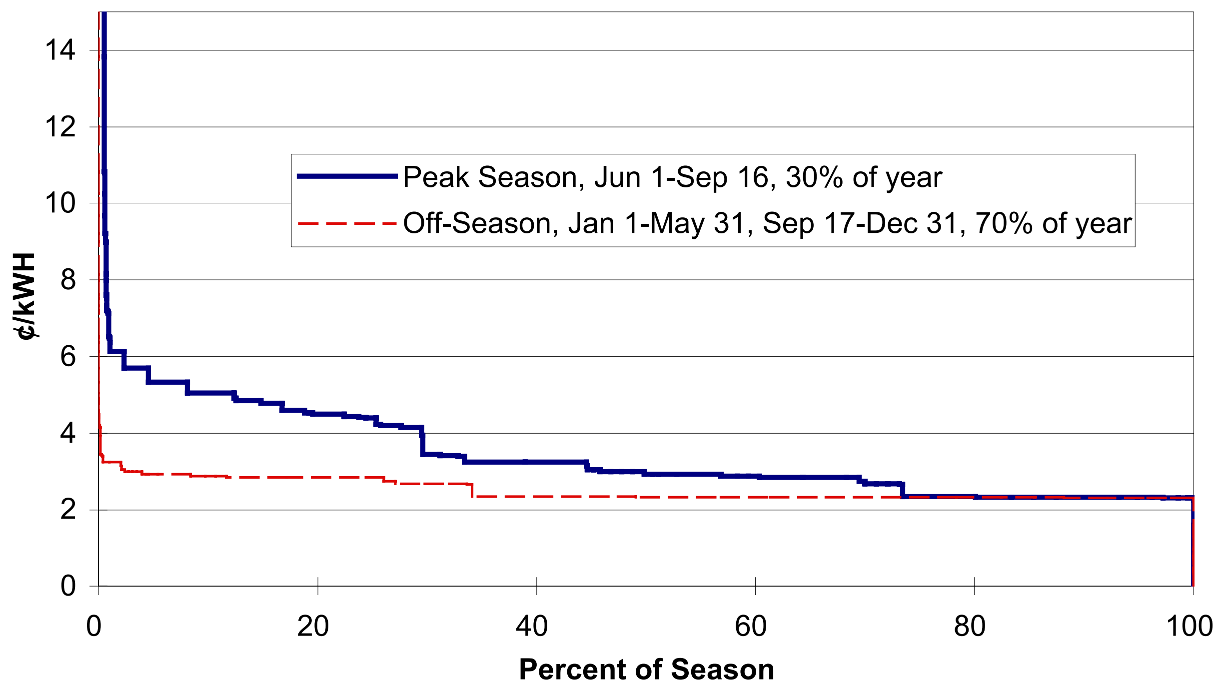
[a] Price received is total revenue divided by sales.
[b] Marginal cost is variable and start-up costs of operation
[c] Total cost includes operations, depreciation, interest, taxes, and expected return on equity

Because there was so much new combined cycle capacity, these plants were on the margin for 54% of the year, even though they operated close to capacity with a capacity factor of 79%. Being similar plants of similar age, their marginal cost and consequent bid prices were also similar, at about 2.3 ¢/kWh. This can be seen in Figure 2, with the long flat part of the supply curve showing the capacity from the new combined cycle plants.

Though their marginal costs were only 2.3 ¢/kWh, their total cost including all operations and capital-related costs were about 3.6 ¢/kWh. If they only received their marginal costs during the portion of the year they were on the margin, there was very little time for them to recover all of the fixed costs and prices would have to be much higher during that part of the year.

Figure 4 shows the market-based prices over the year if all plants solely bid their marginal costs. As can be seen, the prices are below 3.6 ¢/kWh for most of the year. Only during about 30% of the summer peak season, or just 9% of the year, do prices rise above the total cost of new combined cycle plants, as more expensive combustion turbines and gas-fired steam plants set the price.

Figure 4: Real-time market prices with all plants bidding their marginal costs



4.2.2 Marginal plus added fixed costs in bid price

A plant may increase the prices it receives in several ways. First, the owners could bid a higher price into the spot (and day-ahead) markets. If accepted, these prices will give higher revenues. The danger is that other plants will then undercut the price bid. Consequently, the plant may not be called on to run as often and lose revenue. If a plant or set of plants has sufficient market power, then they may be able to raise their prices without being significantly undercut by other generation sources.

With new plants, either gas CC or CT, setting the marginal prices 75% of the time, it is clear that they would need to incorporate their fixed costs into their bids in some way. To simulate an added bid factor, we added 25% of their fixed costs to the variable cost of each plant in their bid price. In order to convert fixed costs to variable we used the capacity factor for each plant from the scenario when they only bid their variable cost. As a consequence, newer plants, with higher fixed capital costs, had higher increases in their bids than the older plants. This slightly changed the loading order and consequent capacity factors that each plant actually had.

The value of 25% of fixed cost was determined because at that amount, the new CC plants earned close to 14% on their equity (Table 9). New gas CT's still make somewhat less than their expected return, but this analysis does not include extra revenue from ancillary services such as spinning reserve. These extra services, which are most often provided by CT's, could raise the total ROE. Older plants, especially coal and hydro, make large returns on their equity. (Hydro as modeled has essentially no equity.)

Table 9: Operating and financial results with all plants at market rates and bids include 25% of fixed costs

Plant Type	Capa-city MW	Capa-city Factor %	Time on Margin %	Price Received[a] ¢/kWh	Marginal Cost[b] ¢/kWh	Total Cost[c] ¢/kWh	ROE %	Regu-lated ROE %
Coal	5156	76	0	3.41	0.97	1.45	652.8	11.9
Hydro	1035	29	0	4.69	0.39	1.54	1260730	0.0
Oil	39	17	0	5.30	2.71	4.62	398.9	11.0
Gas ST	4625	7	20	8.08	3.71	5.40	213.1	11.0
Gas CC/Old	909	37	12	4.40	2.98	3.48	255.5	12.9
Gas CT/Old	343	6	1	8.47	3.45	7.64	51.7	11.0
Gas CC/New	8309	79	54	3.62	2.31	3.63	13.9	14.0
Gas CT/New	1674	15	12	6.45	2.91	7.79	6.7	13.9

[a] Price received is total revenue divided by sales.
[b] Marginal cost is variable and start-up costs of operation plus 25% of fixed cost
[c] Total cost includes operations, depreciation, interest, taxes, and expected return on equity

The older gas plants also make very good returns, partly from the rise in price from the new CT's, and partly from the increase in bid prices from plants operating for only a small part of the year. For example, adding 25% of the fixed cost of $15/kW-year to a plant that operates 1% of the year, or 88 hours, increases its bid price by 4.3 ¢/kWh . If the plant runs 10% of the year the added part is only 0.43 ¢/kWh; if it runs 0.1%, or 9 hours, the added amount is 43 ¢/kWh. This impacts not only its own profitability but the prices of all plants running at that time.

Figure 5 shows the real-time prices over the year under this scenario. Prices are slightly higher in the off-season and during the low-demand period of the peak season, as compared to Figure 4. However, prices rise higher and more rapidly in the peak season as the plants with low capacity factors are called on and their bids include a higher proportion of fixed costs.

However, in this scenario, prices to all customers increased over what they would pay under regulated rates (Table 10 and Figure 3). So while new plants would be solvent in this scenario, the price impact on consumers makes this scenario less feasible.

Variations on the percentage of fixed costs added can be run, including having some plants, such as the older plants, not including the adder. However, as fewer plants include the added cost then they by necessity must include a higher percentage in order to recoup their fixed costs. This causes them to be called on less often since the plants without the expense in their bid now are priced lower. The end effect is that new, efficient plants are called on much less frequently than more expensive, older plants, which is likely not what the reality would be.

Figure 5: Real-time market prices with plants adding 25% of fixed costs to bids

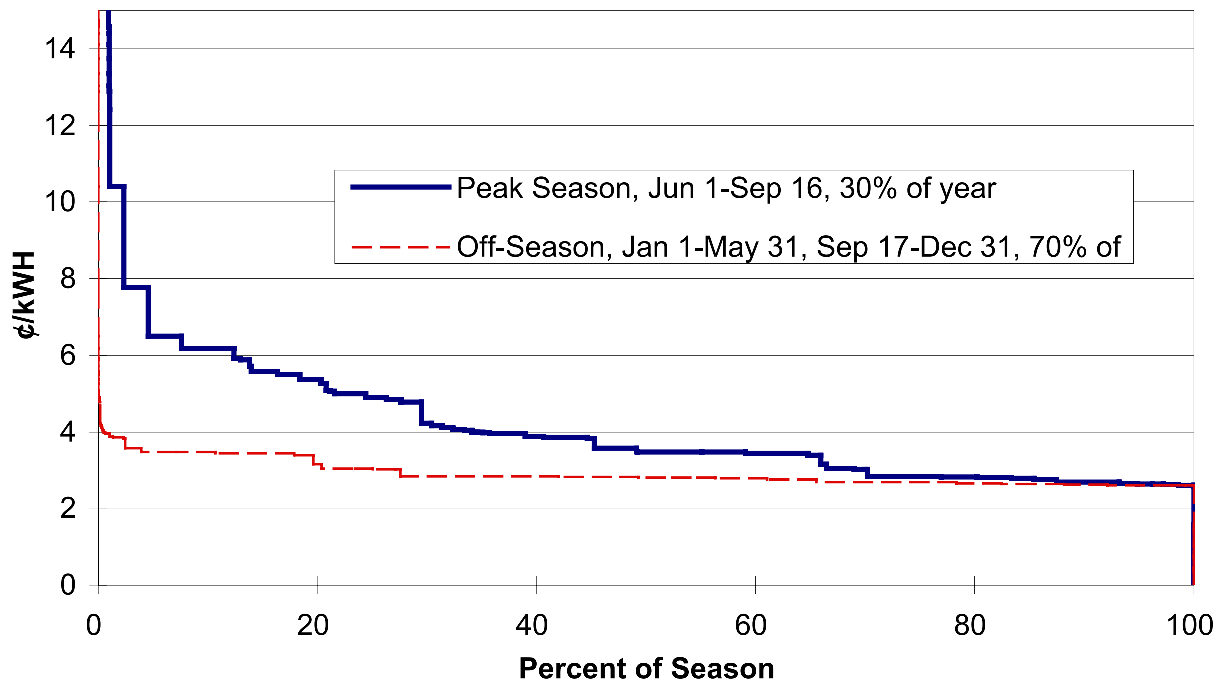


Table 10: Prices with all plants at market rates and bids include 25% of fixed costs

	T&D	Regulated Generation Price	Total Regulated Price	Restructured Generation Price	Total Restructured Price	Differ-ence
Residential	3.34	3.84	7.18	4.18	7.52	0.34
Commercial	2.89	3.15	6.04	4.03	6.92	0.88
Industrial	1.00	3.04	4.04	3.98	4.99	0.95

4.2.3 Regulated pricing of existing coal and hydro plants

Among the major beneficiaries of a change to pricing using market-based prices are the existing low-cost producers, notably coal and hydro facilities. As shown in Table 9, these two plant types receive prices much higher than average costs, while having no influence on the market price since they are never on the margin. It might be feasible during restructuring to mandate that they sell their power at cost plus reasonable profit, instead of at the full market rates. There are precedents of this in other states. For example, as part of its restructuring, California required that the nuclear and hydro facilities owned by the investor-owned utilities price their production at cost. While the rest of the production in the state became very expensive this past year, the nuclear and hydro plants provided some measure of stability.

To examine the impact of having coal and hydro plants sell power at cost instead of market, we modified ORCED so any or all plants could price at a fixed price. We set the price for coal and hydro plants so that they would recover their costs and reasonable return on equity. These plants as modeled actually have very little equity in them by 2010, both because of their age and because the plants owned by government entities were modeled as being debt-financed so with essentially no equity per se. As a result, customer prices dropped such that residential consumers saw prices 0.34 ¢/kWh lower under restructuring than under regulation, and other customer saw only modest increases (Table 11 and Figure 3). Coal and hydro plants had their average price drop to their costs and ROE's of 11.9% and 0% respectively; while all other plants had the same returns as in Table 9.

Table 11: Prices with market prices including 25% fixed cost but existing coal and hydro plants priced at costs

	T&D	Regulated Generation Price	Total Regulated Price	Restructured Generation Price	Total Restructured Price	Differ-ence
Residential	3.34	3.84	7.18	3.51	6.85	-0.34
Commercial	2.89	3.15	6.04	3.25	6.14	0.10
Industrial	1.00	3.04	4.04	3.19	4.19	0.15

4.2.4 Contracts versus spot-market pricing

An alternative to plants selling on the spot market is for plants to sign long-term contracts for some or all of their production. The prices may include a fixed cost for the capacity of the plant and a variable cost for the actual production. This is similar to the system-wide pricing that occurs under regulated rates, but on a plant level. Total revenue requirements are calculated by summing the fixed and variable costs of operations, including capital costs such as depreciation, interest, and a reasonable rate of return. The revenue requirements are then charged to customers either through a single energy-related price or through separate demand and energy charges. (This is a simplification of the actual rate-setting process and types of rates created.)

As an example, below is a statement from the 10-K form from Cogentrix on their power project financing and contracts:

> PROJECT AGREEMENTS, FINANCING AND OPERATING ARRANGEMENTS FOR OUR OPERATING FACILITIES
>
> Project Agreements
>
> Our facilities have long-term power sales agreements to sell electricity to electric utilities and power marketers. A facility's revenue from a power sales agreement

> usually consists of two components: variable payments, which vary in accordance with the amount of energy the facility produces, and fixed payments that are received in the same amounts whether or not the facility is producing energy. Variable payments, which are generally intended to cover the costs of actually generating electricity, such as fuel costs, if supplied by the operating facility, and variable operation and maintenance expense, are based on a facility's net electrical output measured in kilowatt hours. Variable payment rates are either scheduled or indexed to the fuel costs of the electricity purchaser and/or an inflationary index.
>
> Fixed payments, that are intended to compensate us for the costs incurred by the project subsidiary whether or not it is generating electricity, such as debt service on the project financing, are more complex and are calculated based on a declared production capability of a facility. Declared production capability is the electric generating capability of a plant in megawatts that the project subsidiary contractually agrees to make available to the electricity purchaser. It is generally less than 100% of the facility's design production capability dictated by its equipment and design specifications. Fixed payments are based either on a facility's net electrical output and paid on a kilowatt-hour basis or on the facility's declared production capability and can be adjusted if actual production capability varies significantly from declared production capability. (Cogentrix 2000)

If the long-term contracts are based on the company receiving their expected rate of return, there is little difference in prices between the regulated market price and contract price. We ran ORCED with all plants selling under long-term contracts at prices based on their expected returns. As a result, the restructured prices to customers were the same as the regulated prices, and all plants made their regulated ROE. If that is the case, the main difference between a restructured market and regulated market is that the individual plants may contract directly with end-customers rather than just the local utility or wholesale marketers.

The question then arises on whether a plant would choose to sign long-term contracts or bet on the spot market for pricing. And, if it were to sign long-term contracts, would they be priced close to their costs with a reasonable profit, or would they try to set prices close to the expected average spot price? Would they be willing to sacrifice some profit for the sake of firm prices? Similarly, how much more are customers willing to pay over the expected spot prices in order to get some price surety? These questions are asked daily by generators, outside investors, marketers, and utilities in today’s market. Different business plans and portfolios are developed in a complex combination of long-term and short-term purchases, generation, and hedging strategies. Companies may choose to sell some of their generation under long-term contracts, some on the day-ahead or spot market, some as either a spinning or non-spinning reserve, as well as save some for internal use if it is a cogeneration project. All these factors influence the final market.

4.3 Market power: modified bids and withheld capacity

In establishing the base case we modeled that all plants would include a portion of their fixed costs in their price. This is a simple version of market power in that all suppliers tacitly agree to increase their bids. Two more complex mechanisms for plant owners to exert market power are to raise their bid prices as a group or to withhold some of their lower cost capacity.

4.3.1 Group bids

In a more complex market scenario, the owners of new combined cycle plants may recognize that their bids can be raised to just below the cost of the next more expensive technology. The marginal costs of the new CC plants are around 2.35 ¢/kWh; the next most expensive major plant type (new Gas CT) have marginal costs around 2.86 ¢/kWh. If the CC plants were to raise their bids to 2.85 ¢/kWh, they should still have roughly the same sales, yet earn an additional 0.5 ¢/kWh when they are the marginal producers.

Table 8 above showed the results if all plants just bid marginal prices. If just the new CC plants raised their prices to 2.85 ¢/kWh, their ROE does improve from the –2% in the table to 3.4%. However, the higher-cost plant types see little change in their ROE's since their prices were no different than before. Coal and hydro facilities receive an extra windfall as the average price goes up from 2.77 to 3.03 ¢/kWh. Thus, even if all new combined cycle operators, as shown in Table 4, raised their prices together to just below the gas CT prices, there is only some improvement in their profitability.

As a further step, we considered if all new CC and CT plants raised the bids together to the level of the next technology. Gas Steam plants begin entering the market at bid prices of 3.26 ¢/kWh. Raising the CC and CT bids to just below this amount allows them to collectively still operate the same amount while making an additional 0.4 ¢/kWh. CC plants' ROE rose to 9.4% and CT plants rose from –4.2 to -3%.

Lastly, what happens if all the new plants bid 3.25 ¢/kWh but one? Suppose that one of the new CT's that normally would have operated in a peaker mode with a capacity factor of 25% chose to bid its marginal cost instead. It then becomes a baseload unit running 86% of the year, and earning +5% ROE instead of -2%. This is a strong incentive for individual plants to lower their bids, with the hopes that no one else does.

Plants are very reliant on the existence of higher-priced plants in order to make their profits in a spot market. Even if a large segment of the capacity raises its price, it risks being undercut by other technologies unless they bid to just below the others' marginal cost. The incentive for individual plants to "cheat" and lower their bids can undermine the market power potential. Only if a substantial majority of the participants in the market, especially those with higher costs, raise their bids proportionately, do profits rise for all.

4.3.2 Withholding capacity

The other mechanism by which market power can be exercised is through the withholding of capacity. If low cost producers choose to not bid a portion of their capacity, then the market-clearing price will be higher as more expensive plants replace the lost capacity. The individual plant that does not run will lose money, but the other plants that the producer owns may earn enough more through higher prices to compensate.

We ran two examples of capacity withholding: one of a company that owns multiple new plants, and one of an existing producer. In the first case, we lowered the production 10% from the 600 MW Lawton plant owned by Smith Cogeneration. We had modeled it at slightly lower cost than the Pocola plant, so reducing the Lawton plant by 52 MWyr increased the production of Lawton by 8 MWyr. Plants owned by other companies supplied the rest of the missing production. Because the replacement power was more expensive, the average price to customers increased 0.06 ¢/kWh. Smith's revenues declined $6 million, but since they did not have the expense of production, their net income actually rose $2 million. Their overall ROE increased from 12.7% to 13.2%.

In the other example, we reduced the production from the 1015 MW Sooner coal plant owned by Oklahoma Gas and Electric by 10%. This led to an increase in production from other plants, owned by both OG&E and others. OG&E's ROE increased from 46% to 66%, despite the 5% lower overall production. Average prices to customers increased 0.12 ¢/kWh as higher-cost plants provided a larger share of the total. The coal plant's production declined by 76 MWyr, but other plants owned by the utility, most notably their peaker gas steam plants, increased production by 6 MWyr. Since these other plants are unregulated and very profitable in this scenario, the utility's overall profitability increased.

A key reason for improvement in the utility's ROE was the unintended consequence of regulating the price from one plant but not others. OG&E earned the regulated 11% return on their coal plant regardless of its actual production. By reducing its output, other plants owned by OG&E that were not regulated in the scenario increased their production and their revenues (especially since prices increased as well), while the coal plant returns were not reduced.

Because we are only considering the production from Oklahoma plants as substitutes for the lost production, in both cases, reducing production had the effect of raising net income. Prices rose sufficiently to offset the lost income from the production. In the broader regional electricity market, however, capacity from outside the state may enter the market to make up the lost sales without causing a significant increase in price. This depends on the cost and supply of extra generation in the outside market. In the larger regional market, the utilities have less impact on the overall reserves. Since we modeled a significant amount of sales into the outside market, withholding capacity may simply lower external sales with no effect on overall prices. Also, if the plants continued to operate at lower capacity, new construction would enter into the market to more permanently negate this market power. While we used two specific utilities in these examples, we do not wish to imply that they and they alone wield market power in the Oklahoma electricity market.

4.4 Elasticity and real-time pricing

Most experts on restructuring recommend that customers have real-time pricing available (Taylor and VanDoren 2001, Hirst 2001). The actual cost of generation can vary greatly between seasons or even hours. When customers are only aware of the average price from the previous month, they have little knowledge or incentive to adjust their demands as the real-time price changes. If even a small fraction of customers responds to high prices through lower demands, it can have a large impact on the overall market. Plants that normally would run only a few hours are called on less often, while other plants see more use as customers increase purchases during low-cost times. Average prices go down and profitability goes up. Real-time pricing can be implemented whether or not restructuring occurs, although restructuring facilitates it through competition and increased opportunities for change.

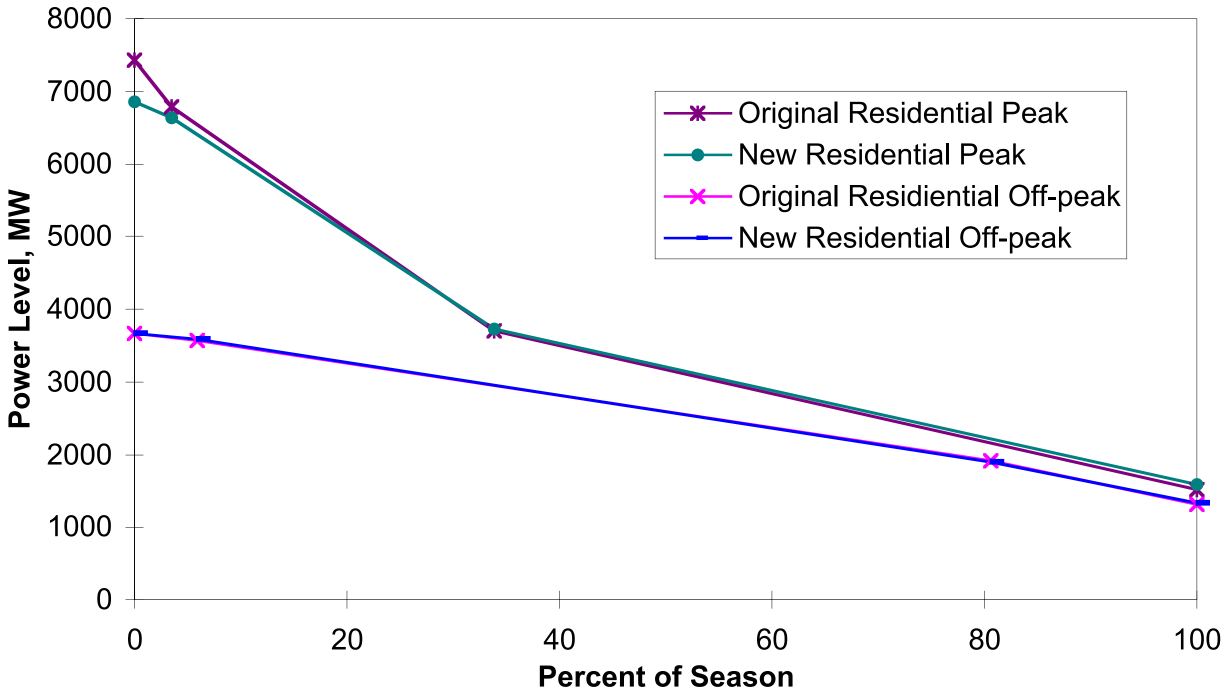
To explore the potential of real-time pricing, both in a regulated and market environment, we recalculated the demand load profiles for each retail customer category. Using the real-time prices shown in Figure 5, we raised or lowered the customer demand depending on how much the price differed from the average price. We did not modify demands in the Other category, which includes the wholesale exports and sales internal to Oklahoma that are not in the three main categories.

We used a price elasticity of –0.10, meaning that a 10% increase in price reduces demand by 1%. There is little information on the correct value to use, although recent price changes in California give a clue. In San Diego in the early summer of 2000, the local utility was allowed to raise its prices to the market rates. A study of the impact on demand was conducted by James Bushnell and Erin Mansur of the Program on Workable Energy Regulation (Bushnell and Mansur 2001). They found that a doubling of rates resulted in a drop in demand of 2.2 to 7.6 percent. More recently, California had rate increases in the late spring of 2001 and saw a reduction of demand of 12% comparing June 2001 use to June 2000 use, after taking out weather-related factors (Hirsh and Kennedy, 2001). However, price changes differed between customer categories, and a large amount of non-price-related incentives were also put in place.

Neither of these data conclusively provides information on customer response over a long period. Generally, elasticity increases as customers become more familiar with the prices and have the time to invest in equipment that will shift or reduce demand. So while San Diegans responded with an elasticity factor between –0.02 and –0.08, given time they may increase their responsiveness and raise the factor. A broader study on the impacts of increasing customer responsiveness is included in our report on generation adequacy (Hirst and Hadley 2000).

Each customer category’s load shape changed slightly in response to the variable prices. Figure 6 shows the change to the residential customer load shape in the peak and off-peak season. Total energy purchases were kept the same but electricity use during the highest-priced part of the peak season was reduced by 7.7% (570 MW) because of the high prices shown in Figure 5. The Off-peak season saw very little change from the original load duration curve because prices did not vary greatly. The commercial and industrial sectors saw slightly higher percentage declines in their peak demands (9.6% and 11.6% respectively). This was mainly because the price differential was greater for them since the fixed T&D cost component are a lower proportion of their overall prices.

Figure 6: Change in Residential Load Duration Curve from real-time pricing and elasticity



The result of changing each customer's load profile was a reduction in retail peak demand of 1,240 MW. This represents a reduction of 9% in retail peak demands. Since exports and other sales were not modified, the total drop was 6.1% of the original system peak demand. The system load factor, which is the ratio of the average demand to the peak demand, improved from 57.4% to 61.1%. This means that while fewer plants may be needed to meet demand, those that are used run for a longer part of the year.

We first ran ORCED with the new demands but same set of plants. This resulted in a reserve margin of 15.4%, significantly higher than the 8.4% with the original demands. Customer prices averaged 0.25¢/kWh lower than in the base scenario, but return on equity for plants dropped. The peaker plants were most seriously affected. While new CC plants had ROE drop from 13.9% to 9.1%, the new CT plants dropped from 6.7% to 0.2% and the old CT plants dropped from +52% to –56%.

Because of the lower demand, we removed two new CT's from the list of plants, reducing capacity by 620 MW. This still left a larger reserve margin than in the original case, 12.2% versus 8.4%. Despite the increase in reserve margin, the total reliability of the two systems as measured by the Loss of Load Probability is roughly the same. The extra reserve margin is needed to make up for the possibility of other plants not being available when needed. With the higher load factor there is a greater need for reserves to back up any plants with forced outages.

In addition to dropping the two plants, we lowered the fixed cost adder from 25% to 22% to leave the CC plants with a 14% ROE. In this scenario, prices to consumers still dropped compared to the case without elasticity, by .09 ¢/kWh for regulated prices and .04 ¢/kWh for market prices. With fewer plants, the returns on equity to the remaining plants stayed nearly the same. New CC plants saw returns of 13.8%, new CT's had 7.7%, and old CT's had a 48% return.

The response of customers to real-time prices has a modest effect on average prices paid. Its larger impact is on prices paid at the peak. In the case without elasticity impacts, market prices were 120 ¢/kWh during the short time (~15 hours) when all plants were at full capacity. In the case with elasticity this price peaked at 100 ¢/kWh. With elasticity and consequent flatter demand profile, peak prices do not have to rise as much to lower demand to available capacity.

5 Economic Analysis

5.1 Introduction

Electricity is a prominent product in the modern economy and a critical input into many production processes, including those of households. The turmoil in California's electric power markets in late 2000 and early 2001 heightened national attention on this product.

In 1998, the value of private electricity production in Oklahoma was 2.3 percent of the total value of production in the state. In that year, 40.7 percent of Oklahoma's electricity generation was used by residential consumers, 26 percent by commercial establishments, and 27.5 percent by industrial consumers (EIA 2000c).

For this economic analysis we used the highest priced scenario, with all plants pricing at market rates including coal and hydro (Table 10). Other scenarios, with prices much closer between regulated and market-based, should show much less economic impact.

The average simulated rate increases of 5 percent for residential prices, 14 percent for commercial, and 23 percent for industrial amount to a weighted average price increase of 12 percent. Thus, the economic analysis below examines a roughly 12-percent price increase in a commodity that accounts for 2.3 percent of state production. Against this aggregate backdrop, it is not surprising that the electricity rate changes identified with potential deregulation of Oklahoma's electric power industry have very small impacts on the overall economy of the state. Depending on the price-change scenario, employment in the state could fall by three or four one-hundredths of one percent while other property income could rise by about one-third of one percent. The differences in impact across the scenarios also are small.

5.2 The Method of Analysis

The impact of changes in the three electricity rates was studied with 528-sector input-output model of the Oklahoma economy.[2] Input-output models trace the flows of expenditures through the production sectors of an economy. Each production sector purchases produced inputs from other industrial and commercial sectors (called intermediate inputs, or intermediate demand), both within the state and outside it; hires labor; pays for the use of capital equipment; and pays indirect business taxes. The labor receiving wages and salaries from each sector spends the income they receive on the products of these industrial sectors, as well as on domestic and foreign imports. These expenditures are called "final demands." Some of the owners of the capital equipment used in the industrial and commercial sectors live in the state and also spend their income on locally produced goods and services. Thus there is a circular flow of income, from production sectors hiring labor, through the spending of that labor income on locally and externally produced products, with the demand for each product requiring inputs from many other production sectors.

---

[2] The IMPLAN model, with 1998 social accounts data for Oklahoma, was used in the analysis: Minnesota IMPLAN Group, Inc., *IMPLAN Professional, Version 2.0; Social Accounting & Impact Analysis Software* (Stillwater, Minn.: Minnesota Implan Group, April 1999).

The usual method of studying economic impacts with an input-output model is to alter the final demand for one or more products. This change injects additional income into the economy at a particular point. That increase in final demand increases intermediate demands for the products used to produce that good, and it also puts more wage and capital income into circulation in the economy as more people and machinery are required to produce the additional output. These dollars are spent as final demands across the entire array of goods produced in the economy, and the increases in the final demands for these products increases the intermediate demands for the other goods required to produce them. The money inserted into the economy circulates through the production sectors and income-receiving households several times, causing an expansion in the economy larger than the initial increase in final demand. However, some of this additional income "leaks out" of the local economy during the spending cycles, as people purchase goods imported from other states and countries, so that each new round of spending gets smaller than the previous, as the purchases circulate through the economy.

The electricity price increases studied here have a different structure than the final demand change usually posited for an input-output model. They are price changes rather than changes in demands. In fact, in the short run, the quantity of electricity demanded, both by households and firms, is quite inelastic, so that the final and intermediate demands for electricity change virtually not at all. Instead, they cost more to produce. To accommodate this change to the input-output framework, we altered the production structure of each sector, making each sector spend more on electricity than before, and the set of final demands for households and other institutions (e.g., state and local government).

In changing the production structure of the industrial and commercial sectors, we recognized that Oklahoma is thoroughly integrated into the United States economy, so that any changes in its local production costs cannot affect the prices it pays for traded commodities.[3] Similarly with the labor and capital markets. Any increase in electricity prices must be offset exactly by reductions in expenditures on other inputs, both other produced inputs and labor and capital. Correspondingly in the expenditure patterns of households and institutions, we keep the initial expenditures constant, taking the extra expenditures on electricity out of all other purchases, in proportion to their expenditure shares in the budget. This imposes very nearly a zero elasticity of demand for electricity on households.

In the first round of effects from the increase in electricity prices, industrial and commercial producers reduce their intermediate demands for virtually all other inputs besides electricity, and households and other institutions reduce their purchases of all products other than electricity. In the next round, come reductions in intermediate purchases by all sectors other than electricity, in

---

[3] Many services are nontraded, and their local prices could diverge somewhat from the prices of similar products in other locations. However, national labor and capital markets, and national markets for the purchased inputs of those activities, act to keep those prices rather close together across locations. The only input that ultimately cannot be moved around to keep its price equalized across locations is land, and land rents will rise or fall locally to absorb differences in prices of nontradable goods and services. An alternative approach to modeling the production changes in each sector would have been to take the incremental electricity expenditure one hundred percent out of the value-added category "other property income," which includes land rents. Our method supposes that producers manage to reduce expenditures proportionally across all their other inputs, rather than experiencing the entire cost squeeze in the rents (residual profits) to land they use (Roback 1982).

response to the direct retrenchments in employment and intermediate purchases. These are indirect effects of the initial round of cuts. However, payments to the electricity sector increase in the direct impact, and that sector's demands for intermediate inputs and for labor and capital rise, at least partially offsetting reductions elsewhere in the economy. The expanding electricity sector, as well as expansions in several closely related industries, coal in particular, increases labor income, which gets spent on the full array of goods and services in the economy. With some sectors expanding and others contracting, the changes in income going to employees induce a series of corresponding expansions and contractions in expenditures across all the sectors.

In an input-output model, a state's exports would change only in response to outsiders' demands for them, although imports respond to both intermediate and final demand changes originating within the state. Thus exports do not change simply because a state "can produce more" of some good. Outside demanders must ask for more of specific goods the state produces. We have not considered an increase in outside demands for electric power from Oklahoma generators. A broader, regional study on the economic consequences of power production and prices may be worthwhile in the future.

5.3 Numerical Results

We present impact results for three scenarios of electricity price changes. In the first scenario (all plants, including hydro- and coal-generation, at market prices, including an adder 25 percent of avoided cost), the residential rate rises by 5 percent, the commercial by 15 percent, and the industrial by 23 percent (Table 12). The second scenario is similar but with the hydro plants regulated. It has the residential rate rise by 4 percent, the commercial by 13 percent, and the industrial by 21 percent. In the third scenario (all plants, including hydro- and coal-generation, at market prices, customer demand shape changed due to elasticity), residential rate rises by 5 percent, the commercial by 16 percent, and the industrial by 26 percent. To gain some insight into the contributions of these separate rate changes within any scenario, we apply the rate changes separately for the third scenario, and find that in some cases the rate increases for different customer classes have opposite effects in some sectors.

Table 12: Percent increase in prices market-based versus regulated, with most or all plants at market rates

	All plants (w/ coal and hydro) at market prices	All plants but hydro at market prices	All plants at market, elasticity change demand
Residential	5	4	5
Commercial	15	13	16
Industrial	23	21	26

Table 13 and Table 14 report the output changes for individual industrial and commercial sectors that are particularly strongly affected–although in absolute terms, all of the changes are small, with the exception of those in the private electricity sector. Table 13 identifies the sectors experiencing the strongest contractionary impacts, and Table 14 reports the comparable information for the sectors undergoing the strongest expansions. The third scenario, which has the highest weighted-average rate change, has the strongest impacts, both negative and positive. The first scenario, with the lowest weighted-average rate increase, has the smallest impacts among contracting industries (Table 13), but generally has the second-largest impacts, after scenario 3, among expanding industries (Table 14).

Table 13: Industrial sectors with output decreases, percents

industry	Scenario 1 % change	Scenario 2 % change	Scenario 3 % change	Scenario 3 Industrial % change	Scenario 3 commercial % change	Scenario 3 residential % change
Explosives	-0.595	-0.551	-0.679	-0.764	0.045	0.040
Logging camps & logging contractors	-0.516	-0.474	-0.586	-0.615	0.008	0.020
Uranium, radium, vanadium ores	-0.411	-0.376	-0.465	-0.468	0.001	0.002
Metal mining services	-0.411	-0.376	-0.465	-0.468	0.001	0.002
Agriculture, forestry, fishery services	-0.393	-0.357	-0.441	-0.416	-0.009	-0.016
Plastics, materials & resins	-0.277	-0.253	-0.312	-0.311	-0.001	-0.000
Synthetic rubber	-0.231	-0.210	-0.260	-0.258	-0.002	-0.000
Paperboard containers & boxes	-0.216	-0.195	-0.241	-0.201	-0.030	-0.010
Wood pallets & skids	-0.200	-0.181	-0.224	-0.184	-0.039	-0.001
State & local government education	-0.211	-0.180	-0.221	0.092	-0.341	0.028
Animal & marine fats & oils	-0.180	-0.164	-0.203	-0.194	-0.004	-0.005

At the level of the individual industrial sectors, the change in the industrial rate tends to have the strongest impact on contracting industries, as shown in Table 13, with the exception of the state and local government production sector, which experiences the strongest contractionary impact from the increase in the commercial rate. The commercial and residential rates have very small impacts on these contracting sectors. Among the expanding sectors, shown in Table 14, the increase in the industrial rate still tends to have the largest impact on the expansions, but the magnitudes of the commercial and residential rate increases are much closer to those of the industrial rate. The 10 to 11 percent expansion in the private electricity sector is in value terms, not in terms of megawatt hours generated.

Table 14: Industrial sectors with output increases, percents

industry	Scenario 1 % change	Scenario 2 % change	Scenario 3 % change	Scenario 3 Industrial % change	Scenario 3 commercial % change	Scenario 3 residential % change
maintenance & repair, other facilities	0.414	0.360	0.446	0.242	0.065	0.140
railroads & related services	0.393	0.393	0.487	0.132	0.207	0.147
steam engines & turbines	1.16	1.011	1.252	0.551	0.411	0.290
coal mining	1.71	1.489	1.844	0.785	0.624	0.435
federal electric utilities	10.674	9.286	11.495	5.085	3.777	2.631
electric services	10.704	9.312	11.526	5.099	3.787	2.638
state & local electric utilities	10.733	9.338	11.558	5.113	3.798	2.645

Aggregate impacts on categories of income are reported in Table 15. The separate contributions of the different rate classes are somewhat different at the aggregate level than among the outputs of the sectors reported individually. Employee compensation falls (which, with a fixed wage, amounts to a reduction in employment) by a very small extent in all three scenarios, but the driving force behind that reduction is the increase in the commercial rate. The industrial and residential rate increases actually have minuscule positive effects on employment. Household consumption increases by small amounts for all income groups. Lower income groups experience slightly larger increases, with the exception of the highest income group, which experiences a larger consumption increase than all but the two lowest income groups. Increases in all three customer classes act to elevate consumption of the lowest three income groups, but the increase in the commercial rate depresses consumption in households earning $15,000 per year and above. Nevertheless, these are all very small changes and may be driven primarily by how the IMPLAN model allocates wage and property income to households. Claiming that these rate increases disproportionately affect different income groups on the basis of this analysis would be exaggerated.

Proprietary income[4] and other property income[5] both rise, the former by about one tenth of one percent, the latter by about one third to four-tenths of one percent. Indirect business taxes also rise, by about the same percent as other property income. The relative contributions of changes in the residential, commercial and industrial rates differ across these income groups.

State and local government non-educational activities increase by a considerable amount, compared to the typical impacts of these rate changes. They respond positively to all three categories of rate increase, while educational and investment respond negatively to the

[4] Income to self-employed individuals, typically private business owners, doctors, lawyers, etc.

[5] Income from interest, rents, royalties, dividends, and profits, including rents paid to individuals on property and corporate profits earned by corporations.

commercial rate increases, which reduces their overall sensitivity to the rate changes to virtually nil. Capital investment also increases slightly in response to all the rate changes. It responds positively to rate changes in all three customer classes, but somewhat more strongly to changes in the industrial rates, probably reflecting increased demand for capital equipment in private electricity generation and coal.

Table 15: Economic impacts of changes in electricity price schedules, percent change

Aggregate income category	Scenario 1 %	Scenario 2 %	Scenario 3 %	Scenario 3 Industrial %	Scenario 3 commercial %	Scenario 3 residential %
Employee compensation	-0.039	-0.034	-0.042	0.005	-0.059	0.011
Proprietary income	0.102	0.086	0.106	0.026	0.032	0.049
Other property income	0.385	0.334	0.413	0.183	0.124	0.107
Indirect business taxes	0.329	0.287	0.355	0.178	0.087	0.0900
Household < $5k	0.128	0.112	0.139	0.069	0.035	0.035
Household $5-10k	0.084	0.073	0.090	0.047	0.019	0.024
Household $10-15k	0.064	0.056	0.069	0.040	0.006	0.023
Household $15-20k	0.056	0.048	0.060	0.041	-0.005	0.024
Household $20-30k	0.043	0.037	0.046	0.037	-0.015	0.024
Household $30-40k	0.040	0.035	0.043	0.036	-0.018	0.026
Household $40-50k	0.030	0.026	0.033	0.031	-0.023	0.024
Household $50-70k	0.024	0.021	0.026	0.028	-0.026	0.024
Household $70k+	0.069	0.060	0.074	0.044	-0.003	0.034
State & local government, non-education	0.144	0.127	0.157	0.092	0.037	0.028
State & local government, education	-0.000	0.001	0.003	0.092	-0.117	0.028
State & local government, investment	-0.000	0.001	0.003	0.092	-0.117	0.028
Capital investment	0.153	0.133	0.165	0.079	0.046	0.040

5.4 Conclusions of input/output analysis

The aggregate economic impacts of the electricity rate increases that appear likely to emerge from deregulation as projected here are very small. These impact projections are likely to be on the high side of actual, long-run impacts, since the assumptions of the input-output framework, as well as assumptions we adopted for this study, minimize the opportunities to substitute away from electricity in both final and intermediate demands. We did not attempt to simulate the potential for substitution away from electricity into natural gas for some energy uses, but over a five- to ten-year period, if some classes of rates stayed twenty to twenty-five percent higher, some substitutions surely would occur in specific uses such as heating, air conditioning and water heating. Additionally, the assumption made here to take the incremental electricity cost out of all inputs instead of sinking them all into land rents, would tend to elevate the short-run response to the rate increases through the indirect effects on demands for other intermediate products.

6 Results and Conclusion

Based on the analysis above, there are several important results for decision-makers in Oklahoma. **First**, due to economics and transmission constraints, it is likely that some of the proposed new plants will be cancelled or postponed. **Second**, existing low-cost coal and hydro capacity will make high returns if allowed to price their production at the wholesale market rates, at the expense of consumers. Based on the rationale of stranded costs as applied by FERC and other states undergoing restructuring, it may be advisable to continue to have their production priced at their cost including a reasonable return instead. Care must be taken to avoid market manipulation if companies own both regulated and unregulated plants. **Third**, the economics of a spot market for electricity pricing do not favor new plants with high capital costs, unless they can incorporate some of their fixed costs into their bids and have sufficient market power to avoid being tremendously undercut by competitors. **Fourth**, customer response to real-time prices can serve to lower peak demands significantly. Less new construction is needed and prices are reduced modestly. **Fifth**, even using the highest electricity price increases we modeled, the overall economic effect on the state's economy was slight. Employment decreased less than 0.05% overall and showed increases in some sectors, notably mining and the electric industry itself.

6.1 Excess capacity and growth in exports

As described in Section 3, the amount of generating capacity planned for construction in Oklahoma greatly exceeds the growth in demand. Even by 2010, internal demand is only expected to rise around 26%, while in-state capacity is projected to double by 2004. While expansion of power exports may consume some of this excess, it would have to expand from current 1,000 MW to over 9,000 MW to utilize all of the capacity and leave a reasonable reserve margin. Transmission capacity limits are likely to limit this export to 6,000 MW at the most, assuming that other states have a need for this power.

In fact, there is a growing realization that the market may be set for a bust in the near future. According to Christopher Ellinghaus, an investment banker at Williams Capital Group, power companies across the country have proposed 350,000 MW of new plants by 2004, but only 100,000 MW of this is expected to actually be built (Bannerjee, 2001). According to the New York Times article, transmission constraints and power plant economics are both playing a role in the lowering of expectations. Many of the announcements of new capacity were based on the expectation of broadly rising prices, as exemplified by California and the entire western region. With the recent decline in wholesale prices, new plant economics are not as favorable.

Furthermore, many of the plants are being located in states with large gas resources, such as Oklahoma and Louisiana. However, transmission systems are not being upgraded quickly enough to be able to ship this excess capacity to states needing it. In Oklahoma, only one additional 345 kV line is planned between now and 2010. Expansion of the transmission system is more difficult to construct than new generation. Current transmission owners see little benefit to build since it dilutes the value of their existing lines. The same goes for owners of plants in the high-cost region. Landowners do not see the benefit since the power is to be used by others. Even intervening states frequently object to new lines. For example, Connecticut recently vetoed a proposed transmission line to Long Island since they would not benefit from it and it may disturb some oyster beds in the region (Behr 2001).

6.2 Regulation of Coal and Hydro

Existing coal and hydro plants have the good fortune of having low costs, both operating and capital. They are and will remain a significant fraction of the overall capacity in the state (28% in 2010) but not enough that they become the marginal producers and consequent price setters. The average price paid to coal plants over the year is 3.41 ¢/kWh while the coal and hydro average costs are only 1.5 ¢/kWh (Table 9). Hydro plants are preferentially run during peak times so see an even higher average price. If the plants receive these market prices, customers' average prices are higher by 0.74 ¢/kWh than if the plants received cost-based rates.

When some other states have restructured they provided that some power plants would continue to be priced at their costs rather than sell at the market rates. The original rationale behind the cost-based pricing was that it was thought that the utilities had some plants and contracts with overall costs much higher than the market would be and deserved to recoup these costs. An implied social contract existed in the past that utilities would be guaranteed a reasonable return on prudent investments. If certain historical investments could not be recovered in a restructured market, then they should be recouped through a "stranded cost" fee or transition charge. Most states that have restructured implemented stranded cost recovery for their utilities. The amount of recovery was set at the start of restructuring, with later true-ups as costs became better known (Hirst and Hadley 1998).

Oklahoma is faced with the opposite situation of other states; its power plants, especially the coal and hydro plants, have costs much lower than the market prices. It may be advisable that this difference be returned to customers in some fashion, through cost-based pricing (such as modeled here), through rebates following the sale of plants, or other mechanisms. However, the mechanisms for these plants to continue selling at their cost rather than market must be carefully constructed to avoid unintended consequences, misplaced incentives, or market manipulation.

6.3 Impact of Market Power

In a purely competitive market where supply bids into a market until demand is satisfied, the optimum bid for any supplier is to bid at their marginal cost. Prices then are set by the highest price bid that fulfills demand. This was described in more detail in our Phase I report. The problem for the electric industry is that in an industry with a high ratio of fixed to variable costs, there is a greater likelihood that the resulting prices will not cover their fixed costs, leading to boom and bust cycles. Examples include such industries as airlines, steel, and cement. In many such industries, what happens is a build-up of inventories that leads to temporary plant closures as demand and supply equilibrate. The lack of an economical electrical storage mechanism makes this process more problematic for the electric generation business. The inelasticity of supply and demand can lead to great volatility.

This problem is especially acute if a large fraction of the suppliers has similar marginal costs. If one supplier tries to include fixed costs in its bid at any given time, another supplier can price slightly below this (but still above their marginal cost) and take the sale. With many suppliers, this rationale drives the price down to the plants' marginal costs and none of them recover their fixed costs.

One definition of market power is the ability to price goods above the competitive level and make those prices stick. This can only happen if a supplier or group of suppliers have a large enough share of the market and that customers do not have a ready substitute for the product.

In our scenarios, we showed how if all suppliers price at their marginal costs, then the new CC and CT plants lose money. We then used a simple model of market power where all suppliers incorporated 25% of their fixed costs (including capital costs) in their bid prices. This simple formula provided most new plants with sufficient income to justify their construction, while providing many older plants with large profits. A more complex and realistic form of market power was modeled by assuming that some low cost technologies raised their prices to just below the level of the next major technology, but others just priced on their margin. While this improved the revenue for these low-cost technologies, it was not sufficient for them to fully cover their fixed costs. They had to have the more expensive technologies also raise their bids so that all would gain revenue, at the expense of consumers. Furthermore, if any one plant within the technology grouping broke ranks and lowered their bid, then they earned much more revenue. This argues against a strong amount of market power through pricing strategies.

The other form of market power we considered was the ability of one company to withhold capacity from its lower cost plants in order to increase the prices and net revenue received by its remaining plants. This form of market power proved more successful in our examples. When the owner of two CC plants lowered the operation of one plant by 10%, the sales increased slightly for the other. But more important, the prices that all plants received increased such that the owner of the two plants had higher profits. For the company that owned both regulated and unregulated plants, withholding capacity proved even more successful. The company earned more on its unregulated plants through increased sales and prices, and the coal plant continued to earn its regulated return even though it produced 10% less.

Our modeling overstates the market power influence of the plants because we only model the plants within Oklahoma. In reality, power plants from other states may offset the lost production of these plants, so that prices would not rise as much. The influence of these other plants would require a broader regional study of the power system.

6.4 Impact of Price Elasticity

Customer response to real-time prices can lower the peak demands significantly, by 8% or more. This lowers the amount of capacity needed to meet demands within Oklahoma. This can free up the capacity for external sales (if transmission capacity exists) or lessens the need for new plants. It has a small effect on the average prices paid, because the largest impact is on the small part of the year when demand is highest. If customers simply shift their demands to other times, then total sales are not affected. Suppliers may want to adjust their pricing to reflect the change in plant utilization, lowering the amount they need to raise their bidding to recover fixed costs.

6.5 Economic impact on state

The aggregate economic impacts of the range of electricity rate increases derived in this study would be very small. Depending on the rate scenario, aggregate employment in the state would fall by as much as 0.042 percent or by as little as 0.034 percent. Neither change would be detectable in routine employment statistics. Outputs in industrial and commercial sectors not intuitively related intimately to the electricity sector are affected by correspondingly small percentages—by roughly one-half of one percent either up or down. The output of coal mining increases by 1.7 to 1.8 percent, depending on the rate scenario, while the value of the private electricity sector's output increases by 9 to 11.5 percent, which is roughly the weighted-average price change of unchanged megawatts of generation. Alternative assumptions used in the economic analysis probably would yield even smaller impacts.

6.6 Conclusions

The economic impact of restructuring the electric power industry could be relatively modest or could raise prices to consumers. A key difference will be how the restructuring takes place: what plants are included in restructuring, how costs or prices are communicated to consumers, and whether capacity additions are in line with expected growth in demands.

Any restructuring must take into account that many of the existing plants have costs well below market rates. The difference between cost and market prices are currently received by consumers since the plants' production is priced at cost plus a reasonable return. Policy-makers will need to address how this future price and cost difference is shared between the state's consumers and the owners of the facilities.

It appears that the announced new plants to be constructed in the state are well in excess of the internal needs of the state and more than the transmission system can effectively export. Delays or cancellations are likely in order to prevent a glut on the market. Customer response to real-time prices and competition in external markets could further reduce the need for new plants. Information such as this study, and evaluation of the market by developers and the OCC, should help to avoid the worst of any market volatility due to an imbalance between supply and demand.

7 References

Bannerjee, Neela, 2001, “As Prices Fall, Utilities Weigh the Economics Of New Plants”. *New York Times*, Section C, p. 1, August 22.

Behr, Peter, “For Operators, a Daily High-Wire Act”, *The Washington Post,* August 22, p. A01. http://www.washingtonpost.com/wp-dyn/articles/A42384-2001Aug21.html

Bushnell, James, and Erin Mansur, 2001, *The Impact of Retail Rate Deregulation on Electricity Consumption in San Diego*, PWP-082, Program on Workable Energy Regulation (POWER), University of California Energy Institute, April.
http://www.ucei.berkeley.edu/ucei/PDF/pwp082.pdf

Cogentrix Energy Inc., 2001, *Form 10-K405 for 12/31/00*, Finnegan O'Malley & Company Inc., April.
http://www.secinfo.com/dsVsf.44yt.htm

EIA (Energy Information Administration) 2000, *Annual Energy Outlook 2001 with Projections to 2020*, DOE/EIA-0383(2001), U.S. Department of Energy, Washington, D.C. December.
http://www.eia.doe.gov/oiaf/aeo/index.html

EIA 2000a, *Electric Power Annual 1999*, DOE/EIA-0348(99)/1, U.S. Department of Energy, Washington, D.C. August.
http://www.eia.doe.gov/cneaf/electricity/epav1/epav1_sum.html

EIA 2000c, *State Electricity Profiles, June 2000*, DOE/EIA-0629 Washington, D.C, June, 222.

EPRI 1982, *Transmission Line Reference Book: 345 kV and Above*, Electric Power Research Institute, Palo Alto, CA.

Hadley, S. W., C. R. Hudson and D. W. Jones, *The Potential Economic Impact of Electricity Restructuring in the State of Oklahoma: Phase I Report*, ORNL/CON-482, Oak Ridge National Laboratory, March 2001.
http://www.ornl.gov/ORNL/BTC/Restructuring/OKRestructure2.pdf

Hirsch, Jerry, and Sam Kennedy, 2001, “High Power Prices Lit Fire Under Conservation; Energy Economists say consumers' quick reaction shows that earlier rate hikes might have tempered the crisis”, *Los Angeles Times*, Part A; Part 1; Page 1; Metro Desk, July 14.

Hirst, Eric and Stan Hadley 1999, *Maintaining Generation Adequacy in a Restructuring U.S. Electricity Industry*, ORNL/CON-472, Oak Ridge National Laboratory, Oak Ridge, TN, October.
http://www.ornl.gov/ORNL/BTC/Restructuring/C472.pdf

Hirst, Eric and Stan Hadley, 1998, *Transition-Cost Recovery and Trueup Mechanisms*, ORNL/CON–456, Oak Ridge National Laboratory, March.
http://www.ornl.gov/ORNL/BTC/Restructuring/c456.pdf

Hirst, Eric 2001, *The California Electricity Crisis: Lessons for Other States*, Edison Electric Institute, Washington, DC, July.
http://www.EHirst.com/PDF/HirstCALessons.pdf

Hirst, Eric and Brendan Kirby, 2001 "Transmission Planning: Weighing Effects on Congestion Costs", *Public Utilities Fortnightly*, Vol. 139(14), 56-63, July 15.

Interlaboratory Working Group, 2000, *Scenarios for a Clean Energy Future* (Oak Ridge, TN; Oak Ridge National Laboratory and Berkeley, CA; Lawrence Berkeley National Laboratory), ORNL/CON-476 and LBNL-44029, November.
http://www.ornl.gov/ORNL/Energy_Eff/CEF.htm

Lasseter, Dawson, 2001, "Fuel Usage of New Power Plants", personal communication, Oklahoma Department of Environmental Quality, July.

Lawton City Council, 2001, Minutes of Special Called Meeting, Lawton, OK, January 18.
http://www.cityof.lawton.ok.us/citycode/LawtonCity/City_Council_Meeting_Minutes/Year_2001/1/18.html

Minnesota IMPLAN Group, Inc., IMPLAN Professional, Version 2.0; Social Accounting & Impact Analysis Software (Stillwater, Minn.: Minnesota Implan Group, April 1999).

NERC (North American Electric Reliability Council) 1998, *EGADS: Electronic Generating Availability Data System,* North American Electric Reliability Council, Princeton, NJ.
http://www.nerc.com/~filez/gar.html
ftp://www.nerc.com/pub/sys/all_updl/gads/gar/gar1998.exe

RDI (Resource Data International) 2001a, *Powerdat Database*, Resource Data International, Boulder, Colo.

RDI (Resource Data International) 2001b, *NewGen Database*, Resource Data International, Boulder, Colo.

Roback, Jennifer 1982,"Wages, Rents, and the Quality of Life," *Journal of Political Economy*, 90, 1257-1279.

SPP (Southwest Power Pool) 2001, *Map of the SPP Region*, Southwest Power Pool, Inc., January.
http://www.spp.org/Publications/Final_Map_Update_condition.pdf

Taylor, Jerry, and Peter VanDoren, *California's Electricity Crisis: What's Going On, Who's to Blame, and What to Do*, Policy Analysis No. 406, Cato Institute, Washington DC, July 3.

INTERNAL DISTRIBUTION

1. S. W. Hadley, 3147, MS-6070
2. C. R. Hudson, 3147, MS-6070
3. D. W. Jones, 4500N, MS-6205
4. D. P. Vogt, 4500N, MS-6205
5. B. J. Kirby, 3147, MS-6070
6. P. D. Fairchild, 3147, MS-6070
7. R. B. Shelton, 4500N, MS-6187
8. J. E. Christian, 3147, MS-6070
9. E. C. Fox, 4500N, MS-6189
10. M. A. Brown, 4500N, MS-6186
11. Central Research Library, 4500N, MS-6191
12. Document Reference Section, 4500N, MS-6191
13. Laboratory Records, 4500N, MS-6285
14. C. I. Moser, 4500N, MS-6199

15-20. S. S. Johnsen, 3147, MS-6070