

Up in Smoke:
An Analysis of Future Costs Associated with
Electricity from the Turk Coal-Fired Power Plant
and Other Types of Generation

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1. Introduction

The proposed coal-fired generating facility at Hempstead County, Arkansas has raised a number of concerns regarding the environmental effects and the cost of containment measures that SWEPCO, the operating company, will face in the future. These concerns led Audubon Arkansas to contract with HISTECON Associates, Inc., for additional research into the potential long-run economic implications for the development of the Turk plant in the southwestern part of the state.

The HISTECON report is an economic study of the types of future pollution abatement that may be required for this type of industry, and the impact of these costs on the delivered price of electricity per kWh. The study reviews the company's generation-cost estimates and analyzes the projected increases in future demand for power. Although environmental-control costs were included by the utility in its calculations, testimony before the state PSC demonstrated that many of its assumptions regarding carbon regulation are too low and that other reputable sources are predicting much higher thresholds for pollution controls, especially regarding CO₂. This study uses other sources and scenarios to project additional cost horizons that must be considered.

Based on these ranges, the study focuses on three key research questions: first, what are the likely costs per kWh if the new pollution thresholds are enacted? Second, what are the likely costs of reducing hazardous air pollutants using maximum control technology as required by a recent decision of the D.C. Circuit Court? And third, at those higher costs, what are reasonable alternative energy sources that could meet the future electricity demand at a lower cost per kWh? A variety of energy use and conservation options are considered in this section, and a matrix of these alternatives was developed.

Also, the company has portrayed a large economic impact for the region from the construction and operation of this plant. Working with the UALR Institute of Economic Advancement, the study reviewed those impacts and independently addressed the issues of economic benefit to the regional and local market areas. Employment opportunities in the alternative energy sector are reviewed for comparison purposes.

Since this research began in mid-2007, an economic recession has officially overtaken the U.S. and western economies. While it is impossible to know how long this downturn will last, it is clear that some short-term cost trends discussed in this report have slowed. In the long-run, however, when markets begin to recover from the effects of the recession, the fundamental factors that pressured prices for construction, coal, and other resources will reassert themselves along with the imminent regulation of carbon emissions.

2. Three Looming Problems Facing Coal-Fired Power Plants Generating Electricity

Newly-proposed power plants using coal as the primary fuel must face several daunting hurdles in the current economic climate: the cost of controlling carbon emissions; the escalating costs of construction; and the rising cost of coal itself.

The Future Cost of Controlling Carbon and Other Emissions

Among the many experts in the energy field, little dispute remains about the need to control or limit the environmentally harmful by-products of coal-fired plants that generate electricity. Where most experts disagree, however, is when and where these types of limits will be placed on the two major concerns that remain: carbon and mercury.

When the earlier environmental protests focused on another pollutant – sulfur dioxide – lawmakers enacted and the first President Bush signed the Clean Air Act Amendments of 1990. This law created a cap-and-trade policy that helped slow sulfur emissions and the formation of acid rain that was ruining many streams, lakes, and forests in the eastern U.S. Ten years later, SO₂ levels were decreased dramatically and water quality was improving as a result.¹

Now the nation (and the world) face the dilemma of ever-increasing levels of greenhouse gases (CHG) in the atmosphere, and the deferred costs of clean-up that are not being paid at present. These costs are significant worldwide, as a recent report makes clear.

In purely economic terms, the continued use of coal is also a ticking time-bomb. ... (an) analysis of the true costs of coal, conducted by the Dutch Research Institute CE Delft, shows that damages attributable to the coal chain of custody amount to roughly €360 billion in 2007. This figure is most certainly an underestimation, as it doesn't account for all damages caused by coal. Nevertheless, it gives an idea of the scale of harm we subject ourselves and our environment to by continuing to mine and burn coal.²

¹Bradford Plumer, "A New Leaf," *Audubon* magazine, October 2008.

²"The True Cost of Coal: How people and the planet are paying the price for the world's dirtiest fuel," study prepared by the Dutch Research Institute CE Delft for Greenpeace International, December 2008, p. 6 and Appendix B. At current exchange rates, this equates to about \$283 billion in 2007 U.S. dollars.

When one looks at the hearings that led to the Arkansas Public Service Commission (PSC) decision,³ by a two-to-one vote, to grant approval of the Turk plant, one critical factor that was downplayed by most utility representatives is this historical perspective from the SO₂ agreements regarding the limitation of today's major air pollutants. Because no current legislation requires carbon limitation, for example, the SWEPCO and its parent AEP representatives did not factor future costs of controlling emissions into their initial cost projections adequately.⁴ During these hearings, many participants – including the PSC commissioners – talked about the problem, but the efforts to account for the impact of carbon costs on the future of markets for electricity was tentative at best. The purpose of this section is to correct that imbalance and to demonstrate how the increased costs for controlling carbon emissions will affect future energy markets dramatically.

The company (and the PSC) focused in the hearings on a comparison of the present values of the cost of building this type of facility (an ultra-supercritical pulverized coal plant) versus other types of generating plants that could supply baseload power (such as natural gas or combined cycle technologies). Using a cumulative present worth method (CPW), the utility's own witnesses found small differences between the total cost of a coal plant and other possible fuel sources, such as integrated gas plants. Even so, the utility's experts found that a coal-fired plant would be more expensive than the alternatives, **even without the addition of reasonable costs in the future for carbon-emissions reductions that may be required.** For example, the managing director of AEP testified:

Q. And even applying those factors to that analysis, the Hempstead pulverized coal unit would still be approximately, what, (\$)100 million more expensive than the gas generic alternative?

A. It depends upon which version you're looking at. Are you using CO₂ numbers offered by staff, using our numbers? If you're using our numbers, it would be, yeah, about 120 to 130 million dollars more expensive.⁵

³Arkansas PSC Docket No. 06-154-U, Nov. 21, 2007.

⁴As the result of the commission's Order #5, the SWEPCO and AEP witnesses did offer supplemental testimony that allowed relatively small increases in carbon-capture costs to increase projected future electricity costs.

⁵Scott Weaver, AEP Managing Director, PSC Docket No. 06-154-U, Aug. 20, 2007 (e.g., Exhibit SCW-S-4).

Using the CPW approach allowed the utility to argue (successfully, to at least two of the PSC commissioners) that variations in costs of \$100 million were not unreasonable given the large overall costs and long time horizons of such projects. Upon trivializing the result of the cost analysis, the utility then maintained that it was a sensible price to pay for two reasons: first, coal costs have been more dependable over the recent past than natural gas, for example; and two, the need for the company to maintain system-wide diversity among its baseload plants effectively “trumped” the extra cost of the Hempstead County coal plant. Here is their attorney’s argument before the PSC:

Simply put, it will be SWEPCO’s position in this case that fuel risk is the greatest risk to its customers, and so the Turk plant will be part of a mixed portfolio of resources which SWEPCO believes will best serve the needs of its customers. While this mixed portfolio will increase the use of natural gas in SWEPCO’s generation fleet, it will still come close to preserving the fuel diversity strategy that has worked so successfully over the years for SWEPCO’s customers. It is SWEPCO’s considered judgment that the use of coal as a fuel to satisfy its customers’ baseload generating needs is in the long-term best interest of those customers ...⁶

Furthermore, it is an odd argument for the utility to make that it must use coal in the short-run when its own reports suggest that carbon-emission costs in the future will force it to use more natural gas and other energy resources in the long-run. Here is the AEP report analysis that was filed with the PSC regarding their prospective operations in 2020:

... AEP is also projected to build new IGCC coal plants to meet growing generation requirements in both the East and the West, and to replace older coal-fired units which are no longer economic. The CO2 reductions required under McCain lead to more IGCC builds, more combined cycle gas builds, and more wind (in the West).⁷

As the PSC learned during expert testimony, what makes the cost comparisons among these different traditional approaches to electricity production unreliable is that even the company’s best estimates are off-the-mark by tens of millions of dollars, at best.

However, those \$17 billion dollar cost projections are not truly exact enough to meaningfully conclude that a 1% difference between them is real. I have no way to determine how large the real margin of error is on these

⁶Stephen Cuffman, PSC Docket No. 06-154-U, May 2007.

⁷“AEP Environmental Scenario Analysis,” June 7, 2004, p. 15; submitted as an exhibit by Bruce Braine in direct testimony before the PSC, Docket No. 06-154-U, Exhibits Volume II, Sept. 24, 2007.

cost projections – \pm 5%, 25%, but given even the obvious uncertainty in carbon costs, let alone the various other long-term future cost estimates, it is not reasonable to maintain that these long-term cost projections ... may warrant rounding, perhaps to \$17,670,000,000, or perhaps \$17,700,000, or perhaps \$18,000,000.⁸

Lastly, while SWEPCO originally based its request for the Turk plant on a future shortage of baseload capacity, in the end it argued before the PSC that the primary need was for diversity among its production facilities (see Cuffman above). Interestingly, related to its original request the recent economic slowdown has caused the company to reduce its electricity demand through 2030 by about 300 megawatts, and the previous customer agreements with cities like Hope and Bentonville are not guaranteed in a period of business downturn.⁹ And an alternative supply of electricity is available for other Arkansas communities from the Entegra plant, a 2,200 mWe gas-fired facility located in El Dorado.¹⁰

Nonetheless, while present-worth methods are widely-used for corporate accounting purposes, in this case they did not incorporate the dynamics of a changing economic and regulatory environment surrounding the issue of greenhouse gases. In the following section, we present a different approach using more reasonable costs for controlling GHG that consumers and other buyers of electricity need to consider in a future world of reduced carbon emissions.

Increased Cost of Coal due to Legislation

Regardless of one's view on the urgency of global warming and greenhouse-gas issues, most observers recognize that state and federal regulations on CO₂ emissions are certain to increase in the near future. In fact, already 24 states have passed their own version of carbon limits, and a total of 39 states have joined the Climate Registry, a federation whose purpose is to find ways to reduce each state's "carbon footprint" through legislation and other measures.¹¹ At the federal level, a number of bills have been proposed, debated, and in some cases defeated in votes that were considered closer than

⁸Direct testimony of James Mangi before the PSC, Docket No. 06-154-U, document #96, June 29, 2007, p. 37.

⁹"Texans back Arkansas coal-fired plant," *Arkansas Democrat*, July 4, 2008, p. D1.

¹⁰"Utility's proposal stirs doubt," *Arkansas Democrat*, Jan. 10, 2007, p. D1.

¹¹Bradford Plumer, "A New Leaf," *Audubon* magazine, October 2008.

expected.¹²

The American public increasingly recognizes global warming as a problem... Four important survey results underlie our belief that public support is growing for policy measures that deal squarely with greenhouse gas emissions and climate change... Any serious efforts by government or industry to address greenhouse gas emissions and global warming in the near term would impose a price or charge on carbon or constrain the use of CO2-emitting fuels.¹³

Most importantly, however, in 2008 the leaders of both political parties and both presidential candidates spoke publicly about the need for a reduction in carbon emissions. In fact, Senator John McCain has been a principal sponsor of legislation that would reduce future emissions to the 1990 level of emissions by 2020, and President Obama's election presents a higher degree of certainty that some form of carbon regulation will be enacted. A recent review of proposed federal legislation and agency regulatory proposals by Synapse Energy Economics, Inc., indicated no fewer than 20 possible scenarios for carbon limitation. They range from a return of carbon levels for year 2000 readings to actual reductions in the current levels of carbon emissions by 2020 or 2050, and originate from federal agencies, congressional proposals, and other state regulatory agencies.¹⁴

Other pollutants are also under review and have created concern among the public and the scientific community. A recent report by the Environmental Integrity Project pointed out how susceptible coal-fired plants are to mercury pollution; while most of the heavily-polluting facilities are older plants, the danger exists for new plants also.¹⁵ According to the U.S. Environmental Protection Agency, "... 60% of the total mercury deposited in the United States comes from U.S.-based sources. ... Coal-fired power plants are the largest unregulated U.S. source of mercury pollution, emitting 41% of known U.S. industrial emissions."¹⁶

¹²*Don't Get Burned: The Risks Of Investing In New Coal-Fired Generating Facilities*, Synapse Energy Economics, Inc., 2008.

¹³*The Future of Coal: Options for a Carbon-Constrained World*, MIT Interdisciplinary Group, Coal Energy Study, 2007, pp. X and 7.

¹⁴"Synapse 2008 CO2 Price Forecasts," Synapse Energy Economics, Inc., July 2008.

¹⁵"Our Mercury Problem," *Indianapolis Star*, Nov. 21, 2008, p. 1.

¹⁶"Mercury Pollution from Power Plants: Myths vs. Facts," National Wildlife Federation, October 2004; see also Environmental Protection Agency, *Mercury Study Report to Congress*,

The EIS that SWEPCO submitted during the PSC hearings indicated that about 300 pounds of mercury would be released into the air each year of operation. One expert testified that the utility's operating plan was inadequate in the face of this level of contamination.

The EIS indicates too that the power plant will emit over 300 pounds of mercury a year, with a service life of 30 years, for a total of four and a half tons of mercury emitted. There are no predictions about how far away from the plant that mercury will land. So, after disclosing that mercury is dangerously poisonous, the EIS makes no prediction about what health impacts the project will have.

However, the EIS does commit the utility to evaluate the impacts of mercury *after* they occur. This seems to me akin to 'Here, eat this fish. Don't worry, if it poisons you we'll do a thorough autopsy on you.' This after-the-fact approach does not support well-informed decision-making.¹⁷

The utility has agreed to use standard technology to limit mercury contamination at the Turk site, and its other plants have proposed being retrofitted with baghouse and carbon injection equipment. However, at present the company does not claim that these methods are effective, as seen in its filings with the PSC:

Mercury control technology (e.g., carbon injection) has not been demonstrated commercially at coal-fired units, and it is uncertain whether the removal performance can be achieved, particularly in the near term. **As such, the mercury constraints and carbon injection added in ... 2009 will likely be technically infeasible.**¹⁸ (Emphasis in original.)

Vol. 3: Fate and Transport of Mercury in the Environment, 1997, p. 5-1; Electric Power Research Institute, "Overview of mercury emissions and their fate in the environment," presentation at the Air & Waste Management Association's annual meeting, June 2003; Carola Hanisch, *Where Is Mercury Deposition Coming From?*, *Envtl. Sci. & Tech.*, Apr. 1, 1998, available at <http://pubs.acs.org/hotartcl/est/98/apr/mer.html>; U.S. EPA, National Emissions Inventory for Hazardous Air Pollutants, 1999, <http://www.epa.gov/ttn/chief/net/1999inventory.html#final3haps>.

¹⁷Direct testimony of James Mangi before the PSC, Docket No. 06-154-U, document #96, June 29, 2007, p. 60.

¹⁸"AEP Environmental Scenario Analysis," June 7, 2004, p. 27; submitted as an exhibit by Bruce Braine in direct testimony before the PSC, Docket No. 06-154-U, Exhibits Volume II, Sept. 24, 2007.

It is clear that, given the present state of carbon-injection technology, the power industry is not ready to adopt this type of carbon capture. Other problems remain also, most notably the issue of scale and the number of injection wells that might be needed under current technology. A new engineering study indicated more than two-and-one-half times more wells would be needed to satisfy the supply of CO₂ from current power plants. “To inject all of the additional gas and thus keep total emissions at 2005 levels, the U.S. will need to drill 100,830 more wells ... to dispose of the additional 2,005 MMt per year of carbon dioxide. For comparison, about 40,000 oil and gas wells are drilled annually in the United States.”¹⁹

A recent coal book pointed out its combustion effects: “... coal-fired power plants ... contribute about three-fifths of all sulfur dioxide, one-third of all mercury, and one-fifth of all nitrogen oxide emissions in the United States.”²⁰

Numerous proposals have been made to reduce power plant emissions of nitrogen oxides (NO_x), sulfur dioxide (SO₂), mercury (Hg), and carbon dioxide (CO₂). Efforts to reduce these emissions will fall primarily on coal generating plants. Depending on the stringency of the proposals, reducing each of these emissions, particularly carbon dioxide, could significantly impact the competitiveness of existing and new coal plants and the market for coal.²¹

However, because these proposals had not been enacted at the time of the Turk plant hearings, some observers and utility witnesses noted that it was uncertain whether such future restrictions would apply to current coal plants or to those under construction. The notion of “grandfathering in” old plants was mentioned as one reason for the uncertainty. Yet if one considers the rate at which greenhouse gases are increasing at present, and the size of the reduction in current emissions that would be required to control this detrimental growth, it is clear that all sources of carbon pollution – new and old alike – will have to participate in the new regulations.

A recent report by the MIT Interdisciplinary Group makes the point emphatically that

¹⁹Xina Xie, “Carbon Sequestration: Injecting Realities,” *Energy Tribune*, Mar. 19, 2008, available on-line at <http://www.energytribune.com/articles.cfm?aid=826>.

²⁰Jeff Goodell, *The Dirty Secret Behind America's Energy Future*, Houghton Mifflin Co, 2006.

²¹*U.S. Dept. of Energy Conference on the Future of Coal*, Energy Information Administration, testimony before the Energy and Natural Resources Committee, Mar. 10, 2005.

controlling CO₂ cannot be limited to new power plants. Coal emissions have been increasing since an earlier flat period. According to this study:

Coal's contribution to total CO₂ emissions had declined to about 37% early in the century, and this fraction is projected to grow to over 40% by 2030. Clearly any policy designed to constrain substantially the total CO₂ contribution to the atmosphere cannot succeed unless it somehow reduces the contribution from this source. ...A major contributor to the global emissions reduction for 2050 is the reduction in CO₂ emissions from coal to half or less of today's level and to one-sixth or less that in the Business As Usual projection.²²

The cost of these carbon reductions – whether achieved through a carbon-permit process, a carbon penalty, a cap and trade system, a technological breakthrough such as carbon capture and storage (CCS), or another approach – will have a direct and dramatic effect on the price that consumers pay for electricity in the future. The 600 mWe Turk plant is slated to use an ultra-supercritical pulverized coal process. CO₂ emissions will be directly proportional to the amount of electricity generated, which is in turn directly related to the quantity of coal used for burning.²³

The major process for reducing CO₂ emissions from coal-fired power plants is called carbon capture and sequestration. ...A number of independent sources such as Duke Energy, the electric industry's Edison Electric Institute, the Massachusetts Institute of Technology and the U.S. Department of Energy's National Energy Technology Laboratory have estimated that adding carbon capture technology would increase the cost of generating power at a pulverized coal-fired plant by 60 percent to 80 percent.

If these costs of carbon capture were included, the projected cost of generating power at Plant Washington (Georgia) would jump (from about 7.5 cents) to 12.2 cents to 13.7 cents per kilowatt hour. If shown to be technically and legally feasible, the costs of transporting and permanently sequestering the CO₂ in the ground may be expected to add another one to three cents per kilowatt hour to this cost, but even this cost range may be

²²*The Future of Coal: Options for a Carbon-Constrained World*, MIT Interdisciplinary Group, Coal Energy Study, 2007, pp. X and 7.

²³A load (or capacity) factor must also be considered, since no plant operates 100 percent of the time. For this study, we have used the common standard of 85 percent.

too low.²⁴ (parentheses added)

Many other utilities and regulatory authorities have faced this same dilemma in recent years, in their attempts to balance electricity generation from coal and its environmental consequences. Projections of future costs for carbon emissions have created a broad range, from basically \$0 – the status quo – to rates in excess of \$60 per ton. As the accompanying chart of 20 separate analyses illustrates, most studies have concluded that carbon costs in the range of \$10 to \$45 per ton are a reasonable assumption during the next 20 years. (Oregon’s PSC, with the status quo included as its lower limit, also includes the highest rate of any state as its upper limit – \$85 per ton – for a mid-point of \$42.50 per ton.)²⁵

For the Turk plant, in Table 1 we have calculated the amount of CO₂ that will be generated annually based on the estimate that 120 rail cars of coal from Wyoming’s Powder River Basin will be needed daily to fuel the plant. That quantity of coal will generate about 3.6 million tons of CO₂ each year of operation²⁶ – some estimates are as high as 5.28 million tons – and provide customers with electricity at a cost of about \$.09 per kWh.²⁷

Table 1 answers the question of how much will it cost consumers to pay for future reductions in carbon emissions from coal-fired power plants. The short answer is: A LOT. If we consider the range of possibilities, projections are about \$5 per ton at the low end and almost \$100 per ton from the EPA analysis of Senate Bill 2191. One

²⁴“The Risks of Building and Operating Plant Washington,” Synapse Energy Economics, Dec. 2, 2008, p. 17.

²⁵“Synapse 2008 CO₂ Price Forecasts.”

²⁶Synapse, 2008, based on a typical 500 mWe coal-fired plant’s emissions; see also “Table 2-1 – Expected Emission Rates of the Proposed Hempstead Power Plant,” EIS. All references in this report to CO₂ emissions are in metric tons; a metric ton is a measurement of mass equal to 1,000 kilograms or 1.1 tons. During the Arkansas PSC hearings, it was claimed that this advanced pulverizing process would reduce emissions, but little evidence was offered in the public record to substantiate that reduction. A company spokesman has said that the process would reduce emissions by only 4 million tons over 30 years; see “Power-plant battle a classic game of maneuver,” *Arkansas Democrat*, Dec. 28, 2008, p. G1.

²⁷Supplemental testimony of Venita McCellon-Allen, COO of SWEPCO, PSC Docket No. 06-154-U, Mar. 22, 2007, p. 4; additional supplemental testimony of Scott Weaver, document #89, Aug. 20, 2007. Initial rate of \$.086 per kWh was increased by inflation factor provided by Ms. McCellon-Allen.

consulting firm, Synapse Inc., has been tracking the various legislative and environmental agency proposals for several years. Two years ago, their projections ranged from \$8 to \$32 per ton of CO₂ emitted. In 2008, these reference numbers have risen dramatically; the Synapse projected cost in 2008 dollars is now from \$15 to \$45 per ton.²⁸

Either of these ranges – \$5 to \$100 in the former example and \$15 to \$45 in the Synapse projections – is substantially above the rates that were used by the Arkansas PSC during its deliberations. (Although a good portion of this testimony was redacted from public view, an AEP report listed carbon costs under the McCain-Lieberman bill from \$9 to \$23 per ton by 2010.²⁹) Including these more reasonable carbon costs as part of the future costs of electricity means that SWEPCO cannot possibly provide electricity at a cost of about \$.09 per kWh, once the effect of new greenhouse-gas legislation is incorporated.

Yet company officials testified that “For the average residential customer, the Hempstead Plant will increase total rates (base and fuel) by approximately \$8.51 per month, or 11 percent.”³⁰ Furthermore, SWEPCO maintained that its overall rates will continue to be favorable when compared to other Arkansas utilities, and cited an Edison Electric Institute report for 2006 that showed SWEPCO residential customers paid \$80.14 per 1,000 kWh versus a range of \$91.66 to \$102.77 per kWh for customers of other investor-owned utilities in Arkansas.

Before we look at the results, let’s consider some of the uncertainties regarding the costs of controlling carbon emissions. In addition to the many legislative proposals that have been analyzed elsewhere and are listed in Table 1, it is not clear how much CO₂ will actually be emitted from the plant. From the MIT study, an estimate was made that this size plant would generate about 3.6 million tons of carbon annually.³¹ However, industry sources have provided higher estimates: in the EIS provided to the PSC, the carbon

²⁸Synapse Energy Economics, Inc. provides research, testimony, reports and regulatory support to consumer advocates, environmental organizations, regulatory commissions, state energy offices, among others. The private firm works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, a variety of environmental groups, foundations, the U.S. EPA, Department of Energy, Department of Justice, Federal Trade Commission, the National Association of Regulatory Utility Commissioners, and others.

²⁹“AEP Environmental Scenario Analysis,” June 7, 2004, p. 39.

³⁰Venita McCellon-Allen, PSC Docket No. 06-154-U, Mar. 22, 2007, p. 4.

³¹*The Future of Coal: Options for a Carbon-Constrained World*, MIT Interdisciplinary Group, 2007, p. 7.

estimate was 5.28 million tons of CO₂.³² In another example, we have: "... operat(ing) at an average annual 85 percent capacity factor, the 850 MW Plant Washington will emit approximately 6 million tons of CO₂ each year for what can reasonably be expected to be a 60-year operating life."³³ So two tables have been prepared that show the projected costs of future carbon containment under two different scenarios.

One way to summarize the added cost is to consider the mid-points of the various projections in the tables. This generates a range of costs from about \$20 to about \$50 per ton. (For comparison purposes, the Texas Public Utility Commission in a ruling after the Arkansas PSC hearing limited SWEPCO's carbon-cost recovery from rate payers at \$28 per ton.)³⁴ If we take an average of the mid-points from Table 1, the projected extra cost for carbon reduction is almost 30 percent higher than the projected gross revenue from the plant's operations. If one considers the most recent numbers from Synapse (July 2008), the mid-range estimate means that costs would **increase by about one-fourth** (26.4 percent) and the upper range estimate places the **increased costs more than one-third above** the company's gross revenue from this plant.

The obvious result of this scale of large cost increases is that the cost of electricity provided to SWEPCO's customers must increase dramatically. Based on the company's estimated gross revenue of \$395 million per year from selling power at an average price of \$0.09 per kWh, these carbon-cost increases could translate to prices of \$0.116 to \$0.129 per kWh. These are moderate projections, based on the lower emissions estimates and a review of Synapse's average and upper range of prices. But if we use the industry figure on the amount of carbon that could be emitted, the costs are even higher.

Consider the alternative projections that place carbon emissions from this size of plant at 5.28 million tons annually. This generates a range of costs from about \$20 to about \$70 per ton. If we take an average of the mid-points from Table 2, the projected extra cost for carbon reduction is about 42 percent higher than the projected gross revenue from the plant's operations. If one considers the most recent numbers from Synapse (July 2008), the mid-range estimate means that costs would **increase by more than one-third** (38.8

³²"Table 2-1 -- Expected Emission Rates of the Proposed Hempstead Power Plant," EIS; see also "Hundreds attend hearing on SWEPCO power plant," *Arkansas Democrat*, Sept. 20, 2008, p. D1, report of testimony before the APSC regarding the proposed Turk power plant.

³³"The Risks of Building and Operating Plant Washington," Synapse Energy Economics, Dec. 2, 2008, p. 12.

³⁴"SWEPCO's Motion for Rehearing," Texas PUC Docket No. 33891, Aug. 29, 2008, p. 3.

percent) and the upper range estimate places the **increased costs more than one-half above** (58.2 percent) the company's gross revenue from this plant.

Try To Follow This PSC Testimony

18 For example, a typical coal plant emits approximately
19 2,150 pounds per megawatt hour or 1.075 tons. Do you
20 see that statement?
21 A. Yes.
22 Q. Now, that 1.075 tons refers to a typical plant,
23 doesn't it? Kind of a generic plant; correct?
24 A. Whatever one would define to be a generic plant.
25 Q. Or a typical one at least in this phrase?
0389
1 A. If that 10,000 heat rate meets that definition.
2 Q. Well, what I'm getting at is, do you know how much
3 CO2 is suppose to be emitted from the Hempstead plant
4 annually?
5 A. I'm aware that the heat rate is by and large
6 estimated to be around 9,000 heat rate. So, basically,
7 you would just replace in this calculation instead of
8 10,000, 9,000, and I think you'll get a value of
9 something along the line of .95 tons per megawatt hour.
10 Excuse me.
11 Q. Okay. Do you know how much CO2 is suppose to be
12 emitted from the Hempstead plant annually?
13 A. I would have to run the calculation, and it would
14 be a function of the capacity factor of the unit as
15 well.

AR PSC Docket No. 06-154-U, Testimony of Scott Weaver, Aug. 20, 2007.

Again, the obvious result of this scale of large cost increases is that the cost of electricity provided to SWEPCO's customers must increase dramatically. Based on the company's estimated gross revenue of \$408 million per year from selling power at an average price of \$0.09 per kWh, these carbon-cost increases could translate to prices of \$0.127 to \$0.145 per kWh. These are upper-range projections, based on the industry emissions estimates and a review of Synapse's average and upper range of prices. But the Synapse upper range remains well below the cost estimates of many other organizations that have followed the legislative trends, as can be seen in Tables 1 and 2.

When SWEPCO responded to the PSC’s Order #5 to explicitly consider these carbon containment issues, the costs that were used were well below those noted in Table 2. In Table 3, the company projections of electricity costs under a “high CO2” are compared to the earlier Synapse middle and upper ranges of CO2 costs (which are considerably lower than the recent 2008 figures). It is easy to see that the SWEPCO “high” costs for Turk or the alternative plans are below the older, middle estimates of the other experts and well below – by about 20 percent – the upper range of the old, now outdated, Synapse costs.

Table 3. Company Estimates of Levelized Cost of Electricity Generation (\$mWh)³⁵

	Hempstead	CT Plan	CC Plan
SWEPCO High CO2	55.99	54.83	54.88
Synapse Mid CO2 w/DSM	56.86	55.06	55.27
Synapse High CO2 w/DSM	67.42	65.09	65.28

It is clear from the PSC filings that the company does not anticipate that future carbon-emission costs will overwhelm its national operations, which throughout the AEP system generate about 38,000 mWe currently. Under the McCain-Lieberman scenario, it reported that increased costs of \$0.5 to \$0.9 billion might be needed for carbon capture or trading, while under the more-stringent Carper bill the costs would increase from \$3 to \$6.4 billion for the entire company.³⁶ While this is a large dollar amount for any company, it pales in comparison to the large increases in costs that future coal-fired plants will face under a more reasonable assessment of carbon legislation (see next page).

What might this mean for Arkansas, Louisiana, and Texas ratepayers in the future? According to the U.S. Department of Energy, in 2005 the average household in the nation paid about \$89 per month for electricity.³⁷ In Arkansas with its long summer cooling

³⁵Submitted as an exhibit by Scott Weaver, AEP Managing Director, in direct testimony before the PSC, Docket No. 06-154-U, Order #6, Exhibits Volume I, SCW-RI-2, p.2, Sept. 24, 2007 (extracted from larger table).

³⁶“AEP Environmental Scenario Analysis,” June 7, 2004, pp. 6 and 19; see also exhibit submitted by Bruce Braine in direct testimony before the PSC, Docket No. 06-154-U, Exhibit BHB-2, pp.12-13, 87.

³⁷*Electric Power Annual and Annual Energy Review*, U.S. Energy Information Administration, 2007.

season, the average bills are higher at about \$92 monthly. If the carbon-driven increase from Table 1 is used, this means that residential bills will rise to about \$129 per month in 2013 when Turk's full costs could enter the rate base, regardless of any additional construction costs and other cost increases that are allowed by the PSC in the meantime. And if the increase from Table 2 is used, this means that residential bills will rise to about \$142 per month in 2013, regardless of any additional construction costs allowed.

In the end, the company hopes that an international carbon-credit system will allow it to offset its carbon emissions by purchasing credits from other companies or countries in the future. According to the Wall Street Journal:

AEP, one of the nation's biggest carbon-dioxide emitters, estimates it could buy a credit for about \$10 (per ton of CO₂), compared with spending roughly \$50 to reduce a comparable amount of emissions by retooling its own power plants, said Bruce Baine... Through 2030, AEP wants to meet roughly 25 percent to 30 percent of its potential emission-cutting obligation by buying credits...³⁸

Another way of looking at these cost data is the comparison of the utility's selected "best alternative" source for the power project. The company's own expert during the PSC hearings admitted that the Turk plant will be more expensive than a generic natural gas plant. "If you're using our numbers, it would be, yeah, about 120 to 130 million dollars more expensive."³⁹ Another company official allowed that at least three alternative power plants would be cheaper to build, by as much as \$300 million. Apparently the company believed that this type of plant was worth the higher price (see sidebar). However, as the projections in Tables 1 and 2 make clear, a realistic assessment of future carbon-abatement costs render this comparison either meaningless or erroneous, depending on the approach taken.

First, this report maintains that it is an empty exercise to compare alternative power costs to coal costs without including a reasonable portion of the future costs of carbon abatement. Second, if one includes future costs similar to the mid-range of carbon-abatement costs shown in Table 4, the resulting comparison is highly unfavorable to the coal option. For example, using the MIT numbers for carbon generation, the average projected cost of carbon emissions from the 20 sources is \$117.5 million for each year of operation. At a 5 percent discount rate for 40 years, the present value of these additional costs to the utility's customers is **\$2 billion**, compared to the "savings" on a gas plant

³⁸"Battle lines form over cost of carbon proposal," *Wall Street Journal*, June 8, 2008.

³⁹Weaver, PSC Docket No. 06-154-U, Aug. 20, 2007 (e.g., Exhibit SCW-S-4).

offered at the APSC hearings of \$130-300 million.

However, if the industry figure of 5.28 million tons of carbon per year is used, the comparison is even worse for coal. As Table 5 shows, the higher level of carbon emissions would make the future penalties larger; the average projected cost from the 20 sources is \$172.3 million for each year of operation. At a 5 percent discount rate for 40 years, the present value of these additional costs to the utility's customers is **more than \$3.0 billion**, compared to the gas plant figure of \$130-300 million.

Rejecting Three Better (and Cheaper) Options for Power

22 Q. Okay. Let's turn to Exhibit 6 and 7 and walk
23 through those quickly.

24 First, Exhibit 6, which is on the last page of
25 your June 19th testimony, when you study case one, the
0323

1 base commodity prices reflected in that particular
2 exhibit, the lowest cost option is going to be either
3 the best all gas, the CT at plus 20 percent, or the port
4 CC in 2011; correct?

5 A. Yes.

6 Q. And is it fair to say that those three lower
7 options are approximately \$300 million less than the
8 Hempstead option?

9 A. That represents the economic result, but that does
10 not consider the impact that would have, for instance,
11 on generation and fuel diversity. If, in fact, you're
12 dealing with an all gas plan, you're basically adding
13 1250 megawatts of gas, and basically in -- decreasing,
14 rather, the energy position of SWEPCO and potentially
15 creating more volatility as it relates to prices that
16 would be experienced by SWEPCO's customers going
17 forward, whether it be through volatility of gas prices
18 or if SWEPCO ultimately needs to acquire additional
19 purchased energy, the volatility in purchased energy
20 cost as well.

AR PSC Docket No. 06-154-U, Testimony of Scott Weaver, Aug. 20, 2007.

In the following section, more evidence is offered about the projected costs of power plants and the inadequacy of the cost estimates prepared by the utility.

The Increasing Costs of Power-Plant Construction

While the wide ranges of potential future costs for carbon abatement make a precise estimate of the emissions costs in the future difficult, it should be clear that substantial price increases are in store for utility customers who rely on coal-powered power plants. However, in addition to these higher costs, utilities that plan to build new plants are facing a persistent trend of rapidly rising construction costs that has emerged since the 1990s.

Increased Cost for Construction

A recent report to the U.S. Department of Energy presents this case in stark and unambiguous terms. Prepared by the Cambridge Energy Research Associates, the 2008 study looked at building costs for power plants since 2000 and found that costs have more than doubled for proposed plants in just eight years; even when expensive proposed nuclear plants are removed from the averages, the remaining plants still have increased about 80 percent in costs (see Figure 1).

A new Power Capital Cost Index (PCCI), developed by IHS Inc. and Cambridge Energy Research Associates (CERA), suggests that the cost of new power plant construction in North America increased 27% in the past 12 months; 19% in the past 6 months alone... A North American power plant that would have cost \$1 billion in 2000 would, on average, cost \$2.31 billion today... The latest increases have been driven by continued high activity levels globally, especially for nuclear plants, with continued tightness in the equipment and engineering markets, as well as historically high levels for raw materials... Lead times for engineered equipment have increased up to 50% in the last 6-12 months for some items... These cost pressures are a major strategy issue for power companies, and will affect timing and availability of new plants... Unless there is a sudden and dramatic change in the industry, activity and market pressures should keep the PCCI at these levels, if not higher, for the next 12-18 months.⁴⁰

⁴⁰“Construction Costs for New Power Plants Continue to Escalate,” IHS CERA Power Capital Costs Index, Cambridge, Mass., May 27, 2008, available on-line at <http://energy.ihs.com/News/Press-Releases/2008/IHS-CERA-Power-Capital-Costs-Index.htm>.

Figure 1 shows the trend lines for all generating plants and for the non-nuclear sites, and although the latter increases are slightly lower they are still forcing utilities and other energy producers to reevaluate their construction budgets every six months. This has been reflected in SWEPCO's projected costs for the Turk plant, whose costs have risen from the original \$1.3 billion to the latest figure of \$1.6 billion.⁴¹ Company officials have already begun discussions about how this increase will be passed to customers if the plant comes on-line in 2013.⁴²

Since late 2006, more than twenty proposed coal-fired power plants have been cancelled. More than three dozen others have been delayed. State regulatory Commissions in North Carolina, Florida, Virginia, Oklahoma, Washington State, Oregon, and Wisconsin have rejected proposed power plants. The Secretary of Health and Environment of the State of Kansas also has rejected permits for two 700 MW coal-fired power plants.⁴³

Government and academic observers are not the only knowledgeable parties who have publicized this disturbing trend. The chief economist for the Associated General Contractors of America, a trade group that represents the companies that build these plants and many other types of industrial and commercial projects, has reported on these price hikes.

Over the past four years, the costs of basic materials such as asphalt, concrete, steel and diesel fuel have risen 40% because of construction booms in China and torrid demand in other countries... Diesel fuel costs over the past four years have soared by 202%, asphalt by 120% and steel-mill products by 60%... I'm hearing from government agencies at all levels, from the Army Corps of Engineers down to local school districts, that when they open bids for projects they had first done an estimate on three or four years ago, they're seeing huge increases certainly consistent with this 40%

⁴¹This figure does not include financing costs, which would raise the cost to \$1.8 billion not including the Welch additions or the transmission lines. See "SWEPCO's Motion for Rehearing," Texas PUC Docket No. 33891, Aug. 29, 2008, p. 2.

⁴²"Higher power bills ahead," Marshall News Messenger (Texas), Nov. 22, 2008; available on-line at http://www.marshallnewsmessenger.com/featr/content/features/stories/2008/112308_web_swepco.html.

⁴³"The Risks of Building and Operating Plant Washington," Synapse Energy Economics, Dec. 2, 2008, p. 4.

escalation... My prediction is that for the next several years we'll be seeing construction materials costs go up an average of 6 to 8% each year.⁴⁴

While the economic slowdown of 2008 may reduce some of the steam in these overheated markets – and SWEPCO has indicated that it has “pre-purchased” some of the equipment that will be installed at the Turk site – a long-term trend of even seven-percent price increases means that last year’s power plant supposedly costing \$1.6 billion could have an eventual price tag of \$2 billion or more by the time of its completion in 2013. This year, the company announced that other plants under construction nearby are facing surprising cost increases.

... costs for the 500-megawatt Stall plant (in Shreveport) rose 35 percent since its 2006 proposal (for the gas-fired plant) from \$325 million to \$439 million, SWEPCO disclosed in a Tuesday filing with the commission. As a result, Arkansans’ share of Stall’s price tag stands to nearly double to \$3.02 per 1,000 kilowatt-hours of residential power used. SWEPCO blamed that rise on increased competition for “gray market” equipment - new or used items not sold by the original manufacturer - that was initially earmarked for Stall but that later became unavailable.

A follow-up search yielded “slightly different” equipment that proved more expensive, while material and labor costs rose as well, SWEPCO officials said. ...‘This sort of thing is happening industry wide as more utilities try to meet increased electricity demand,’ (SWEPCO spokesman Peter) Main said. ‘Whether it’s steel, concrete or industrial parts, ultimately those costs are driving up.’⁴⁵

As an indicator of what is happening to the costs of similar coal-fired power plants, Table 6 looks at six recently announced plants and their construction costs per unit of output. Only one of these plants has a construction cost that is less than Turk’s \$2,667 per kW, and most have building-cost estimates nearer \$3,500 per kW. For example, the Marshalltown plant, which plans to use a supercritical pulverized coal technology (like Turk) and has an output of 630 mWe, has a total cost of \$2.2 billion and **a per kW cost of \$3,538**. Comparisons like these call into question the reliability of the costs originally provided by SWEPCO and their later upward adjustments, given the recent trends in power-plant construction costs.

⁴⁴“Emissions-free coal plant’s cost worries feds,” *USA Today*, Jan. 6, 2008; see also “Five Minutes with Ken Simonson,” *Pittsburgh Business Times*, July 11, 2008.

⁴⁵“Will seek rate surge, SWEPCO says,” *Arkansas Democrat*, Dec. 11, 2008.

Table 6. Recent Coal-Fired Power Plant Cost Estimates
(nominal year dollars, no financing costs)

Plant	Type of Coal	Plant Owner	Date of Estimate	TotalCost (Billions)	Size MW	Cost/kW
Plant Washington	SCPC	Power4Georgians	January-08	\$2.00	850	\$2,353
Turk	SCPC	SWEPCO	Spring 2008	\$1.60	600	\$2,667
Karn-Weadock	SCPC	Consumers Energy	September-07	\$2.21	800	\$2,765
Meigs County	SCPC	AMP-Ohio	October-08	\$3.26	960	\$3,394
NelsonDewey3	CFB PC	Wisconsin Power & Light	September-08	\$1.26	326	\$3,865
Columbia 3	Sub Critical PC	Wisconsin Power & Light	September-08	\$1.28	326	\$3,936
Marshalltown	SCPC	Interstate Power & Light	September-08	\$2.23	630	\$3,538

Source: “The Risks of Building and Operating Plant Washington,” Synapse Energy Economics.

Notes:

SCPC = supercritical pulverized coal power plant

CFB PC = circulating fluid bed pulverized coal plant

Sub Critical PC = subcritical pulverized coal plant

These construction-cost inflationary factors were known during the LPSC hearings, and at least one witness warned that the result of these higher costs would be that coal-fired plants in particular would lose their traditional position as having a reliably low-cost advantage over gas-fired plants.

The price increases experienced over the past several years have affected all electric sector investment costs. In the generation sector, all technologies have experienced substantial cost increases in the past three years, from coal plants to windpower projects.

... infrastructure costs were relatively stable during the 1990s, but have experienced substantial price increases in the past several years. Between

January 2004 and January 2007, the costs of steam-generation plant, transmission projects and distribution equipment rose by 25 percent to 35 percent (compared to an 8 percent increase in the GDP deflator). For example, the cost of gas turbines, which was fairly steady in the early part of the decade, increased by 17 percent during the year 2006 alone.

As a result of these cost increases, the levelized capital cost component of baseload coal and nuclear plants has risen by \$20/MWh or more—substantially narrowing coal’s overall cost advantages over natural gas-fired combined-cycle plants—and thus limiting some of the cost-reduction benefits expected from expanding the solid-fuel fleet.⁴⁶

Other states have noted these disturbing future trends and have acted forcefully to protect ratepayers. In 2007, for example, Florida regulators found the following: “... the decision of the Florida Public Service Commission in denying approval for the 1,960 MW Glades Power Project was based on concern over the uncertainties of plant construction costs, coal and natural gas prices, and future environmental costs, including carbon allowance costs.”⁴⁷

Thus, while the utility and the state’s commissioners appeared to agree that price volatility in the natural-gas markets warranted a move toward coal-fired power plants, they were less concerned that consistently increasing costs to build large power plants would make any of them less cost-effective than either alternative forms of energy production or increased spending on improved energy efficiency. As later sections of this report will demonstrate, these demonstrable higher future costs for traditional forms of electricity generation are making comparisons with alternative energy less favorable each year.

Higher Prices for Delivered Coal

Nevertheless, one last cost escalation that the PSC largely ignored in allowing the proposal to go forward is fundamental to the Turk plant – the future price of coal itself. The Turk plant expects to use about 3.3 million tons of coal annually as its sole fuel source.⁴⁸

⁴⁶Testimony of David A. Schlissel, LPSC, Docket No. U-30192, Sept. 14, 2007, p. 149.

⁴⁷Florida PSC, Order No. PSC-07-0557-FOF-EI, Docket No. 070098-EI, July 2, 2007.

⁴⁸Environmental Impact Statement, PSC Docket No. 06-154-U, Document #66, Exhibit JCH-1, p. 9.

Increased Coal Demand and Price

A number of observers have also noted that the world's increasing demand for coal has been placing upward pressure on coal prices recently, and pressure in general on the railroads that deliver virtually all the coal to market. In 2007, the U.S. Energy Information Administration noted in its Annual Energy Outlook: "For states east of the Mississippi River, coal demand is projected to increase by 5.9 quadrillion Btu, or 39 percent, from 2005 to 2030."⁴⁹

This year, the agency generated a set of forecasts for coal prices that reflected its concern for effect of this increased demand on future coal prices. "In the high coal cost case, the average delivered coal price in 2006 dollars is \$2.76 per million Btu in 2030—52 percent higher than in the reference case. As a result, U.S. coal consumption is 4.8 quadrillion Btu (16 percent) lower than in the reference case in 2030, reflecting both a switch from coal to natural gas, nuclear, and renewables in the electricity sector... ." ⁵⁰

So the increasing demand is having the predictable economic effect of pressuring coal prices upward, as even SWEPCO's witnesses were forced to admit during the PSC hearing (see exchange in the sidebar). Even though the company's cost projections were based on spot coal prices that were "flat in real dollar" terms at \$0.26 per million Btu, in reality the price of coal increased to about \$0.55 per million Btu.⁵¹ Rather than merely keeping pace with overall inflation of about three percent annually (a "flat" trend), prices for coal from the Power River Basin (PRB) rose during the previous five years at a 16 percent annual rate.

Although these cost increases pale in comparison to the large dollar increases that the company faces in both carbon emissions and rising construction expenses, it is clear to many experts that rising coal costs are the "other shoe" dropping on the economic prospects for coal-fired power plants. The SWEPCO testimony indicated that delivered coal prices would climb to about \$1.40 per million Btu – about \$23 per ton – by 2013, the original scheduled start date for the plant. However, absent a prolonged worldwide recession caused by the finance and banking crisis, prices are likely to rise above that level.

⁴⁹U.S. Energy Information Administration, *Annual Energy Outlook*, 2007.

⁵⁰U.S. Energy Information Administration, *Annual Energy Outlook*, 2008.

⁵¹Supplemental testimony of Judah L. Rose, PSC Docket No. 06-154-U, Exhibit-7, p. 24,

Investors have noted the upward pressure on coal prices and have bid up the stock prices of mining companies like Peabody, Massy, and Arch during this decade. Based on increased worldwide demand and accompanying price rises, one analyst has predicted that delivered coal prices would reach \$33-35 per ton, or about \$2.00-2.10 per million Btu. That represents a difference of 50 percent above the projections that the company used in its testimony before the PSC, and is based on a number of market-related developments.

I would put price increases at 25% annually for the years 2012/2013, or approximately \$35/ton. My support is: 1) criticism of EIA numbers from EIA itself; 2) price projections from the major corporations that do mining in the country --- and the current "Buy" status that a number of the large institutional banks have on them, and 3) a host of structural factors that have clearly changed in the last few years.

... The "new" news: 1) 60% of new plants under construction in the country are slated to use PRB coal; 2) Arch is saying they have new orders from existing plants in the east; (and) 3) Enough pressure in global markets to keep metalurgical-coal market hot means further U.S. exports. ...The PRB analysis goes to a structural understanding of the industry. The simple case is that long-term historic performance is no longer the appropriate measure.⁵²

⁵²Personal communication with Tom Sanzillo, coal-industry analyst, Aug. 26 and Sept. 5, 2008.

That's Not "Flat"

BY MR. ADDISON (CONT.):

Q. I believe in your analysis you treat coal prices as flat for some 20 or 30 years, don't you?

A. It's flat in real dollars. It's escalating with the general inflation rate of two and a half percent per year.

1026

Q. Let's look at what this table shows. 2000, what was the cost of Powder River Basin coal according to Table 7?

A. 26 cents a million BTU.

Q. And by the way, this table -- we're here in 2007, aren't we?

A. Yes.

Q. Eight months after January 30th or so; correct?

A. Yes.

Q. You don't have any numbers for 2006 or 2007 on these tables, do you?

A. No, but I have some general knowledge which I would be glad to fill the Commission in on.

Q. My next question to you is, between 2000 -- based on the numbers that are on your table, between 2000 and 2005, PRB coal prices went from 26 cents to 55 cents, didn't they?

A. Between 2000 and 2005?

Q. Yes, sir.

A. That's correct.

Q. Now, that would be an increase of how much per year on average between that period of time? Approximately four percent?

A. No, I think it's larger than that. I mean, in an absolute basis, it's not --

1027

Q. Excuse me. Based on those numbers, I would like to know what's the average when you compare five years from 26 cents to 55 cents?

A. That's 16 percent.

Q. Per year?

A. Per year.

Q. That's a little higher than the inflation rate of 2.5, isn't it? Yes, sir?

A. Yes.

Q. Thank you.

Supplemental testimony of Judah L. Rose, APSC Docket No. 06-154-U.

Others in the industry see regulatory constraints and international competition as growing impediments to domestic coal use in the future. Another analyst has labeled the changing coal environment as the "new coal economics." (see next sidebar)

Lastly, not only is the long-term trend for coal prices running substantially above history-based patterns, but also the coal-delivery infrastructure may not be capable of handling the transportation demands of increased coal use. A recent review of the nation's coal delivery system demonstrated that capacity is already strained in parts of the railroad organization.

The Energy Information Administration (EIA) projects that the U.S. will consume almost 1,800 million tons of coal in 2030, up from about 1,150 million tons this year... EIA's estimates do not take coal-to-hydrogen production into consideration, several recent studies suggest that if the hydrogen economy ever comes to fruition coal could be a feedstock of choice... An increase in future coal demand fuels legitimate concerns about the impacts on global climate and regional air pollution...

Often overlooked is the possibility that the current coal distribution infrastructure may not be able to reliably deliver the additional demand.... Railroads deliver about two-thirds of U.S. coal at present, but certain coal-carrying rail corridors are already up against their capacity limits. Any future demand increases will probably necessitate significant capital investment by the railroad companies.⁵³

So, given the litany of economic and environmental problems associated with the increased use of coal – large future carbon-abatement costs and the cost of controlling other pollutants, persistently rising construction costs, upward price trends in the cost of the coal itself, predictable stresses on the nation's rail system, and others – is coal-fired electricity still the cheap, dependable, and cost-effective source for our nation's power? The next section explores the role that other forms of producing and conserving energy can play in a world where, because of so many increasing costs, coal has lost its competitive edge.

⁵³David L. McCollum, "Future Impacts of Coal Distribution Constraints on Coal Cost," Institute of Transportation Studies, University of California, Davis, Research Report UCD-ITS-RR-07-26 (2007).

New Coal Economics (excerpted)

With the falling dollar, selling to Asia, Europe or South America is giving coal producers a higher return than selling into the United States. "If I were running a coal company and I looked at what's happening on Capitol Hill and the states, I'd be very inclined to send my marketing team overseas," said Michael Morris, AEP chairman, president and CEO. "That's where it appears the growth market is going to be, not here domestically."

In 2007, the United States exported almost 60 million tons of coal. This year, many expect that figure to be between 80 and 90 million tons. Estimates for 2009 are even higher at 100 million tons. Through June of this year, producers sent 40.4 million tons overseas, up 57 percent from 2007. ... In today's marketplace, coal increasingly no longer wins economically.

"If coal stays at \$100-\$150 a ton, and if natural gas remains as low as it is or continues to fall in price, a lot of utilities will look at gas instead," said Mike Hendon, senior manager of coal acquisitions at TVA. "It's going to be interesting to see what pressure that puts on the coal market: \$120 coal versus \$7 gas. "We're at that point now with (Central Appalachian) coal. Gas is becoming a viable alternative."

Lee Buchsbaum, "New Coal Economics," EnergyBiz Insider, Dec. 24, 2008, available on-line at <http://www.energycentral.com/site/newsletters/ebi.cfm?id=614>.

3. DSM: the Cheaper Alternative to Higher Priced-Coal and Electricity

It is difficult for a lay person to understand the reluctance of some utility companies like SWEPCO to invest more fully in alternative energy sources in the modern era of higher-priced energy and declining resources such as oil. When one looks at the comparison of today's cost of traditional sources of electricity, such as coal and natural gas, with a number of other possible ways of managing the demand for power, the potential solution for today's energy problems seems more appealing than ever. According to a recent study by Lawrence Berkeley Laboratory:

Mandatory renewables portfolio standards (RPS) policies have been created in 25 states and Washington D.C.; four additional states have non-binding goals. Few Southern states have adopted these standards yet, and except for Texas no states surrounding AR/LA have mandatory RPS in '08.

In 2007, four states established new RPS policies, 11 states significantly revised pre-existing RPS programs (mostly to strengthen them), and three states created non-binding renewable energy goals. Forty-six percent of nationwide retail electricity sales will be covered by the mandatory state RPS policies established through the end of 2007, once these programs are fully implemented.

Assuming that full compliance is achieved, current mandatory state RPS policies will require the addition of roughly 61 gigawatts (GW) of new renewable capacity by 2025, equivalent to 4.7 percent of projected 2025 electricity generation in the U.S., and 15 percent of projected electricity demand growth.⁵⁴

Many other studies have examined the potential contribution of more energy efficiency in the U.S. economy, and have generally found very positive results for energy savings in the 20 percent range, including electricity use (see accompanying sidebar on page 33 with a report on 11 such studies). While this approach to incorporating alternative energy sources into the power mix was presented to the APSC during the SWEPCO public hearings, it did not appear to have a major impact on the commission's deliberations.

Demand Side Management (DSM) is the electric-resource strategy with which many U.S. utilities control growing electric demand and energy consumption by means of targeted

⁵⁴“Renewable Portfolio Standards in the U.S.: A Status Report with Data Through 2007,” Lawrence Berkeley National Laboratory, April 2008.

improvements in customer end-use efficiency or equipment operation. In utility DSM programs, energy resources are procured by means of shifting customer peak loads and by promoting the installation of high-efficiency customer equipment such as lighting, air-conditioning, motors, pumps, insulation, industrial process equipment and household appliances. In contrast to traditional generation or “supply side” utility activities, demand side resources originate on the customer or “demand” side of the electric meter.

DSM can also promote the public interest by maximizing economic benefits of utility ratepayers and reduce environmental impacts and escalating costs associated with power plant generation. Other regions, including northern states and our neighbor Texas, have embraced the use of DSM in a serious way. Studies in Texas have shown that a large portion of the projected growth in electricity demand for the next 20 years can be offset by the investment of utilities and their customers in a variety of conservation and renewable-energy techniques.

Although wind generates only about 1% of all electricity globally, it provides a respectable portion in several European countries: 20% in Denmark, 10% in Spain and about 7% in Germany. Wind power is also on the rise in America, where capacity jumped by 45% last year to reach nearly 17 gigawatts (GW) at the end of 2007. In China the pace has been faster still. Since the end of 2004, the country has nearly doubled its capacity every year.

Globally, wind power installations are expected to triple from 94GW at the end of 2007 to nearly 290GW in 2012, according to BTM Consult, a Danish market-research firm. They will then account for 2.7% of world electricity generation, the company predicts, and by 2017 their share could be nearly 6%.⁵⁵

For example, the U.S. added more windpower capacity during 2007 alone than all of the coal-fired capacity added from 2003-2007, and Texas was the largest single state for wind additions. That was a 45-percent increase in the size of the wind-power market over 2006, and preliminary figures for 2008 show another 50-percent increase in the market. That represents an estimated 8,000 mWe of new capacity in the U.S.⁵⁶ With generation prices in the \$0.035 to \$0.05 per kWh during the 2000 decade, windpower continues to be

⁵⁵“Wind of Change,” *The Economist*, Dec. 8, 2008.

⁵⁶Todd Woody, “Trying to Catch the Wind,” *Fortune*, Nov. 10, 2008, p. 163.

highly competitive with all forms of traditional electricity sources.⁵⁷ Yet Arkansas seems unable or unwilling to make the change to this level of commitment. SWEPCO has announced a goal of adding 1,000 mW of wind power by 2011, and signed a wind-farm contract for about 80 mWe in January.⁵⁸

The state has an active weatherization program, energy-efficiency grants, Energy Star ratings, and some utility-based DSM. However, in looking at 20 state climate-action plans, the Center for Climate Strategies found that Arkansas remains behind other states in establishing an RPS program for reducing utility reliance on traditional power sources like coal-fired power plants.⁵⁹

A recent study of national efforts in DSM indicates that states like Florida, Massachusetts, and Texas lead in the amount of money spent on energy efficiency and conservation. From their budgets, these states provided from \$83 to \$250 million in funding for energy-efficiency programs in 2007.⁶⁰ Residential programs and load management were important areas for funding; only large-population states like California and New York exceeded the amounts of those three states.

The industry's own research arm has calculated that a serious national program of energy-efficient techniques could save hundreds of billions of kWh of electricity annually by 2030. "EPRI estimates that energy-efficiency programs have the potential to realistically reduce this (EIA) growth rate (of 1.07%) by 22% to 0.83% per year from 2008 through 2030. Under conditions ideally conducive to energy-efficiency programs, this growth rate can be reduced by up to 36% to 0.68% per year."⁶¹

Although the company talked about energy efficiency (EE) and renewables during its PSC testimony, the level of effort described by the AEP managing director can only be described as half-hearted.

⁵⁷R. Wiser and M. Bolinger, "Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007," USDOE/EERE, LBL-43025, May 2008.

⁵⁸"SWEPCO signs deal with Texas wind farm," *Arkansas Democrat*, Jan. 21, 2009, p.D1.

⁵⁹Center for Climate Strategies, "Economic Stimulus, Recovery, and Climate Mitigation: Policy and Program Opportunities from the States," (draft) December 2008; available on-line at <http://www.climatestrategies.us/ewebeditpro/items/O25F20662.pdf>

⁶⁰"The Energy-Efficiency Program Industry," Consortium For Energy Efficiency, 2008 available on-line at <http://www.cee1.org/ee-pe/2007/budgets-main.php3>.

⁶¹"Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.," Electric Power Research Institute, January 2009.

The company is in the process of evaluating the various measures, program options, and their related costs and impacts for the July 2007 filing. ... Specific EE measures are still under evaluation but could include, as an example, promotion of residential and commercial **compact fluorescent lamps applications**. (Emphasis added.)

... SWEPCO does not have sufficient reserve margin that, when combined with aggressive energy efficiency and demand reduction programs and short-term purchase power agreements, would provide SWEPCO with the opportunity to defer the plant investment decision.⁶²

Of course, critics of DSM have pointed out for years that much of the success of DSM programs lies in the potential for customers, both residential and business, to change their energy-use behavior. That can be a difficult process when energy prices are low. But as we have learned during the recent upheaval in world oil prices, that change becomes much easier to facilitate when resource costs rise dramatically. And that is the reality that the U.S. and Arkansas face today.

National leaders have begun to address this new reality. In 2006, a group composed of more than 50 leading organizations (including the Natural Resources Defense Council) representing diverse stakeholder perspectives (utilities, government agencies, environmental organization, etc.) created a “National Action Plan for Energy Efficiency.” The overall goal was to create a sustainable, aggressive national commitment to energy efficiency through natural gas and electric utilities, utility regulators, and partner organizations. Its Leadership Group developed a plan that included five key points:

1. Recognize energy efficiency as a high-priority energy resource.
2. Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.
3. Broadly communicate the benefits of and opportunities for energy efficiency.
4. Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.
5. Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify rate-making practices to promote energy efficiency investments.⁶³

⁶²Supplemental testimony of Scott Weaver, AEP Managing Director, before the PSC, Docket No. 06-154-U, Mar. 22, 2007, pp. 11, 14.

⁶³Hale Powell, direct testimony before FL PSC, Docket No. 060635, Nov. 2, 2006, p. 13.

The Technical, Economic and Achievable Potential for Energy-Efficiency in the U.S. – A Meta-Analysis of Recent Studies

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ABSTRACT

In recent years, eleven studies have been conducted on the technical, economic, and/or achievable potential for energy efficiency in the U.S. These studies cover many regions (e.g., California, Massachusetts, New York, Oregon, Utah, Vermont, Washington, the Southwest and the U.S. as a whole), sectors (residential, commercial, and sometimes industrial), energy types (electricity and/or natural gas) and time frames (e.g., 5, 10 and 20 years). This paper summarizes the results of these different studies and then compares and contrasts them to tease out overarching findings. The 11 recent studies examined in this paper show that a very substantial technical, economic and achievable energy efficiency potential remains available in the U.S. Across all sectors, these studies show a median technical potential of 33% for electricity and 40% for gas, and median economic potentials for electricity and gas of 20% and 22% respectively. The median achievable potential is 24% for electricity (an average of 1.2% per year) and 9% for gas (an average of 0.5% per year). We compare the achievable potential findings to recent-year actual savings from portfolios of electric and natural gas efficiency programs in leading states and find substantial consistency. The paper concludes with several recommendations for future energy efficiency potential work.

From the proceedings of the *2004 ACEEE Summer Study on Energy Efficiency in Buildings*.

What kinds of energy savings are possible for the state if an aggressive DSM program were put in place? We don't know the exact numbers for this state – that analysis is lengthy and not part of this study – but several excellent comparisons can be made of other states that have embarked on this program. Table 7 shows the general experience of seven states during the past 25 years, and the results have been very positive with “payback” rates of from 2:1 to almost 6:1 for their investments.⁶⁴ Even though the displaced amount of traditional energy production is not always large (see “Cumulative Annual mW Savings”), in several cases like California the amount equals or exceeds the annual electricity output of an average power plant.

Massachusetts was an early adherent to DSM because of their traditional reliance in heating oil, a victim of the Arab oil embargos of the 1970s. “As an example of what might be applied in the State, the 1,363 commercial and industrial customers who participated in Massachusetts Electric DSM programs in 2005 saved a total of 76.7 million kWh. Over the lifetime of the DSM equipment installed in 2005 alone, these programs produced net benefits of approximately \$57 million, and 2005 residential net benefits were approximately \$56 million.”⁶⁵ A more recent study demonstrated the role that energy efficiency is playing in that state's electricity markets.

Massachusetts electric utilities are currently achieving energy efficiency program savings of about 1% of their annual energy needs with energy efficiency programs at a CSE (cost of saved energy) of around 3 cents/kWh. Our data suggest that the cost of saved energy could decrease if the utilities were to increase their program scale further, perhaps up to the level of annual savings equal to 2% or 3% of annual sales. This implies that the cost effectiveness and benefits of energy efficiency programs could be even greater in the future with greater program scale.⁶⁶

Our neighbor Texas has a much larger population and economic base that requires more electricity than Arkansas, and its two principal cities of Dallas-Ft. Worth and Houston

⁶⁴Hale Powell, direct testimony before FL PSC, Nov. 2, 2006, p. 14. Technically, these are benefit-to-cost ratios over the course of treatment, and longer terms of treatment will tend to increase the benefit portion of the ratio.

⁶⁵Powell, see Exhibit 1, p. 8.

⁶⁶Doug Hurley et al, “Costs and Benefits of Electric Utility Energy Efficiency in Massachusetts,” prepared for Northeast Energy Efficiency Council, Synapse Energy Economics, August 2008.

Table 7 - Successful Energy Efficiency Program Results from Other States and Regions

State or Region	Starting Year for Savings in This Table	Cumulative Annual mWh Savings	Cumulative Annual mW Savings	Program-to- Date Benefit/Cost Ratio
California	2000	6,727,000	1,559	n/a
Efficiency Maine	2002	52,437	n/a	2.3
Efficiency Vermont	2000	251,500	75	2.3
New York Energy \$mart	1998	1,400,000	860	4
Energy Trust of Oregon	2002	974,919	96	n/a
NW Energy Efficiency Alliance	1997	1,278,960	146	n/a
Wisconsin Focus on Energy	2001	783,957	140	5.7

Note 1: The numbers in this table are presented for each State or Region for the time period starting at the beginning of the organization's programs, except for California which started energy efficiency programs in 1976.

have larger energy appetites than any city in the state. But it is instructive to look at recent projections for the energy savings that DSM programs might have in Texas, because many of those techniques could easily be transferred to this state. Figures 2 and 3 from a recent report by the American Council for an Energy-Efficient Economy (ACEEE) illustrate the effect on DFW and Houston of a strategy of replacing traditional base-load energy sources like coal-fired power plants with a mix of demand-reducing measures and renewable energy, and Table 8 shows the detailed potential savings available from different energy policies..

Table 8 Annual Electricity Savings by Policy, DFW only (p.15)

Policies	Annual Energy Savings			
	2013	2013	2023	2023
	Demand Savings (MW)	Elect Savings (million kWh)	Demand Savings (MW)	Elect Savings (million kWh)
Utility Savings Target	170	2,247	251	7,282
Improved CHP Policies	227	1,790	606	4,772
Onsite Renewables	81	803	736	5,528
Policy Package				
More Stringent	123	568	570	2,524
Bldg Codes				
Advanced Bldg Programs	23	105	155	689
Public Bldgs Programs	132	603	422	1,798
Appliance Equip Standards	352	377	606	737
Short-term Pub Ed	50	168	-	-
& Rate Incentives				
Expanded Demand-Response Programs	700	NA	3,266	NA
Total (GWh)	1,858	6,660	6,610	23,330

Another recent report on Texas power needs pointed out that substantial reductions in electricity demands could be accomplished with a combination of energy efficiency and demand response measures. “By 2021, we estimate overall reductions of 20% in forecast

energy load and 22% in forecast peak demand. This translates into average annual load decreases of 1.5% and 1.7% for energy and demand, respectively. As a result, ambitious efficiency policies and programs can **limit growth in energy usage to just one-fifth** of the forecast growth over the next 15 years.”⁶⁷ (emphasis added.)

This is essentially what opponents of a coal-fired repowering project called Little Gypsy told the Louisiana PSC during its hearings. The advantages of a utility-sponsored DSM program are numerous, but can be summarized as follows.

... the following six public-interest objectives ... will be served by enhanced DSM resource acquisition. Note that many of these specific benefits are substantiated by Entergy’s own recently produced “Demand Side Management Strategy Overview.”⁶⁸

1. DSM promotes the public interest by minimizing long-term electric-resource costs.
2. DSM provides additional diversity benefits; no fossil fuel is immune from future price volatility.
3. DSM will reduce exposure to CO₂ regulatory risk.⁶⁹ Testimony has confirmed that the scale of compliance costs with future greenhouse-gas regulation will be a major determinant of the long-term economic viability of the Little Gypsy proposal. Since DSM is an electric resource that reduces carbon emissions, an company portfolio with sizable demand-side resources will provide the state with a hedge against future costs associated with power plant carbon emissions.⁷⁰
4. DSM can defer the utility’s need for costly new generation.
5. DSM can reduce consumers’ bills and reduce the cost of business

⁶⁷“Power to Save: An Alternative Path to Meet Electric Needs in Texas,” Optimal Energy, Inc., prepared for Natural Resources Defense Council and Ceres, January, 2007, p. 10.

⁶⁸This report was redacted from public view; contact company for public document.

⁶⁹Direct Testimony of Anthony P. Walz before the LA PSC (Docket No. U-30192), Oct. 2, 2007, p. 94.

⁷⁰This testimony was supposedly redacted, but is available on-line at <https://p8.lpsc.org/Workplace/WcmSignIn.jsp>.

operations. By improving the energy efficiency of ratepayer homes and businesses, DSM programs will reduce the energy bills and the costs of operation for citizens.

6. Increased electric energy efficiency by ratepayers can reduce upward pressure on volatile natural gas prices. The utility is currently a very large consumer of natural gas, producing a large proportion of annual MWh output with gas-fueled generation.⁷¹

Let's consider these points individually and see what the lessons from studies in Texas and Florida can reveal about the potential of alternative energies for Arkansas customers.⁷²

1. DSM promotes the public interest by minimizing long-term electric-resource costs

A recent study on the effectiveness of policies geared toward meeting the energy needs of the Dallas/Fort Worth and Houston, TX metro area found that they have the ability to fulfill 101 percent and 76 percent of the electricity load growth over the next 15 years for the Dallas/Fort Worth and Houston metro areas, respectively (see Figures 4 and 5). The nine studied policies were:

1. Expanded Utility-Based Energy Efficiency Improvement Program
2. New State-Level Appliance and Equipment Standards
3. More Stringent Building Energy Codes
4. Advanced Energy-Efficient Building Program
5. Energy-Efficient State and Municipal Buildings Program
6. Short-Term Public Education and Rate Incentives
7. Increased Demand Response Programs
8. Combined Heat and Power (CHP) Capacity Target
9. Onsite Renewable Energy Incentives

⁷¹Hale Powell, testimony before the LA PSC (Docket No. U-30192), Sept. 14, 2007.

⁷²Much of the original research for the following section is contained in two reports: R. Neal Elliott and Maggie Eldridge, "Role of Energy Efficiency and Onsite Renewables in Meeting Energy and Environmental Needs in the Dallas/Fort Worth and Houston/Galveston Metro Areas," American Council for an Energy-Efficient Economy (ACEEE), Report No. E078, September 2007; and R. Neal Elliott et al, "Potential for Energy Efficiency and Renewable Energy to Meet Florida's Growing Energy Needs," ACEEE, Report E072, June 2007.

These policies would reduce forecasted electricity use by over 24 percent and 21 percent for the DFW area and Houston area, respectively. Peak demand can be further reduced through the deployment of expanded demand response programs, which provide an additional 14 percent demand reduction in DFW and 11 percent in Houston. Combined, these policies would reduce peak demand in DFW by 38 percent and in Houston by 31 percent or roughly 6,700 MW in DFW and 5,600 MW in Houston by 2023 (see Figures 4 and 5). In the Boulder, CO area, the power company Xcel has projected that radical improvement of the local power grid (called “SmartGrid”) could reduce customer demand by about 29 percent.⁷³

A similar study done in Florida involved policies that were aimed at slowing energy demand growth with energy efficiency resources and demand response, and diversifying the supply resources with renewables. The 11 studied policies were:

1. Utility-Sector Energy Efficiency Policies and Programs (EERS)
2. Appliance and Equipment Standards
3. Building Energy Codes
4. Advanced Building Program
5. Improved Combined Heat and Power (CHP) Policies
6. Industrial Competitiveness Initiative
7. State and Municipal Buildings Program
8. Short-Term Public Education and Rate Incentives
9. Expanded Research, Development, and Demonstration Efforts
10. Renewable Portfolio Standard (RPS)
11. Onsite Renewables Program

If all the policies were implemented, Florida could reduce its projected future use of electricity from conventional sources (i.e., natural gas, coal, oil, and nuclear fuels) by about 29 percent in the next 15 years (see Figure 6). Energy efficiency accounts for about two-thirds of the 2023 total 102,513 million kWh electricity reductions, with the renewable energy provisions accounting for the balance. Calculations show that these energy efficiency and renewable energy policies can also reduce peak demand for electricity by over 20,000 MW in 2023, or 32 percent of projected peak demand. In addition, a strong DSM effort could reduce peak demand by an additional 4,353 MW in 2013 and 9,637 MW in 2023, or 9 percent and 15 percent of projected peak demand,

⁷³“Xcel Energy Announces Smart Grid Consortium,” Xcel press release, Boulder, CO, Jan. 16, 2008.

respectively.⁷⁴

2. DSM provides additional diversity benefits

Many more demand-side management techniques exist than the current number of nonrenewable energies. Practices include something as simple as installing proper insulation and automatic thermostats to education campaigns and revised building codes. Nonrenewable energies are also subject to future price volatility. Political events, environmental disruptions, extreme weather events and other factors produce commodity price volatility and supply disruptions that cannot be predicted. Additionally, the majority of DSM resources have no “fuel costs,” a huge advantage over supply-side resources. Once DSM measures like insulation are installed, they quietly provide energy savings for many years with no on-going fuel cost. This same feature is not true of fossil-fueled supply side resources such as coal and gas-fired generation plants.

The level of forecast fuel and allowance prices is central to the evaluation of DSM cost effectiveness. If forecast fuel and allowance prices are low, DSM resources appear costly by comparison and are deemed not cost effective. Conversely, high fuel and allowance costs would render DSM resources more cost effective. Higher than forecast commodity and emissions allowance prices may well erode the economic viability of the Little Gypsy plant, reduce demand for its output and make its generation less competitive with other supply and demand side alternatives.

3. DSM will reduce Arkansas’s exposure to CO2 regulatory risk

Power plants are the largest U.S. source of greenhouse gas emissions, producing 2.5 billion tons of heat-trapping pollution every year. DSM resources, on the other hand, have no emissions and can help reduce climate change impacts. There are significant environmental benefits for DSM programs due to reductions in carbon dioxide, sulfur dioxide, nitrogen oxides, and particulates. The policies discussed in DFW and Houston are cost-effective means to avoid emissions, and are estimated that they could result in avoided emissions as indicated in Figure 7.

The Florida state study also concluded that the environment would benefit, with reductions in conventional power plant operations reducing SO₂ by more than 16 thousand tons and NO_x by almost 11 thousand tons. With concern growing about global warming, these efficiency measures would reduce CO₂ by over 37 million metric tons in 2023, making a down payment of reducing the state’s carbon signature.

⁷⁴R.N. Elliott et al, “Potential for Energy Efficiency and Renewable Energy to Meet Florida’s Growing Energy Demands,” ACEEE, Report No. E072, June 2007.

4. DSM can defer SWEPCO's need for costly new generation

The Texas policy study found that demand response, efficiency, and renewable energy resources are a lower cost alternative to construction of conventional generation resources while enhancing energy security and economic growth within Texas. In 2000 the National Association of Regulatory Utility Commissioners found that, "in remedying situations of inadequate supply or constrained transmission, demand responses to market prices should be equally and fairly compared to alternatives which require the construction of generation or transmission."

Within the utility industry, interest in energy efficiency has never been greater. Indeed, the industry faces a "perfect storm" of high fuel prices, escalating construction costs, increased uncertainty surrounding cost-recovery for new generation plants, mounting concerns around system reliability, public opposition to the construction of new generation and transmission facilities, and looming environmental costs, particularly potential carbon emissions costs. In these circumstances, energy efficiency in other states has become increasingly perceived as a viable, even preferred, resource option because of its unique attributes in positively addressing all these concerns.

5. DSM can reduce consumers' bills and the cost of operation for Arkansas business

The policies analyzed in the DFW and Houston report would significantly reduce customer expenditures for electricity. Over the next five years customers would save over \$3 billion on energy expenditures and almost \$22 billion over the next 15 years. Over the next 15 years, consumers and businesses in the Houston metro area would save almost a net \$10 billion, while customers in the DFW Metro Area would also save almost a net \$10 billion.

The study conducted in Florida suggest that the economic savings from the recommended energy efficiency policies can cut Florida consumers' electricity bills by about \$840 million by 2013 and \$28 billion by 2023.⁷⁵ While these savings will require substantial investments, they cost less than the projected cost of electricity from conventional sources. In addition, the investments would save consumers money while creating new jobs for the state.

6. Increased electric energy efficiency by Arkansas ratepayers can reduce upward pressure on volatile natural gas prices

⁷⁵R.N. Elliott et al, "Potential for Energy Efficiency and Renewable Energy to Meet Florida's Growing Energy Demands," ACEEE, Report No. E072, June 2007.

Arkansas and Florida face similar energy vulnerabilities that have become apparent during the past several years. Florida is one of the most natural-gas-dependent states in the country, with more than a third of its electricity generated by natural gas. In December 2005, the natural gas “crisis” drove utility prices from less than \$3 per thousand cubic foot to over \$14, a price that hurt Floridians’ pocketbooks. The pain intensified when Hurricane Katrina disrupted natural gas supplies and jeopardized electricity generation.

While the price of natural gas has fallen over the past year, it still costs over two and a half times more than it did when many of the state’s new natural gas power plants were planned. The current course calls for investments in new coal, gas, and potentially nuclear generation to make sure that the state has enough electricity to sustain its economic prosperity. Energy efficiency and renewable energy resources would offset some of that growth in demand, offering a lower cost, cleaner, and more stable energy path, without sacrificing Florida’s quality of life or its economic growth.

Finally, the National Association of Regulatory Utility Commissioners (NARUC) has stated “that energy conservation and efficiency are, in the short term, the actions most likely to reduce upward pressure on natural gas prices.”⁷⁶ In a 2005 resolution, NARUC underlined the potential beneficial price impacts of reducing gas demand, noting that the current balance between gas supply and demand causes even modest increases in gas demand to produce sharp, upward changes in natural gas prices.

Returning to Table 8, the example of Dallas’s potential reduction in electricity demand of 23,000 GWh by 2023 is ample evidence that DSM can make a substantial difference in the utility’s energy production needs. However, is DSM affordable for the utility and its customers, relative to the costs of newly-installed coal or natural gas facilities? The answer is clearly yes, as was revealed during the Louisiana PSC hearings.

... national utility experience with DSM programs establishes that aggressive programs are cost effective relative to most supply side resources. Nationwide, average levelized costs of utility DSM programs are approximately \$0.03 to \$0.05 per saved kWh, well less than 50% of the levelized cost per kWh of the proposed Little Gypsy project.

Depending on the specific scenario, ELL has forecasted that levelized costs (in 2006 dollars) for Little Gypsy beginning in 2012 will be within the

⁷⁶National Association of Regulatory Utility Commissioners, a resolution approved on Nov. 5, 2005.

range of \$0.805 (sic) to \$0.115 per kWh. (APW-11, APW-16) In contrast, the average cost of DSM resources as acquired by US utilities has been less than 50% of those estimated generation costs. An average cost of between \$0.025 and \$0.05 per kWh has been the typical experience of aggressive DSM programs operated by US regulated utilities. My exhibits, as well as Entergy's recent DSM Strategic Overview,⁷⁷ substantiates this cost estimate for DSM resources.

In an effort to identify the potential costs of implementing a large scale DSM program in 2006, the Vermont Department of Public Service DSM commissioned a multi-state study of the program costs of DSM resources as reported to regulatory authorities by mature DSM programs. Using data derived from U.S. Energy Information Administration (USEIA) databases and DSM filings, the research found that, on a national basis, the average DSM program cost per saved or "avoided" kilowatt hour *was approximately three to four cents.*⁷⁸ (Emphasis added.)

Closer to home, during the 1990s the Texas Office of Public Utility Counsel reported that "the average cost/kWh for all programs analyzed for the seven-year period 1992 to 1998 was 2.4 cents (1998 dollars). However, in 1997 and 1998, the average cost/kWh for all programs was approximately 1.5 cents. This figure is less than the fuel and O&M costs per kWh for nearly all types of fossil-fueled electric generators."⁷⁹

And windpower continues to appear more attractive and cost-efficient in a carbon-constrained world. According to a study by researchers at Stanford University,

...global wind-energy potential in 2000 was about 72,000GW—nearly five times the world's total energy demand. (And) ... the technology needed to tap into this source of energy is getting cheaper: the cost of generating electricity from wind power has fallen from as much as 30 cents per kilowatt hour in the early 1980s to around ten cents in 2007. ...With a tax of \$30 per tonne of carbon dioxide, ... electricity produced from wind could

⁷⁷This testimony was supposedly redacted, but is available on-line at <https://p8.lpsc.org/Workplace/WcmSignIn.jsp>.

⁷⁸Powell, LPSC Docket U-30192, Sept. 14, 2007, Exhibit 4, n.p.

⁷⁹Powell, LPSC Docket U-30192, Sept. 14, 2007, Exhibit 7, n.p.

compete with fossil fuels in most markets even without subsidies.⁸⁰

Finally, consider the recent comparison of electricity costs per kWh that was prepared by the California Public Utility Commission (CPUC) for a 2008 energy plan. For the purposes of the present study, two findings from the accompanying table are particularly striking:

1. The California study confirms that, even at historically high natural-gas prices of early 2008, combined-cycle gas-fired power plants **have a clear cost advantage over any of the coal-fired technologies**; and
2. If a reasonable projection is used for the cost of carbon capture or an equivalent carbon tax, **“clean coal” costs would far exceed solar, wind, and even geothermal** (available in the West) alternatives that are currently producing electricity.

CPUC selected a team led by Energy and Environmental Economics, Inc. to model the electricity sector’s compliance with AB32, California’s Global Warming Solutions Act. This law requires a reduction in statewide greenhouse gas (GHG) emissions to 1990 levels by 2020.

The modeling provides the CPUC and California Energy Commission with critical information on how different methods of reducing GHGs will achieve emission reduction goals for the sector and affect utility costs and consumers’ electricity bills. This information will be used by the CPUC and CEC to advise the California Air Resource Board on setting and implementing GHG standards for the electricity sector.⁸¹

While these data are recent and were not available to the APSC at the time of the SWEPCO hearings, other testimony was offered by witnesses that demonstrated the same cost advantages of natural gas and alternative energy sources over coal use, especially when carbon-capture technologies are included (see this report’s Section 2). Yet, for reasons that were presented earlier, neither the commission nor the utility were willing to change course from the traditional approach of meeting increased electricity demand with building GHG-emitting coal-fired plants.

⁸⁰“Wind of Change,” *The Economist*, Dec. 8, 2008.

⁸¹“CPUC GHG Modeling,” Energy and Environmental Economics, Inc., May 2008, available on-line at http://www.ethree.com/cpuc_ghg_model.html.

Table 9. A Comparison of Busbar Electricity Costs, 2008

Busbar cost, 2008 dollars	cents/kWh
Geothermal	16.485
Solar thermal	12.653
Wind	8.91
Coal Integrated Gasification Combined Cycle (IGCC)	11.481
Coal IGCC with Carbon Capture & Storage (IGCC with CCS)	17.317
Coal Super-critical	10.554
Gas Combined Cycle	9.382

Source: Energy and Environmental Economics, Inc., San Francisco, CA, May 2008. Busbar refers to the cost of power after it is generated but before its voltage is transformed at the power plant's switching station.

Other states are changing course even as AEP and SWEPCO steam forward; in November, Wisconsin Public Service Commission unanimously rejected Alliant Energy's \$1.3 billion coal plant in Cassville, Wisconsin. Said Charlie Higley, executive director of Citizen's Utility Board, "Building coal plants has never made sense from an environmental perspective, and no longer makes sense from an economic perspective. When cleaner alternatives would save ratepayers \$800 million, the perception that dirty coal is cheap is nothing but hot air."⁸² In addition, of the 151 proposed coal-fired plants that were listed by the U.S. Department of Energy in May, 2007, more than one-half have been cancelled or are on hold at present because of cost or environmental concerns.⁸³

⁸²Thomas Content, "PSC rejects Alliant Energy's proposed coal plant," *Milwaukee Journal Sentinel*, Nov. 11, 2008; see also "Coal Plant Proposal Rejected for First Time in Wisconsin History," Clean Wisconsin press release, Nov. 11, 2008.

⁸³This is a regularly changing status list of projects, but is available on-line at http://www.sourcewatch.org/index.php?title=What_happened_to_the_151_proposed_coal_plants%3F.

Recently, the nation's largest coal-plant developer (Dynergy) announced that “very little (new development) can be economically justified in the current environment.” Last year Dynergy had announced plans to build more than half a dozen new coal-burning power plants around the country with partner LS Power.⁸⁴ Another energy provider, Xcel Energy, received approval from Colorado regulators to shutter two coal-fired plants by 2012 to reach GHG reduction targets. One observer noted: “We’ve reached this critical point... There was slow progress over the last decade, and you’re now seeing this tipping point.”⁸⁵ In North Dakota, the Minnkota utility has announced it will await the passage of new environmental legislation from the 111th Congress before proceeding with the Milton Young 3, a new power plant.⁸⁶

⁸⁴“Dynergy CEO Says New Coal Plants Not ‘Economically Justified’,” Energy Justice press release, Nov. 10, 2008.

⁸⁵“Power Shift,” *Washington Post*,” Aug. 25, 2008, p. 22 and “Out With the Coal,” *Audubon* magazine, November-December 2008, p. 24.

⁸⁶Lauren Donovan, “Economic pinwheels spinning in Oliver,” *Bismarck Tribune*, June 25, 2008.

4. A Comparison of the Employment Benefits from the Turk Plant to the Benefits from “Green Jobs”

When the Turk plant was originally proposed, SWEPCO officials estimated that 1,400 jobs would be created during the construction phase and over 100 permanent jobs would be located at the site when it began operating in 2013. Not surprisingly, the high-paying positions attracted much attention in the area, and local business leaders expressed pleasure at the idea that the plant would be a boom to economic development in southwestern Arkansas.⁸⁷

This section explores the numbers behind this enthusiastic reception, and demonstrates that the company’s projected employment boom is misleading for several reasons. Not only has SWEPCO over-stated the actual economic effect of their proposed plant, but also it has failed to fully recognize how its demand for specialized labor skills cannot be met by the current workforce in that region. Thus, the full benefit of the economic growth will not go to the people of Arkansas but rather to surrounding states whose workers will migrate temporarily to the area.

In addition, the public is increasingly aware of the employment and growth potential of an alternative set of energy-related jobs, often called “green jobs.” While no one argues that large, centralized energy plants like Turk won’t create jobs, the alternative investments in energy efficiency and renewable resources also create jobs that could benefit local economies, too.

But first, let’s look at the techniques used by economists to calculate these effects, and then compare numbers with the company’s projections.

⁸⁷“Utility’s proposal stirs doubt ,” *Arkansas Democrat*, Jan. 10, 2007, p. D1.

Economic Multipliers in Brief

Table 10 shows the anticipated levels of employment at the Turk plant during the construction and operations phases.⁸⁸ However, these estimates of the number of construction and operation workers employed by the energy facility provide only a partial accounting of the total employment impacts from energy development. As work begins on the new energy facility, productive inputs other than labor will be required. To the extent that existing firms in the impacted county are able to supply these requirements, their demand for additional employment will also rise. This is referred to as an **indirect** employment consequence of the presence of the energy industry.

Furthermore, with the increase in employment at the site, the increased total personal income of the surrounding area (e.g., Hempstead County) can be expected to precipitate additional demand for locally provided goods and services. In response to this increased demand, local retail and commercial firms will expand and new firms will be established. The additional employment generated in local retail, service, and commercial trades is an **income-induced** consequence of the presence of the energy facility. Thus, the total employment impacts associated with the construction and operation of an energy facility in a particular county are the sum of the direct, indirect, and income-induced employment requirements. Figures 8 and 9 show a normal yearly pattern of job growth during the construction and operation of the power plant.

Traditionally, estimates of the indirect and income-induced (i.e., secondary) employment effects have been made with the use of employment multipliers derived from economic-base theory. Stated simply, this theory holds that the growth of an area depends upon the growth of its basic or export-producing sector. The multiplier is simply a scalar number that relates the total employment of a region (e.g., a county) to its basic employment, where basic employment is defined to be that portion of jobs in the region that are supported by revenues from outside the county. In the majority of counties, agriculture, mining, most manufacturing, construction, transportation, and federal and state government positions are considered to be basic employment categories. By multiplying a given change in any of these employment categories by the multiplier computed for the county, an estimate of the total change in county employment is derived.

⁸⁸EIS filed with APSC, Docket No. 06-154-U, Document 66, Exh. JCH-1, pp. 2-116 to 2-122. The company's numbers were annualized using a standard employment phasing for electric power plants developed at Argonne National Laboratory; see E.J. Stenehjem and J.E. Metzger, *A Framework for Projecting Employment and Population Changes Accompanying Energy Development*, Phases I and II, ANL/AA-14, October 1976.

Because of the obvious influence that the employment multiplier has upon any forecast of future employment requirements for a given county, considerable care must be exercised in its computation and use. Unfortunately, there is no single best manner for computing employment multipliers. Instead, there are a variety of techniques and procedures for performing this calculation; none appear to provide best estimates under all circumstances. Because certain computational methods lead to multipliers that perform better than others under certain conditions, this report analyzed two distinct employment multipliers: one from Regional Economic Modeling, Inc. (REMI) and another model for impact-analysis planning called IMPLAN.

Multipliers over Time

Either of the two multipliers discussed in this chapter is a good choice for use in forecasting total employment effects of energy development in Hempstead County. However, the one problem common to each of these multipliers, which has not been discussed, is the influence of time on the estimates. The following section offers the user a brief review of this problem and a procedure for solving it.

An employment multiplier, regardless of how it is computed, is simply a number that when multiplied by a change in basic employment reveals the final equilibrium change expected in total employment. The length of time required for this equilibrium level to be achieved rarely is considered explicitly. Instead, most economists and regional analysts have been content to assume that these adjustments occur either instantaneously or within a single period (usually one year). Such assumptions are gross simplifications that are not likely to be observed in real world situations. Instead, it is far more probable that as new basic jobs are created in a given county, the indirect and income-induced effects on secondary employment will occur slowly, and it may require several years before the total employment change is completed.

For example, consider Dunn County, North Dakota, which has a regression multiplier of 1.6 for construction and manufacturing employment. If 100 construction jobs were created in Dunn County in 2006, the regression multiplier predicts that total employment will rise to 160. According to the explanation provided in the introduction to this chapter, this means that the creation of 60 jobs can be expected in local supplying industries and the retail and commercial sectors of the Dunn County economy.

However, these new jobs will not be created until the demands of the new basic firm and the new construction workers have compelled local businesses to expand their outputs

and hire new workers. Clearly, this adjustment will not occur at the instant the 100 construction jobs become available. Nor is it likely that these adjustments will be completed within one year. Instead, there will be a lag in the time required for the 160 new jobs predicted by the multiplier to be created. Again, Figures 8 and 9 show a normal yearly pattern of job growth.

Employment and Income Estimates Overstated for the Turk Plant

It appears that the employment and income projections that have been used by SWEPCO overstate the effect of the new plant for two reasons: first, the multiplier used was too large for this type of facility, and second, not all of the construction and operations positions can be filled by local Arkansans and their communities will not benefit fully from the economic growth. Table 11 will demonstrate how few Arkansas workers can fill the types of positions normally required to build a power plant.

Based on our findings we believe that an imprecise multiplier was used to calculate many of the figures provided by the coal plant's owners. Table 10 shows the difference that a correct multiplier makes when calculating the secondary jobs that could be created. Using the inputs provided by the SWEPCO plant we found that 151 fewer temporary jobs will be created. That is **13 percent less than the company's estimate**. Also, our numbers show that there will be 80 fewer permanent jobs created. That is **28 percent less than the coal plant's findings**.

This overestimation in job creation figures leads to exaggerated earnings as well. Based on this study's more reasonable multipliers, the maximum additional income from the indirect (or off-site) employment during the entire construction phase would be \$294 million, or **22.6 percent less** than the amount estimated by SWEPCO. The company's over-estimate is even more dramatic for the longer operations period; its new income figure for the local economy was **72.4 percent** higher than the \$2.5 million that this study finds for a plant producing in this area (see Table 10). Yet as we shall see next, not even this lower amount of income will actually accrue to the towns and communities of southwestern Arkansas, because many of these jobs will eventually go to non-Arkansans.

Skilled Labor is not Available At Present

14 A. Yes, sir, and we're going to work very hard to try
15 to make sure that's true. In fact, you might have had
16 an opportunity back on August the 30th, it was carried
17 in the Hope Star, that we've already begun working with
18 some of the local community colleges. In fact, I want
19 to be sure I got the name right. The University of
20 Arkansas Community College at Hope, the chancellor spoke
21 at the Hempstead County Economic Development Corporation
22 and mentioned how the Shaw Group, who is the EPC
23 contractor for the project, along with SWEPCO, is
24 already working with that entity to start to build
25 skilled labor programs for training for those jobs, for
1 the 1400 construction jobs, as well as some of the
2 permanent jobs. Now, these are not going to be walk in
3 off the street jobs and anybody can apply and be hired.
4 Some of these are going to be skilled labor jobs.

Supplemental testimony of Venita McCellon-Allen, COO of SWEPCO, PSC Docket No. 06-154-U, Mar. 22, 2007.

The second reason for the overestimation is that many of the skills required by the construction and operation of the power plant are not well-represented in southwest Arkansas. To the extent that workers are not available here, the positions will be filled by workers from Louisiana and Texas who “in-migrate” for the job opportunities. This is especially true for the temporary construction jobs, as has been experienced in many large energy projects during the past thirty years.⁸⁹

In addition to the issue of overestimating the multiplier there is a problem with the number of employable workers in the area. The coal plant predicts a need of 1,400 temporary construction positions to construct the plant. According to the state Department of Workforce Services, Hempstead County belongs to a regional labor market that includes six counties in the southwestern part of the state. This region is not a

⁸⁹Two good local studies are: Wieland et al, *Characteristics and Settlement Patterns of Energy-Related Operating Workers in the Northern Great Plains*, Agricultural Economics Report No. 123, North Dakota State University, Fargo, ND (October 1977); and J.E. Metzger and P.W. Mosen, *Local Socioeconomic Changes and Public Fiscal Implications of Coal Development in Wayne County, West Virginia*, ANL/EES-TM-26, Argonne National Laboratory, September 1978.

heavily industrialized area, and thus does not have a large population of skilled laborers for this type of construction.

Therefore, our findings show that even if every qualified employee in Southwest Arkansas were to work on the construction of the coal plant, recent skill patterns show a shortage of over 400 workers (see Table 11). Yet even this outcome is highly unlikely, because many of these individuals are already employed and would continue working elsewhere during the construction phase of the power plant. (The same situation may be true with the 111 operations jobs, since only 40 civil engineers are listed for the area, but the required skill set is not as well known for the permanent jobs.) The company has indicated that training programs are anticipated, but this would produce dozens, not hundreds, of newly-skilled workers (see testimony in sidebar).

Because of coal plant's proximity to Texas and Louisiana borders, many of these additional employees would come from the neighboring states. Unfortunately, the promised economic benefits would therefore return to those states and not to Arkansas. This includes not only the direct employment at the Turk plant, but also the secondary employment that would normally occur in the region around the plant. Much of that economic activity will probably be located in the area where these in-migrating workers actually live; i.e., in Texas or Louisiana.

Many Industrial Skills Have Been Developed in Nearby States

2 One, northeast Texas is an area of high industrial
3 concentration. There are already several power plants
4 in that area. TXU has two lignite fired plants in
5 northeast Texas, the Monticello plant and the Martin
6 Creek plant. We have the Welsh units are there, along
7 with the Pirkey units. And so it's already
8 significantly populated with solid fuel units.

9 In addition, there's the Eastman Chemical Company
10 is housed there, as well it's just a pretty highly
11 populated with industrial entities, which is not typical
12 of southwest Arkansas.

Supplemental testimony of Venita McCellon-Allen, COO of SWEPCO, PSC Docket No. 06-154-U, Mar. 22, 2007.

Employment Possibilities Lie Elsewhere in the Future

One of the new realities that is often overlooked by the advocates of large power-plant developments and their eye-catching payrolls is that very encouraging employment opportunities exist in other parts of the energy industry. Some recent research has pointed out how important these types of alternative energy jobs can be to the Arkansas economy.

Large power plants are capital-intensive endeavors that provide relatively few jobs on a permanent basis. At a cost of \$1.6 billion, the Turk plant will employ about 110 workers during its operations phase. That equates to about \$15 million of investment per position, and is not a very efficient job-creation process because the “labor-intensity” is not very high.

However, employment in the areas of renewable energy and energy efficiency are much more labor-oriented and create a wide swath of jobs in factories and construction that supports such projects as energy conservation, housing rehabilitation, wind farms, etc. Some of these are new types of industry, such as wind blades and turbines, and many others are simply new applications of older technologies such as fabrication and tool and die work. These jobs would be spread throughout the economy, as a new report on this employment vehicle makes clear: *Green Recovery: A Program to Create Good Jobs and Start Building a Low-Carbon Economy*. The report was commissioned by the Center for American Progress and prepared by the University of Massachusetts Political Economy Research Institute (PERI). The report looked at six green economic strategies (global-warming solutions), and the various job-types that would be in demand if these strategies are pursued.⁹⁰

The report shows today that by making a rapid green economic investment, two million jobs can be created in two years. This results from the relative labor intensity of a “green recovery,” as opposed to capital-intensive energy projects like power plants. For example, the public expenditure of \$100 billion on large energy projects like oil and natural gas development might generate 542,000 jobs; if spend on a public stimulus package such as the April 2008 tax rebates, about 1.7 million jobs could be generated.

However, according to the U.S. Bureau of Economic Analysis, that level of public investment would create about two million jobs in the national economy in the next two

⁹⁰PERI, *Green Recovery: A Program to Create Good Jobs and Start Building a Low-Carbon Economy*, Center for American Progress, September 2008.

years, with a significant proportion (800,000 jobs) in the struggling construction and manufacturing sectors.⁹¹ This would create roughly triple the number of good jobs—paying at least \$16 dollars an hour—as spending the same amount of money within the oil industry (see Table 12). Investments in renewable energy and energy efficiency are central to the proposed recovery program with a combination of direct public-fund expenditures, tax credits, and loan guarantees to spur private sector investment.

For Arkansas, based on its limited population and state domestic product, about \$814 million of this program could be spent in the state. This would generate about 20,000 new jobs in two years, enough to bring the state’s unemployment rate down from June’s 5.3 percent to about 3.9 percent. These jobs would also reflect the readily available skills of the area’s workforce, as noted in Table 12.

Other reports have determined that similar job creation is feasible from lesser reliance on traditional forms of energy generation. According to a recent ACEEE study on applying energy efficiency to the Arkansas economy over the next 20 years, an informal estimate of new employment created showed more than 21,600 net new jobs by 2030.⁹²

According to PERI’s Green Investment Strategies, the green recovery program would attempt to boost private and public investment in six energy efficiency and renewable energy strategies:

- Retrofitting buildings to improve energy efficiency
- Expanding mass transit and freight rail
- Constructing “smart” electrical grid transmission systems
- Wind power
- Solar power
- Next generation biofuels

⁹¹PERI, *Green Recovery*, p. 10 and Appendix 1.

⁹²“Energy Productivity: Efficiency Benefit for Both the Arkansas Economy and the Global Climate,” American Council for an Energy-Efficient Economy, Nov. 13, 2008.

Table 12. Green Investments and Representative Jobs

Building Retrofitting	Electricians, Heating/Air Conditioning Installers, Carpenters, Construction Equipment Operators, Roofers, Insulation Workers, Carpenter Helpers, Industrial Truck Drivers, Construction Managers, Building Inspectors
Mass Transit/Freight Rail	Civil Engineers, Rail Track Layers, Electricians, Welders, Metal Fabricators, Engine Assemblers, Bus Drivers, Dispatchers, Locomotive Engineers, Railroad Conductors
Smart Grid	Computer Software Engineers, Electrical Engineers, Electrical Equipment Assemblers, Electrical Equipment Technicians, Machinists, Team Assemblers, Construction Laborers, Operating Engineers, Electrical Power Line Installers and Repairers
Wind Power	Environmental Engineers, Iron and Steel Workers, Millwrights, Sheet Metal Workers, Machinists, Electrical Equipment Assemblers, Construction Equipment Operators, Industrial Truck Drivers, Industrial Production Managers, First-Line Production Supervisors
Solar Power	Electrical Engineers, Electricians, Industrial Machinery Mechanics, Welders, Metal Fabricators, Electrical Equipment Assemblers, Construction Equipment Operators, Installation Helpers, Laborers, Construction Managers
Advanced Biofuels	Chemical Engineers, Chemists, Chemical Equipment Operators, Chemical Technicians, Mixing and Blending Machine Operators, Agricultural Workers, Industrial Truck Drivers, Farm Product Purchasers, Agricultural and Forestry Supervisors, Agricultural Inspectors

Source: PERI, 2008, p. 6.

5. Investing in Our Energy Future: the Stark Reality We Must Face

For more than a century, the U.S. economy has depended on coal as a primary fuel for its industries and its energy production. In the last thirty years especially, after the oil-price shocks of the 1970s, that reliance increased as the nation looked for a substitute for expensive (and dwindling) supplies of foreign petroleum.⁹³ Once the Clean Air Act provided a way to drastically reduce the amount of sulfur dioxide that coal-fired power plants emitted, it appeared that coal was a large part of the solution to our energy-shortage problems.

But in the past ten years or more, the world's understanding about global warming and the dangers of greenhouse gases have forced us to face the new reality that coal use is not a solution but is part of a larger problem. As the nation begins to grapple with its large volume of carbon emissions and the cost of controlling them, it must adapt to the stark reality that cheap coal will no longer exist in the future. This report has demonstrated, in the study of one power plant in southwestern Arkansas, that coal in the future will be an expensive fuel source and not competitive with many other alternative energy sources.

In addition, new information appears regularly that the consequences of GHG emissions are already beginning to affect our region at the local level. This year, Environment America released a new national report documenting that the average recorded temperatures in places such as Ft. Smith and Little Rock in 2007 was 1.7 and 2.3°F above the historical average. The year 2007 tied for the second warmest year on record globally and was the 10th warmest year on record in the United States. It appears that these record temperatures are part of a trend toward rising temperatures resulting from global warming.⁹⁴

“Throw out the record books because global warming is raising temperatures in Arkansas and across the country,” said Audubon Arkansas’s Ken Smith. “While one or two degrees may not seem like much, just as any parent with a sick child knows, even a small rise in temperature can have a big effect,” he continued.⁹⁵

⁹³*National Coal Utilization Assessment: A Preliminary Assessment*, Argonne National Laboratory, ANL/AA-6, January 1977.

⁹⁴Emily Figdor, “Feeling the Heat: Global Warming and Rising Temperatures in the United States,” Environment America Research & Policy Center, October 2008.

⁹⁵Audubon Arkansas press release, Little Rock, Ark., Oct. 15, 2008.

According to NASA, seven of the eight warmest years on record globally have occurred since 2001. These above-average temperatures led Environment America to more closely examine recent temperature trends at the local level. The report compared government temperature data for the years 2000-2007 with the historical average, or “normal,” temperature for the preceding 30 years, 1971-2000. Table 13 shows the evidence from this decade for several key cities in the state.

The Intergovernmental Panel on Climate Change – the prestigious United Nations body that won a Nobel Prize last year for its work – has concluded the evidence of global warming is “unequivocal” and that human activities are responsible for most of the increase in global average temperatures. Burning fossil fuels to power cars, homes, and industry produces most U.S. global warming emissions, it noted.⁹⁶

Table 13. Recent Temperature Trends in Arkansas Cities

City	Temperature Change, 2000-07	Temperature Change, 2006-07
Ft. Smith	1.4 degrees	1.7 degrees
Little Rock	1.1 degrees	2.3 degrees
Memphis	1.6 degrees	3.4 degrees

Academic and energy experts have considered the future course of electricity production in the U.S. and worldwide. According to one study, three interconnected energy resources are key to determining how much coal will be used – and how much carbon will be emitted from power plants – in the next 50 years.⁹⁷ First, the speed with which CCS can be developed economically, if possible, and adapted to new and old plants using coal. Second, nuclear capacity has been stable during the past two decades, due to continuing concerns about safety and waste disposal. If these issues could be resolved as some experts believe,⁹⁸ nuclear-power generation could increase three-fold by 2050. This would alleviate greatly the pressure on the use of coal for electricity purposes in many parts of the world.

⁹⁶Ibid.

⁹⁷*The Future of Coal: Options for a Carbon-Constrained World*, p. 9.

⁹⁸*The Future of Nuclear Power*, MIT Interdisciplinary Group, 2003, available on-line at www.web.mit.edu/nuclearpower.

Third, the availability of natural gas and its price volatility influence the use of coal for power plants. A solution to the liquefied-natural-gas transportation and storage problems, and an opening of the vast natural-gas supplies that currently unavailable to the U.S. from nearby countries like Mexico and Venezuela, would both stabilize the supply of this resource and allow a more predictable price forecast. Either or both of these future developments would make natural gas the preferable fuel for electricity generation because of its lower emissions levels and lower price in a carbon-restricted world.⁹⁹

In the meantime, many utilities and energy producers have recognized that coal use now comes with an expanded set of responsibilities. As a consultant report to producer AEP noted:

This tells us that a fixed and finite amount of CO₂ can be released to the atmosphere over the course of this century.

- We all share a planetary greenhouse gas emissions budget.
- *Every ton of emissions released to the atmosphere reduces the budget left for future generations.* (emphasis added)
- As we move forward in time and this planetary emissions budget is drawn down, the remaining allowable emissions will become more valuable.
- *Emissions permit prices should steadily rise with time.*¹⁰⁰ (Emphasis added.)

In the face of those expected rising permit prices, many utilities are cutting back on plans to use coal, as was cited at the end of section 2. Many are also pondering the recent trends in declining electricity use in the U.S. and what effect that will have on their long-term need for additional baseload power plants like Turk. According to the *Wall Street Journal*:

The data are early and incomplete, but if the trend persists, it could ripple through companies' earnings and compel major changes in the way utilities run their businesses. ... if electricity demand is flat or even declining, utilities must either make significant adjustments to their investment plans or run the risk of building too much capacity. That could end up burdening

⁹⁹Price instability in the natural-gas market was frequently mentioned as a reason for the choice of a coal-fired plant for the Turk site during PSC hearings, for example.

¹⁰⁰"Briefing for AEP's Executive Council: Overview of Potential Large-scale Commercial Deployment of Carbon Dioxide Capture and Storage Technologies," Battelle, Jan. 30, 2007, p. 2.

customers and shareholders with needless expenses.

... American Electric Power Co., which owns utilities operating in 11 states, saw total electricity consumption drop 3.3% in the same period from the prior year (2007). **Among residential customers, the drop was 7.2%.** (emphasis added)

Some feel that the drop heralds a broader change for the industry. Mr. Rogers of Duke Energy says that even in places ‘where prices were flat to declining,’ his company still saw lower consumption. ‘Something fundamental is going on,’ he says.

Michael Morris, the chief executive of AEP, one of the country's largest utilities, says he thinks the industry should to be wary about breaking ground on expensive new projects. ‘The message is: be cautious about what you build because you may not have the demand’ to justify the expense, he says.¹⁰¹

The U.S. EIA’s most recent forecasts for 2009-2030 confirmed the downward trends in electricity demand that these industry leaders have noticed.¹⁰² It appears that the Arkansas PSC commissioners saw the implications of these many factors after the SWEPCO hearings. Even though he ruled in favor of the certificate, the chairman voiced support for much of the testimony that had pointed out the dangers of global warming.

This debate centered upon the fact that coal-fired generating plants emit more pollution – including CO₂ – than natural gas-fired plants and upon concerns regarding potential increases in coal-fired generation costs due to possible U.S. government restrictions of CO₂ emissions.

... I realize more than ever, that this nation – and the world – needs comprehensive policies to transform societies to slow and reduce our GHG emissions.

¹⁰¹“Surprise Drop in Power Use Delivers Jolt to Utilities,” *Wall Street Journal*, Nov. 2008, available on-line at <http://online.wsj.com/article/SB122722654497346099.html>.

¹⁰²“Annual Energy Outlook 2009: Early Release,” U.S. Energy Information Administration, Dec. 17, 2008; available on-line at www.eia.doe.gov.

... Conservation must be a primary part of our efforts to reduce GHG emissions. Fortunately, the marketplace today gives retail customers an increasing array of cost-effective options to reduce their consumption of electricity by purchasing energy efficiency products. Federal, state and local government must play an assertive role in implementing conservation. Stricter building codes, reductions in electric consumption by government buildings, and requiring substantial technological improvement and in the efficiency of our electrical system will be critical to successfully implement conservation and energy efficiency. Updates to our electric system need to range from the accelerated installation of high temperature superconductors on our transmission grid to replacing old, inefficient transformers with newer more efficient transformers.¹⁰³

In the end, it was only the one special commissioner (standing for another who had recused himself), in voting against the certificate of need, who made the clearest statement about the larger issues of the proceeding that the others eventually ignored. In his lengthy dissenting opinion against granting the company's request, Judge David Newbern asserted:

The sacrifices that may become necessary to reduce the demand for electric power or to move toward renewable sources of energy in the effort to achieve a cleaner environment can be minimized if not entirely avoided by shifting utility regulation and management practices. To minimize the problems inherent in our current power-production scheme, priority must be placed upon demand reduction and energy efficiency efforts as well as the technology necessary to capture and sequester all of the harmful emissions from power producers. Planning for future energy production must emphasize renewable energy sources.

Aggressive pursuit of energy efficiency along with demand reduction can make a huge difference in the way we meet future energy needs. That is particularly so in Arkansas, where this Commission has found that Arkansas is ranked in the lowest tier of the states in terms of spending on energy efficiency, whether measured on a per capita basis (46th state), on the basis of our total retail energy sales (43rd), or on the basis of percentage of total utility revenues (47th). A change in this respect can

¹⁰³Opinion of Commission Chairman Paul Suskie, APSC Docket No. 06-154-U, Nov. 21, 2007.

come about through utilities and regulators working together to change the economic signals to companies – rewarding them for helping their customers use less energy, have lower bills, and increase the amount of work they accomplish with a given amount of energy.

The momentum of “business as usual” will make the necessary changes difficult for both the public and the power industry, but we must turn the inevitable corner and begin now to refuse to countenance the further degradation of our atmosphere without taking every reasonable step to nurture and promote cleaner, more efficient alternatives. To allow an increase in atmospheric pollution in this instance is shortsighted. This Commission and the regulatory agencies of other states, as well, should lead the effort to reduce atmospheric pollution by example.¹⁰⁴

Finally, the Governor’s own Commission on Global Warming voted by a narrow margin to recommend a moratorium on building new coal-fired power plants in the state, noting that reductions in CO2 emissions had not been addressed for any current or future facilities.¹⁰⁵

This report has maintained that a sufficient amount of data about carbon emissions and costs is now available for utilities, energy companies, and regulators to understand the potentially dramatic effects that continued use will have on the environment and on their operations. As we have seen, many other utilities and state regulators have “seen the light” and begun to change course and steer in a new and more carbon-aware direction.

Using a reasonable approach to analyzing the probable costs of future carbon abatement, as contained in this study, presents a sobering picture of substantially higher costs of electricity from coal use, one that will affect both the companies’ bottom line and the customer’s pocketbook. The sensible course at this juncture would be to reevaluate both the wisdom of building this particular plant and the need for this type of power generation in the future.

¹⁰⁴Dissenting opinion of Commissioner David Newbern, APSC Docket No. 06-154-U, Nov. 21, 2007.

¹⁰⁵“Arkansas Governor’s Commission on Global Warming: Final Report,” Oct. 2008, available on-line at <http://www.arclimatechange.us/stakeholder.cfm>; Peggy Harris, “Panel Tentatively Endorses Ban On New Plants,” Associated Press, Sept. 25, 2008.