Arkansas Electricity Generation Fuel Diversity:

Implementation of EPAct 2005 Amendments to PURPA Section 111(d) (Docket No. 06-028-R)

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EXECUTIVE SUMMARY

The Energy Policy Act of 2005 (EPAct 2005) amended Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (PURPA) by adding a fuel diversity standard:

> (12) Fuel Sources — Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

Under PURPA the Arkansas Public Service Commission (PSC) is required to consider this standard but is not required to adopt it. If it decides not to adopt this standard the PSC must provide a public statement presenting its reasons. It must begin consideration of the standard by August 8, 2007 and complete its consideration by August 8, 2008.

In consideration of this standard, the PSC issued Order 1 in Docket No. 06-028-R requiring utilities to provide data on their fuel profiles and requiring Staff to research utility planning practices that require fuel and technology diversity. The resulting fuel profile and planning report was to be the basis for the Commission's consideration of a Section 111 (d) 12 standard.

Staff retained Synapse Energy Economics (Synapse) to prepare this report in response to Order No. 1. The report provides background on fuel diversity policies and practices to assist Staff in their determination of whether to recommend the adoption of a fuel diversity standard, and if appropriate, the content of such a standard. The report

- describes various methods of defining and measuring fuel diversity,
- presents the fuel diversity of Arkansas utilities according to those metrics,
- outlines the potential benefits and costs of fuel diversity, and
- discusses best practices in utility policies and planning regarding fuel and technology diversity.

The report demonstrates that electric utilities in Arkansas, as in the United States in general, are highly dependent upon generation from three fuels – coal, nuclear and natural gas. It identifies the benefits to utilities, in the form of reduced risk and lower air emissions, from increasing fuel and technology diversity. Finally, the report notes that the Resource Planning Guidelines approved by the Commission in Docket 06-028-R effectively require Arkansas electric utilities to use a diverse range of fuels and technologies.

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Appendix A - Survey of Fuel Diversity Policies and Practices in Selected States

1. Introduction

Diversity of fuel supply for electric generation has received increasing attention in the United States and abroad in recent years as a result of rising energy prices and increasing recognition of risks of supply disruptions and price volatility in world fuel markets. This increasing awareness of the risks associated with over-reliance on fossil fuels has led many regions to consider diversification in favor of renewable resources. In his 2006 State of the Union Address, President Bush declared that "America is addicted to oil" and emphasized the need for the U.S. to diversify its energy mix and to reduce its reliance on foreign fuel sources.

The electric utility industry has traditionally relied heavily on a narrow range of fuel resources such as fossil fuels, nuclear power, and in some regions large-scale hydro power. On a regional basis, fuel supplies have tended to be even more concentrated based on local production and delivery infrastructure. The development of competitive generation markets has tended to worsen this situation in many regions, as generating companies have often looked to the optimization of individual resource choices instead of portfolio diversification. In other cases, such as in Arkansas, resource development has been driven by access to certain low-cost fuel supplies, leading to a heavy reliance on a one or two fuel sources. However, a diverse regional power portfolio can mitigate operational and financial risks to consumers, including price volatility risks, as well as provide environmental and reliability benefits. When evaluating the merits of increasing fuel diversity, these benefits must be balanced against the costs associated with developing resources that may appear to be more expensive than traditional resources when considered in isolation.

Electric generating plants are generally long-lived and capital intensive, making these investments inherently risky for utilities and highly sensitive to forecasts of fuel prices and availability. Diversification of investment portfolios is one important strategy for minimizing risk. Federal, regional, state, and local rules and laws have the potential to encourage investments in a limited set of technologies as well as to encourage risk-minimization through diversification. Thus, it is important that laws, regulations and policies provide clear and consistent guidance to utilities for developing power portfolios.

Many states require regulated utilities to conduct a planning process and to file resource plans with the state utility commission. The purpose of the planning process is to develop a resource procurement plan that will reliably meet expected future energy demand at least cost, subject to other constraints which may include fuel diversification. In many cases, the lowest cost resource plan, based on available fuel price forecasts and other uncertain information, may not result in the most diverse portfolio. As a result, some jurisdictions and utilities have developed planning policies and practices that balance least cost reliable service with environmental and social concerns, accounting for a wide array of risk factors.[1] Fuel diversity plays an important role within this context. In Order 6 in this Docket, issued January 4, 2007, the AR PSC promulgated Integrated Resource Planning guidelines which provide such guidance.

[1] Specific examples of state and utility planning practices and policies are discussed later in this report.

In Arkansas today roughly 51% of utility generation is from coal, most of which (~94%) is sub-bituminous coal from the Powder River Basin region. Another 41% of Arkansas utility generation is from nuclear sources, about 5% is natural gas, and about 3% is hydropower. This supply mix has left Arkansas relatively unaffected by the volatility of gas prices over the last several years. However, the state may be vulnerable to potential supply and transportation disruptions affecting domestic coal, potential future regulation of CO_2 emissions, and to security and reliability issues facing nuclear plants. Arkansas also has a very low proportion of electricity generation from renewable sources, which have historically entailed higher capital cost but which are immune to fuel supply interruptions, future increases in fuel prices and costs associated with air emissions.

2. EPAct 2005 PURPA Amendments

1. Standard 12 of EPAct 2005 §111(d): Fuel Diversity

Title XII of the Energy Policy Act of 2005 (EPAct 2005), concerning electricity issues, includes a Section E entitled "Amendments to PURPA" which includes three new federal standards for fossil fuel generator efficiency, net metering, and fuel diversity. In addition to adding the net metering and fossil fuel generator efficiency standards, Section 1251 amended the Public Utility Regulatory Policies Act of 1978 (PURPA) Section 111(d) by adding the following standard:

> (13) Fuel Sources.—Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

This standard reflects the sense that over-reliance on a single fuel source leaves utilities unnecessarily exposed to various operational and financial risks, and may not be the optimal way to supply electricity. While this standard does not require states to take any particular action with respect to diversifying fuel sources, it does highlight the importance of considering this issue as part of regional energy planning and management processes.

2. Consideration of the Fuel Diversity Standard in Arkansas

Under PURPA, state regulatory authorities and non-regulated utilities shall consider the PURPA standards and then can determine whether or not it is appropriate to implement each standard. These bodies must consider these standards but are not required to adopt them. If state commissions or utilities decline to adopt a standard, they are required to state in writing their reasons and make this statement available to the public. Commissions and utilities must begin consideration of the new standards by August 8, 2007 and must complete any consideration by August 8, 2008.

In consideration of this standard, the Arkansas Public Service Commission issued an order[2] that required electric utilities operating in Arkansas to file a fuel usage report for the past ten years by fuel type and tasked the APSC Staff with compiling this data to create a statewide profile of fuel used to generate electricity. The order also required the Staff to research best practices benchmarks for utility planning policies that require fuel and technology diversity and compare these to the practices of Arkansas electric utilities. The fuel profile and planning policy report will be the basis for developing a fuel and generating technology standard, should that be deemed appropriate. In preparing this report we analyzed the current level of fuel diversity in Arkansas, the costs and benefits of fuel diversity, and fuel diversity practices and polices in other jurisdictions.

3. Defining and Measuring Fuel Diversity

1. Defining Fuel Diversity

Grubb *et al*. (2005)[3] describes fuel diversity as consisting of three components citing Stirling (1998)[4] and Jansen *et al.* (2004)[5]. The first component is *variety* or the number of categories of resources. Variety can include several aspects such as fuel type, technology type, generator unit size, and geographic diversity of fuel sources. The second component is *balance* or evenness of distribution among resources within a portfolio. For example, consider two portfolios each comprised of five categories of generation sources: one is dominated by one fuel source with minor contribution from the other four sources while in the second portfolio each resource generates an equal share of the total energy. The second portfolio is clearly more diverse than the first portfolio. The third component of fuel diversity is *disparity* or the amount of difference between categories. For example, a portfolio that utilizes three coal types (bituminous, sub-bituminous, and lignite) has less disparity (and hence less diversity) than a portfolio that utilizes bituminous coal, nuclear power, and wind power. Disparity between fuels can involve several dimensions such as environmental attributes, storability, methods of transportation, potential for supply disruptions, effect on domestic economy, price volatility, regulatory incentives, and so on. Variety and balance are fairly easy to compute, however, disparity can be conceptually more subtle.

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[2] Arkansas Public Service Commission, Initial Order: In the Matter of Resource Planning Guidelines for Electric utilities and Consideration of Section 111(d)(12) of the Energy Policy Act of 2005. Order No. 1 issued February 8, 2006, Docket No. 06-028-R.

[3] Grubb, M., Butler, L., and Twomey, P., 2005. Diversity and security in UK electricity generation: The influence of low-carbon objectives. *Energy Policy,* article in press. http://dx.doi.org/10.1016/j.enpol.2005.09.004

[4] Stirling, A., 1994. Diversity and ignorance in electricity supply investment. *Energy Policy* 22, 195-216.

[5] Jansen, J.C., Van Arkel, W.G., Boots, M.G., 2004. Designing indicators oflong-term energy supply security. Working paper ECN-C-04-007, Energy Research Centre of the Netherlands.

2. Fuel Diversity Metrics

Fuel diversity metrics often cited in energy literature generally are derived from three fields: ecology, business, and finance. Ecological diversity measures were originally developed to measure species diversity. There are several ecological indices that are used to measure various aspects of species diversity, but the most applicable index for electric utilities is the Shannon-Wiener index[6]. Diversity metrics derived from business measures, such as the Herfindahl-Hirschmann Index, are designed to measure market concentration. Financial measures are derived from portfolio theory and are generally used to measure the risk and return of a given investment portfolio. While there are many indices cited in the energy literature, this section focuses on the most commonly used metrics: the Herfindahl-Hirschmann Index, the Shannon-Wiener Index, and portfolio variance.

A. Herfindahl-Hirschmann Index

The Herfindahl-Hirschmann Index, or HHI, is a measure of the degree of market concentration and is generally applied in competition and market power analysis. It has been widely applied in the electric power industry to evaluate the impact of mergers and acquisitions on regional electricity market concentration. In the context of fuel diversity measurement, the HHI is calculated as the sum of the squares of the market share of each resource category, as shown in the following formula:

$$HHI = \sum_{i=1}^{N} p_i^2$$

Here p_i is the market share for the i^{th} resource, expressed as a percentage of the total, and N is the number of resource categories in total.

The maximum value for the HHI is 10,000. This maximum represents a market or portfolio with a single participant (or resource type) representing 100% of the market (see Figure 1). In the context of market concentration, The U.S. Department of Justice generally considers a market with an HHI value above 1800 to be highly concentrated; a value between 1000 and 1800 is considered to indicate moderate market concentration, and a value below 1000 is considered to represent a competitive marketplace.

HHI can be calculated based on capacity or generation and can be used to measure relative fuel type diversity, unit size diversity, and technology diversity. However, absolute standards for interpreting HHI values in these areas would have to be developed for any given application

B. Shannon-Wiener Index

The Shannon-Wiener Index is a diversity measure traditionally used in ecology to measure species diversity. The Shannon-Wiener Index is similar to the HHI in that it is

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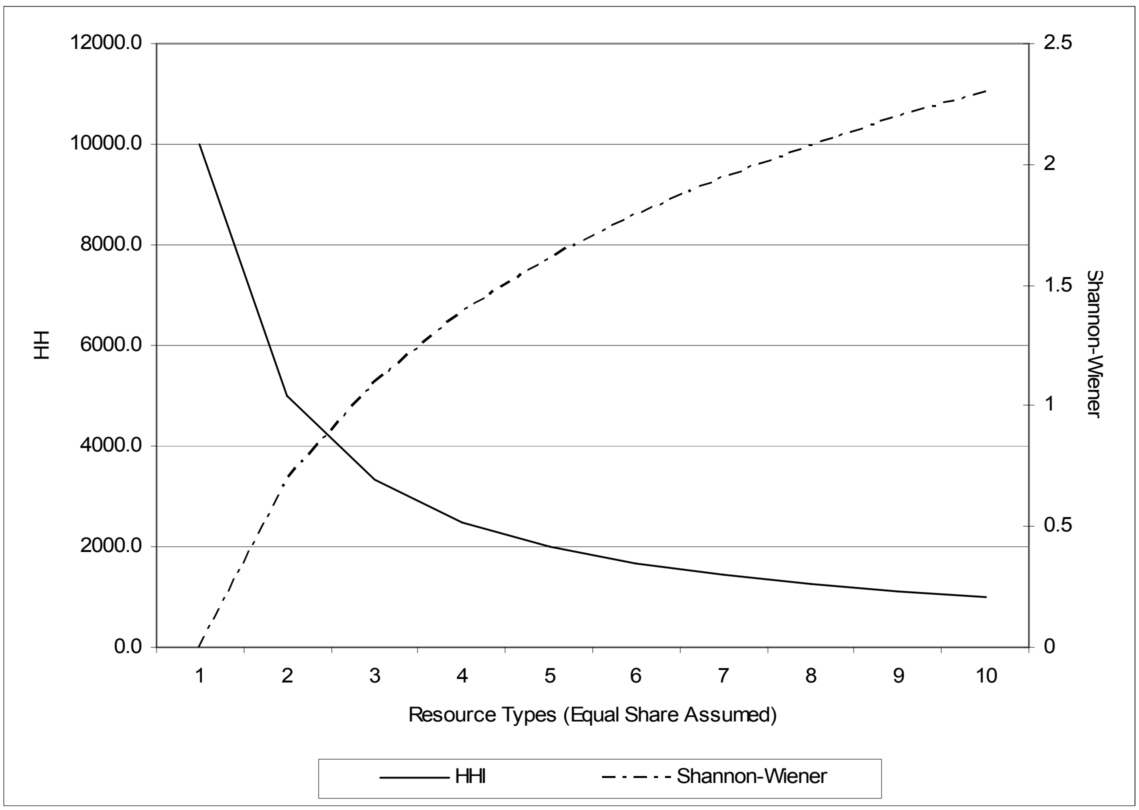
[6] Feldman, M., 1998. Diversity and risk analysis in a restructured California electricity market. California Energy Commission Report, Contract #500-96-019.

based on the market share of each resource. The Shannon-Wiener Index is represented by the following formula:

$$H' = \sum_{i=1}^{N} - p_i \ln(p_i)$$

where p_i is the market share for the i^{th} resource measured as a proportion and N is the number of resources (categories). The Shannon-Wiener Index increases from zero as the number of resources increases (see Figure 1).

Figure 1. Comparison of Herfindahl-Hirschman and Shannon-Wiener indices assuming equal distribution among resources.



Both the Shannon-Wiener and HHI metrics require classification of resources, which can be a subjective task. For example, should bituminous and sub-bituminous coals be considered separately, or lumped into a larger category encompassing all types of coal? How resources are classified can have a large impact on the results, For portfolios that generate relatively equal shares of total generation from bituminous and sub-bituminous coal, an HHI that is calculated based on one umbrella category for coal may be significantly higher than an HHI with separate categories for bituminous and sub-bituminous coals. Thus the classification of resources should be made with a careful eye toward the specific types of risk to which the system may be subject. For example, both types of coal involve exposure to future emissions control costs, but transportation issues for the two varieties (and source regions) would be different.

C. Portfolio Variance

Portfolio theory holds that portfolios should be assembled and evaluated with the characteristics of the portfolio as a whole in mind, rather than as a collection of individually-assessed resources. Individual resources are associated with specific risks that affect their performance. Similar resources, such as coal and oil under the rubric of fossil fuels, tend to face similar specific risks, and their performance tends to correlate as a result. For example, both of these fuels emit CO_2 when combusted and are thus associated with climate change regulatory risk, which in turn would likely increase costs and affect the performance of oil- or coal-fired generation. On the other hand, disparate resources (e.g., coal and wind) have lower performance correlations—and hence more value for offsetting resource-specific risks within the portfolio—than resources that have little disparity.

Portfolio theory and portfolio variance measures account for risk and uncertainty by incorporating correlations between resources when projecting overall portfolio performance, as measured by the standard deviation of cost or some other measure of performance. The standard deviation can be calculated for a number of portfolios, each with a variety of different resources, to find portfolios that simultaneously minimize cost and risk.

While the HHI and Shannon-Wiener Index are computationally straightforward and provide a good indicator of the variety and balance of a portfolio, they offer no information about the disparity among resource types, and therefore they are of little use as indicators for the performance of a given portfolio in the face of many types of uncertainty and risk. Portfolio theory and portfolio variance measures account for risk by incorporating correlations between resources, to find the portfolio that minimizes the standard deviation of some measure of the portfolio's performance, such as cost. Portfolio analysis incorporates the same inputs for the Shannon-Wiener Index and HHI (market share of each resource) and by explicitly incorporating various cost streams and the disparity among these cost streams for different resources, portfolio variance measures provide a good indication of the diversity of a portfolio and how that level of diversity performs against risk and uncertainty.

Sterling[7] defines three types of "incertitude"—risk, uncertainty, and ignorance. According to Sterling, *risk* refers to possible outcomes that are known and can be assigned meaningful probabilities of occurrence. *Uncertainty* refers to possible outcomes that are known but there exists no basis for assigning probabilities. *Ignorance* refers to possible outcomes which are unknown and, therefore, cannot possibly be assigned probabilities. Sterling argues that portfolio variance analysis reflects only the quantifiable risk, and he conceptualizes diversity as a response to ignorance or random, unpredictable events. Awerbuch and Berger[8], however, claim that portfolio risk includes "total risk" which is the sum of random and systematic fluctuations, measured as the

[7]Stirling, A., 1994. Diversity and ignorance in electricity supply investment. Energy Policy 22, 195-216.

[8]Awerbuch, S., and Berger, M., 2003. Applying Portfolio Theory to EU Electricity Planning and Policy Making. Report No. EET/2003/03, International Energy Agency.

standard deviation of historic cost streams. This includes unpredictable random events such as, in the case of fuel security risks, war, cartel activities, natural disasters and technological failure. Although events like these cannot be predicted, analogous events are likely to happen in the future and therefore the future variance in various cost streams should be fairly consistent with historic variance.

Portfolio analysis does not readily incorporate non-price and qualitative benefits of fuel diversity, such as energy independence or environmental health. Therefore, when choosing among portfolios with different cost-risk profiles care should be taken to consider not both price and non-price factors.

D. Applicability of Fuel Diversity Metrics

Several studies have used the aforementioned metrics to analyze the fuel diversity of electricity generating portfolios primarily in the context of portfolio risk and security. Grubb *et al*. (2005)[9] use both the HHI and the Shannon-Wiener Index to assess the diversity of various future generation portfolios for the United Kingdom electricity market in the context of security and the influence of low-carbon objectives. They present three major conclusions based on their analysis. First, renewable-intensive, low-carbon portfolios tend to be more diverse than conventional portfolios due to the greater natural resource limitations on contributions from an individual source. However, the capacity value of a particular intermittent renewable resource, such as wind, decreases as the penetration level of that particular intermittent resource increases. Generators could avoid those diminishing returns by developing a portfolio of diverse renewable resources, e.g. wind, solar, biomass. Second, the UK electricity market framework, in which the marginal unit (typically gas-fired) sets the electricity price does not provide a strong incentive for generators to diversify. Under that framework, electricity prices correlate well with gas prices, and, therefore, profit streams for utilities are generally fairly stable. By diversifying its portfolio with renewable resources a generator might face more volatile profit streams. To overcome that financial disincentive Grubb *et al*. suggest the introduction of a "concentration charge" which would penalize generators who fail to diversify. Third, it is impossible to predict with confidence the specific sources of insecurity and risk over the long-term utility planning horizon of twenty years or more. Therefore, rather than trying to predict the future and invest in a portfolio based on that vision of the future, a more realistic approach is to invest in a diverse system that is robust under a wide range of possible risks.

Awerbuch and Berger (2003) applied portfolio variance metrics to assess the value and diversity of resource portfolios in the U.S. and the European Union. The authors used the portfolio variance approach to evaluate the efficiency of current and alternative future generating mixes. The results of the portfolio analysis suggest that increasing diversity by adding "fixed cost" resources such as wind can significantly reduce risk without increasing overall portfolio generating costs. The important implication of this type of

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[9]Grubb, M., Butler, L., and Twomey, P., 2005. Diversity and security in UK electricity generation: The influence of low-carbon objectives. *Energy Policy,* article in press. http://dx.doi.org/10.1016/j.enpol.2005.09.004

portfolio analysis is that the relative value of generating assets must not be determined by comparing alternative assets, but by comparing alternative portfolios. The total cost of an individual wind plant may be higher than an energy-equivalent conventional resource, but because the wind plant is relatively risk-free when considering fuel costs, operating costs, and environmental and social costs, the wind plant can improve the overall value of the portfolio by minimizing the variance in portfolio cost.

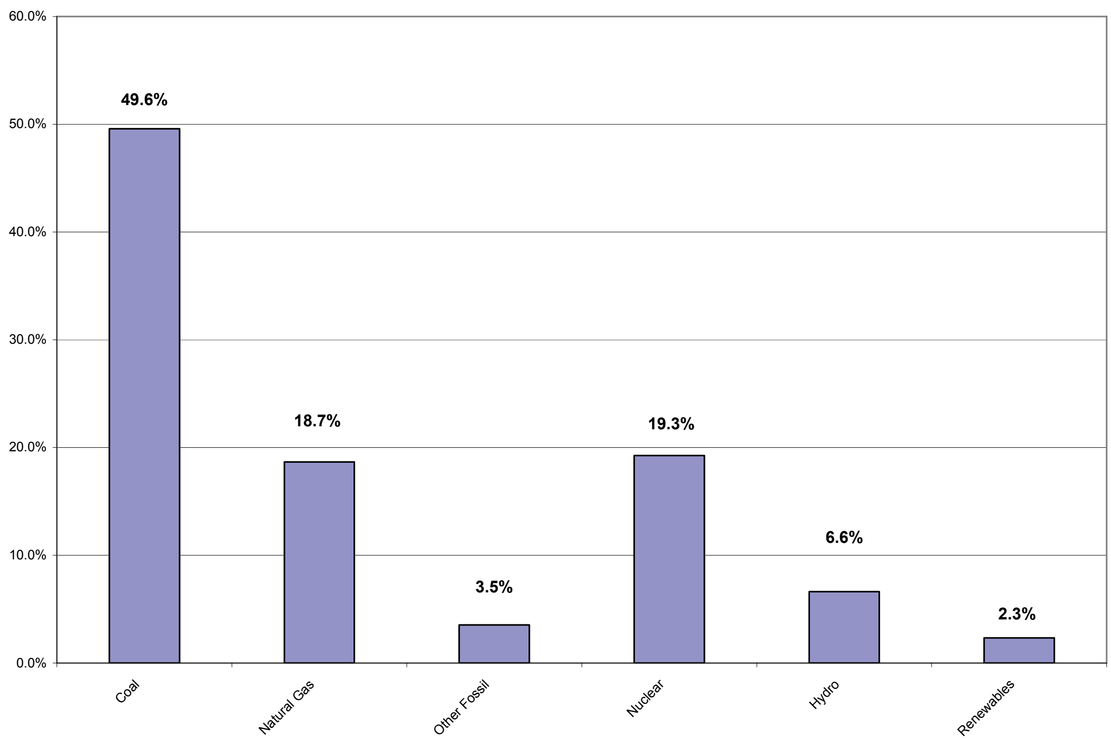
Many U.S. utilities currently incorporate diversity indices and/or portfolio analysis in their resource planning processes. Many states incorporate these practices into their utility planning guidelines. Examples of these practices are discussed in Section 7.

4. Fuel Diversity in Arkansas

1. National and Regional Fuel Diversity[10]

The U.S. electric power industry is heavily dependent on fossil fuels, primarily coal and natural gas, as indicated in Figure 2. In 2005 fossil fuels which accounted for 72% of electricity generation. In that year 88% of electricity was generated from only three sources: coal, natural gas, and nuclear power. The HHI for the national fuel mix is 3,257 and the Shannon-Wiener index is 1.38.

Figure 2. 2005 Fuel Diversity for the U.S. Electric Power Industry



The Arkansas region, consisting of Arkansas, Kansas, Louisiana, Mississippi, Missouri, Oklahoma, and Tennessee, is even more dependent on fossil fuels than the U.S. as a whole, as indicated in Figure 3. In 2005 fossil fuels accounted for 77% of electricity generation in the region. The region is also heavily dependent upon three sources - coal, natural gas, and nuclear power – which represented 92% of the region's generation in 2005. The HHI for the regional fuel mix in 2005 was 3,787 and the Shannon-Wiener index is 1.22.

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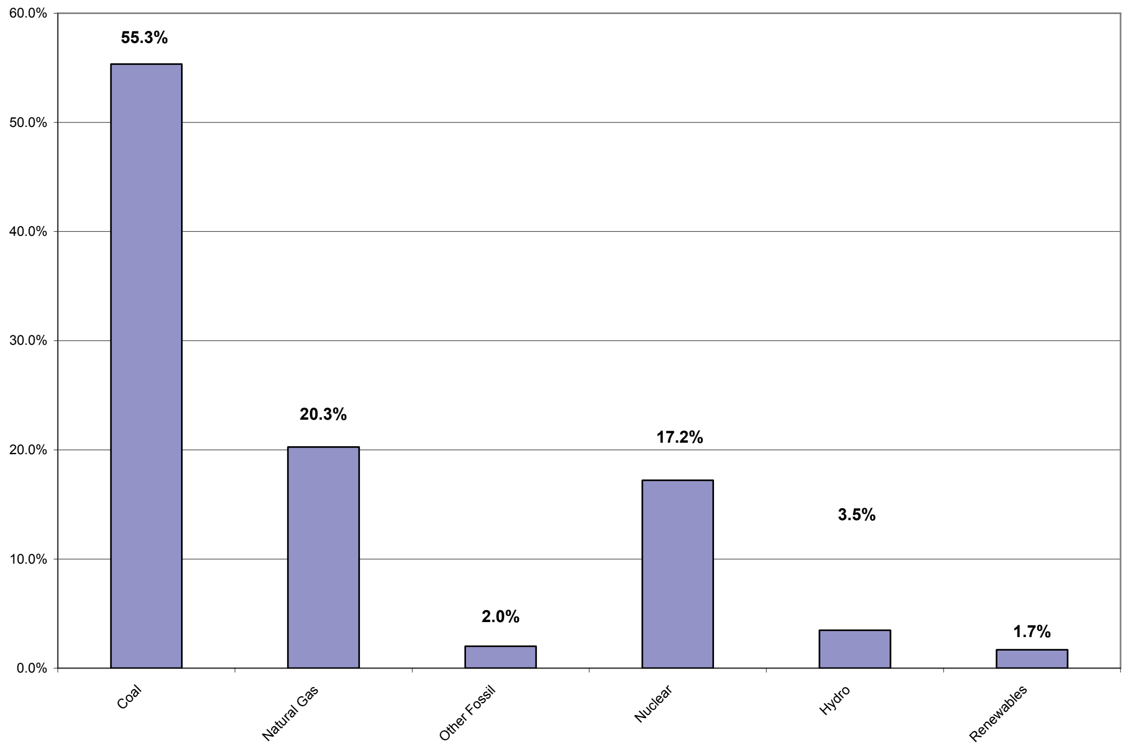
[10] National and regional data is from EIA Form 906 database. The database currently only has data through 2004.

Figure 3. 2005 Fuel Diversity for the Arkansas region



2. Statewide Fuel Diversity[11]

The fuel mix in Arkansas is heavily dependent on conventional resources with coal, natural gas, and nuclear power providing 75.8% of all energy delivered to Arkansas utility customers in 2005. Figure 4 shows the generation mix over the past ten years for Arkansas utilities. While there have been fluctuations in the amount of energy generated from each source over this time period, the general fuel mix in Arkansas has not changed.

[11] Fuel diversity data for Arkansas and utilities is derived from data responses provided by the five Arkansas electric utilities.

Figure 4. Electricity Generation in Arkansas by Fuel Type (1996-2005)

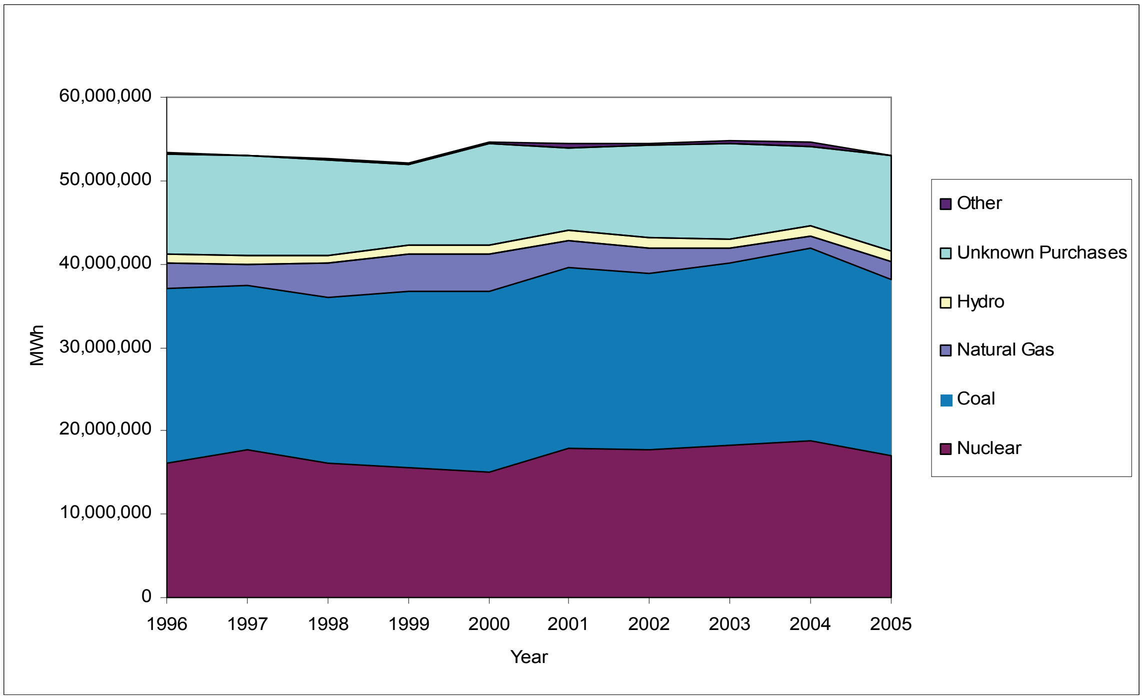


Figure 5 shows the fuel diversity of the total of Arkansas electric utilities. Fuel diversity among utility-owned generation by Arkansas utilities shows an even stronger dependence on coal, natural gas, and nuclear power with these three sources accounting for 97.6% of utility-owned generation. According to reports submitted by the utilities, there is no power generated or purchased in Arkansas that is derived from non-hydro renewable resources.

Figure 5. 2005 Fuel Diversity for Arkansas Electric Utilities.

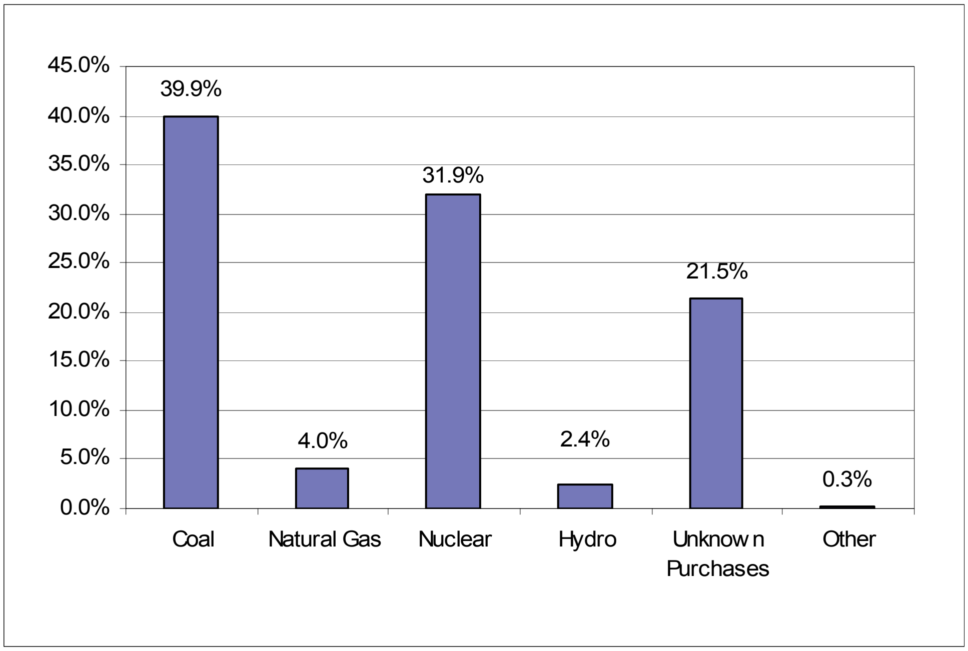


Table 1a shows the generation percentage by fuel type for the ten-year period, and Table 1b shows the generation percentage by fuel type excluding unknown purchases. Table 1b emphasizes the reliance on coal and nuclear power. Table 2 shows the diversity of coal resources used with approximately 94% of coal generation coming from sub-bituminous coal during this period.

Table 1a. Generation percentage by fuel type

Fuel Source	Year									
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Coal	39.2%	37.3%	38.0%	40.5%	39.5%	39.5%	38.8%	40.0%	42.5%	39.9%
Natural Gas	5.8%	4.6%	7.5%	8.7%	8.2%	6.2%	5.5%	3.1%	2.5%	4.0%
Nuclear	30.3%	33.4%	30.5%	30.1%	27.6%	33.1%	32.7%	33.3%	34.4%	31.9%
Hydro	1.8%	2.2%	2.0%	1.9%	2.1%	2.0%	2.4%	2.2%	2.4%	2.4%
Unknown Purchases	22.7%	22.4%	21.7%	18.6%	22.2%	18.1%	20.4%	21.0%	17.5%	21.5%
Other	0.1%	0.1%	0.2%	0.2%	0.4%	1.0%	0.2%	0.5%	0.8%	0.3%

Table 1b. Generation percentage by fuel type (excluding purchased power)

Fuel Source	Year									
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Coal	50.7%	48.1%	48.6%	49.8%	50.8%	48.3%	48.7%	50.6%	51.5%	50.8%
Natural Gas	7.5%	5.9%	9.6%	10.7%	10.6%	7.5%	6.9%	3.9%	3.0%	5.1%
Nuclear	39.2%	43.1%	39.0%	36.9%	35.5%	40.4%	41.1%	42.1%	41.6%	40.6%
Hydro	2.3%	2.9%	2.5%	2.3%	2.7%	2.5%	3.0%	2.7%	3.0%	3.0%
Other	0.2%	0.1%	0.2%	0.2%	0.5%	1.3%	0.2%	0.6%	1.0%	0.4%

Table 2. Composition of coal for Arkansas utility generation

Fuel Source	Year									
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Anthracite	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Bituminous	0.0%	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Sub-bituminous	94.6%	94.1%	94.7%	95.1%	95.0%	95.3%	94.1%	94.2%	94.1%	93.7%
Lignite	5.3%	5.9%	5.3%	4.9%	4.9%	4.6%	5.8%	5.8%	5.8%	6.2%

3. Fuel Diversity of Arkansas Utilities

The Arkansas utilities that reported electric generation data by fuel source for this report include Arkansas Electric Cooperative Corporation (AECC), Entergy Arkansas, Inc. (EAI), Empire District Electric (EDE), Oklahoma Gas and Electric (OGE), and Southwestern Electric Power Company (SWEPCO). Figure 6(a-e) shows the 2005 fuel mix for each utility. With the exception of EAI, each utility derives at least 63% of its power from coal. EAI generates the majority of its electricity from nuclear power.

Figure 6(a). 2005 Fuel Diversity for AECC

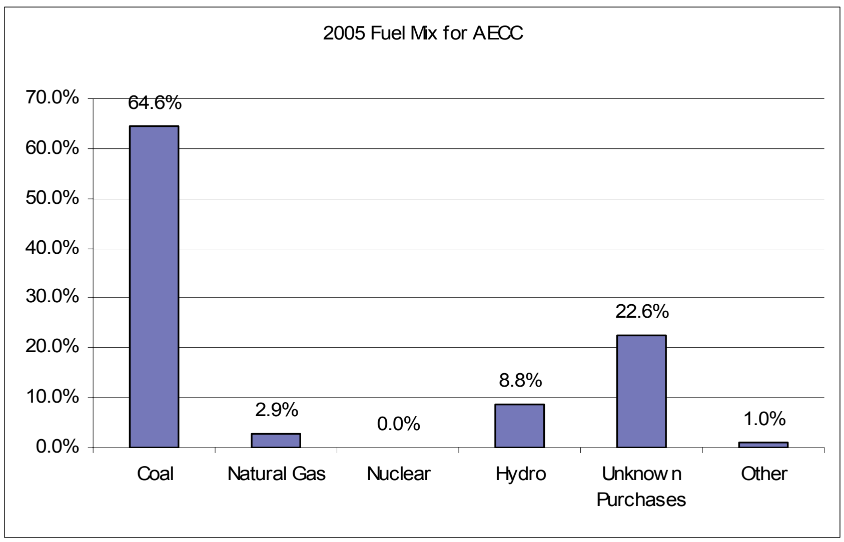


Figure 6(b). 2005 Fuel Diversity for EAI

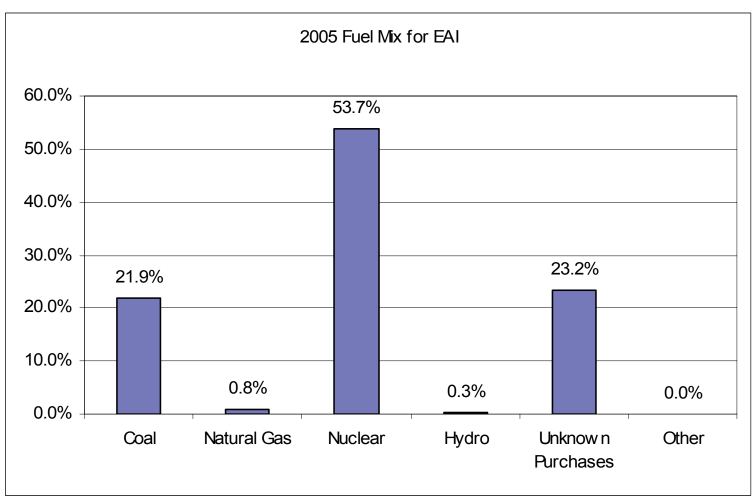


Figure 6(c). 2005 Fuel Diversity for EDE

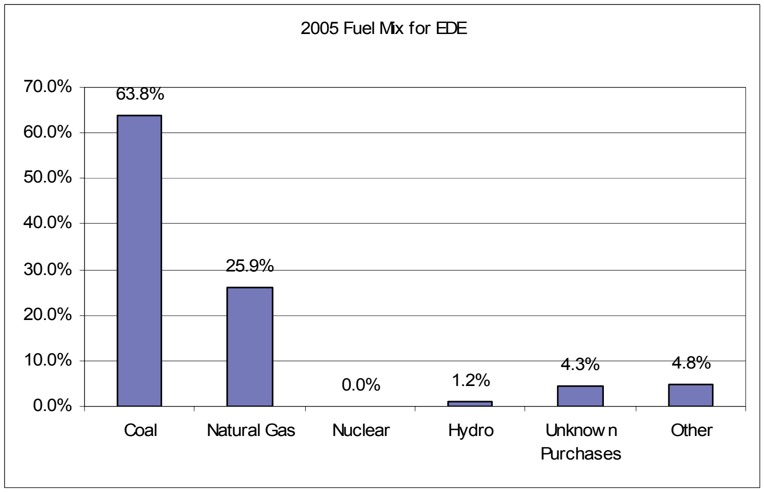


Figure 6(d). 2005 Fuel Diversity for OGE

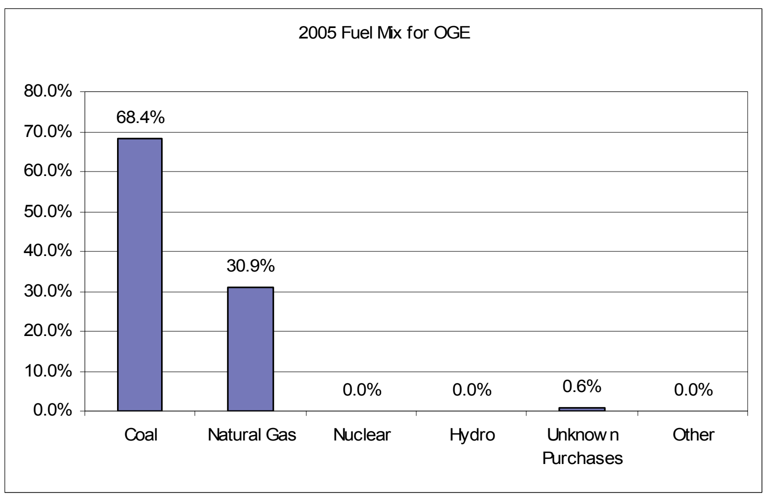
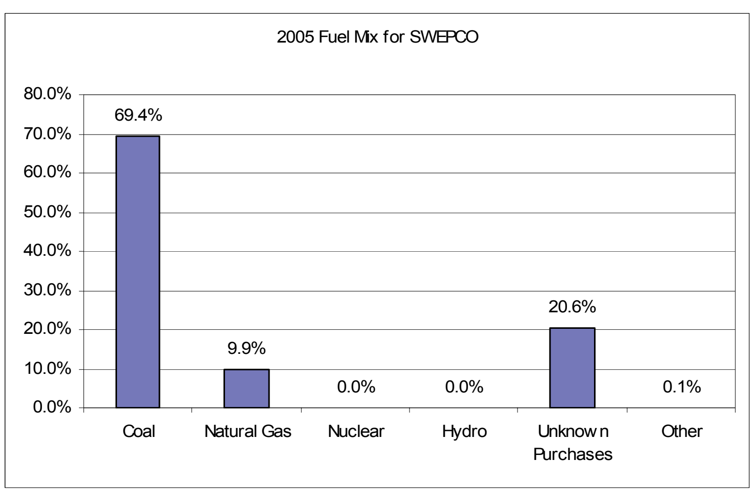


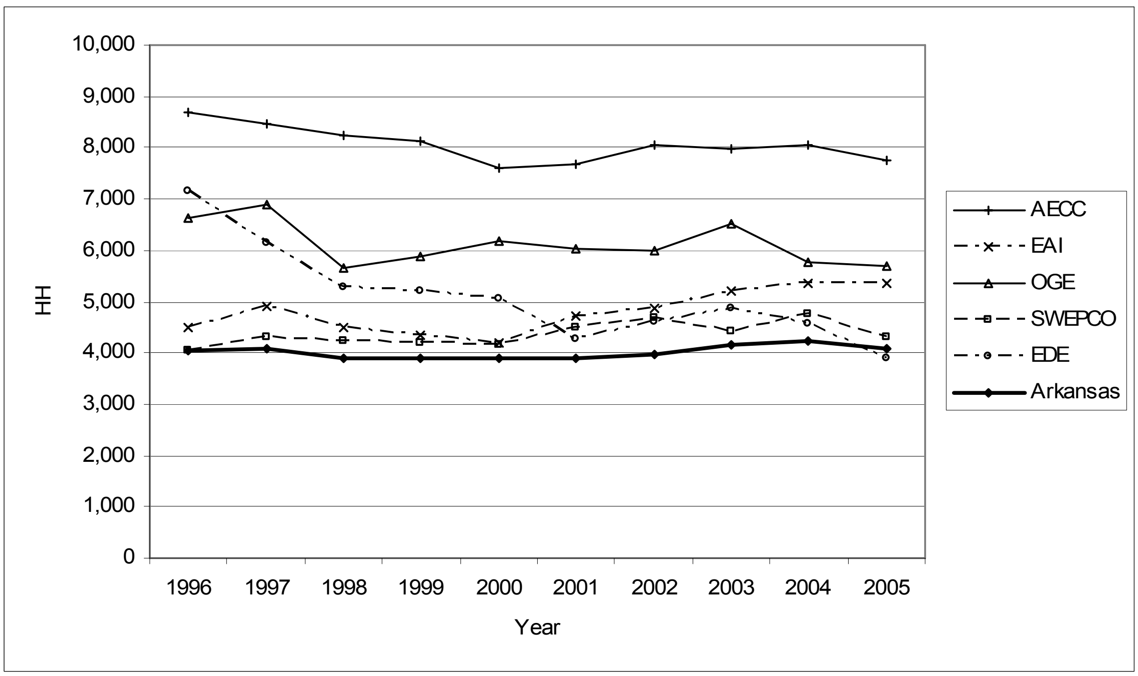
Figure 6(e). 2005 Fuel Diversity for SWEPCO



The HHI and Shannon-Wiener Index were calculated for the 1996-2005 time period for each utility. These indices are shown in Figures 7 and 8, respectively. Although these indices do not inherently say anything about the performance of each utility's portfolio with regards to risk, they do indicate high reliance on very few sources.

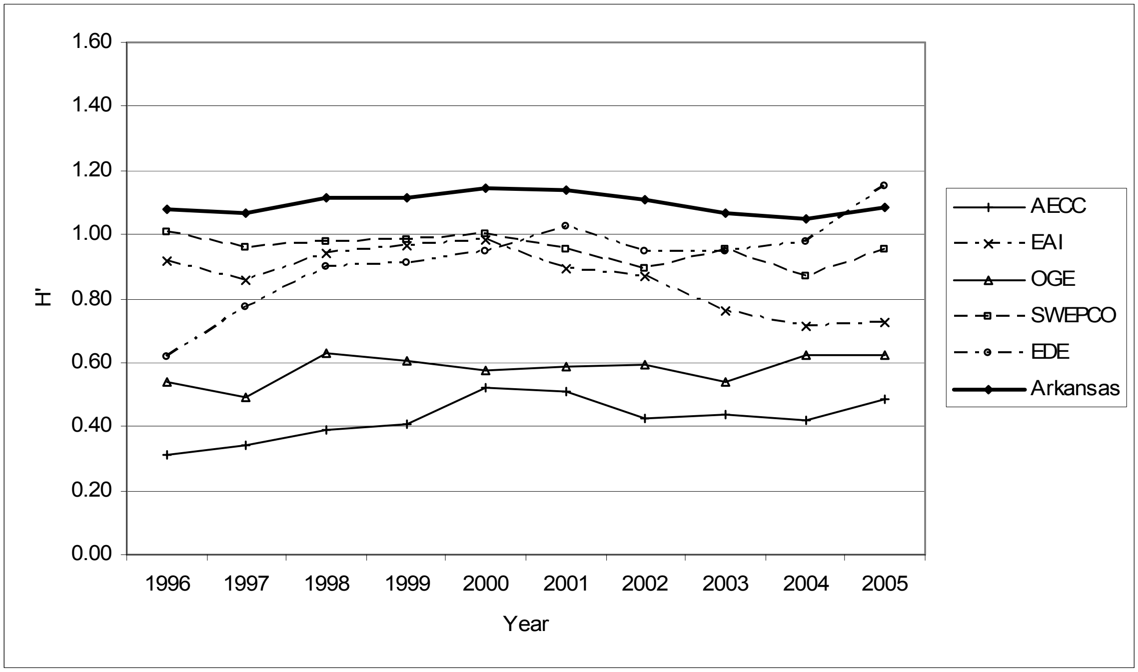
The dominance of coal in four out of five utility portfolios represents significant operational risks in the form of potential supply disruptions as well as financial risks with the strong potential for carbon regulation.[12] Coal is the most carbon-intensive fuel source for generating electricity, contributing huge amounts of CO_2 to the atmosphere. These coal-dominated portfolios also present major environmental risks due to the high SO_2, NO_x, Mercury, and particulate emissions. Portfolio variance analysis, although beyond the scope of this report, would provide valuable insight into the risk performance of each utility's portfolio.

Figure 7. HHI for each utility and for the entire state based on utility-owned generation.



[12] California recently passed legislation establishing an ambitious carbon dioxide emissions reduction target and an allowance trading market to achieve this goal. A coalition of Northeastern states (the Regional Greenhouse Gas Initiative) is in ongoing negotiations to establish a similar system. Also, a handful of proposals have been made at the federal level.

Figure 8. Shannon-Wiener Index for each utility and for the entire state based on utility-owned generation



4. Availability of Alternative Resources

A diverse supply mix obviously depends on the availability of a diversity of resources. The Energy Efficiency and Renewable Energy (EERE) Division of the U.S. Department of Energy lists information on the availability of alternative energy resources in each state including biomass, geothermal, solar, wind, and energy efficiency resources. According to the EERE website, Arkansas has excellent biomass resource potential as well as significant solar, hydro, and wind resource potential.[13] Arkansas also has excellent demand-side resource potential in the form of energy efficiency. According to the Alliance to Save Energy, Arkansas does not have any energy efficiency standards for appliances and there is no energy efficiency public benefits fund. Also, there are no tax incentives or funds available for energy efficiency.[14]

Efficiency and renewable resources have been under utilized in Arkansas. By increasing its reliance on these resources Arkansas could improve the diversity of its electrical supply. The State is making progress in this direction.

[13] U.S. Department of Energy, Energy Efficiency and Renewable Energy www.eere.energy.gov/states/alternatives/resources_ar.cfm.

[14] Alliance to Save Energy, www.ase.org/content/article/detail/2545.

- In January 2007 the Arkansas Public Service Commission adopted rules that will lead to the establishment of a utility-funded weatherization program to be offered to all residential customers
- In January 2007 the Commission issued a set of Resource Planning Guidelines[15] for electric utilities that should lead them to make greater use of efficiency and renewable resources in the future.
- Oklahoma Gas and Electric expects to acquire 120 MW of wind generation from the Centennial Wind Energy Project staring in 2007.

5. Costs and Benefits of Fuel Diversity

1. Potential Benefits

A. Risk Mitigation

Fuel Price Risk. Fuel prices can fluctuate over time for many different reasons. Recent years have seen high volatility in the prices of fossil fuels, especially natural gas and fuel oils. Coal prices have also seen recent price spikes due to transportation problems. A diverse fuel mix can help hedge against price spikes in individual fuel classes by reducing exposure to this volatility.

Portfolio theory states that a truly diverse and efficient portfolio of generation fuels is one that includes resources whose cost streams are poorly correlated.[16] In other words, because prices of fossil fuels are highly correlated, a portfolio dominated by oil and gas resources, even though the portfolio may include a diverse mix of these fuels, is still highly susceptible to risks associated with fossil fuel price volatility. On the other hand, a portfolio that includes resources whose cost streams correlate poorly with fossil fuel prices (e.g., renewables, hydro, nuclear, energy efficiency) will provide a strong hedge against price spikes in volatile fossil fuel markets and can ultimately lead to lower and more stable costs to customers.

A diverse fuel mix may also help a utility leverage better fuel contracts, if the utility is able to switch one fuel type for another, by the power of individual suppliers to set prices. Purchasing fuels from a diversity of suppliers among various fuel types can also help a utility mitigate price risk due to geographic differences in various fuel prices, which may also be poorly correlated. Also, including resources whose cost streams are relatively stable may allow a utility to enter into low-risk, long-term contracts that can help provide stable rates to customers over the long term.

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[15] Docket No. 06-028-R, Order No. 6

[16] Lovins, A. B., E. K. Datta, T. Feiler, K. R. Rabago, J. N. Swisher, A. Lehmann, and K. Wicker. 2002. *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size.* Rocky Mountain Institute, Snowmass, CO.

Volumetric Risk. While the aim of fuel price risk mitigation is to save money, the aim of volumetric risk mitigation is to make a particular kind of physical or market disruption or load volatility less likely to lead to supply interruptions and reliability problems. Different fuels and their associated technologies have certain operational and financial characteristics that lend themselves to providing certain types of power. For example, a large coal-fired plant, due to its high capital cost, inability to start or ramp quickly, and low operating cost, is best suited for base load generation. A gas turbine, on the other hand, is relatively cheap to construct, can start quickly, but has a high operating cost, and, therefore is best suited for peaking generation. A utility needs to have a resource mix that can reliably serve all load levels.

While fuel type diversity and technology diversity can help mitigate volumetric risk, a portfolio that does not include a diversity of suppliers can leave the utility and its customers vulnerable to supply disruption. Transportation problems out of the Powder River Basin in May of 2005 led to "major disruptions in coal shipments that then resulted in precariously low stock levels and led to a major scramble to find other sources of coal to help ease the situation."[17] Having a diversity of suppliers can help a utility hedge against this form of risk.

Regulatory Risk. The regulatory environment is constantly changing, and utilities need to consider current and future potential regulations when developing their resource mix. One major regulatory change that is likely in the near term is some form of carbon dioxide emissions regulation. This sort of regulation poses a major risk to utilities that are highly dependent on fossil fuels, particularly coal. Non-emitting resources (e.g. wind, solar, geothermal, nuclear, hydro) and carbon-neutral fuels (biofuels) are the best means of reducing this risk. The costs and risks of current emissions regulations (SO_2, NO_x, Mercury, particulates) can also be hedged by incorporating non-emitting or low-emitting resources. The costs of such resources should be balanced against the costs of adding pollution control technology to dirtier resources.

B. Environmental Benefits

A conventional portfolio that is highly dependent on fossil fuels has a significant impact on the environment, due to the emissions generated by conventional power plants as well as the emissions associated with extraction of such fuels from the earth, refining them, and transporting them. A diverse generation portfolio that includes renewable resources and energy efficiency and minimizes the use of fossil fuels can help reduce the environmental impact of a portfolio, improving ecosystem and human health. Depending on the regulatory environment, such "eco-friendly" resources can also reduce costs associated with emissions permits and disposal of waste products.

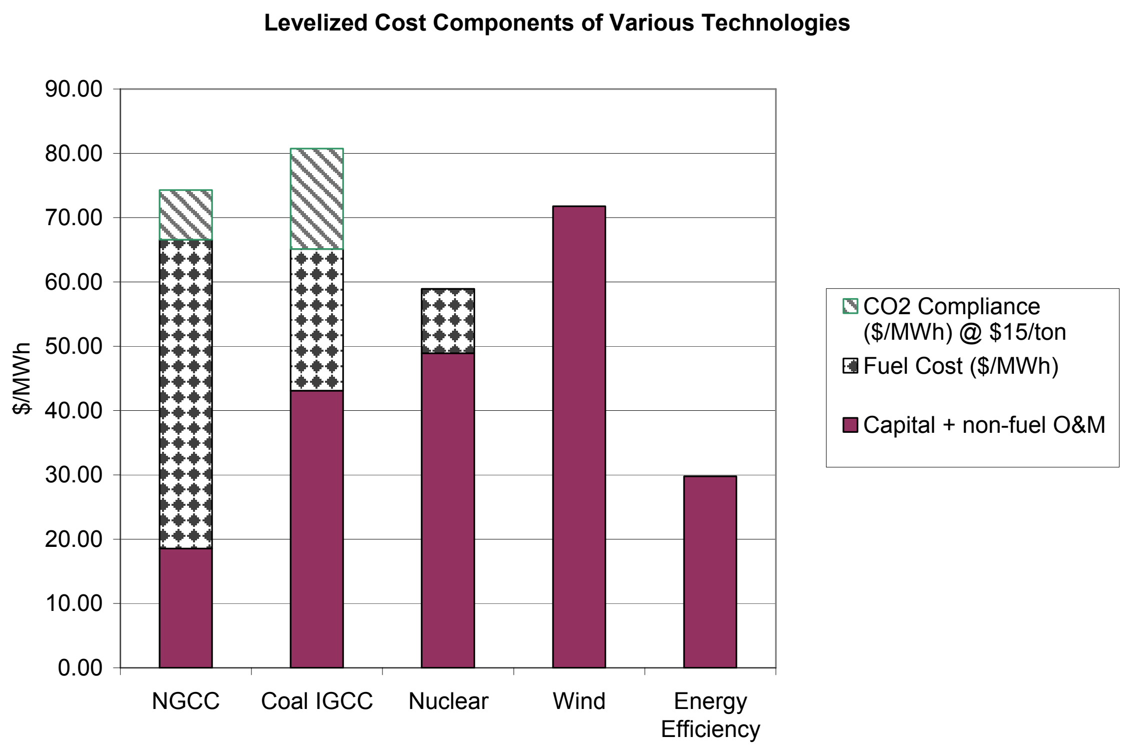
[17] EIA, "U.S. Coal Supply and Demand, 2005 Review". April, 2006. http://www.eia.doe.gov/cneaf/coal/page/special/feature.html.

2. Potential Costs

A. High Resource Costs

Certain resources that may add to the diversity of a utility's portfolio may be relatively costly compared to the existing resource mix in the portfolio. In the face of carbon regulation and volatile gas markets, integrated gasification combined cycle coal plants are being developed that burn cleaner than conventional coal plants but still utilize cheap and abundant coal. The high capital costs and immaturity of the technology, however, have been barriers to private investment in this technology. Other resources that may help diversify a portfolio and mitigate certain risks may also be relatively expensive. Some renewable technologies (photovoltaics, solar thermal, geothermal, biomass) as well as advanced nuclear, large scale hydro, and fuel cells are relatively expensive when compared with gas plants (see Figure 9)[18]. It is important to consider entire life-cycle costs and benefits when making investment decisions, however. Many of these expensive technologies can provide valuable benefits such as hedging value against fuel price volatility and environmental regulations.

Figure 9



[18] Synapse estimates based upon reviews of various sources.

B. Political and Operational Challenges

Adding certain resources to a portfolio may be difficult or impossible due to geographic constraints, socio-political challenges, or other operational challenges. Power plant siting can be a lengthy, highly contested process. When considering resources, utilities must consider the location of the planned site with relation to the neighboring population, land value, environmental regulations, generating technology, and how the resource will interconnect with the grid.[19] Through this process, a utility generally must demonstrate that the benefits of the project will be greater than any harm that may be incurred by any party. The process can be very costly and there is always the risk that a project may not be permitted by the regulatory agencies.

Certain resources such as hydro and wind are highly constrained geographically. Even if a potential site exists, large scale wind projects often face local opposition and damming a river is never an easy task. Proximity to existing transmission facilities may also be a challenging factor, particularly for remote resources.

C. Lack of Experience

A utility that does not have a very diverse generation portfolio may incur costs due to the lack of experience with developing a new resource type that is currently not included in the portfolio. A utility that relies mostly on a single generating technology may be very efficient at generating power with that technology, however, a diverse portfolio would require a utility to master several technologies possibly resulting in lost efficiencies. One goal of diversifying a portfolio would be to overcome these losses with the savings gained through mitigation of other risk factors.

6. Best Practices in Utility Policies and Planning Regarding Fuel and Technology Diversity

Order 1 in Docket No. 06-028-R requires Staff to "…search for best practices benchmarks of utility planning policies/practices that call for a diverse range of fuels and technologies, including renewable technologies, and use them to compare with those of the Arkansas electric utilities." This Chapter describes the results of our review of best practices, and how they compare to the practices of Arkansas electric utilities under the Commission's new Resource Planning Guidelines.

[19] Rose, K. and K. Meeusen. "Reference Manual and Procedures for Implementation of the "PURPA Standards" in the Energy Policy Act of 2005." APPA/EEI/NARUC/NRECA, March 22, 2006.

1. Survey of Fuel and Technology Diversity Planning Practices

Our survey examined fuel diversity policies and practices in Missouri, Louisiana, Mississippi, Kansas, Montana, Florida, Colorado and California. We included states bordering Arkansas, except for Texas (a retail competition state) and Tennessee (with the vast majority of load served by a federally-regulated entity, the TVA) which we considered to be substantially different from Arkansas. Some of the states, such as Montana, are not large but their planning practices are considered to be quite good.

Those states have established various mechanisms to encourage their electric utilities to increase their fuel and technology diversity. The mechanisms have been established through various combinations of legislation, regulations and explicit statements of state energy policy. The survey identified the following mechanisms for increasing fuel diversity in these states:

- Adoption of a reasonable cost standard, or least-cost/least-risk standard, to evaluate utility supply strategies. (MO, MT, CA)
- Flexibility for utilities to consider non-price variables and risk factors such as fuel price, regulation and political climate, weather, resource lead time and water availability in developing their strategies. (MO, LA, MT)
- Requirement that utilities consider a range of demand- and supply-side resources in planning and procurement, (MO, MT)
- Requirement to recognize and evaluate externalities, such as emissions costs or benefits of fuel and portfolio diversity, in planning & procurement. (MT, FL, CA)
- Renewable Portfolio Standards (RPS) with diversity provisions, such as set-asides (i.e., a certain share or amount of energy or capacity must come from specific resources) or credit multipliers (certain resources are given more weight towards complying with an RPS goal) (CO)
- Policies encouraging energy efficiency (FL) and renewables (LA and MT – green pricing; FL – R&D funding)
- Priority order or special weighting for certain resources for resource planning & acquisition, e.g. a loading order (MT, CA)

2. Fuel and Technology Diversity Planning Practices of Arkansas Electric Utilities

Our next step was to compare to compare the "best practices" identified in our survey to the policies/practices of Arkansas electric utilities under the new Resource Planning Guidelines as reflected in the compliance filings of each utility. That comparison is presented in Table 3.

Table 3

Best Practice	EAI	AECC	Empire	SWEPCO	OG&E
1. Adoption of a reasonable cost standard, or least-cost/least-risk standard, to evaluate utility supply strategies. (MO, MT, CA)	EAI's resource plan covers the period 2007 – 2016 (p. 14). EAI selects the portfolio that results in the lowest evaluated total production cost consistent with the planning principles and objectives. The highest-value portfolio alternatives are tested for sensitivity to changes in planning assumptions (p. 8). EAI's cites as goals: limiting exposure to volatility in fuel and purchased power prices, and limiting exposure to other systematic risks such as locational capacity concentration (p. 53).	AECC's resource plan covers the period 2007-2017 (p. 5). When evaluating new resource options, the primary goal for AECC with resource planning is to select a reliable resource with the lowest life-cycle cost (p. 4). Rate impacts and risk abatement are important considerations (p. 4).	IRP covers the period 2006-2025 (p. 2). Empire's planning model minimized the net present value of revenue requirements. Empire personnel took the model outputs and applied business judgment and took non-modeling considerations into account to determine the preferred plan (p. 60). Empire chose a plan that is expected to achieve reasonable outcomes for all of the scenarios and uncertainties (p. 22).	IRP covers period 2005-2014 (p. 7). SWEPCO's model determines the regulatory least-cost resource mix (p. 31) for high, low, and medium gas price forecasts (p. 33). The objective of the IRP modeling effort was to recommend an optimum mix of incremental resources, not only from a least-cost perspective but also from the perspectives of risk, achievability, and affordability (p. 28).	IRP has a 30-year study period. Results are presented for a 10-year horizon, and the key output of the OG&E IRP is the Five-Year Action Plan. OG&E identifies the strategies that minimize total net present value of revenue requirements given different sets of assumptions. OG&E evaluates the impact of uncertainty with respect to key input assumptions and uses its judgment to assess its analytical modeling results (p. 68).

Table 3

Best Practice	EAI	AECC	Empire	SWEPCO	OG&E
2. Flexibility for utilities to consider non-price variables and risk factors such as fuel price, regulation and political climate, weather, resource lead time and water availability in developing their strategies. (MO, LA, MT)	EAI's plan cites the objectives of risk mitigation and supply diversity--mitigating the exposure to major supply disruptions that could occur from concentrated or systematic risks (p. 102). Evaluation of new supply involves quantitative criteria, such as estimated fuel delivery cost adders, and qualitative criteria, such as locational elements of transportation reliability, used to measure expected cost, reliability and flexibility of fuel supply (p. 97).	The optimum supply mix analysis considers expected costs for emission allowances, including costs for SO_2, seasonal NO_x, and mercury. For the base case no costs are included for CO_2 (p. 20).	Planning exercise modeled uncertainties in factors such as gas prices, load forecast, and environmental costs (p. 20). Empire monitors federal efforts with regard to imposition of a carbon tax (p. 77). Alternative models included a carbon tax (p. 21) and 10% RPS (p. 12). Empire concluded that the primary drivers of uncertainty were market/gas prices and load (p. 16).	SWEPCO considered the anticipated value of various commodity prices that have a direct bearing on generation assets. Such commodity prices include natural gas, energy, delivered coal (by-type), emission allowances that are currently transacted within liquid markets, namely, SO_2, NO_x and, to a lesser extent, CO_2 (p. 8). For natural gas, SWEPCO used high, medium, and low anticipated values (p. 33).	OG&E modeled risk parameters, including: retail load, natural gas price, coal price, environmental costs, and capital costs (p. 4). OG&E assesses potential impacts of legislative and regulatory developments (e.g. FERC orders, environmental regulatory changes) (p.61-67). OG&E's analysis includes scenarios where regulation leads to costs for CO_2 and/or constraints on technology (p. 82).

Table 3

Best Practice	EAI	AECC	Empire	SWEPCO	OG&E
3. Requirement that utilities consider a range of demand- and supply-side resources in planning and procurement, (MO, MT)	The current portfolio process considers DSM resources only to the extent that they have impacted the forecasts of load on which the portfolios are based—i.e. EAI does not consider DSM on an equal footing with supply-side resources (p. 8) Has interruptible customers and incentives for customers to change load profiles (p. 4). Expects to develop processes to identify and characterize demand-side resources (p. 7). High-level strategy for stable fuel prices that includes relying more on renewables (p. 29).	AECC has encouraged energy conservation and efficiency (e.g. via loans, audits, education), demand response, and rate designs which provide a correct price signal for: net-metering; co-generation; distributed generation; and peak avoidance (p. 8-9). The energy and capacity savings associated with these past and future demand side efforts are considered in all AECC and member cooperative planning (p. 9).	DSM resources considered outside of the modeling (p. 10). Plans to model DSM programs as resource options when it prepares its 2007 Electric Resource Plan (p. 41). Considered conventional and renewable resources, including: distributed generation, wind, biomass (p. 11).	SWEPCO claims that over the past decade, low regional prices have limited the opportunities for cost-effective DSM (p. 16). SWEPCO will develop an initial "order of magnitude" estimate of cost-effective DSM based on the Rate Impact Measure (RIM) benefit-to-cost ratio (p. 16).	IRP optimization model considered an 80 MW wind farm and 10 MW DSM program. (p. 70-71). Three demand response programs and 10 DSM programs (p. 40-41). Conducting a study of the potential for DSM programs (p. 15). OG&E managed six energy efficiency programs, including efforts to promote heat pumps and home weatherization (p. 42-43).

Table 3

Best Practice	EAI	AECC	Empire	SWEPCO	OG&E
4. Requirement to recognize and evaluate externalities, such as emissions costs or benefits of fuel and portfolio diversity.	See #2 above				
5. Renewable Portfolio Standards (RPS) with diversity provisions	AR does not have an RPS				
6. Policies encouraging energy efficiency and renewables	See #3 above				
7. Priority order or special weighting for certain resources for resource planning & acquisition	AR does not have a preferred loading order				

The comparison presented in Table 3 indicates that the planning policies and practices of Arkansas electric utilities under the new Resource Planning Guidelines are consistent with, but not identical to, the best practices identified in our survey of other states. The practices of Arkansas electric utilities differ from those in other states because of differences in energy policies. Specifically, Arkansas has not adopted a RPS nor has it adopted a weighting or loading order that gives priority to certain resources.

3. Conclusions

Under the new Resource Planning Guidelines the planning policies and practices of Arkansas electric utilities with respect to fuel and technology diversity are consistent with the best practices in other states.

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Appendix A - Survey of Fuel Diversity Policies and Practices in Selected States

This Appendix describes the results of our survey of fuel diversity policies and practices in several states, including states bordering Arkansas.[20] The survey identified the following mechanisms for increasing fuel diversity being used in these states:

- Adoption of a reasonable cost standard, or least-cost/least-risk standard, to evaluate utility supply strategies. (MO, MT, CA)
- Flexibility for utilities to consider non-price variables and risk factors such as fuel price, regulation and political climate, weather, resource lead time and water availability in developing their strategies. (MO, LA, MT)
- Requirement that utilities consider a range of demand- and supply-side resources in planning and procurement, (MO, MT)
- Requirement to recognize and evaluate externalities, such as emissions costs or benefits of fuel and portfolio diversity, in planning & procurement. (MT, FL, CA)
- Renewable Portfolio Standards (RPS) with diversity provisions, such as set-asides (i.e., a certain share or amount of energy or capacity must come from specific resources) or credit multipliers (certain resources are given more weight towards complying with an RPS goal) (CO)
- Policies encouraging energy efficiency (FL) and renewables (LA and MT – green pricing; FL – R&D funding)
- Priority order or special weighting for certain resources for resource planning & acquisition, e.g. a loading order (MT, CA)

These mechanisms were established through various combinations of legislation, regulations and explicit statements of state energy policy.

1. Mechanisms For Increasing Fuel and Technology Diversity

A. Resource planning

Resource planning is in general a process conducted by load-serving entities to assess alternative resource procurement strategies for reliably meeting expected future energy demand. The planning process may vary from utility to utility and state to state depending on market structure, utility type, and the values incorporated into the planning process. A robust resource planning process is an essential driver for diversification of

[20] Texas (a retail competition state) and Tennessee (with the vast majority of load served by a federally-regulated entity, the TVA) were considered to be substantially different from Arkansas and not included in the survey.

utility resource portfolios. In order for truly diverse portfolios to emerge from the planning process, the planning process must include rigorous analytical techniques and incorporate a full range of risks to utilities, ratepayers, society, and the environment.

Planning generally falls into one of two categories: integrated resource planning (IRP) or portfolio management (PM). PM and IRP are not really different as far as the overall objectives. Rather, they are terms that emphasize different aspects of resource planning, all of which aspects should be included in an ideal resource planning process. An IRP process generally seeks to assemble a least-cost portfolio of resources based on a number of potentially available resources (generation, transmission, purchases, DSM) over a period of 10 to 20 years and is typically conducted by vertically integrated utilities. PM has been used mainly to emphasize assembling and managing a collection of purchases with varying degrees of diversification of expiration dates, vendors and, sometimes, term lengths. Painstakingly designed competitive procurements are often the centerpiece of PM.

Integrated Resource Planning

Integrated Resource Planning (IRP) refers to a process by which a utility evaluates a mix of energy supply-side and demand-side resources that will meet current and future needs at the lowest reasonable cost to the utility and its ratepayers. Some state public utility commissions (PUCs) require regulated vertically integrated utilities to prepare an IRP periodically (typically, every two to three years) as a way to provide least-cost electric service to customers over the long term and to minimize or manage risks faced by ratepayers.[21]

The IRP process generally involves the following steps:

- Developing forecasts of load, fuel and market power prices, and other key factors;
- Documenting the particulars of existing supply and demand resources including existing generation and transmission facilities, purchase contracts, demand side management (DSM) programs, and market purchases of power;
- Identifying and characterizing new supply and demand resources that could be acquired over the life of the IRP;
- Developing a variety of different resource plans that could meet future load requirements, and screening them based on cost;
- Selecting the best resource plans scenarios and testing their sensitivity to risk factors such as load uncertainty, fuel price volatility, and regulatory uncertainty.
- Selecting a preferred plan, usually based on a combination of present value life cycle cost (under on or another definition of cost) and risk profile; and,
- Developing an action plan.

[21] States that currently have IRP requirements include California, Colorado, Delaware, Hawaii, Idaho, Indiana, Minnesota, Missouri, Montana, Oregon, Vermont, and Washington.

While the general IRP process is similar from state to state, the requirements specified by PUCs vary. These differences may include:

- the treatment of DSM programs with respect to generation resources;
- costs that may or may not be included in market prices, such as environmental and societal costs, as well as other factors that may not be easily monetized;
- Treatment of the potential carbon dioxide emissions regulation;
- Opportunity for stakeholder input, including customer input;
- Sources of risk;
- Role of the PUC in the IRP process;
- Planning time horizon and time cycle for submitting and updating IRPs; and,
- Analytical methods to evaluate and compare alternative resource portfolios.

Portfolio Management

Portfolio management (PM) refers to a planning and procurement process that involves meeting a purchaser's requirements through consideration of a variety products, ranging from direct purchases of various lengths and starting dates, options to purchase or sell, other hedging products, and the possibilities of producing one's own product (now or in the future) or of reducing ones need for the product. Obviously, this is a very general concept. When applied to electric power procurement, "producing one's own product" equates to building and running generation, while "reducing one's need for the product" translates into any of the available DSM resources. For many traditional, vertically integrated utilities, especially those outside the northeast, those were the main possibilities, and PM would have been very similar to IRP, perhaps differing mainly in emphasis. With the introduction of more intensive market trading of electricity and the beginnings of hedging products for power, natural gas, weather, and emission permits, utility resource planning begins to look more like the type of PM seen in financial and commodity markets, although crucial differences remain. And, as some states began to engage in retail competition and competitive procurement of default service supply (with or without divestiture of utility power plants), some aspects of power supply more closely approached a state where purely financial players could participate and utility ownership of physical generation is sometimes not an option.

Portfolio management has emerged in recent years in states that have restructured their electric utilities and is becoming particularly important with respect to utilities that provide default service where retail choice is available. In IRP, vertically integrated utilities can weigh various utility-owned resource options including new generation, transmission expansion, and DSM programs as well as power purchase contracts. With electric industry restructuring, many utilities were required to divest generation and transmission resources and are now required to serve load with a portfolio of power purchases consisting of short and long-term contracts with generators, energy marketers, or other utilities, or purchases from the spot market. Some state PUCs require utilities to conduct portfolio management as a way to provide least-cost and stable electric service to customers over the long term[22].

B. Renewable Portfolio Standard

Several states currently use some form of renewable portfolio standard to increase fuel diversity and generation from renewable resources[23]. The standards vary from state to state in the quantitative targets set by these standards, the level of obligation placed on utilities to meet the targets, and the resources that qualify as renewable.

Renewable portfolio standards are advantageous in that they can ensure that a known quantity of renewable energy will be delivered; they are competitively neutral if applied to all load-serving entities; administrative costs are relatively low; they can be applied in regulated and restructured markets; and they can lower the cost of achieving the target by providing private market flexibility. However, an RPS can be difficult to design, and may not be flexible in offering targeted support to specific resources. Also, operating experience is limited, and there is uncertainty about cost impacts associated with these standards, as well as questions about whether an RPS will lead to long-term contracts.[24]

2. Fuel Diversity Policies and Practices in Other States

This survey examined fuel diversity policies and practices in Missouri, Louisiana, Mississippi, Kansas, Montana, Florida, Colorado and California.

A. Missouri

Missouri initially adopted resource planning rules in 1993. In the late 1990s, due to the changing competitive environment for electricity, the Public Service Commission (PSC) allowed utilities to operate under a waiver from the formal resource planning process and instead participate in semi-annual informal resource planning meetings with PSC staff. The waivers expired in December of 2005, and resource planning has been in transition since that time.

The Resource Planning rule lays out a fundamental objective: to provide the public with energy services that are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest. While cost is the primary criterion for comparison of the alternatives, utilities must explicitly identify and quantify other considerations that

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[22]States that currently have instituted portfolio management requirements include Delaware, Montana, Maine, Maryland, Massachusetts, New Jersey, Illinois, and District of Columbia.

[23]States that currently have renewable portfolio standards of some form include Arizona (proposed), California, Colorado, Connecticut, Delaware, District of Columbia, Hawaii, Iowa, Maine, Maryland, Massachusetts, Minnesota, Montana, Nevada, New Jersey, New Mexico, New York, Pennsylvania, Rhode Island, and Wisconsin.

[24] Wiser, R., "State RPS Policies: Experiences and Lessons Learned." A presentation for Oregon Renewable Energy Working Group, May 31, 2006.

work towards the objectives of the resource planning process. These other considerations include mitigation of:

> 1. Risks associated with critical uncertain factors that will affect the actual costs associated with alternative resource plans;
>
> 2. Risks associated with new or more stringent environmental laws or regulations that may be imposed at some point within the planning horizon; and
>
> 3. Rate increases associated with alternative resource plans.[25]

Utilities are required to document the rationale and process used to make tradeoffs between least expected cost and other factors.

The Resource Planning rule requires utilities to consider a variety of resources, and demand-side resources are given equal footing with supply-side resources. However, utilities have done a better job of analyzing supply-side resources than demand-side ones.[26]

The state has been highly reliant on coal, which represents 85% of the electricity sector's energy input in 2003.[27] While utilities are required to analyze risks in the context of resource planning, the PSC does not give explicit consideration to fuel diversity as a risk mitigation tool in these proceedings or in others. PSC Staff thinks that existing rules are sufficient but not explicit in addressing fuel diversity; the current rules may be revised to be clearer on this issue.[28]

B. Louisiana

Per a 2002 General Order, the Louisiana Public Service Commission (PSC) established criteria for planning and procurement. Reliable service at the lowest reasonable cost is the primary factor, but utilities may also consider public interest factors such as project or contract risk attributes and fuel diversity. (Section 7.2 contains an example of how a utility conducted its procurement using these criteria.)

The state draws 35% of its electricity from coal-fired generation, and another 35% from natural gas; the remainder is almost entirely from nuclear power. Supply disruptions during Hurricane Katrina and Rita highlighted the state's need for increased energy security. The PSC is continually looking to increase the diversity of its fuel mix and improve its energy security. In addition to a just-opened docket on implementing

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[25] See Missouri State Code, 4CSR240-22.

[26] Interview, Lena Mantle, Missouri Public Service Commission. September 19, 2006.

[27] U.S. EIA, State Energy Consumption, Price, and Expenditure Estimates (SEDS). Table 12. Electric Power Sector Consumption Estimates, Selected Years, 1960-2003, Missouri.

[28] Missouri's case for considering fuel diversity pursuant to EPAct, number EO-2006-0494, is on-going. Interview, Lena Mantle, Missouri Public Service Commission. September 19, 2006.

integrated resource planning, its latest efforts include adoption of a Green Pricing pilot program. Deterred by the rate impacts that implementation of a Renewable Portfolio Standard would have on all customers, the PSC pursued another option for expanding the development of renewable energy: a voluntary Green Pricing Tariff (GPT). Customers enrolled in the GPT pay the incremental cost that the utility incurs over and above the utility's avoided cost, plus marketing and administrative costs.[29] Although it is just getting off the ground, upwards of 500 customers signed up for the pilot.[30]

C. Mississippi

Mississippi does not have an integrated resource planning (IRP) process, although it does review IRPs produced by its multi-jurisdictional utilities, Entergy Mississippi and Mississippi Power Company (a Southern Company subsidiary). Mississippi utilities are encouraged to produce hedging plans for purchased power but are not held accountable for divergence from these plans. While these mechanisms have the potential to encourage fuel diversity, non-cost factors are not given explicit consideration.

D. Kansas

Kansas has seen rapid development of wind power in recent years, at a rate of 100 to 150 MW of new capacity additions per year. These resources were developed without prompting by state policy or incentives. In February of 2007, Governor Kathleen Sebelius announced a goal for increasing wind power to 10% of the state's electricity by 2010. Following on the heels of the Governor's announcement, Westar Energy responded with a Request for Proposals for up to 500 MW of renewable energy by 2010, with the most likely source being wind power[31]. The rapid development of these resources without the involvement of policy makers may obviate the need for a formal policy, such as a Renewable Portfolio Standard. Indeed, the state's approach to encouraging wind power, working with utilities rather than mandating utilities build wind farms, may be seen as a success. Kansas does not have an integrated resource planning process.

In December, 2006, the Kansas Corporation Commission opened a docket for the purpose of complying with section 1251 of EPAct, including consideration of a fuel diversity standard. Comments were received in March, 2007, but the proceeding is still in a relatively early stage.

E. Montana

In 1992, the Montana Public Service Commission (MPSC) enacted IRP guidelines that encourage electric utilities to develop and implement least cost planning. Five years later, restructuring legislation established customer choice and mandated the functional break up of Montana Power Company. Montana Power Company was later purchased by

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[29] Louisiana Public Service Commission Staff Position Paper. Nov. 21, 2006. Docket No. R-28271.

[30] Interview, Melissa Watson, Louisiana Public Service Commission. May 10, 2007.

[31] Westar Energy. "Westar Energy Requests Bids for Renewable Energy: Utility looks to add up to 500 MW of energy from renewable resources." Press release, Feb. 26, 2007)

NorthWestern Energy (NWE), which became the default supply utility (DSU) in most of the state. The other major investor-owned utility, Montana-Dakota Utilities (MDU), which provides power in eastern Montana, was exempted from restructuring and remained a vertically integrated utility.[32] In 2003, the PSC enacted guidelines on long-term portfolio planning, management, and resource procurement for default service electricity supply. As a result, there are two separate planning processes applying to the two major service territories: traditional Integrated Resource Planning (applicable to MDU) and electricity resource planning and procurement for default service customers (applicable to NWE).

IRP guidelines. Montana's IRP guidelines provide a fairly comprehensive framework for conducting least cost planning, addressing a variety of costs and risk factors. The guidelines place strong emphasis on managing and reducing risks associated with resource choices in a manner that addresses environmental, societal, and ratepayer risks as well as risks to shareholders. The IRP rules require that utilities consider all available resource options, including DSM, and evaluate these options based on a broad range of resource attributes. Using "best available" methodology, resource plans should explicitly evaluate quantifiable and non-quantifiable environmental externalities, including the uncertainty and risk associated with future environmental regulations, uncertainty regarding the size and importance of external environmental costs, and environmental costs associated with continued operation of existing resources.

Although utilities determine the sources of risk using their own techniques and judgment, the IRP guidelines suggest that utilities consider these potential sources of risk:

- Future fuel availability and price,
- Resource lead-time,
- Water availability,
- Future load growth,
- Shortcomings of various forecasting methods,
- Performance and useful lives of existing resources,
- Costs and performance of future demand- and supply-side resources,
- The rate of technological change,
- The existence and social evaluation of environmental externalities, and
- The future sociopolitical and regulatory environment.

The IRP guidelines also present a list of potential planning techniques for utilities to consider for managing risks associated with the above sources:

- assessing the risk of resource alternatives,
- developing resource options that increase scheduling flexibility,

[32] PacifiCorp was also affected by restructuring. PacifiCorp sold its Montana service territory to Flathead Electric Cooperative. Rural electric cooperatives opted not to open their territories to competition.

- developing small, short lead-time resources that better match loads with resources and reduce the amount of, and period over which, capital must be invested to meet future load growth,
- diversifying the resource portfolio to allow adaptation to a range of future outcomes,
- managing loads to increase utility control over resource requirements,
- encouraging the acquisition of resources through competitive processes,
- incorporating consumer response to rate design into forecasting models,
- providing for public involvement and education in resource decisions, and
- maintaining a transparent integrated least cost resource planning and acquisition process (i.e., one which produces resource plans that can be reasonably understood by the public and the commission.)

The guidelines require that demand-side resources be given special consideration in resource evaluation.[33] Utilities are required to weight and rank existing and potential resources on the basis of, in part, their environmental impacts.[34]

Special attention is given to consistency between the IRP and rate making processes in the IRP guidelines. IRPs must explicitly recognize rate design opportunities to develop demand-side resources.

While the determination of how to assess resource diversity, environmental externalities and risk factors is left to the utility's judgment, the IRP guidelines do require that the utility clearly and thoroughly document the decision process for choosing resource options.

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[33] The IRP guidelines also include provisions on sizing and evaluating demand side resource options. The impact of price-induced conservation (i.e. conservation undertaken by customers in the absence of any utility-sponsored program) should be accounted for either in the load forecast or as part of the total available resource. The revenue impacts of decreased sales resulting from demand-side resources are not added to cost of acquiring such resources. Also, in considering demand-side resources, until a point at which there are no market barriers or market failures that may interfere with investment in demand-side resources. As opposed to supply-side resources, demand-side resources are considered cost-effective up to 115% of the utility's long-term avoided cost. The total societal cost test and the total resource cost test are required elements of an IRP. (Montana Administrative Rules , sub-chapter 20: Least Cost Planning – Electric Utilities. 38.5.2004; Baldwin, Liz. Regulatory Assistance Project Electric Resource Long-range Planning Survey: Montana. Sep 29, 2005(a))

[34] The screening process in Montana's IRP guidelines requires that the cost assigned to each resource reflects all relevant attributes. Attributes generally include those that influence utility costs as well as long-term societal costs, including risk and uncertainty. Other attributes to be considered are environmental externalities, the overall efficiency with which the resource produces energy services, administrative costs of acquisition programs, the cost effectiveness of the resource within the context of the utility system, reliability, and associated transmission costs. (Montana Administrative Rules, sub-chapter 20: Least Cost Planning – Electric Utilities. 38.5.2004)

Default Electric Supplier Procurement Guidelines. Montana's largest restructured IOU, NorthWestern Energy, is subject to Montana's default electric supplier procurement guidelines.[35] These guidelines were developed with the following stated objectives:

- Provision of adequate, reliable default supply services, stably and reasonably priced, at the lowest long-term total cost
- Pricing that is both equitable and promotes rational, economically-efficient consumption and retail choice decisions
- A balanced, environmentally-responsible portfolio of power supply and demand-side management resources, coordinated with economically-efficient cost allocation and rate design
- Diversity with respect to resource types and contract durations
- Dissemination of information to customers regarding the mix of resources in the supply portfolio and corresponding level of emissions and other environmental impacts

Each DSU is required to develop an Electric Default Supply Procurement Plan (EDSPP) to comply with these objectives. This plan is based on a comprehensive resource needs assessment, considering all aspects of customer load, resource availability, and product type availability. The plan must assess the resource diversity and flexibility of the existing portfolio, as well as the effect of cost allocation and rate design on future resource needs. To evaluate these factors independently of resource options, DSUs must employ rigorous computer modeling and analysis in the portfolio management and resource procurement processes. Analyses must also be used to develop least-cost scenarios and conduct risk sensitivity analyses for the various options. Table A-1 shows the risk factors that DSUs are required to consider.

[35] In NorthWestern Energy's territory, there is currently no competitive supply available for residential and small business customers. A statutory change in 2005 will allow entities to aggregate residential and small business customers, subject to regulatory approval. The Commission lacks authority to adopt portfolio rules for aggregators, but it may be approving some sort of planning guidelines in the future.

Table A-1. Sources of risk that should be considered in prudent default supply resource planning and procurement (MT 38.5.8219)

Underlying Risk Factor	Price Uncertainty Risk	Load Uncertainty Risk
Fuel prices and price volatility	X	X
Environmental regulations & taxes (including carbon regulation)	X	X
Default supply rates	X	
Competitive suppliers' prices	X	
Transmission constraints	X	
Weather	X	X
Supplier capabilities	X	X
Supplier creditworthiness	X	
Contract terms and conditions	X	X

DSUs must apply cost-effective resource planning and acquisition techniques to manage and mitigate the risks posed by the factors shown in Table 5, above. Such techniques include contingency planning, portfolio diversification, and transparency in the planning and procurement process. These utilities must balance environmental responsibility with other portfolio objectives, including lowest-long term total cost, reliability and price stability.

The guidelines require DSUs to develop methods for incorporating portfolio objectives into the resource procurement, for example by weighting resource attributes and ranking bids in competitive solicitation processes. The guidelines suggest that weights may be given to reflect, among other things, contributions to achieving optimal resource diversity as well as fuel source, associated price volatility, and regulatory risk (including regulations on carbon emissions).

A default service provider should evaluate the performance of alternative resources under various loads and resource combinations through scenario, portfolio, sensitivity, and risk analyses. As an example of these modeling efforts, for its 2005 EDSPP NWE conducted a 20-year horizon resource planning analysis involving the following steps:

1. Define the load obligation
2. Accumulate data on resource options and model inputs, including expected carbon costs and gas and electricity price forecasts
3. Create portfolios of resources that are representative of the feasible possibilities that NWE could pursue

4. Conduct intrinsic analysis[36] of the portfolios to identify key risk drivers, and employ scenario analysis for gas and electricity prices, load, and CO_2 regulations[37]
5. Select the most robust portfolios, considering the major risk factors inherent in the portfolios
6. Conduct the final screening of the most robust portfolios using stochastic analysis using thousands of simulations
7. Select the best portfolios based on their placement on a risk-adjusted mean efficiency frontier
8. Conduct qualitative analysis of the best portfolios
9. Create an Action Plan outlining how the selected resource characteristics will be acquired over the time frame of the Plan

As a requirement of providing default electric supply service, a default supplier is required to also provide customers with the option of choosing a "green" product composed of or supporting power from certified environmentally preferred resources such as wind, biomass, solar or geothermal resources. Further promoting resource diversity, the Montana PSC recently adopted a rule establishing a Renewable Energy Resource Standard.

F. Colorado[38]

Amendment 37 was approved by the Colorado voters on November 2, 2004 and became effective on December 1, 2004. Under this Amendment and subsequent clarifying legislation, Colorado electric utilities with more than 40,000 customers (called Qualifying Retail Utilities, or QRUs) are required to procure 10 percent of their retail sales with qualifying renewable energy resources under a Renewable Energy Standard (RES).

Fuel diversity is one of the specific goals of Amendment 37. The Amendment ballot declared that:

> Energy is critically important to Colorado's welfare and development, and its use has a profound impact on the economy and environment. Growth of the state's

[36] Intrinsic analysis employs fixed market prices and static resource assumptions. (NorthWestern Energy, 2005 Electric Default Supply Resource Procurement Plan)

[37] The analysis considers the potential implementation of a CO_2 tax using forecasts of medium, high, and zero taxes. The expected case (medium) was drawn from NPCC's estimate of a 67% chance of a \$6.00/ton-CO_2 charge starting in 2010 and rising to \$14/ton in 2017. (NorthWestern Energy, 2005 Electric Default Supply Resource Procurement Plan)

[38] Rich Mignogna, Public Utilities Commission of Colorado, personal communication with A. Napoleon, Sept 7, 2006.

> population and economic base will continue to create a need for new energy resources, and Colorado's renewable energy resources are currently underutilized.
>
> Therefore, in order to save consumers and businesses money, attract new businesses and jobs, promote development of rural economies, minimize water use for electricity generation, diversify Colorado's energy resources, reduce the impact of volatile fuel prices, and improve the natural environment of the state, it is in the best interests of the citizens of Colorado to develop and utilize renewable energy resources to the maximum practicable extent.

In March 2007, the state legislature raised the RES for investor owned utilities (IOUs) and expanded its coverage to cooperative utilities and municipal utilities with more than 40,000 customers. Under the new RES, IOUs are required to generate or purchase energy from qualifying energy resources starting at three percent of their sales in 2007 and increasing to 20 percent by 2020. Other QRUs are required to generate or purchase one percent of their retail sales from qualifying energy resources starting in 2008; the requirement for other QRUs rises to 10 percent by 2020.

Colorado's RES is designed to promote and encourage certain fuel resources. For IOUs, four percent of the standard has to be met by solar-electric technologies. At least one-half of this solar-electric requirement must be met by customer-sited generation facilities. (The other half can be utility-scale solar plants.) Rural Electric Associations receive more than 100 percent credit towards the RES for in-state facilities, community-based projects no greater than 30 MW, and certain solar generation facilities.

The RES law also has a provision that requires QRUs to have contracts with qualifying resources for a minimum of 20 years, unless the seller desires a shorter period for the contract. This is a critical design feature, because renewable energy resources with high capital costs often cannot secure funding for a project without long-term contracts for its output.

Under the RES, a QRU can set its own budget and allocate the budget between non-solar, on-site solar, and other solar. QRUs are allowed to recover costs associated with the RES from rates, subject to a net rate impact limitation of two percent as well as Commission oversight under competitive acquisition and Least Cost Planning standards. If a QRU cannot meet the RES within the two percent increase, it can borrow "forward" from future rates.[39]

Public Service Company of Colorado (PSCo) & Aquila, the two QRUs subject to the original RES, started solar rebate programs to comply with the customer-sited resource requirement. The utilities are making progress towards their goals, but it is possible that neither utility will meet the 2007 customer-sited solar electric requirement. PSCo started its rebate program in March 2006 and, as of March 2007, accumulated almost 5,000

[39] Rich Mignogna, Public Utilities Commission of Colorado, personal communication with A. Napoleon, June 22, 2007.

Renewable Energy Credits (RECs) in 2006 and roughly 2,100 in the first three months of 2007 towards its 2007 requirement for 16,000 on-site solar RECs.[40][41]

To comply with the remaining portion of the solar set-aside for 2007, PSCo issued a Request for Proposals for solar electric resources producing approximately 13,700 MWh per year (7-10 MW capacity), and entered a stipulation approving a Solar Energy Purchase Agreement for the energy produced by a 8 MW facility in Alamosa County. The remaining 96 percent of renewable resources will probably not be diversified. Even though a number of other types of resources qualify, Staff anticipates that the non-solar component will consist almost entirely of wind.[42,43] PSCo, for example, intends to fulfill its non-solar REC requirement primarily with wind resources procured in a 2005 RFP. (PSCo 2006a)

The RES is binding only up to a two percent increase in rates, as long as the QRU can show that meeting the RES would result in a higher rate impact. A QRU that does not meet its RES must explain why it was unable to do so to the Commission. In this case, the QRU's funding decisions would likely come under close scrutiny.[44] (Interview Rich Mignogna 2006)

Within the RES structure, the objective of fuel diversity is treated more or less tangentially[45]. However, the logic behind an on-site solar set-aside is consistent with promoting geographic and fuel diversity. As the dominant renewable resource in Colorado today, wind would likely crowd out other renewable resources if the RES were unrestricted.

The fuel mix in Colorado has a long way to go to become diversified, even with the recent increase in wind and solar development. Coal accounted for an estimated 72% of net generation in Colorado in 2005.[46]

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[40] Monthly Renewable Energy Standard Adjustment reports, available at http://www.dora.state.co.us/puc/rulemaking/Amendment37/Amendment37.htm.

[41] An eligible renewable energy facility earns one REC for each MWh of electricity that is generated in a given year.

[42] Other eligible resources include Landfill Gas, Biomass, Geothermal Electric, Anaerobic Digestion, Small Hydro (10 MW or less), and Fuel Cells (renewable fuels).

[43] Interview, Rich Mignogna, Public Utilities Commission of Colorado. Sept 7, 2006.

[44] If a QRU is unable to meet the RES within the one percent rate increase, fuel and resource diversity will be affected by how the QRU set and allocated budgets between the different types of RES procurements. Emphasis on the non-solar component could leave too little to attain the solar standard, while focusing on the on-site solar programs could displace wind and other renewables that become more economic in the future.

[45] For example, the Commission declined a request for more data on generation resource representation and changes in energy resource diversity in Colorado. (Colorado PUC 2005)

[46] U.S. EIA, Electric Power Annual 2005, Net Generation by State by Type of Producer by Energy Source (EIA-906). Released Nov 2006.

G. Florida

In 2006, the Florida Legislature passed the Florida Renewable Energy Technologies & Energy Efficiency Act (Senate Bill 888) to diversify the state's fuel supply and promote energy conservation and efficiency. Bill 888 was intended to address Florida's vulnerability to interruptions in fuel production, supply and delivery due to storms and the state's high projected load growth.[47]

Amending the Power Plant Siting Act, Senate Bill 888 streamlined the process for approval of new electric generation capacity to improve reliability. Bill 888 also amended Florida Statutes to allow the Public Service Commission (FL PSC) to consider fuel diversity and reliability in certain determinations. For the assessment of ten-year site plans, the FL PSC is required to consider the effect on fuel diversity within the state. (Ten-year site plans may be classified as suitable or unsuitable, but they do not constitute a binding plan of action for utilities. Their purpose is largely informative.)[48]

Outlined in a four year, $100 million plan, Bill 888 contained provisions for economic incentives for energy efficiency and consumer solar installations, grants for renewable energy and "next generation" research and development, and tax incentives for manufacture, purchase and use of hydrogen fuel cells. It also seeks to promote the use and development of biodiesel, ethanol, hydrogen and other renewable fuels.

H. California

Following a tumultuous two-year period of testing customer choice in retail markets, in 2003 the CPUC ordered the state's investor owned utilities to resume planning and procuring resources to meet consumers' electric load. The Long-Term Procurement Planning process (LTPP) is one part of overall resource planning, which is being coordinated and integrated with previously separate processes for Community Choice Aggregation, Demand Response, Distributed Generation, Energy Efficiency, Qualified Facilities, Renewable Portfolio Standards (RPS), Transmission Assessment and Planning proceedings and Resource Adequacy requirements. Every two years, utilities are required to submit LTPPs detailing their projections of demand and lay out how they propose to meet that demand over a 10-year horizon.[49] Analysis underlying and presented in the plans must include sensitivity analyses for load growth as well as for gas and market prices,[50] and the proposed resource mix must meet the criterion of least cost – best fit.[51]

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[47] "2006 Florida Energy Act Summary" downloaded May 1, 2007. http://www.dep.state.fl.us/energy/energyact/files/EnergyAct_1-Pager.pdf.

[48] Review of 2006 Ten-Year Site Plans for Florida's Electric Utilities. Florida Public Service Commission. December 2006.

[49] Baldwin, Liz. Regulatory Assistance Project Electric Resource Long-range Planning Survey: California. May 20, 2005.

[50] Demand forecasts must include three levels of demand, with a high load forecast that is set at the 95th percentile. Scenario analysis of energy and gas costs is likewise to be evaluated at the 95th percentile. (CPUC, Ruling and Scoping Memo 37116 in Rulemaking 04-04-003. Jun 4, 2004).

[51] Baldwin, Liz, May 2005, op. cit.

In its Energy Action Plan (EAP), California set a goal of ensuring ample supply of reasonably-priced electrical resources without over-relying on a single fuel source. California has several policies that address fuel diversity, albeit indirectly. Its most direct attempt to promote fuel diversity is its "loading order" established in the EAP. Under the loading order, utilities are directed to prioritize demand-side and renewable resources in the planning process to account for the environmental externalities and regulatory risk associated with fossil fuels. The EAP established the following priority list[52]:

1. Energy efficiency and demand response
2. Renewable energy (including renewable DG)
3. Clean fossil-fueled DG and clean fossil-fueled central-station generation

The state and its utilities are meeting their goals for energy efficiency, suggesting that the planning process and loading order may have had some affect on procurement decisions. For example, SCE requested an additional $38 million for efficiency programs, to meet an anticipated energy shortfall. However, goals for demand response and renewables have been somewhat elusive, in part due to perceived increased risk of contract failure by renewables, as well as transmission development and cost recovery risks. In part to address these problems, the CPUC combined long-term RPS planning with the general procurement planning proceeding (R.04-04-003). Also, it directed utilities to identify and conduct contingency planning addressing impediments towards meeting the RPS.[53]

While the EAP emphasizes demand-side and renewable resources, it does not loose sight of the contribution conventional resources make to diversity of electric supply. The EAP acknowledged the need for capital investments to "augment existing facilities, replace aging infrastructure, and ensure that California's electrical supplies will meet current and future needs at reasonable prices and without over-reliance on a single fuel source." Ongoing proceedings confirm the need for investments in conventional power plants.[54]

Another policy targeting the overall fuel mix is the greenhouse gas (GHG) adder. California requires utilities to consider environmental factors, including the cost of future

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[52] State of California. *2003 Energy Action Plan*. May 8, 2003. http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF

The loading order originates in the 2003 Energy Action Plan, proposed by a joint subcommittee of the California Energy Commission, the CPUC, and another agency that is now defunct. These agencies approved the final plan, which required the State Energy Resources Conservation and Development Commission to conduct assessments to address public-interest energy strategies including "identification of policies that would permit fuller realization of the potential for energy efficiency, either through direct programmatic actions or facilitation of the market." The Energy Action Plan was required under SB 1389 (California SB 1389, Bowen. Signed Sep 14, 2002. Available at http://www.leginfo.ca.gov/pub/01-02//bill/sen/sb_1351-1400/sb_1389_bill_20020915_chaptered.html, accessed Jul 12 2006).

[53] U.S. EPA, op. cit.; Center for Resource Solutions Team, "Achieving a 33% Renewable Energy Target" Nov 1 2005. Prepared for the California Public Utilities Commission. Available at http://www.cpuc.ca.gov/word_pdf/misc/Achieving_33_Percent_RPS_Report.pdf, accessed Jul 12 2006.

[54] California PUC, Draft Decision of ALJ Brown: Opinion on New Generation and Long-Term Contract Proposals and Cost Allocation. Jun 20, 2006. Rulemaking 06-02-013

carbon reduction regulations, in their long-term planning and resource comparisons. Utilities are instructed to add $8 per ton of CO_2 to the cost of fossil-fired resources for planning purposes (i.e., the adder is not used in ratemaking) to reflect the cost of climate change to California and to incorporate some of these resources' financial, regulatory, and environmental risks into resource decisions.[55] The goal of this requirement is to reduce California's dependence on fuel sources that pose considerable and increasing environmental risks. The GHG adder, together with the loading order and the state's effort to fully integrate the RPS into the long-term resource planning process, address the state's goal of diversifying and balancing its fuel mix.

More recently, SB 1037 reaffirmed the importance of fuel diversity in procurement plans. Under SB 1037, utilities are required to include a plan for achieving appropriate increases in fuel-supply diversity, as well as diversity of ownership and contract duration. The utility must also demonstrate diversity in supply versus demand-side resources.[56]

[55] U.S. EPA. *Clean Energy-Environment Guide to Action: Policies, Best Practices, and Action Steps for States*, April 2006. Available at http://epa.gov/cleanenergy/stateandlocal/guidetoaction.htm.

[56] California SB 1037, signed Sep 29, 2005. http://info.sen.ca.gov/pub/bill/sen/sb_1001-1050/sb_1037_bill_20050929_chaptered.html