Schwartz, Seth. Coal and the Kentucky Economy. November, 1985 (for KCA, KY Energy Cabinet).

Developed a profile of industry expenditures.

Used the profile to determine what the industry spent on all taxes. Used federal personal income data. States that "(S)ales, income, motor fuels, vehicles, and property tax receipts are proportional to state economic activity, which can be measured by personal income." Estimates that the coal industry accounted for 14% of personal income in the goods-producing industries. Concludes that, "(I)f personal income in non-goods-producing industries is proportionally related, it would seem reasonable to assume that the coal industry was responsible for receipts approaching 14% of sales, income, motor fuels, vehicles, and property taxes, as well as direct payments of severance and license taxes." (p. 34).

Concludes from these assumptions that in FY 1984, the coal industry was responsible for about $570 million of the state's total revenue of $3,041 million (18.7 percent) in the General and Transportation Funds."

Does not show personal income tax estimate. Does show total KY individual income tax revenues in FY 1984 as $710.4 million. If one assumes, as above, that the coal industry accounted for 14% of all the list of taxes, it might be concluded that the coal industry accounted for 14% of total KY personal income tax, or $99.5 million. It is not clear whether Schwartz means 14% of the bundle of taxes or 14% of each tax. However, Schwartz's separate calculation of corporate income tax of $7.9 million suggests that he is here referring to the basket of taxes. (see sheet re Corporate Income Tax).

NOTE:

(1) It appears that the figures are tax revenues resulting from the total economic activity resulting from coal mining in KY. The $570 million appears to be all taxes including the direct payments of severance and license taxes.

(2) This study does differentiate between state and federal taxes. The Haywood study, above did not differentiate.

Moore Economics. The Economic Contributions of the Mining Industry in 2005. January, 2007. (for National Mining Association).

Table 14 shows state/local personal income tax in KY "generated by the coal mining industry" as $130 million in 2005. This appears to be total state/local personal income taxes from total earnings of $1,261 million direct and $1,419 million in-state indirect. (NOTE) the direct earnings figure seems to be pretty accurate. The study shows 23,100 miners in 2005. In 2004, average wages were $50,544. Multiplying 23,100 times $50,544 = $1,168 million. In 2006, average earnings were $58,568. The average of 2004 average earnings and 2006 average earnings is $54,556. Multiplying $54,556 times 23,100 miners yields $1,260 million. The calculation for 2006 is 17,669 miners times $58,568 = $1,035 million. All of these figures are state data found in Coal Facts. (2006 data page attached).

Value of Product

Baldwin, Haywood for GOEP/KCA Coal Facts. 2007

Shows as $4.47 billion. Source of figure is severance tax data from Revenue Cabinet. This is published in Coal Facts. The latest figures are on the Coal Facts page attached to summary sheet titled **Coal Severance Tax**.

Makes point that coal sales brought more than $3.50 billion into KY. (The number of states should be 28; the number of foreign countries should be 4. These corrections will be made in the 2008-2009 Coal Facts, under preparation.)

Shows that total economic activity in KY resulting from coal production was $9.70 billion. The distribution of this by type of economic activity is shown on p. 2.

Straus, Thompson, Haywood. CBER. August, 1996. ("In part an update of the 1985 study done by Seth Schwartz, Energy Ventures Analysis"). (See Schwartz, below). Also says that the methodology for estimating taxes other than severance tax in this 1996 study was from Haywood, "Estimating the Economic Impact of Reduced Production of Western Kentucky Coal. CBER., 1991

Shows as $3.39 billion. Same source as above.

Shows that total economic activity in KY resulting from coal production was $8.97 billion. Provides a great deal of information about how this activity was distributed and the sectors benefiting.

Schwartz, Seth. Coal and the Kentucky Economy. November, 1985 (for KCA, KY Energy Cabinet).

Shows as $3.8 billion. Does not show indirect economic activity resulting from coal production.

Provides great deal of information about the percentage distribution of the receipts. Makes point that most stays in KY; about half goes directly to miners.

Moore Economics. The Economic Contributions of the Mining Industry in 2005. January, 2007. (for National Mining Association).

Shows direct receipts as $4.750 billion. Indirect as $5.370 billion. Shows that, of the indirect, $5.140 is in-state. Table, p. 56.

Corporate Income Tax

Baldwin, Haywood for GOEP/KCA Coal Facts. 2007

Shows total estimated KY tax revenues due to coal mining of $593.1 million. This is total economic activity resulting from coal mining of $9.70 billion.

Does not break out corporate income tax.

Straus, Thompson, Haywood. CBER. August, 1996. ("In part an update of the 1985 study done by Seth Schwartz, Energy Ventures Analysis"). (See Schwartz, below). Also says that the methodology for estimating taxes other than severance tax in this 1996 study was from Haywood, "Estimating the Economic Impact of Reduced Production of Western Kentucky Coal. CBER., 1991

Estimates total tax revenue resulting from coal mining as $544.0 million. This is tax revenues from total economic activity resulting from coal mining. (pp. 9-10)

Estimated total taxes directly paid by the mining industry as $255 million. This includes local, state, and federal. Does not break out amount paid in state taxes. (States that this expenditure, and others, "was estimated using a coal industry expenditure profile developed with help from industry experts. Where this profile was sufficiently detailed, it was used directly. Where more detail was needed, the categories of expenditure information provided by industry experts were disaggregated to more detail categories using proportions from the 1987 US Department of Commerce benchmark use table." (see p. 2 for explanation of the profile methodology and of methodology for obtaining more detail when needed.) Does not break this total $255 million into types of taxes paid, e.g., corporate income, license, sales, etc.

Did not use federal government statistics for the coal mining industry, because these include the Western US coal mining industry which differs greatly from the KY industry.

Shows "Corporate Income Tax and Other" as $69.1 million.

Does show severance tax for FY 1994 = $179.6 million.

NOTES:

(1) We (GOEP) could get data from industry for updating the expenditure profile.

Schwartz, Seth. Coal and the Kentucky Economy. November, 1985 (for KCA, KY Energy Cabinet).

Developed a profile of industry expenditures.

Employment / Wages by County

Coal County Employment and Wages, 2006

County[1]	Direct Mining Employment	% of Labor Force	Miners as % of Total Employed	Mining Wages	% of Total County Wages	Average Weekly Mining Earnings[3]
Eastern Kentucky						
Bell	1,038	10.7	11.6	$46,509,267	18.0	$861.67
Boyd	146	0.6	0.7	$12,545,464	1.3	$1,652.46
Breathitt	175	3.1	3.3	$11,860,343	12.4	$1,303.33
Carter	19	0.1	0.1	$817,696	0.5	$827.63
Clay	76	1.1	1.2	$3,613,721	3.6	$914.40
Floyd	986	6.5	6.9	$49,840,588	13.0	$972.08
Harlan	1,318	12.9	14.0	$80,624,789	30.9	$1,176.39
Johnson	158	1.6	1.8	$6,684,425	4.1	$813.59
Knott	1,408	21.4	23.0	$90,009,846	60.0	$1,229.37
Knox	52	0.4	0.5	$1,783,412	0.8	$659.55
Laurel	319	1.2	1.3	$18,142,538	2.8	$1,093.71
Lawrence	50	0.9	0.9	$1,959,136	2.1	$753.51
Leslie	532	14.3	15.7	$36,259,487	44.7	$1,310.71
Letcher	1,262	13.8	14.9	$65,135,393	31.8	$992.55
Magoffin	59	1.4	1.5	$1,965,406	3.3	$640.61
Martin	617	17.0	18.4	$33,589,519	40.1	$1,046.92
Perry	1,746	15.2	16.3	$106,981,132	23.5	$1,178.31
Pike	4,305	17.1	18.2	$250,825,423	30.5	$1,120.46
Whitley	47	0.3	0.3	$1,987,273	0.6	$813.12
Subtotal	14,313			$821,134,858		$1,103.27
EKY Total[2]	**14,433**			**$826,518,289**		**$1,101.27**
Fayette & Jefferson Counties	Note: The direct mining employment classification does not include most of the administrative/professional employees of coal companies located in these Kentucky metropolitan areas and does not include any private services or indirect employment.					
Western Kentucky						
Daviess	6	0.1	0.1	$423,584	0.1	$1,357.64
Henderson	290	1.3	1.3	$22,570,615	3.4	$1,496.73
Hopkins	1,188	5.1	5.4	$82,819,340	13.8	$1,340.64
Muhlenberg	579	4.5	4.9	$37,633,835	15.4	$1,249.96
Union	576	8.0	8.5	$37,044,556	22.3	$1,236.80
Webster	220	3.3	3.4	$12,215,970	12.3	$1,067.83
Subtotal	2,859			$192,707,900		$1,296.23
WKY Total[2]	**2,983**			**$197,429,630**		**$1,272.79**
State Total[2]	**17,669**			**$1,034,834,951**		**$1,126.30**

1 Counties with less than three employers or one employer with 80% of the total county miner workforce were withheld to avoid disclosure of individual company data. These counties are as follows: Boyle, Clark, Elliott, Fayette, Greenup, Hancock, Jackson, Jefferson, Lee, McCreary, McLean, Mason, Ohio & Pulaski. It is suspected that multi-county mining employment attributes to some counties being under reported and others being over reported.

2 Columns do not add to the EKY & WKY totals due to withheld data and do not equal state totals due to county of employment being reported outside of coal field.

3 Variation in average weekly mining income affected greatly by hours worked per week as well as hourly wage rate.

Values and methodologies used in this table may not be consistent with LGEDF regulations (page 15). Do not use these values for LGEDF estimates.

Coal Deliveries — State to State

* Total receipts by all consuming sectors.

Kentucky shipped coal to thirty (30) states.		Kentucky received coal from eleven (11) states	
Destination State	Total tons	Origin State	Total tons
Alabama	3,987,807	Alabama	970
		Colorado	2,338,762
Arkansas	55,710		
Delaware	184,268		
Florida	13,033,227		
Georgia	18,200,791		
Illinois	373,470	Illinois	403,289
Indiana	1,371,160	Indiana	1,582,967
Iowa	316,123		
Kansas	7,471		
Kentucky	24,955,953	Kentucky	
		East	7,433,149
		West	17,522,804
Louisiana	26,609		
Maryland	1,660,873		
Massachusetts	10,518		
Michigan	5,623,923		
Minnesota	110,548		
Mississippi	1,256,129		
Missouri	57,383		
New Jersey	13,784		
New York	113,290		
North Carolina	10,000,957		
North Dakota	11,639		
Ohio	7,997,089	Ohio	1,466,991
Oklahoma	1,049		
Pennsylvania	186,266	Pennsylvania	8,137
South Carolina	14,092,012		
Tennessee	8,287,472	Tennessee	139,870
Utah	190		
Virginia	5,233,634	Virginia	16,385
West Virginia	1,198,989	West Virginia	9,288,174
Wisconsin	736,911		
		Wyoming	3,721,170
TOTALS	**119,105,245**		**43,922,668**

***** Kentucky distributed a total of 121,781,745 tons of coal in 2006.**
79.5% of Kentucky coal is shipped out of state
20.5% of Kentucky coal remains in state.

* All consuming sectors include Electricity generation, coke plants, Industrial plants, Residential & Commercial.
** Does not include export shipments.
*** Includes 2,676,500 tons of coal that was exported.

Source: U.S. DOE—Energy Information Administration, Coal Industry Annual 2006.

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Electric Utility Week

February 4, 2008

Constellation to sue Maryland over 1999 restructuring; governor, others vow fight

Constellation Energy Group said last week it would sue Maryland in federal court to enforce its rights under an industry restructuring agreement it signed with state officials in 1999. Governor Martin O'Malley and state legislators vowed to fight back.

Constellation last Wednesday also notified the Maryland Attorney General that it will terminate their 14-month-old litigation agreement not to sue each other over $386 million the company said was unconstitutionally taken from it by the state Legislature in 2006.

Constellation will ask the federal court to uphold the 1999 restructuring settlement as valid and to declare that the $386 million the company agreed to pay during merger negotiations with FPL was unlawfully taken from it because the merger never happened.

"We have reluctantly concluded that we have no choice but to file a federal court action to enforce our rights under a nearly decade-old settlement, which has been upheld twice by Maryland courts," said Mayo Shattuck, Constellation's chairman,

(continued on page 30)

Government puts the kibosh on FutureGen, proposes smaller projects to capture carbon

FutureGen as envisioned by its industry backers no longer exists, skewered last week when an already reluctant Department of Energy definitively withdrew its support from the plan to build a 275-MW coal-fired power plant with carbon capture and sequestration facilities.

Instead, the department said, it would help to fund several smaller carbon capture and sequestration facilities across the US.

While the escalating cost of the facility was the main driver behind DOE's pullout, the real deal killer was the inability of the two sides — the FutureGen Industrial Alliance and DOE — to agree on who would pay for what, and how much.

When first proposed in 2003, the facility was estimated to cost $950 million but it grew to $1.8 billion. DOE was to pick up 74% and the 13-member alliance 26%. The members include American Electric Power, Southern Company, PPL Corp., Luminant and E.ON US, among other energy companies.

"The signing of the cooperative agreement in March is what brought our attention to the costs," Deputy Secretary of Energy

(continued on page 7)

Coal and emissions top S&P's issues list, with uncertainties cited by Moody's, Deloitte

In a trifecta of cautionary notes on the uncertainty facing the power industry, Moody's Investors Service, Standard & Poor's and Deloitte said the coming years will bring significant challenges on several fronts.

The possibility of carbon-control legislation, shrinking reserve margins, increasing demand and escalating costs in fuels, material and labor could bring legislative and regulatory backlashes that make life difficult for utilities and their parent companies, the three firms said.

The next 12 to 18 months may see evenly balanced ratings activity between positive and negative actions, but "there are significant negative trends developing over the longer-term horizon," Moody's said in its report on the electric utility sector. The overall business and operating risks facing utilities are rising at an increasingly fast pace while balance sheets remain relatively stable, which could result in credit quality deterioration, Moody's said.

As if the news headlines, power plant rejections and congressional debate have not been enough to show utilities that the fate of coal-fired generation and controlling greenhouse

(continued on page 27)

INSIDE THIS ISSUE

Fourth-quarter 2007 earnings coverage, pages 17-27

(continued from page 4)

and running through April 2015.

Manitoba Hydro, owned by the provincial government, already has a series of cross-border interties into the US, enabling it to sell power to more than 50 utilities and marketers.

Much of the power exported is sold into the market of the Midwest Independent Transmission System Operator, which includes Manitoba. It also sells power into Ontario.

Meanwhile, the provincial government is launching a new power export industry, but this time it is wind power. The goal is for independent developers to build 1,000 MW of wind within 10 years. In a request for proposals last April for 300 MW of wind, it received 84 proposals for more than 10,000 MW. In December it shortlisted 10 projects. Manitoba Hydro expects to issue three more wind solicitations of 200 MW each between 2013 and 2018.

— *Harriet King*

Government puts the kibosh on FutureGen ... from page 1

Clay Sell told reporters in a press briefing on January 30. "That was the first time that the senior leaders of the project noticed that the baseline had gone from $950 million to $1.8 bill."

"I have seen this movie before, the baseline increasing that early in the project. I knew this would not end well," he added.

The cooperative agreement gives the alliance the ability to pull out of the project if it objects to the conditions that DOE wants to incorporate into the Record of Decision. "If the alliance finds the conditions and requirements to be unacceptable, the alliance reserves the right to withdraw from the project upon written notice to DOE," the agreement says.

DOE said last week it would not be issuing the ROD for the project.

Senior leaders in the alliance and DOE held several meetings in the hopes of working out a new cost structure, according to Sell. On January 14, alliance spokesman Lawrence Pacheco said in an interview that the group sent a letter to DOE outlining its ideas for a new cost structure. He said the alliance offered to increase its share of the cost of the project, but he would not say by how much. He also said the alliance offered to repay DOE for its percentage of the inflation costs it incurs over $1.8 billion.

According to Sell, DOE wanted to split the cost 50-50 for anything over the $1.8 billion price tag which the alliance agreed to. But the alliance also proposed borrowing against the plant assets to fund its portion, roughly $350 million. That was unacceptable to DOE, he said

"The alliance's plan would leave DOE without a security net," Sell said.

Secretary of Energy Samuel Bodman described the new plan as an "All around better deal in my judgment for America."

Alliance, DOE differ on offers

In what it called a "DOE Proposal Fact Check" released on January 31, the alliance admitted DOE's share of the cost had increased from its original $800 million in 2003, to the current share of $1.1 billion. But that amount, according to the alliance, was reduced by the contributions from international participants — Australia, China, India, Japan, and South Korea — which each paid $10 million to join.

The fact sheet makes no mention of the alliance borrowing against the plant's assets to fund the project. "DOE's notion that they [alliance members] might default [on payments] is nonsense," the fact sheet said.

The alliance says DOE wants "ironclad funding guarantees from the industry" yet provides no guarantees of its own because funding for the project is made available through appropriations, which can change from year to year.

In President Bush's 2008 budget, FutureGen received just $75 million of the requested $108 million.

DOE officials brushed off all accusations that it was abandoning the project and that it was jeopardizing the future of public and private partnerships. DOE said it was standing behind the "objectives" of FutureGen to advance clean coal and carbon capture and sequestration technology.

DOE eyes projects at several sites

The FutureGen plant was slated to come online in 2012, the change in plans delays commercialization of CCS technology by almost four years. Under DOE's plan these new plants would not be operational until 2015-2016.

A DOE request for information issued January 30 seeks comments on the feasibility of funding several carbon capture and sequestration projects at integrated gasification combined-cycle facilities of at least 300 MW. Comments on the RFI must be received by March 3.

Right now there are only two commercial-scale IGCC plants operating in the US. Both were developed through public/private partnerships with DOE: Tampa Electric's 260-MW Polk Power Station in Polk County, Florida, which began operation in 1997, and the 262-MW Wabash River Coal Gasification Repowering Project in Terre Haute, Indiana, which began operating in 1995.

DOE also intends to issue a funding opportunity announcement in the second quarter of this year. Under the new plan, DOE will only pay for the costs associated with adding CCS technology onto a facility. To be eligible for funding, facilities will need to capture about 90% of the CO_2; 99% of the sulfur dioxide; 0.05 lb/million Btu of the nitrogen oxides; 0.0005 lb/million Btu of the particulate matter and 90% of the mercury emissions. During the demonstration period the plant will store at least one million metric tons of CO_2 per year in a saline storage formation, the RFI says.

According to the department, Mattoon, Illinois, the site the alliance chose in December, will be eligible to host one of the new projects, as will Tuscola, Illinois, and both Texas sites, Jewett and Odessa, that were in the late rounds of running for selection.

To help pay for the new venture, Bodman announced last week that DOE's Office of Fossil Energy's budget request was boosted to $648 million, which includes $407 million for coal research and $241 million for carbon capture and sequestration.

Calls to FutureGen Industrial Alliance, American Electric

879 GW, or 10% of global capacity.

When it comes to reaching a low-carbon future, "public policymaking has to be codified so that the industry knows where to go," Herman Schopman, president and CEO of Suez Energy Generation North America, said last week at a Department of Commerce conference in Washington. That a trio of banks has codified lending practices for coal-fired generation projects (*see story, page 1*) is a step in the right direction, but the federal government has not provided much certainty to utilities or the investment community, John Cavalier, vice chairman at Credit Suisse, said at the same event.

The policy certainty of other countries when it comes to renewable energy has led to huge manufacturing gains and an economic stimulus from clean energy technologies, including growth in solar power in Germany, Italy and Spain, speakers said. In the US, however, "we've had a dearth of leadership on global warming" policy, and the country's manufacturing jobs have declined because of it, said Rhone Resch, president of the Solar Energy Industries Association.

Manufacturing is not dead in the US, and a revival of the nuclear industry and planned additions from wind generation and other renewable technologies will foster growth in US markets, other speakers said. Clean energy technologies represent a "huge opportunity" for economic growth, and "we believe that the US will lead the way" with new investments, said Commerce Secretary Carlos Gutierrez.

The timing of any carbon control legislation from Congress and the flexibility in being able to comply with such a mandate will be key factors in whether utilities can meet any mandate without significant impacts such as increased strains on natural gas supply and demand, said Thomas Kuhn, president and CEO of the Edison Electric Institute.

The most prominent bill to date, by Senators Joe Lieberman, Independent Democrat-Connecticut, and John Warner, Republican-Virginia, sets annual caps on greenhouse gas emissions or carbon dioxide equivalents starting in 2012, which is not far off, speakers said. Not putting emission reduction targets far enough in the future could affect natural gas usage and prices. "It's easy for a politician to pick out a timetable," but if that schedule is off, there can be serious economic consequences, Kuhn said.

Without enough flexibility — a carbon cap-and-trade system or enough time to meet a control mandate — coal-fired generation could become uneconomic to build and natural gas prices could soar, added Schopman. A price cap or "safety valve" of $20 or $30/metric ton would enable more economic stability for adding coal-fired generation and ensure that there are not stranded generation assets in the future, he said.

The 2012 time frame in the Lieberman-Warner bill is not likely to change, said John Shanahan, minority counsel on the Senate Environment and Public Works Committee. Using natural gas as a "bridge fuel" until more renewable resources and new nuclear power plants are added presents real challenges for the energy industry in terms of energy security and price volatility in global markets, Shanahan said.

— *Jeff Barber, Tom Tiernan*

FutureGen backers thrash DOE for axing the project and pledge to keep pursuing it

Lawmakers and industry supportive of the rejected FutureGen project last week pelted Energy Secretary Samuel Bodman with criticism for scuttling the coal-fired power plant and vowed to fight to keep it in Illinois.

The most public moments of Bodman's gauntlet of criticism came during two congressional hearings on the Department of Energy's budget proposal, where senators and representatives confronted him about why he pulled support for the $1.8 billion advanced coal-fired power plant with carbon capture and storage.

DOE decided last month that instead of collaborating on a single plant, the department would partner with utilities to help them build carbon capture and storage capabilities onto integrated gasification combined-cycle plants already on the drawing board.

"Illinois worked hard only to be crushed," said Illinois Republican Representative John Shimkus at a hearing of the House Energy and Commerce Committee. He cited a November 30 letter from Bodman that said DOE would approve the $1.3 billion in federal funding by the end of the year. The nearly $460 million remaining would come from the industry consortium known as the FutureGen Industrial Alliance.

"I signed the letter because I believed we had a deal with the Alliance," Bodman said. Shimkus angrily fired back, "You guys are far, far from ever coming to a deal. I've seen Democrats and Republicans closer than DOE and the alliance [will ever be.]"

Senators in the Energy and Natural Resources Committee focused more of their comments on DOE's decision to end the project after touting it for five years. Chairman Jeff Bingaman, Democrat of New Mexico, said, "while the FutureGen project may certainly have its flaws, the question is whether we have something better to take its place or not."

Bodman responded that he would like to have three or four projects under the newly restructured FutureGen. He added that he was "afraid" Congress would stop funding it after several years given escalating costs. "I think the cost is going to go much higher. ... That is the reason I felt it didn't make sense to go forward," he said.

In an interview, FutureGen Industrial Alliance CEO Mike Mudd criticized the department for not discussing its decision to pull support before doing it. "There was no discussion between DOE and the alliance between November 30 and his decision to not issue the [record of decision]," he said after the alliance board met in the rejected site of Mattoon, Illinois, for two days.

Some of Illinois' most prominent politicians also unleashed scathing remarks against DOE. Governor Rod Blagojevich, a Democrat, sent a letter to House Energy and Commerce Committee Chairman John Dingell, Michigan Democrat, asking him to join the fight to keep the project in Illinois.

DOE's change of plan, Blagojevich said, "raises many serious questions about US DOE, among them: How can business and international partners rely on the word [of] the US government if the US DOE abandons a process that it started and to which it has been committed for almost five years?"

Earlier in the week, Illinois Senator Dick Durbin, a

Democrat, and Representative Tim Johnson, a Republican, wrote to Bodman citing disparaging remarks about Mattoon from Under Secretary Clarence "Bud" Albright. The community is in Johnson's congressional district and the project was expected to have brought hundreds of jobs.

"According to a number of confirmed accounts, during a recent phone conference with stakeholders in the FutureGen project, Mr. Albright asserted that the US Department of Energy was not interested in 'building Disneyland in some swamp in Illinois,'" the members of Congress wrote.

"Mr. Albright's statement is insulting to the people of Mattoon and central Illinois and all of those who worked so diligently on the FutureGen project," the lawmakers said. "The nature of these remarks should cause you to seriously reconsider whether or not this man can objectively serve in a post as sensitive as under secretary of energy."

Albright was remorseful in a statement released immediately after the letter was sent to DOE. "As I said at the time, I regret the comment I made," he said. "It does not reflect my view then or now, nor does it reflect the view of the department, or of Secretary Bodman."

The alliance and Bodman also sparred about the cost of the project. In a letter to the *St. Louis Post-Dispatch*, Bodman wrote that when the project was announced in 2003, it was to have cost $950 million. "The project's estimated cost has almost doubled and innovations in technology and changes in the marketplace have created other viable options for demonstrating carbon capture and storage on a commercial scale. That diminished the need for a demonstration project."

The alliance issued a statement disagreeing with Bodman's "assertion that IGCC technology is so mature that testing it in integration with carbon capture and sequestration is unnecessary." The group said DOE's share had not doubled, but had risen from an original $800 million to $1.1 billion.

— *Alexander Duncan*

Six co-ops get $31 million in clean-bonds funding for renewables work in five states

Rural electric cooperatives in five states will get nearly $31 million in funding through the federal Clean Renewable Energy Bonds program for development of renewable power.

The National Rural Utilities Cooperative Finance Corp. said the money made available through the Clean Renewable Energy Bonds program will be used by six cooperatives to complete 27 projects in Arizona, Indiana, Kentucky, Minnesota and Vermont to generate electricity from solar, wind and landfill gas and other approved renewable resources.

The approved projects range in capacity from 20 kW to 4 MW for a total of 16.8 MW from the $31 million CREBs issuance. The bond allocations vary from $45,000 to $4 million per project.

The finance corporation last week said it planned to issue additional CREBs by mid-year. Based in Herndon, Virginia, the corporation serves as an aggregator to allocate CREBs to co-ops. The Internal Revenue Service has already approved more than 65 project applications filed by the corporation on behalf of its members.

The US Treasury authorized $1.2 billion in CREBs through December 31, with $450 million reserved for co-ops. Of that amount, the corporation known as NRUCFC received $314 million to issue as bonds to help rural co-ops finance renewable projects. The $30.5 million bond was the first issued by NRUCFC. It was purchased by Allstate.

"The nation's exponential increase in the demand for energy, which is expected to grow by 39% by 2030, along with the push to reduce greenhouse gas emissions, only enhances the value of CREBs financing," said James Andrew, administrator of the Rural Utilities Service at the Department of Agriculture. "Given that rural electric cooperatives serve 12% of the US population, their investment in renewable energy is very important."

Sulphur Springs Valley Electric Cooperative in Willcox, Arizona, got $11.5 million in bonds to finance solar photovoltaic systems at 40 schools. East Kentucky Power Cooperative, in Winchester, Kentucky, received a CREBs loan of $8.6 million to fund four landfill gas development projects that will generate between 1.6 and 4 MW each.

Other cooperatives receiving CREBs loans this go-round were the Hoosier Energy Rural Electric Cooperative in Bloomington, Indiana; Federated Rural Electric Association of Jackson, Minnesota; Nobles Cooperative Electric of Worthington, Minnesota, and Washington Electric Cooperative of East Montpelier, Vermont.

Richard Larochelle, senior vice president at NRUCFC, said in an interview that the process of awarding projects is "granular" and involves due diligence involving third-party certification of engineering to ensure projects meet the federal program's requirements and consider regulatory and financing needs.

"We look for projects that make sense for cooperatives," he said. "We believe the projects [awarded CREB money] are going to go forward and produce renewable energy."

Created by the Energy Policy Act of 2005, the CREB program gives federal tax credits to buyers of the bonds that in turn provide low-cost capital to co-ops, municipal utilities and Indian tribes for development of generation fueled by renewable resources. The program was devised to give these entities an incentive equal to the production and investment tax credits given to investor-owned utilities for development of wind, solar, biomass, geothermal and incremental hydro.

The US Senate tried to attach provisions to a national economic stimulus package that would add $450 million to CREBs in 2009 but the legislation failed in a vote last week. Proponents expect a similar provision to be considered on Capitol Hill later this year as part of a package to extend the renewable production and investment tax credits for utilities that expire in December.

— *Cathy Cash*

Otter Tail, Minnkota team to build line to carry 400 MW from planned wind farms

Otter Tail Power and Minnkota Power have teamed to build a 60-mile transmission line in North Dakota that would carry 400 MW from new wind farms that developers have proposed.

(continued on page 6)

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278.010 Definitions for KRS 278.010 to 278.450, 278.541 to 278.544, 278.546 to 278.5462, and 278.990.

As used in KRS 278.010 to 278.450, 278.541 to 278.544, 278.546 to 278.5462, and 278.990, unless the context otherwise requires:

(1) "Corporation" includes private, quasipublic, and public corporations, and all boards, agencies, and instrumentalities thereof, associations, joint-stock companies, and business trusts;

(2) "Person" includes natural persons, partnerships, corporations, and two (2) or more persons having a joint or common interest;

(3) "Utility" means any person except, for purposes of paragraphs (a), (b), (c), (d), and (f) of this subsection, a city, who owns, controls, operates, or manages any facility used or to be used for or in connection with:

   (a) The generation, production, transmission, or distribution of electricity to or for the public, for compensation, for lights, heat, power, or other uses;

   (b) The production, manufacture, storage, distribution, sale, or furnishing of natural or manufactured gas, or a mixture of same, to or for the public, for compensation, for light, heat, power, or other uses;

   (c) The transporting or conveying of gas, crude oil, or other fluid substance by pipeline to or for the public, for compensation;

   (d) The diverting, developing, pumping, impounding, distributing, or furnishing of water to or for the public, for compensation;

   (e) The transmission or conveyance over wire, in air, or otherwise, of any message by telephone or telegraph for the public, for compensation; or

   (f) The collection, transmission, or treatment of sewage for the public, for compensation, if the facility is a subdivision collection, transmission, or treatment facility plant that is affixed to real property and is located in a county containing a city of the first class or is a sewage collection, transmission, or treatment facility that is affixed to real property, that is located in any other county, and that is not subject to regulation by a metropolitan sewer district or any sanitation district created pursuant to KRS Chapter 220;

(4) "Retail electric supplier" means any person, firm, corporation, association, or cooperative corporation, excluding municipal corporations, engaged in the furnishing of retail electric service;

(5) "Certified territory" shall mean the areas as certified by and pursuant to KRS 278.017;

(6) "Existing distribution line" shall mean an electric line which on June 16, 1972, is being or has been substantially used to supply retail electric service and includes all lines from the distribution substation to the electric consuming facility but does not include any transmission facilities used primarily to transfer energy in bulk;

FN 18

807 KAR 5:001. Rules of procedure.

RELATES TO: KRS Chapter 278
STATUTORY AUTHORITY: KRS 278.310(2)
NECESSITY, FUNCTION, AND CONFORMITY: KRS 278.310(2) provides that all hearings and investigations before the commission or any commissioner shall be governed by rules adopted by the commission. This administrative regulation prescribes requirements with respect to formal and informal proceedings before the commission.

Section 1. General Offices and Hearings. (1) The commission will be in continuous session for the performance of administrative duties.
(2) Meetings of the commission for the consideration of all matters requiring formal hearings will be held on such days, at such hours and at such places as the commission may designate.
(3) Notice of hearing will be given by the secretary to parties to proceedings before the commission, except when a hearing is not concluded on the day appointed therefor and verbal announcement is made by the presiding commissioner or hearing examiner of an adjourned date. Verbal announcements so made shall be deemed due notice of continued hearing.

Section 2. Secretary to Furnish Information. (1) Upon request, the secretary will advise any party as to the form of a petition, complaint, answer, application or other paper desired to be filed; and he will make available from the commission's files, upon request, any document or record pertinent to any matter before the commission.
(2) The secretary may reject for filing any document which on its face does not comply with the rules and administrative regulations of the commission.

Section 3. General Matters Pertaining to All Formal Proceedings. (1) Address of the commission. All communications should be addressed to "Public Service Commission, Frankfort, Kentucky."
(2) Case numbers and styles. Each matter coming formally before the commission will be known as a case and will receive a number and style, descriptive of the subject matter. Such number and style shall be placed on all subsequent papers in such case.
(3) Form of papers filed. All pleadings and applications filed with the commission in formal proceedings shall be printed or typewritten on one (1) side of the paper only, and typewriting shall be double spaced.
(4) Signing of pleadings. Every pleading of a party represented by an attorney shall be signed by at least one (1) attorney of record in his individual name and shall state his address. Except when otherwise specifically provided by statute, pleadings need not be verified or accompanied by affidavit.
(5) Amendment. At its discretion, the commission may allow any complaint, application, answer or other paper to be amended or corrected or any omission supplied therein.
(6) Witnesses and subpoenas.
(a) Upon the application of any party to a proceeding, subpoenas requiring the attendance of witnesses for the purpose of taking testimony may be signed and issued by a member of the commission.
(b) Subpoenas for the production of books, accounts, papers or records (unless directed to issue by the commission on its own authority) will be issued only at the discretion of the commission, or any commissioner, upon application in writing, stating as nearly as possible the books, accounts, papers or records desired to be produced.
(7) Service of process. When any party has appeared by attorney, service upon such attorney will be deemed proper service upon the party.
(8) Intervention and parties. In any formal proceeding, any person who wishes to become a party to a proceeding before the commission may by timely motion request that he be granted leave to intervene. Such motion shall include his name and address and the name and address of any party he represents and in what capacity he is employed by such party.
(a) Each person granted leave to intervene shall be considered as making a limited intervention unless he submits to the secretary a written request for full intervention. A person making only a limited intervention shall be entitled to the full rights of a party at the hearing in which he appears and shall be served with the commission's order, but he shall not be served with filed testimony, exhibits, pleadings, correspondence and all other documents submitted by parties. A person making a limited appearance will not be certified as a party for the purposes of receiving service of any petition for rehearing or petition for judicial review.
(b) If a person granted leave to intervene desires to be served with filed testimony, exhibits, pleadings, correspondence and all other documents submitted by parties, and to be certified as a party for the purposes of receiving service of any petition for rehearing or petition for judicial review, he shall submit in writing to the secretary a request for full intervention, which shall specify his interest in the proceeding. If the commission determines that a person has a special interest in the proceeding which is not otherwise adequately represented or that full intervention by party is likely to present issues or to develop facts that assist the commission in fully considering the matter without unduly complicating or disrupting the proceedings, such person shall be granted full

agreement and any unwillingness to enter into a protective agreement shall be fully explained. Any party may respond to the petition within ten (10) days after it is filed with the commission. The commission shall determine if the petitioner is entitled to the material, and the manner and extent of the disclosure necessary to protect confidentiality.

(6) Requests for access to records pursuant to KRS 61.870-884. No time period prescribed in this section shall limit the right of any person to request access to commission records pursuant to KRS 61.870-884. Upon a request filed pursuant to KRS 61.870-884, the commission shall respond in accordance with the procedure prescribed in KRS 61.880.

(7) Procedure for request for access to confidential material. Any person denied access to records requested pursuant to KRS 61.870-884 or to material deemed confidential by the commission in accordance with the procedures set out in this section, may obtain this information only pursuant to KRS 61.870-884, and other applicable law.

(8) Use of confidential material during formal proceedings. Any material deemed confidential by the commission may be addressed and relied upon during a formal hearing by the following procedure:

(a) The person seeking to address the confidential material shall advise the commission prior to the use of such material.

(b) All persons other than commission employees not a party to a protective agreement related to the confidential material shall be excused from the hearing room during direct testimony and cross-examination directly related to confidential material.

(c) The court reporter shall produce a sealed transcript of that portion of the record directly related to the confidential material.

(9) Material granted confidentiality which later becomes publicly available or otherwise no longer warrants confidential treatment.

(a) The petitioner who sought confidential protection shall inform the commission in writing at any time when any material granted confidentiality becomes publicly available.

(b) If the commission becomes aware that material granted confidentiality is publicly available or otherwise no longer qualifies for confidential treatment, it shall by order so advise the petitioner who sought confidential protection, giving ten (10) days to respond. If the commission finds that material has been disclosed by someone other than the person who requested confidential treatment, in violation of a protective agreement or commission order, such information shall not be deemed or considered to be publicly available and shall not be placed in the public record.

(c) The material shall not be placed in the public record for twenty (20) days following any order finding that the material no longer qualifies for confidential treatment to allow the petitioner to seek any remedy afforded by law.

Section 8. Applications. (1) Contents of application. All applications must be by petition in writing. The petition must set forth the full name and post office address of the applicant, and must contain fully the facts on which the application is based, with a request for the order, authorization, permission or certificate desired and a reference to the particular provision of law requiring or providing for same.

(2) Number of copies. At the time the original application is filed, ten (10) additional copies must also be filed, and where parties interested in the subject matter of the application are named therein, there shall be filed an additional copy for each named party and such other additional copies as may be required by the secretary.

(3) Articles of incorporation. If the applicant is a corporation, a certified copy of its articles of incorporation, and all amendments thereto, if any, shall be annexed to the application. If applicant's articles of incorporation and amendments thereto, if any, have already been filed with the commission in some prior proceeding, it will be sufficient if this fact is stated in the application and reference is made to the style and case number of the prior proceeding.

Section 9. Applications for Certificates of Public Convenience and Necessity. (1) Application to bid on a franchise pursuant to KRS 278.020(3). Upon application to the commission by the utility for a certificate of convenience and necessity authorizing applicant to bid on a franchise, license or permit offered by any governmental agency, the applicant shall submit with its application, the following:

(a) A copy of its articles of incorporation (see Section 8(3) of this administrative regulation).

(b) The name of the governmental agency offering the franchise.

(c) The type of franchise offered.

(d) A statement showing the need and demand for service. Should the applicant be successful in acquiring said franchise, license or permit, it shall file a copy thereof with the commission.

(2) New construction or extension. When application is made by the utility, person, firm, or corporation for a certificate that the present or future public convenience or necessity requires, or will require, the construction or extension of any plant, equipment, property or facility, the applicant, in addition to complying with Section 8 of this administrative regulation, shall submit the following data, either in the application or as exhibits attached thereto:

(a) The facts relied upon to show that the proposed new construction is or will be required by public convenience or necessity.

(b) Copies of franchises or permits, if any, from the proper public authority for the proposed new construction or extension, if not previously filed with the commission.

(c) A full description of the proposed location, route, or routes of the new construction or extension, including a description of the manner in which same will be constructed, and also the names of all public utilities, corporations, or persons with whom the proposed new construction or extension is likely to compete.

(d) Three (3) maps to suitable scale (preferably not more than two (2) miles per inch) showing the location or route of the proposed new construction or extension, as well as the location to scale of any like facilities owned by others located anywhere within the map area with adequate identification as to the ownership of such other facilities.

(e) The manner in detail in which it is proposed to finance the new construction or extension.

(f) An estimated cost of operation after the proposed facilities are completed.

(g) All other information necessary to afford the commission a complete understanding of the situation.

(3) Extensions in the ordinary course of business. No certificate of public convenience and necessity will be required for extensions that do not create wasteful duplication of plant, equipment, property or facilities, or conflict with the existing certificates or service of other utilities operating in the same area and under the jurisdiction of the commission that are in the general area in which the utility renders service or contiguous thereto, and that do not involve sufficient capital outlay to materially affect the existing financial condition of the utility involved, or will not result in increased charges to its customers.

(4) Renewal applications. Insofar as procedure is concerned, applications for a renewal of a certificate of convenience and necessity will be treated as an original application.

Section 10. Applications for General Adjustments in Existing Rates. (1) All applications requesting a general adjustment in existing rates shall be supported by:

(a) A twelve (12) month historical test period which may include adjustments for known and measurable changes; or

(b) A fully forecasted test period and shall include:

1. A statement of the reason the adjustment is required;

2. A statement that the utility's annual reports, including the annual report for the most recent calendar year, are on file with the commission in accordance with 807 KAR 5:006, Section 3(1);

3. If the utility is incorporated, a certified copy of the utility's articles of incorporation and all amendments thereto or out-of-state documents of similar import. If the utility's articles of incorporation and amendments have already been filed with the commission in a prior proceeding, the application may state this fact making reference to the style and case number of the prior proceeding;

4. If the utility is a limited partnership, a certified copy of the limited partnership agreement and all amendments thereto or out-of-state documents of similar import. If the utility's limited partnership agreement and amendments have already been filed with the commission in a prior proceeding, the application may state this fact making reference to the style and case number of the prior proceeding;

5. If the utility is incorporated or is a limited partnership, a certificate of good standing or certificate of authorization dated within sixty (60) days of the date the application is filed;

6. A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that such a certificate is not necessary;

7. The proposed tariff in a form which complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed;

8. The utility's proposed tariff changes, identified in compliance with 807 KAR 5:011, shown either by:

a. Providing the present and proposed tariffs in comparative form on the same sheet side by side or on facing sheets side by side; or

b. Providing a copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions; and

9. A statement that customer notice has been given in compliance with subsections (3) and (4) of this section with a copy of the notice.

10. For the purposes of this administrative regulation, an affiliate is an entity that:

a. Is wholly owned by a utility; or

b. In which a utility has a controlling interest; or

c. That wholly owns a utility; or

d. That has a controlling interest in a utility; or

e. That is under common control with the utility.

11. For the purposes of this administrative regulation, a utility, or other entity, shall be deemed to have a controlling interest in, or be under common control with, an entity or utility if it:

a. Directly or indirectly has the power to direct, or to cause the direction of, the management or policies of any entity; and

b. Exercises such power:

FN 20

278.285 Demand-side management plans -- Review and approval of proposed plans and mechanisms -- Assignment of costs -- Home energy assistance programs.

(1) The commission may determine the reasonableness of demand-side management plans proposed by any utility under its jurisdiction. Factors to be considered in this determination include, but are not limited to, the following:

   (a) The specific changes in customers' consumption patterns which a utility is attempting to influence;

   (b) The cost and benefit analysis and other justification for specific demand-side management programs and measures included in a utility's proposed plan;

   (c) A utility's proposal to recover in rates the full costs of demand-side management programs, any net revenues lost due to reduced sales resulting from demand-side management programs, and incentives designed to provide positive financial rewards to a utility to encourage implementation of cost-effective demand-side management programs;

   (d) Whether a utility's proposed demand-side management programs are consistent with its most recent long-range integrated resource plan;

   (e) Whether the plan results in any unreasonable prejudice or disadvantage to any class of customers;

   (f) The extent to which customer representatives and the Office of the Attorney General have been involved in developing the plan, including program design, cost recovery mechanisms, and financial incentives, and if involved, the amount of support for the plan by each participant, provided however, that unanimity among the participants developing the plan shall not be required for the commission to approve the plan; and

   (g) The extent to which the plan provides programs which are available, affordable, and useful to all customers.

(2) A proposed demand-side management mechanism including:

   (a) Recover the full costs of commission-approved demand-side management programs and revenues lost by implementing these programs;

   (b) Obtain incentives designed to provide financial rewards to the utility for implementing cost-effective demand-side management programs; or

   (c) Both of the actions specified

   may be reviewed and approved by the commission as part of a proceeding for approval of new rate schedules initiated pursuant to KRS 278.190 or in a separate proceeding initiated pursuant to this section which shall be limited to a review of demand-side management issues and related rate-recovery issues as set forth in subsection (1) of this section and in this subsection.

(3) The commission shall assign the cost of demand-side management programs only to the class or classes of customers which benefit from the programs. The commission shall allow individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs if the alternative

measures by these customers are not subsidized by other customer classes. Such individual industrial customers shall not be assigned the cost of demand-side management programs.

(4) Home energy assistance programs may be part of a demand-side management program. In considering a home energy assistance program, the commission shall only utilize the criteria set forth in subsections (1)(f) and (3) of this section.

Effective: June 21, 2001

History: Amended 2001 Ky. Acts ch. 11, sec. 2, effective June 21, 2001. -- Created 1994 Ky. Acts ch. 238, sec. 2, effective July 15, 1994.

278.183 Surcharge to recover costs of compliance with environmental requirements for coal combustion wastes and by-products -- Environmental compliance plan, review and adjustment.

(1) Notwithstanding any other provision of this chapter, effective January 1, 1993, a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal in accordance with the utility's compliance plan as designated in subsection (2) of this section. These costs shall include a reasonable return on construction and other capital expenditures and reasonable operating expenses for any plant, equipment, property, facility, or other action to be used to comply with applicable environmental requirements set forth in this section. Operating expenses include all costs of operating and maintaining environmental facilities, income taxes, property taxes, other applicable taxes, and depreciation expenses as these expenses relate to compliance with the environmental requirements set forth in this section.

(2) Recovery of costs pursuant to subsection (1) of this section that are not already included in existing rates shall be by environmental surcharge to existing rates imposed as a positive or negative adjustment to customer bills in the second month following the month in which costs are incurred. Each utility, before initially imposing an environmental surcharge pursuant to this subsection, shall thirty (30) days in advance file a notice of intent to file said plan and subsequently submit to the commission a plan, including any application required by KRS 278.020(1), for complying with the applicable environmental requirements set forth in subsection (1) of this section. The plan shall include the utility's testimony concerning a reasonable return on compliance-related capital expenditures and a tariff addition containing the terms and conditions of a proposed surcharge as applied to individual rate classes. Within six (6) months of submittal, the commission shall conduct a hearing to:

(a) Consider and approve the plan and rate surcharge if the commission finds the plan and rate surcharge reasonable and cost-effective for compliance with the applicable environmental requirements set forth in subsection (1) of this section;

(b) Establish a reasonable return on compliance-related capital expenditures; and

(c) Approve the application of the surcharge.

(3) The amount of the monthly environmental surcharge shall be filed with the commission ten (10) days before it is scheduled to go into effect, along with supporting data to justify the amount of the surcharge which shall include data and information as may be required by the commission. At six (6) month intervals, the commission shall review past operations of the environmental surcharge of each utility, and after hearing, as ordered, shall, by temporary adjustment in the surcharge, disallow any surcharge amounts found not just and reasonable and reconcile past surcharges with actual costs recoverable pursuant to subsection (1) of this section. Every two (2) years the commission shall review and evaluate past

operation of the surcharge, and after hearing, as ordered, shall disallow improper expenses, and to the extent appropriate, incorporate surcharge amounts found just and reasonable into the existing base rates of each utility.

(4) The commission may employ competent, qualified independent consultants to assist the commission in its review of the utility's plan of compliance as specified in subsection (2) of this section. The cost of any consultant shall be included in the surcharge approved by the commission.

(5) The commission shall retain all jurisdiction granted by this section and KRS 278.020 to review the environmental surcharge authorized by this section and any complaints as to the amount of any environmental surcharge or the incorporation of any environmental surcharge into the existing base rate of any utility.

Effective: July 14, 1992

History: Created 1992 Ky. Acts ch. 102, sec. 1, effective July 14, 1992.

FN 21

278.465 Definitions for KRS 278.465 to 278.468.

As used in KRS 278.465 to 278.468:

(1) "Eligible customer-generator" means a customer of a retail electric supplier who owns and operates an electric generating facility that is located on the customer's premises, for the primary purpose of supplying all or part of the customer's own electricity requirements.

(2) "Eligible electric generating facility" means an electric generating facility that:

(a) Is connected in parallel with the electric distribution system;

(b) Generates electricity using solar energy; and

(c) Has a rated capacity of not greater than fifteen (15) kilowatts.

(3) "Kilowatt hour" means a measure of electricity defined as a unit of work of energy, measured as one (1) kilowatt of power expended for one (1) hour.

(4) "Net metering" means measuring the difference between the electricity supplied by the electric grid and the electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period.

Effective: July 13, 2004

History: Created 2004 Ky. Acts ch. 193, sec. 1, effective July 13, 2004.

807 KAR 5:056. Fuel adjustment clause.

RELATES TO: KRS Chapter 278

STATUTORY AUTHORITY: KRS 278.030(1)

NECESSITY, FUNCTION, AND CONFORMITY: KRS 278.030(1) provides that all rates received by an electric utility subject to the jurisdiction of the Public Service Commission shall be fair, just and reasonable. This administrative regulation prescribes the requirements with respect to the implementation of automatic fuel adjustment clauses by which electric utilities may immediately recover increases in fuel costs subject to later scrutiny by the Public Service Commission.

Section 1. Fuel Adjustment Clause. Fuel adjustment clauses which are not in conformity with the principles set out below are not in the public interest and may result in suspension of those parts of such rate schedules:

(1) The fuel clause shall provide for periodic adjustment per KWH of sales equal to the difference between the fuel costs per KWH sale in the base period and in the current period according to the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where F is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) periods, all as defined below.

(2) FB/SB shall be so determined that on the effective date of the commission's approval of the utility's application of the formula, the resultant adjustment will be equal to zero.

(3) Fuel costs (F) shall be the most recent actual monthly cost of:

(a) Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation; plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) of this subsection, but excluding the cost of fuel related to purchases to substitute for the forced outages; plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) The cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(e) All fuel costs shall be based on weighted average inventory costing.

(4) Forced outages are all nonscheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the commission, include the fuel cost of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel cost (F) in subsection (3)(a) and (b) of this section the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

(5) Sales (S) shall be all KWH's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of:

(a) Generation;

(b) Purchases;

(c) Interchange-in; less

(d) Energy associated with pumped storage operations; less

(e) Intersystem sales referred to in subsection (3)(d) above; less

(f) Total system losses. Utility used energy shall not be excluded in the determination of sales (S).

(6) The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees.

(7) At the time the fuel clause is initially filed, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the commission and all other agreements, options or similar such documents, and all amendments and modifications thereof related to the procurement of fuel supply and purchased power. Incorporation by reference is permissible. Any changes in the documents, including price escalations, or any new agreements entered into after the initial submission, shall be submitted at the time they are entered into. Where fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted and the utility shall explain and justify them in writing. Fuel charges which are unreasonable shall be disallowed and may result in the suspension of the fuel adjustment clause. The commission on its own motion may investigate any aspect of fuel purchasing activities covered by this administrative regulation.

(8) Any tariff filing which contains a fuel clause shall conform that clause with this administrative regulation within three (3) months of the effective date of this administrative regulation. The tariff filing shall contain a description of the fuel clause with detailed cost support.

(9) The monthly fuel adjustment shall be filed with the commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment which shall include data and information as may be required by the commission.

(10) Copies of all documents required to be filed with the commission under this administrative regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

(11) At six (6) month intervals, the commission will conduct public hearings on a utility's past fuel adjustments. The commission will order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustments it finds unjustified due to improper calculation or application of the charge or improper fuel procurement practices.

(12) Every two (2) years following the initial effective date of each utility's fuel clause the commission in a public hearing will review and evaluate past operations of the clause, disallow improper expenses and to the extent appropriate reestablish the fuel clause charge in accordance with subsection (2) of this section. (8 Ky.R. 822; eff. 4-7-82.)

278.010 Definitions for KRS 278.010 to 278.450, 278.541 to 278.544, 278.546 to 278.5462, and 278.990.

As used in KRS 278.010 to 278.450, 278.541 to 278.544, 278.546 to 278.5462, and 278.990, unless the context otherwise requires:

(1) "Corporation" includes private, quasipublic, and public corporations, and all boards, agencies, and instrumentalities thereof, associations, joint-stock companies, and business trusts;

(2) "Person" includes natural persons, partnerships, corporations, and two (2) or more persons having a joint or common interest;

(3) "Utility" means any person except, for purposes of paragraphs (a), (b), (c), (d), and (f) of this subsection, a city, who owns, controls, operates, or manages any facility used or to be used for or in connection with:

(a) The generation, production, transmission, or distribution of electricity to or for the public, for compensation, for lights, heat, power, or other uses;

(b) The production, manufacture, storage, distribution, sale, or furnishing of natural or manufactured gas, or a mixture of same, to or for the public, for compensation, for light, heat, power, or other uses;

(c) The transporting or conveying of gas, crude oil, or other fluid substance by pipeline to or for the public, for compensation;

(d) The diverting, developing, pumping, impounding, distributing, or furnishing of water to or for the public, for compensation;

(e) The transmission or conveyance over wire, in air, or otherwise, of any message by telephone or telegraph for the public, for compensation; or

(f) The collection, transmission, or treatment of sewage for the public, for compensation, if the facility is a subdivision collection, transmission, or treatment facility plant that is affixed to real property and is located in a county containing a city of the first class or is a sewage collection, transmission, or treatment facility that is affixed to real property, that is located in any other county, and that is not subject to regulation by a metropolitan sewer district or any sanitation district created pursuant to KRS Chapter 220;

(4) "Retail electric supplier" means any person, firm, corporation, association, or cooperative corporation, excluding municipal corporations, engaged in the furnishing of retail electric service;

(5) "Certified territory" shall mean the areas as certified by and pursuant to KRS 278.017;

(6) "Existing distribution line" shall mean an electric line which on June 16, 1972, is being or has been substantially used to supply retail electric service and includes all lines from the distribution substation to the electric consuming facility but does not include any transmission facilities used primarily to transfer energy in bulk;

(7) "Retail electric service" means electric service furnished to a consumer for ultimate consumption, but does not include wholesale electric energy furnished by an electric supplier to another electric supplier for resale;

(8) "Electric-consuming facilities" means everything that utilizes electric energy from a central station source;

(9) "Generation and transmission cooperative" or "G&T" means a utility formed under KRS Chapter 279 that provides electric generation and transmission services;

(10) "Distribution cooperative" means a utility formed under KRS Chapter 279 that provides retail electric service;

(11) "Facility" includes all property, means, and instrumentalities owned, operated, leased, licensed, used, furnished, or supplied for, by, or in connection with the business of any utility;

(12) "Rate" means any individual or joint fare, toll, charge, rental, or other compensation for service rendered or to be rendered by any utility, and any rule, regulation, practice, act, requirement, or privilege in any way relating to such fare, toll, charge, rental, or other compensation, and any schedule or tariff or part of a schedule or tariff thereof;

(13) "Service" includes any practice or requirement in any way relating to the service of any utility, including the voltage of electricity, the heat units and pressure of gas, the purity, pressure, and quantity of water, and in general the quality, quantity, and pressure of any commodity or product used or to be used for or in connection with the business of any utility, but does not include Voice over Internet Protocol (VoIP) service;

(14) "Adequate service" means having sufficient capacity to meet the maximum estimated requirements of the customer to be served during the year following the commencement of permanent service and to meet the maximum estimated requirements of other actual customers to be supplied from the same lines or facilities during such year and to assure such customers of reasonable continuity of service;

(15) "Commission" means the Public Service Commission of Kentucky;

(16) "Commissioner" means one (1) of the members of the commission;

(17) "Demand-side management" means any conservation, load management, or other utility activity intended to influence the level or pattern of customer usage or demand, including home energy assistance programs;

(18) "Affiliate" means a person that controls or that is controlled by, or is under common control with, a utility;

(19) "Control" means the power to direct the management or policies of a person through ownership, by contract, or otherwise;

(20) "CAM" means a cost allocation manual which is an indexed compilation and documentation of a company's cost allocation policies and related procedures;

(21) "Nonregulated activity" means the provision of competitive retail gas or electric services or other products or services over which the commission exerts no regulatory authority;

(22) "Nonregulated" means that which is not subject to regulation by the commission;

(23) "Regulated activity" means a service provided by a utility or other person, the rates and charges of which are regulated by the commission;

(24) "USoA" means uniform system of accounts which is a system of accounts for public utilities established by the FERC and adopted by the commission;

(25) "Arm's length" means the standard of conduct under which unrelated parties, each party acting in its own best interest, would negotiate and carry out a particular transaction;

(26) "Subsidize" means the recovery of costs or the transfer of value from one (1) class of customer, activity, or business unit that is attributable to another;

(27) "Solicit" means to engage in or offer for sale a good or service, either directly or indirectly and irrespective of place or audience;

(28) "USDA" means the United States Department of Agriculture;

(29) "FERC" means the Federal Energy Regulatory Commission;

(30) "SEC" means the Securities and Exchange Commission;

(31) "Commercial mobile radio services" has the same meaning as in 47 C.F.R. sec. 20.3 and includes the term "wireless" and service provided by any wireless real time two (2) way voice communication device, including radio-telephone communications used in cellular telephone service, personal communications service, and the functional or competitive equivalent of a radio-telephone communications line used in cellular telephone service, a personal communications service, or a network radio access line; and

(32) "Voice over Internet Protocol" or "VoIP" has the same meaning as in federal law.

Effective: July 12, 2006

History: Amended 2006 Ky. Acts ch. 239, sec. 5, effective July 12, 2006. -- Amended 2005 Ky. Acts ch. 109, sec. 2, effective June 20, 2005. -- Amended 2002 Ky. Acts ch. 365, sec. 15, effective April 24 2002. -- Amended 2001 Ky. Acts ch. 11, sec. 1, effective June 21, 2001. -- Amended 2000 Ky. Acts ch. 101, sec. 5, effective July 14, 2000; ch. 118, sec. 1, effective July 14, 2000; and ch. 511, sec. 1, effective July 14, 2000. -- Amended 1998 Ky. Acts ch. 188, sec. 1, effective July 15, 1998. -- Amended 1994 Ky. Acts ch. 238, sec. 1, effective July 15, 1994. -- Amended 1982 Ky. Acts ch. 82, sec. 1, effective July 15, 1982. -- Amended 1978 Ky. Acts ch. 379, sec. 1, effective April 1, 1979. -- Amended 1974 Ky. Acts ch. 118, sec. 1. -- Amended 1972 Ky. Acts ch. 83, sec. 1. -- Amended 1964 Ky. Acts ch. 195, sec. 1. -- Amended 1960 Ky. Acts ch. 209, sec. 1. -- Recodified 1942 Ky. Acts ch. 208, sec. 1, effective October 1, 1942, from Ky. Stat. sec. 3952-1.

278.212 Filing of plans for electrical interconnection with merchant electric generating facility -- Costs of upgrading existing grid.

(1) No utility shall begin the construction or installation of any property, equipment, or facility to establish an electrical interconnection with a merchant electric generating facility in excess of ten megawatts (10MW) until the plans and specifications for the electrical interconnection have been filed with the commission.

(2) Notwithstanding any other provision of law, any costs or expenses associated with upgrading the existing electricity transmission grid, as a result of the additional load caused by a merchant electric generating facility, shall be borne solely by the person constructing the merchant electric generating facility and shall in no way be borne by the retail electric customers of the Commonwealth.

Effective: April 24, 2002

History: Created 2002 Ky. Acts ch. 365, sec. 11, effective April 24, 2002.

278.287 Voluntary energy cost assistance fund -- Customer contributions -- Time of and eligibility for disbursements -- Biennial reports -- Administration costs.

(1) As used in this section:

(a) "Voluntary energy cost assistance fund" means a fund that shall:

1. Be administered by a utility or provider for the purpose of receiving voluntary contributions from customers and disbursing subsidies to customers;

2. Be administered in coordination with one (1) or more community action agencies that assist the Cabinet for Health and Family Services in administering federal Low-Income Home Energy Assistance Program (LIHEAP) funding; and

3. Be maintained in trust and separate from any customer assistance program otherwise implemented by the utility or provider;

(b) "Provider" means any person or persons, excluding an electric power system owned and operated by a municipality, that provide service to retail customers and that own, control, operate, or manage any facility used or to be used for or in connection with any activity described in KRS 278.010(3)(a) or (b) but are not regulated by KRS Chapter 278; and

(c) "Fund" means a voluntary energy cost assistance fund.

(2) Any utility as defined in KRS 278.010(3)(a) or (b) that provides service to retail customers and that does not already administer an energy assistance program prior to July 12, 2006, may establish a fund.

(3) Any provider that does not already administer an energy assistance program prior to July 12, 2006, may establish a fund.

(4) A customer's voluntary monthly contribution amount to the fund shall be:

(a) An amount equal to the difference of the customer's monthly bill and the amount of the next highest whole dollar; or

(b) A standard amount not to exceed one dollar ($1).

(5) A customer may make a special contribution to the fund at any time in any amount.

(6) Annual disbursements from the fund may be made in November and December of each year by the utility or provider upon the recommendation of a community action agency for the purpose of providing a utility or provider bill subsidy for residential customers who:

(a) Use electricity or natural or manufactured gas as a principal source of home energy;

(b) Are responsible for their home heating costs either directly or indirectly as an undesignated portion of the rent;

(c) Have a total household income that is at or below one hundred ten percent (110%) of the federal poverty guidelines as defined in KRS 205.5621;

(d) Have liquid monetary resources that do not exceed one thousand five hundred dollars ($1,500) if those liquid monetary resources are not used for the medical and living expenses of a household member with a catastrophic illness;

(e) Have liquid monetary resources that do not exceed four thousand dollars ($4,000) if those liquid monetary resources are used for the medical and living expenses of a household member with a catastrophic illness; and

(f) Are customers of the utility or provider.

(7) If available, additional disbursements from the fund may be made from January 1 through March 15 of each year by the utility or provider upon the recommendation of a community action agency for the purpose of providing a utility or provider bill subsidy for residential customers who:

(a) Use electricity or natural or manufactured gas as a principal source of home energy;

(b) Are responsible for their home heating costs either directly or indirectly as an undesignated portion of the rent;

(c) Have a total household income that is at or below one hundred ten percent (110%) of the federal poverty guidelines as defined in KRS 205.5621;

(d) Have liquid monetary resources that do not exceed one thousand five hundred dollars ($1,500) if those liquid monetary resources are not used for the medical and living expenses of a household member with a catastrophic illness;

(e) Have liquid monetary resources that do not exceed four thousand dollars ($4,000) if those liquid monetary resources are used for the medical and living expenses of a household member with a catastrophic illness; and

(f) Are utility or provider customers who:

1. Have received a disconnect notice from the utility or provider;

2. Are within four (4) days of running out of fuel oil, propane, kerosene, wood, or coal; or

3. Have received an eviction notice for nonpayment of rent, when heat is included as an undesignated portion of the rent.

(8) If available, additional summer cooling disbursements from the fund may be made on a one (1) time basis from May through August of each year by the utility or provider upon the recommendation of a community action agency for the purpose of providing an air-conditioning unit to residential customers who:

(a) Are responsible for their home heating costs either directly or indirectly as an undesignated portion of the rent;

(b) Have a total household income that is at or below one hundred ten percent (110%) of the federal poverty guidelines as defined in KRS 205.5621;

(c) Have liquid monetary resources that do not exceed one thousand five hundred dollars ($1,500) if those liquid monetary resources are not used for the medical and living expenses of a household member with a catastrophic illness;

(d) Have liquid monetary resources that do not exceed four thousand dollars ($4,000) if those liquid monetary resources are used for the medical and living expenses of a household member with a catastrophic illness;

(e) Are customers of the utility or provider;

(f) Do not have access to an air conditioner; and

(g) Have a household member who:

1. Has a health condition or disability that requires cooling to prevent further deterioration as verified by a physician's statement;

2. Is sixty-five (65) years of age or older; or

3. Is under the age of six (6).

(9) For the six (6) month period from January 1 to June 30 of each year, each utility or provider that administers a fund shall provide a detailed report of costs in administering the fund and a detailed report of receipts to and disbursements from the fund to the commission no later than July 31, and for the six (6) month period from July 1 to December 31, no later than January 31 of the following year. Any balances remaining in the fund at the end of a year shall remain in the fund for use in succeeding years.

(10) The commission shall require all utilities as defined in KRS 278.010(3)(a) and (b) that administer a fund and provide service to retail customers in Kentucky to develop and implement a mechanism for soliciting and receiving contributions to the fund. The mechanism and format shall be approved by the commission and may include but shall not be limited to a check-the-box format. Contributions shall be made as described in subsections (4) and (5) of this section.

(11) Any provider that administers a fund shall comply with the requirements to implement a mechanism for soliciting and receiving contributions to the fund as provided in subsection (10) of this section.

(12) Those utilities and providers that are already administering an energy assistance program prior to July 12, 2006, shall not be subject to subsections (9), (10), and (11) of this section.

(13) All contributions to the fund shall be voluntary and shall be uniformly assessed monthly, except in the case of a special contribution, which can be made in any amount at any time, for all customers of the utility or provider. A customer shall not be subject to making contributions until such time as his or her intent is submitted to the applicable utility in a manner prescribed by the commission. A customer who no longer wishes to contribute to the fund shall be exempted from making further contributions to the fund once his or her intent is submitted to the applicable utility in a manner prescribed by the commission.

(14) Contributions received by utilities or providers, together with any interest accruing thereon, shall be transferred to the fund immediately upon receipt.

(15) A utility or provider that administers a fund may recover up to three percent (3%) of each contribution received for its costs in administering the fund. The commission shall allow any additional, reasonable cost a utility incurs in administering the

receipt and disbursement of contributions to the fund in the cost of service of the utility for ratemaking purposes.

Effective: July 12, 2006

History: Created 2006 Ky. Acts ch. 231, sec. 1, effective July 12, 2006.

807 KAR 5:016. Advertising.

RELATES TO: KRS Chapter 278

STATUTORY AUTHORITY: KRS 278.040, 278.190(3)

NECESSITY, FUNCTION, AND CONFORMITY: KRS 278.190(3) provides that at any hearing involving a rate or charge of a utility for which an increase is sought, the burden of proof shall be on the utility to show that the increased charge or rate is just and reasonable. This administrative regulation specifies what advertising expenses of a utility will be allowable as a cost to the utility for rate-making purposes.

Section 1. General. The purpose of this administrative regulation is to insure that no direct or indirect expenditures may be includable in a gas or electric utility's cost of service for rate-making purposes which are for promotional advertising, political advertising or institutional advertising. It is also the purpose of the administrative regulation to insure that no direct or indirect expenditures may be includable in a telephone, water, or sewage utility's cost of service for rate-making purposes which are for political advertising or institutional advertising. "Advertising" means the commercial use of any media, including newspaper, printed matter, radio and television, in order to transmit a message to a substantial number of members of the public or to utility consumers.

Section 2. Advertising Allowed. (1) No advertising expenditure of a utility shall be taken into consideration by the commission for the purpose of establishing rates unless such advertising will produce a material benefit for the ratepayers.

(2) As used in this administrative regulation, advertising expenditures shall include costs of advertising directly incurred by the public utility and those costs of advertising incurred by contribution to third parties, including parent and affiliated companies.

Section 3. Material Benefit. (1) Advertising expenditures by gas or electric utilities which produce a "material benefit" include, but are not limited to the following:

(a) Advertising limited exclusively to demonstration of means for ratepayers to reduce their bills or conserve energy;

(b) Advertising conveying safety information in the direct use of utility equipment;

(c) Advertising which furnishes factual and objective data programs to educational institutions on the subject of energy technology;

(d) Advertising providing information to the public regarding potential safety hazards associated with construction or a utility's maintenance program;

(e) Legal advertising notices to ratepayers required by statute, rule or order of the commission;

(f) Advertising which explains a utility's proposed or existing rate structure, its energy-related problems and its public programs and activities, provided such reference includes a description of how a consumer benefits from or is affected by same.

(2) Advertising expenditures by telephone, water, or sewage utilities which produce a "material benefit" include, but are not limited to the following:

(a) Advertising limited exclusively to demonstration of means for ratepayers to reduce their bills or conserve energy;

(b) Advertising promoting competitive or other services which would have the effect of holding down the cost of providing basic service;

(c) Advertising conveying safety information in the direct use of utility equipment;

(d) Advertising promoting off-peak usage of existing facilities;

(e) Advertising which explains the use, cost, applicability or availability of new or existing utility equipment and other utility services where energy consumption would either be reduced or not materially increased;

(f) Advertising which furnishes factual and objective data programs to educational institutions on the subject of water, sewer or communications technology;

(g) Advertising providing information to the public regarding potential safety hazards associated with construction or a utility's maintenance program;

(h) Legal advertising notices to ratepayers required by statute, rule or order of the commission.

Section 4. Advertising Disallowed. (1) Advertising expenditures for political, promotional, and institutional advertising by electric or gas utilities shall not be considered as producing a material benefit to the ratepayers and, as such, those expenditures are expressly disallowed for rate-making purposes.

(a) "Political advertising" means any advertising for the purpose of influencing public opinion with respect to legislative, administrative, or electoral matters, or with respect to any controversial issue of public importance.

(b) "Promotional advertising" means any advertising for the purpose of encouraging any person to select or use the service or additional service of an energy utility, or the selection or installation of any appliance or equipment designed to use such utility's service.

(c) "Institutional advertising" means advertising which has as its sole objective the enhancement or preservation of the corporate image of the utility and to present it in a favorable light to the general public, investors, and potential employees.

(d) The terms "political advertising," "promotional advertising," and "institutional advertising" do not include:

1. Advertising which informs utility customers how they can conserve energy;
2. Advertising required by law or administrative regulation;
3. Advertising regarding service interruption, safety measures, or emergency conditions;
4. Advertising concerning current employment opportunities;
5. Advertising which promotes the use of energy efficient appliances, equipment, or services.

(2) Advertising expenditures for political and institutional advertising by telephone, water, or sewage utilities shall not be considered as producing a material benefit to the ratepayers and, as such, these expenditures are expressly disallowed for rate-making purposes.

(a) "Political advertising" means any advertising for the purpose of influencing public opinion with respect to legislative, administrative, or electoral matters, or with respect to any controversial issue of public importance.

(b) "Institutional advertising" means advertising which has as its primary objective the enhancement or preservation of the corporate image of the utility and to present it in a favorable light to the general public, investors, and potential employees.

(c) The terms "political advertising" and "institutional advertising" do not include:

1. Advertising which informs utility customers how they can conserve energy;
2. Advertising required by law or administrative regulation;
3. Advertising regarding service interruption, safety measures, or emergency conditions;
4. Advertising concerning current employment opportunities;
5. Advertising which promotes the use of energy efficient appliances, equipment, or services.

Section 5. Burden of Proof. The utility shall have the burden of proving that any advertising cost or expenditures proposed for inclusion in its operating expenses for rate-making purposes within a given test year fall within the categories enumerated in Section 3 of this administrative regulation or that such advertising is otherwise of material benefit to its ratepayers. (8 Ky.R. 802; eff. 4-7-82.)

pp. 22-23

KENTUCKY'S ENERGY ⚡ OPPORTUNITIES FOR OUR FUTURE

A COMPREHENSIVE ENERGY STRATEGY

Kentucky
UNBRIDLED SPIRIT

GOVERNOR ERNIE FLETCHER

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FIGURES AND TABLES

To the Citizens of Kentucky,

Kentucky is a land blessed with abundant natural resources, industrious people and great natural beauty. Our challenge today is to continue to grow our economy, utilize our resources in a sustainable manner and protect and maintain our commitment to environmental quality. To accomplish these objectives, Kentucky must have a comprehensive state energy strategy.

Kentucky's energy sector is currently well positioned but that position is not guaranteed. The Legislative Research Commission's Interim Special Subcommittee on Energy realized in 2003 that Kentucky must formulate a statewide energy policy. A resolution passed by the subcommittee recognized the "tremendous challenges and tremendous opportunities in the energy arena." I am committed to work with the legislature to develop and implement a comprehensive energy policy for the benefit of all Kentuckians.

When I announced the formation of the Commonwealth Energy Policy Task Force, I outlined three principles to guide policy development:

- Maintain Kentucky's low-cost energy
- Responsibly develop Kentucky's energy resources
- Preserve Kentucky's commitment to environmental quality

The work of the task force, articulated through this comprehensive energy strategy, is consistent with these principles.

I appreciate the hard work of the task force to produce this energy strategy. I thank the legislators who played such a vital role in its development.

Most important, I look forward to implementing the recommendations of this energy strategy to move Kentucky forward.

As Kentuckians unite to build a Commonwealth of opportunity, the competitive advantage Kentucky enjoys in low-cost energy is an important building block. We must act now to secure a low-cost energy future through the responsible development of Kentucky's energy resources and a sustained commitment to environmental quality.

All Kentuckians hope to leave the next generation with a more prosperous and more beautiful Kentucky. This strategy serves as a framework to get us there.

Sincerely,

Governor,
Commowealth of Kentucky

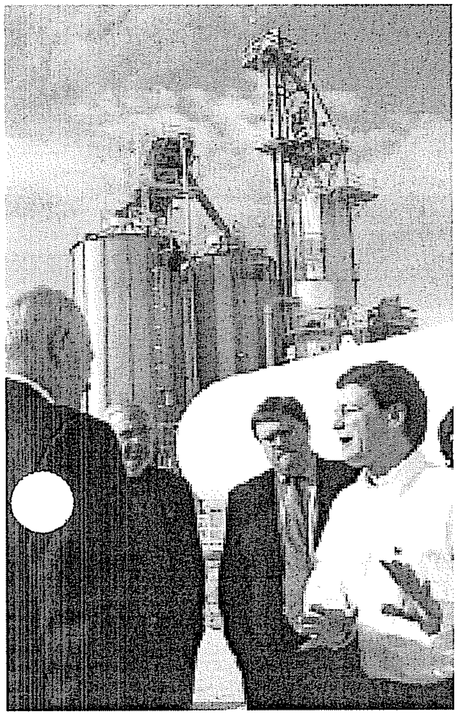
Commonwealth Energy Policy Task Force
Public Input

East Kentucky Power Cooperative
Cinergy Gas & Electric
Kentucky Coal Association
Kentucky Oil & Gas Association
Columbia Gas
Louisville Gas & Electric
University of Kentucky
University of Louisville
Environmental Quality Commission
Kentucky Public Service Commission
Kentucky Attorney General's Office
Kentucky Division of Energy
Rocky Mountain Elk Foundation
Kentucky Resources Council
Kentucky Association for Community Action
Kentucky Department for Environmental Protection
Greater Louisville Inc.
Northern Kentucky Chamber of Commerce
Kentucky Chamber of Commerce
Associated Industries of Kentucky
Kentucky Farm Bureau
Sierra Club
Kentuckians for the Commonwealth
Kentucky Geological Survey
Kentucky Solar Partnership
Midwest ISO
College of Agriculture – University of Kentucky
Kentucky Division of Oil & Gas
American Electric Power
DTX Technologies
Kentucky Coal Council
Coal Operators & Associates
Hazard Community College
Kentucky Division of Mine Safety
Appalachia Science in the Public Interest
Kentucky Department for Natural Resources
Kentucky Department for Fish and Wildlife
EnviroPower
National Energy Education Development
Kentucky Association of Electric Cooperatives
Kentucky Energy and Environmental Consortium
Berea College—Sustainability and Environmental Studies
Interstate Natural Gas Company
Kentucky Clean Fuels Coalition
Kentucky Corn Growers Association
Kentucky Soybean Association
Kentucky Industrial Utilities Customers
Century Aluminum
Alacan Sebree Aluminum
SECAT, Inc.
Center for Applied Energy Research
Western Kentucky University
Peabody Energy
Tennessee Valley Authority
Madisonville Community and Technical College
Municipal Electric Power Association of Kentucky
United Steel Workers
Center for Technology Enterprise

and
Citizens of the Commonwealth of Kentucky

Executive Summary

Kentucky is a land blessed with abundant natural resources, industrious people and great natural beauty. Our challenge today is to continue to grow our economy, utilize our resources in a sustainable manner and protect and maintain our commitment to environmental quality. To accomplish these objectives, Kentucky must have a comprehensive state energy strategy.



Kentucky's energy sector is currently well positioned but that position is not guaranteed. The Legislative Research Commission's Interim Special Subcommittee on Energy realized in 2003 that Kentucky must formulate a statewide energy policy. A resolution passed by the subcommittee recognized the "tremendous challenges and tremendous opportunities in the energy arena."

The resolution encouraged the incoming administration "to craft state policy and insure that developments in the energy field take place in a planned and thoughtful fashion." Governor Fletcher has committed to work with the legislature to develop and implement a comprehensive energy policy for the benefit of all Kentuckians.

Announcing the formation of the Commonwealth Energy Policy Task Force, Governor Fletcher outlined three principles that guided policy development:

- Maintain Kentucky's low-cost energy
- Responsibly develop Kentucky's energy resources
- Preserve Kentucky's commitment to environmental quality

The Commonwealth Energy Policy Task Force conducted three public meetings at locations across the state to ensure that development of an energy policy encompassed broad citizen and stakeholder input. The task force listened to testimony from energy producers, environmental organizations, the business community, educators and individual citizens.

The days of considering state energy policy within an isolated context are long over. State, national and international economies are interconnected. The transfer of goods and services continues to be liberalized. Like other commodities, energy supplies pursue markets—wherever they exist—that promise sufficient rates of return. Certain environmental issues know no borders.

An adequate supply of energy resources is a prerequisite to economic growth. Rapid economic growth in developing nations—particularly India and China—will play an increasingly important role in worldwide energy trends. The industrialized world is also expected to realize sustained growth over the long term. The United States economy is projected to grow by three percent annually for the next 20 years.

Evidence suggests that economic growth, increased energy demand and energy efficiency are not mutually exclusive. According to the United States Department of Energy (DOE), "energy intensity, as measured by energy use per dollar of GDP, is projected to decline at an average annual rate of

1.5 percent (over the next 20 years)... with efficiency gains and structural shifts in the economy offsetting growth in demand for energy services." Growing energy demand is also expected to present environmental challenges. New federal rules targeting mercury emissions from power plants are forthcoming in 2005. Carbon gas emissions from burning fossil fuels could become targeted for reduction.

In 2002, Kentucky residents enjoyed the lowest cost residential electricity rates in the nation. Consider how Kentucky's residential electricity rates compare with surrounding states:

- 9% lower than West Virginia residents.
- 12% lower than Tennessee residents.
- 18% lower than Indiana residents.
- 20% lower than Missouri residents.
- 27% lower than Virginia residents.
- 32% lower than Ohio residents.
- 33% lower than Illinois residents.
- 33% lower than the national average.

The three largest coal producing states—Wyoming, West Virginia and Kentucky—have the three lowest electricity costs in the nation. Projections indicate that states with significant coal-fired generation within their energy portfolio should, with the proper policy environment and attention to energy efficiency, continue to enjoy the benefits of low cost electricity.

While Kentucky's economy has grown—although at a slower rate than our competitive states—indicators suggest that air quality, a significant environmental measure, has dramatically improved within the state .

These facts demonstrate that energy development, economic development and environmental quality are mutually inclusive goals.

Education Secretary Virginia Fox and Economic Development Secretary Gene Strong

Energy Efficiency: Saving Energy, Saving Money and Protecting the Environment

A sound energy policy requires balancing supply and demand forces in the market. On the demand side, efficient energy use and conservation can reduce overall energy costs and help address environmental issues. The United States has made impressive gains in energy efficiency. Since 1973, the U.S. economy has grown by 126 percent, while energy use has increased by only 30 percent.

Over the years, Kentucky's low rates have encouraged energy-intensive practices, processes and procedures. This historic energy intensity provides a great opportunity for energy efficiency to help lower consumption, reduce energy bills and improve the environment.

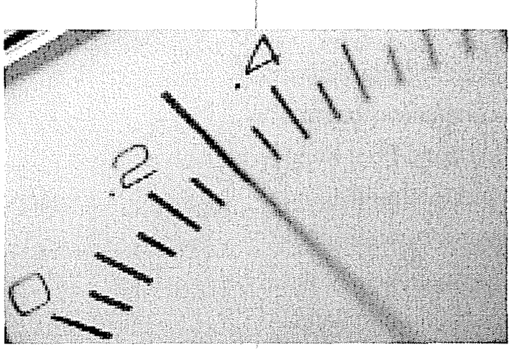
To achieve greater energy efficiency in Kentucky, the comprehensive energy strategy proposes that state government "lead the way" and focus on energy efficiency education and outreach.

Renewable Energy: A Sustainable Commitment

The growth potential in renewable resources is especially strong in our transportation sector, where Kentucky is in an enviable position to take advantage of the emerging biodiesel and ethanol markets. A strong biofuels market offers a myriad of benefits—improved health through reduced emissions of harmful pollutants, improved air quality and economic growth, particularly in agriculture. The use of clean transportation fuels such as natural gas, ethanol, propane and biodiesel has increased in recent years throughout Kentucky in both public and private vehicle fleets.

In 2003, two million gallons of biodiesel were produced in Kentucky, with 300,000 gallons consumed in Kentucky. In 2003, 24 million gallons of ethanol were produced in Kentucky, and 12 million gallons were consumed in Kentucky. A lack of retail distribution has impeded consumption of cleaner fuels.

Biodiesel fuel specifications have been written by the Finance and Administration Cabinet, enabling fuel suppliers to bid on this fuel as they do standard diesel and gasoline. The state diesel fuel use annually is roughly 2.4 million gallons. Ethanol production is an ideal market for Kentucky farmers, who produce 166 million bushels of corn per year.



The comprehensive energy strategy is focused on enhancing the renewable energy resource portion of Kentucky's energy portfolio by promoting its production, consumption and availability with in the state.

Kentucky's Low Cost Electric: Strategic Investment

Kentucky enjoys some of the lowest rates of electricity in the nation. This provides significant benefits to Kentucky's residential consumers and is a comparative advantage in recruiting and retaining industry. It is shortsighted, however, to think that these advantages are guaranteed. Kentucky must strategically develop its energy portfolio to ensure that the state continues to enjoy the benefits of low-cost electric.

The Kentucky Public Service Commission (PSC) collects some information related to the projected needs for new generation going forward. However, there is no comprehensive assessment of statewide needs that could serve as a blueprint for strategic investment.

According to the U.S. Department of Energy, renewable energy resources' contribution to electric generation will increase by 38 percent by 2025. New electricity generation technology is providing the opportunity for renewables—i.e. wood waste, landfill gases, biomass—to supplement primary resources in electric generation.

Kentucky's comprehensive energy strategy focuses on designing a 'strategic blueprint' to guide investment in Kentucky's electricity sector and promoting, without mandating, the utilization of renewable energy resources as an energy resource for electric generation.

Coal: Energy at Kentucky's Feet

A thorough discussion of Kentucky's low-cost electric must include the role played by coal. Ninety percent of Kentucky's electricity is produced from coal-fired generation. According to the U.S. Department of Energy, Kentucky ranked third—behind Wyoming and West Virginia—in the United States in coal production in 2002. However, Kentucky's coal production has significantly declined over the last decade.

Environmental emission requirements present a significant challenge to the Kentucky coal industry. Kentucky's coal industry can realize benefits from the electricity generation industry investing in "clean coal technology."

Companies are finding that it makes economic sense to construct generation capacity directly at coal sites to diminish transportation costs. One benefit of mine mouth generation is that it adds value to the energy resource through jobs in the mining industry and at the generation plants. Further, the proposed plants must conform to the environmental requirements of the state so environmental concerns are addressed before any construction begins.

In an effort to provide a viable bonding alternative for medium-to-small sized coal companies, the state legislature created the Kentucky Bond Pool Fund in 1986. The Kentucky Bond Pool is administered by the Bond Pool Commission and is required to maintain a level of funding adequate to meet the bonding commitments of the member companies. At current funding levels, the Kentucky Bond Pool faces limitations in its capacity to take on additional bond liability to keep pace with the increasing demand.

Other states are investing in the coal industry. For example, Illinois's Coal Infrastructure program provides grants that match private sector investment aimed at improving coal production, transportation and utilization systems. Additionally, the U.S. Department of Energy is promoting research and development into coal gasification as an alternative to conventional petroleum-based fuel. This research could provide new markets for Kentucky coal.

While Kentucky's coal industry continues to employ a significant number of people, employment has been on a downward trend since the 1970s. The recent uptick in coal demand has been complicated by the fact that the coal industry is facing a shortage of qualified miners due to retirements of the current generation and a lack of sufficient training in the next generation.

Even well-trained miners can face challenges on the job if they are wrestling with a substance-abuse problem. According to the federal Department of Labor, "the rate of fatal accidents has steadily been decreasing since 2000. The challenge now is dealing with preventable problems caused by people who are impaired by drugs or alcohol."

Finance & Administration Secretary Robbie Rudolph, Representative Tanya Pullin, Environmental and Public Protection Secretary LaJuana Wilcher

There are opportunities to promote the responsible development of Kentucky's energy resources. The Department for Natural Resources has partnered with the University of Kentucky and the Environmental Quality Commission to promote the planting of high-value hardwood species on mined lands. The Starfire Mine site is the location where elk were reintroduced into eastern Kentucky.

The energy resources inherent to coal refuse can be harnessed while promoting the proper reclamation of abandoned mine sites. The state can initiate a dialogue between appropriate energy and environmental parties to discuss the issues surrounding area mining to determine if consensus can be built around potential policy solutions.

Kentucky's comprehensive energy strategy focuses on promoting new growth in Kentucky's coal industry through clean coal technology, targeted investment, workforce training, addressing the pervasive substance abuse problem and responsibly developing our energy resources through progressive policy.

Kentucky's Natural Gas: Untapped Potential

Kentucky has 1.9 billion cubic feet of proven natural gas reserves—or about one percent of the nation's proven reserves. In 2002, Kentucky produced over 86 million cubic feet of natural gas. If this gas were wholly consumed within the state (which it was not) Kentucky's production would have accounted for only 41 percent of the state's consumption. Consequently, Kentucky is a net importer of natural gas.

Forty-four percent of Kentucky's home-heating market is fueled by natural gas. Nationally, natural gas prices have risen sharply in recent years. Prices during the winter of 2003-2004 were 20 to 40 percent higher than during the 2002-2003 heating season. Recent projections expect the trend to continue.


Commerce Secretary Jim Host and Senator Robert Stivers

Recent complications have impeded the responsible development of Kentucky's natural gas reserves. Getting natural gas from the field to the interstate pipelines that cross the state has been made difficult due to significant infrastructure barriers. A robust natural gas infrastructure is essential to providing reliable and cost-effective service to Kentucky's consumers.

Coal-bed methane is a promising source of energy and economic development. Methane gas is also a byproduct of refuse decomposition. Methane is being leaked into the atmosphere at many of Kentucky's landfills. Capturing this resource would supplement the state's energy portfolio and diminish the environmental impact of landfills. Further, methane is a component part of multiple products, particularly plastics. The need for methane as an input into industrial processes provides an opportunity for Kentucky to leverage this inherent resource to grow value-added industry.

Kentucky's comprehensive energy strategy is focused on investment in natural gas infrastructure and the emerging opportunities associated with methane and natural gas.

Kentucky's Energy Future: A Perpetual Commitment

Kentucky does not have a high-level government organization dedicated to energy. This has not always been the case. During the energy shortages of the 1970s, Kentucky had an Energy Cabinet. Over the years, however, the dedication to energy issues has been diminished. In order to better ensure Kentucky's low-cost energy future, there must be a perpetual commitment.

Although Kentuckians enjoy the lowest electricity rates in the nation, low-income citizens, particularly those on fixed incomes, have a difficult time paying their energy bills, especially in the wintertime when natural gas and propane prices are generally higher. There are a number of programs in place to provide assistance to low income Kentuckians that need to be better promoted.

Billions of dollars for energy research and development are available through the federal government. Unfortunately, Kentucky has a very poor track record capturing these resources. This must change.

According to the U.S. Department of Homeland Security, "energy drives the foundation of many of the sophisticated processes at work in American society. It is essential to our economy, national defense and quality of life." Additionally, "it is important to remember that protection of our critical infrastructures and key assets is a shared responsibility. Accordingly, the success of our protective efforts will require close cooperation between government and the private sector at all levels." Kentucky, with its critical energy infrastructure being vital to the state and national economy, must be engaged in ensuring that this national security priority is fulfilled.

Kentucky's comprehensive energy strategy is focused on establishing a high level emphasis on energy policy within state government, developing Kentucky's energy workforce, promoting initiatives to help low income Kentuckians with energy bills, securing federal energy research and development resources and securing Kentucky's critical energy infrastructure.

Conclusion: Kentucky's Energy — Opportunities For Our Future

Kentucky's energy sector is currently well positioned but that position is not guaranteed. Our challenge today is to continue to grow our economy, utilize our resources in a sustainable manner and protect and maintain our commitment to environmental quality. To accomplish these objectives, Kentucky must have a comprehensive state energy strategy.

Governor Fletcher has committed to work in a bipartisan manner with the legislature to develop and implement a comprehensive energy strategy for the benefit of all Kentuckians. As Kentuckians unite to build a Commonwealth of opportunity, the competitive advantage Kentucky enjoys in low-cost energy is an important building block. We must act now to secure a low-cost energy future through the responsible development of Kentucky's energy resources and a sustained commitment to environmental quality.

All Kentuckians hope to leave the next generation with a more prosperous and more beautiful Kentucky. This strategy serves as a framework to get us there.

Energy Strategy Recommendations

Energy Efficiency: Saving Energy, Saving Money and Protecting the Environment

Recommendation 1:
The Commonwealth of Kentucky, through the Finance and Administration Cabinet, should dedicate staff toward implementing an aggressive and sensible utility savings initiative throughout state government and other state-funded institutions to improve energy efficiency.

Recommendation 2:
The Commonwealth of Kentucky should develop and implement procurement polices that encourage sustainable practices, products and energy efficiency.

Recommendation 3:
The Commonwealth of Kentucky should encourage high performance, energy-efficient design for new construction of state facilities.

Recommendation 4:
The Commonwealth of Kentucky should require interagency cooperation to promote energy efficiency initiatives.

Recommendation 5:
The Commonwealth of Kentucky should encourage the continued development of public-private partnerships dedicated to promoting energy efficiency through education and outreach.

Recommendation 6:
The Commonwealth of Kentucky should work with industries, businesses, schools, universities and communities to promote and give preference to energy-efficient products and practices.

Recommendation 7:
The Commonwealth of Kentucky should support energy assessment initiatives that will help our industries and businesses improve their profitability through energy efficiency and resource management.

Recommendation 8:
The Commonwealth of Kentucky should examine its building codes and specifications to determine if enhanced energy efficiency gains are possible through progressive policy.

Recommendation 9:
The Commonwealth of Kentucky should pursue funding opportunities to strengthen K-12 energy education.

Renewable Energy: A Sustainable Commitment

Recommendation 10:
The Commonwealth of Kentucky should require its state fleet to utilize a 10 percent blend of ethanol (E10) and gasoline and a two percent blend of biodiesel (B2) wherever these clean fuels are available, and encourage Kentucky's post-secondary institutions to adopt similar initiatives.

Recommendation 11:
The Commonwealth of Kentucky should design and implement policies to promote the production, consumption and availability of biodiesel and ethanol within Kentucky.

Recommendation 12:
The Commonwealth of Kentucky should design policies to promote the utilization of a 20 percent blend of biodiesel in the public school bus fleet.

Kentucky's Low Cost Electricity: Strategic Investment

Recommendation 13:

The Commonwealth of Kentucky should develop a comprehensive statewide assessment of Kentucky's electricity infrastructure— generation, transmission and distribution—which includes reasonable projections of future electricity requirements.

Recommendation 14:

The Commonwealth of Kentucky should periodically update the comprehensive statewide assessment to reflect changes in both electric infrastructure and future electricity requirements.

Recommendation 15:

The Commonwealth of Kentucky assessment should serve as a "strategic blueprint" for policymakers to determine future investment requirements in Kentucky's electricity generation, transmission and distribution infrastructure.

Recommendation 16:

The Commonwealth of Kentucky should utilize the "strategic blueprint" to develop policies that promote sufficient investment in electricity infrastructure—generation, transmission and distribution—to sustain Kentucky's low cost electricity into the future.

Recommendation 17:

The Commonwealth of Kentucky should identify impediments to investment in electricity generation, transmission and distribution and develop policies to promote investment while ensuring that appropriate environmental protections are maintained and local voices are heard.

Recommendation 18:

The Commonwealth of Kentucky should design and implement policies that promote, but do not mandate, the use of renewable energy resources in Kentucky's electricity generation portfolio.

Coal: Energy at Kentucky's Feet

Recommendation 19:

The Commonwealth of Kentucky should examine its regulatory policies and traditional economic-development incentives to design and implement policies that promote investment in clean coal technology.

Recommendation 20:

The Commonwealth of Kentucky should develop policies to provide incentives for the purchase of Kentucky coal at clean-coal facilities.

Recommendation 21:

The Commonwealth of Kentucky should ensure that the Kentucky Bond Pool Fund is sufficiently enhanced to promote the growth and productivity of Kentucky's coal mining industry.

Recommendation 22:

The Commonwealth of Kentucky should examine its current mine permitting policies and identify streamlining opportunities.

Recommendation 23:

The Commonwealth of Kentucky should design and implement policies to promote electricity generation at Kentucky mine sites.

Recommendation 24:

The Commonwealth of Kentucky should design and implement policies to promote capital investment within the coal industry.

Recommendation 25:
The Commonwealth of Kentucky should support projects and initiatives intended to open new markets for Kentucky coal.

Recommendation 26:
The Commonwealth of Kentucky should partner with post-secondary institutions and industry to develop and invest in a program targeted at workforce development within the coal industry.

Recommendation 27:
The Commonwealth of Kentucky should partner with post-secondary institutions and industry to pursue federal resources to implement workforce development initiatives for the coal mining industry.

Recommendation 28:
The Commonwealth of Kentucky should partner with the Southern States Energy Board to develop a model workforce development initiative that can be replicated in other coal-producing states.

Recommendation 29:
The Commonwealth of Kentucky should partner with the federal government, the mining industry, employee organizations and with other coal producing states to study the extent of the drug and alcohol problems in the mines.

Recommendation 30:
The Commonwealth of Kentucky should partner with the mining industry and employee organizations to develop policies that promote drug screening and rehabilitation within the mining industry.

Recommendation 31:
The Commonwealth of Kentucky should pursue federal funding opportunities to promote drug screening and rehabilitation within the mining industry.

Recommendation 32:
The Commonwealth of Kentucky should continue to promote progressive reclamation practices through reforestation and the creation of wildlife habitats that support environmental restoration and enhanced economic development and tourism opportunities.

Recommendation 33:
The Commonwealth of Kentucky should design and implement policies that promote the recovery of the energy resources inherent to abandoned coal refuse and the proper reclamation of those properties.

Recommendation 34:
The Commonwealth of Kentucky should monitor the proposals of the Office of Surface Mining surrounding the issues of area mining and determine what appropriate changes should be made to the current state regulatory program to bring it in line with proposed federal rule changes.

Recommendation 35:
The Commonwealth of Kentucky should support dialogue between appropriate energy and environmental parties to determine the policy options related to area mining within the context of the proposed federal rule changes.

Recommendation 36:
The Commonwealth of Kentucky should design and implement policies to promote the transformation of waste into value-added products, particularly directed at opportunities to reduce the environmental impact of coal-fired emissions.

Kentucky's Natural Gas: Untapped Potential

Recommendation 37:

The Commonwealth of Kentucky should develop and implement policies that encourage investment in intrastate natural gas pipelines, gathering lines and distribution capacity.

Recommendation 38:

The Commonwealth of Kentucky should determine the opportunities for increased natural gas storage capacity and, if appropriate, promote its development.

Recommendation 39:

The Commonwealth of Kentucky should promote research to accurately determine the extent of coal bed methane and natural gas reserves in Kentucky and its prominent locations.

Recommendation 40:

The Commonwealth of Kentucky should design and implement policies to promote the recapture of methane from the state's landfills.

Recommendation 41:

The Commonwealth of Kentucky should identify the potential of coal bed methane value-added industries and, if feasible, design economic development strategies to grow those industries around the state's coal bed methane reserves.

Kentucky's Energy Future: A Perpetual Commitment

Recommendation 42:

The Commonwealth of Kentucky should place a high-level emphasis on energy policy to continue the vital work necessary to ensure Kentucky's low cost energy future, the responsible development of Kentucky's energy resources and Kentucky's commitment to environmental quality.

Recommendation 43:

The Commonwealth of Kentucky should engage federal regulatory and energy agencies to ensure that the state has a "place at the table" while energy issues are being discussed.

Recommendation 44:

The Commonwealth of Kentucky should investigate the emerging impact of global and national policies and institutions on Kentucky's energy future.

Recommendation 45:

The Commonwealth of Kentucky should partner with post-secondary institutions, industry and the federal government to develop and invest in programs targeted at workforce development within the energy industry.

Recommendation 46:

The Commonwealth of Kentucky should partner with community-action agencies and the energy industry to provide energy assistance to Kentucky's neediest citizens.

Recommendation 47:

The Commonwealth of Kentucky should promote the awareness of utility check-off programs and encourage widespread participation.

Recommendation 48:

The Commonwealth of Kentucky should partner with the state's universities, private industry and non-profit organizations to aggressively pursue federal research and development resources that are dedicated—but not limited—to clean-coal technology, energy efficiency, hydrogen technology and renewable energies.

Recommendation 49:
The Commonwealth of Kentucky should initiate a full-scale effort to attract and site the federal FutureGen facility in Kentucky.

Recommendation 50:
The Commonwealth of Kentucky should encourage and assist the state's universities, private industry and non-profit organizations to leverage available federal energy research and development resources.

Recommendation 51:
The Commonwealth of Kentucky should promote greater collaboration between Kentucky's universities to synergize ongoing energy research efforts at individual institutions.

Recommendation 52:
The Commonwealth of Kentucky should partner with the federal government, local governments and private industry to promote enhanced security of Kentucky's critical energy infrastructure.

Recommendation 53:
The Commonwealth of Kentucky should partner with local governments and private industry to pursue federal funding opportunities that promote enhanced security of Kentucky's critical energy infrastructure.

Recommendation 54:
The Commonwealth of Kentucky should partner with the federal government to enhance the nation's energy security through research and development directed at transforming Kentucky's energy resources into the resources that fuel the nation.

The Need for a Comprehensive Energy Strategy

Kentucky is a land blessed with abundant natural resources, industrious people and great natural beauty. Our challenge today is to continue to grow our economy, utilize our resources in a sustainable manner and protect and maintain our commitment to environmental quality. To accomplish these objectives, Kentucky must have a comprehensive state energy plan.

Kentucky historically has relied primarily on coal to produce its electricity, and likely will do so in the future. Simply stated, without an adequate supply of coal, Kentuckians will not continue to enjoy the benefits of low-cost electricity rates. Nonetheless, we have opportunities to diversify our energy portfolio to help our citizens save money and protect the environment.

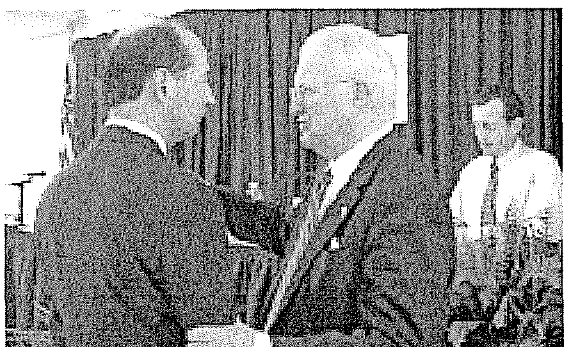
Recent trends also reveal opportunities to strengthen Kentucky's energy position. Although Kentucky enjoys the lowest electricity rates in the nation, we rank 23rd in residential energy consumption and are the seventh highest per capita primary energy-consuming state. The average monthly industrial electric bill in Kentucky is 123% higher than the national average. This indicates that our low electricity rates do not translate into low energy bills if we consume more energy than necessary in our homes and businesses.

Energy production and usage also affect the state's environment. Energy consumption, including the energy we use to light and heat our homes, contributes to carbon dioxide, sulfur dioxide, nitrogen and mercury emissions. Technological advances—such as clean coal technology, alternative fuels, hybrid vehicles and hydrogen fuel cells—offer great promise to enhance environmental quality. State government can and should play a role in promoting cleaner fuels, but Kentuckians must also realize that individual choices are vital to a cleaner environmental future.

Kentucky's energy sector is currently well positioned but that position is not guaranteed. The Legislative Research Commission's Interim Special Subcommittee on Energy realized in 2003 that Kentucky must formulate a statewide energy policy. A resolution passed by the subcommittee recognized the "tremendous challenges and tremendous opportunities in the energy arena."

The resolution encouraged the incoming administration "to craft state policy and insure that developments in the energy field take place in a planned and thoughtful fashion." Governor Fletcher is committed to work with the legislature to develop and implement a comprehensive energy policy for the benefit of all Kentuckians.

During the announcement of the Commonwealth Energy Policy Task Force, Governor Fletcher stated, "I am optimistic that by including the co-chairs of the Legislative Research Commission (LRC) Special Subcommittee on Energy, we can build the necessary bi-partisan support on energy issues to move this state forward."



Commerce Secretary Jim Host, right and House Majority Floor Leader Rocky Adkins.

Governor Fletcher outlined three principles that guided policy development:

Maintain Kentucky's low-cost energy

The citizens and businesses of Kentucky currently enjoy some of the lowest energy rates in the United States. Kentucky's residential electricity rates are among the lowest in the nation while Kentucky's industrial electricity rate *is* the lowest in the nation. Unfortunately, low-cost energy for Kentuckians is not guaranteed. According to Governor Fletcher, "Kentucky must strategically plan to preserve the low-cost energy advantage that all its citizens enjoy."

Responsibly develop Kentucky's energy resources

Kentucky is blessed with abundant energy resources—our fossil-fuel resources are enviable, and include coal (Kentucky ranks third in the nation in coal production), oil, natural gas and coal bed methane. The Commonwealth is also in a strong position to take advantage of its renewable energy resources (including hydropower, solar energy, wind power, landfill gas and biofuels).

Preserve Kentucky's commitment to environmental quality

Energy exploration, production, generation and use have impacts on the environment. However, these impacts can be significantly minimized with a sound, forward-thinking energy policy that guides the state in determining its energy future.

As Governor Fletcher stated, "Responsible energy development and commitment to preserving our environment are not mutually exclusive of one another. We can find the proper balance."

The members of the Commonwealth Energy Policy Task Force are:

- **Jim Host**, Secretary of Commerce, Task Force Co-Chair
- **LaJuana Wilcher**, Secretary of Environmental and Public Protection, Task Force Co-Chair
- **Virginia Fox**, Secretary of Education
- **Robbie Rudolph**, Secretary of Finance and Administration
- **Gene Strong**, Secretary of Economic Development
- **Senator Robert Stivers**, LRC Special Subcommittee on Energy
- **Representative Tanya Pullin**, LRC Special Subcommittee on Energy

The Commonwealth Energy Policy Task Force conducted public forums in Lexington, Hazard and Hopkinsville to gather input from citizens and stakeholders. The task force listened to testimony from energy producers, environmental organizations, government officials, the business community, educators and individual citizens.

The speakers addressed a diverse range of subjects such as clean coal technology, funding for research and development, energy education for students and adults, alternative energy sources, reforestation of coal mine sites, transmission of natural gas resources and the need for skilled coal miners.

The diverse locations also allowed members of the Task Force an opportunity to witness firsthand Kentucky's wealth of energy resources. In eastern Kentucky, members toured a reclaimed coal-mine site that not only provides habitat for Kentucky's restocked and growing elk population, but that also showcases the economic potential of hardwood reforestation on progressively reclaimed mined properties. In western Kentucky, the panel toured the state's first ethanol production facility, designed to produce 20 million gallons of ethanol fuel per year.

The recommendations contained in the following report reflect the testimony from participants in the public meetings, information shared on the tour of energy sites, the broad experience of the Task Force members and research from executive staff.

Energy Trends: National and International

The days of considering state energy policy within an isolated context are long over. State, national and international economies are interconnected. The transfer of goods and services continues to be liberalized. Like other commodities, energy supplies pursue markets—wherever they exist—that promise sufficient rates of return. Certain environmental issues know no borders.

An adequate supply of energy resources is a prerequisite to economic growth. Rapid economic growth in developing nations—particularly India and China—will play an increasingly important role in worldwide energy trends. According to the *International Energy Outlook 2004*[1]*:*

- Energy use in developing nations is projected to increase more rapidly than in other regions over the coming decades.
- Energy demand in the emerging economies of Asia, which include China and India, is projected to more than double over the next quarter century.
- Industrial energy consumption in developing countries was nearly 40 percent of the worldwide industrial sector total in 2001. Their share is projected to increase to almost one-half of all industrial sector energy consumption by 2025.
- In the face of these projections, it is reassuring to note that "global energy resources are thought to be adequate to support the growth expected through 2025."[2]

The industrialized world is also expected to realize sustainable growth over the long term. The United States economy is projected to grow by 3% annually for the next 20 years. Consequently by 2025[3]:

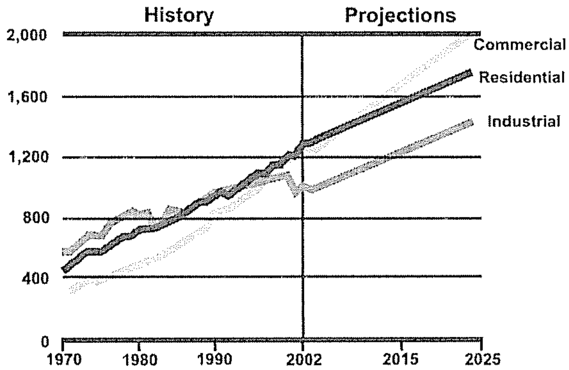
- U.S. energy consumption is expected to grow by 36%
- Petroleum consumption is expected to grow by 39%
- Natural gas consumption is expected to grow by 40%
- Coal consumption is expected to grow by 35%
- Renewable energy resources are expected to grow by 38%

[1] U.S. Department of Energy, International Energy Outlook 2004. See www.eia.doe.gov

[2] U.S. Department of Energy, International Energy Outlook 2004. See www.eia.doe.gov

[3] Growth measured in quadrillion British Thermal Units (BTUs). These projections are based on existing federal and state laws and regulations remaining unchanged throughout the forecast period. Changes in existing laws and regulations could alter these projections. U.S. Department of Energy. *Annual Energy Outlook 2005.*

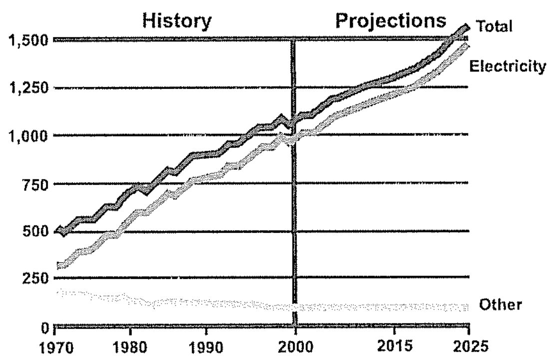
U.S. Annual Electricity Sales by Sector
1970 - 2025
(billion kilowatt hours)



Source: U.S. DOE

Coinciding with the nation's economic growth, demand for electric generation in the United States is projected to increase. Investment in generating capacity is expected to meet short-term demand, however, "more capacity will be needed eventually, as electricity use grows and older, inefficient plants are retired."[4]

U.S. Electricity and Other Coal Consumption
1970 - 2025
(million short tons)

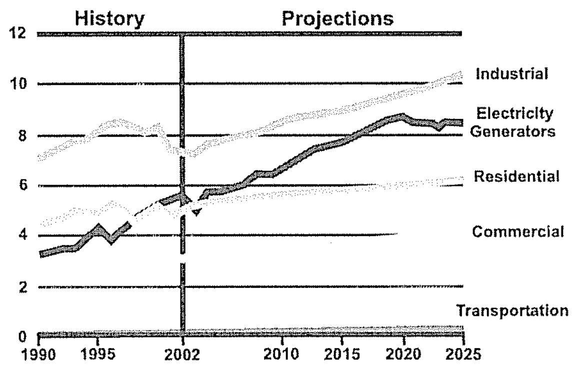


Source: U.S. DOE

Natural gas is expected to become increasingly important in generating electricity. However, by 2025, only 31% end-use natural gas consumption will be dedicated to generation. On the other hand, the overwhelming majority of coal consumption will be dedicated to electric generation. According to the Energy Information Administration's projections, by 2025 coal will comprise 53% of total electricity generation, with natural gas and renewable energy sources contributing 18% and 10% respectively.

Evidence suggests that economic growth, increased energy demand and energy efficiency are not mutually exclusive. According to the United States Department of Energy, "energy intensity, as measured by energy use per dollar of GDP, is projected to decline at an average annual rate of 1.5 percent (over the next twenty years)... with efficiency gains and structural shifts in the economy offsetting growth in demand for energy services."[5]

U.S. Natural Gas Consumption by End-Use Sector
(trillion cubic feet)

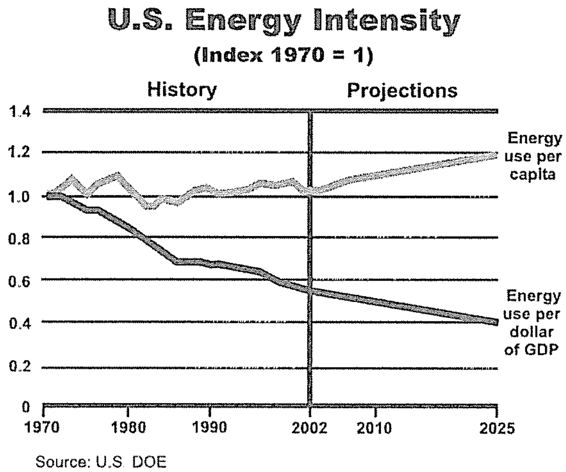


Source: U.S. DOE

Growing energy demand is also expected to present environmental challenges. New federal rules targeting mercury emissions from power plants are

[4] U.S. Department of Energy, *Annual Energy Outlook 2005*. See www.doe.gov

[5] U.S. Department of Energy, *Annual Energy Outlook 2004*. See www.doe.gov

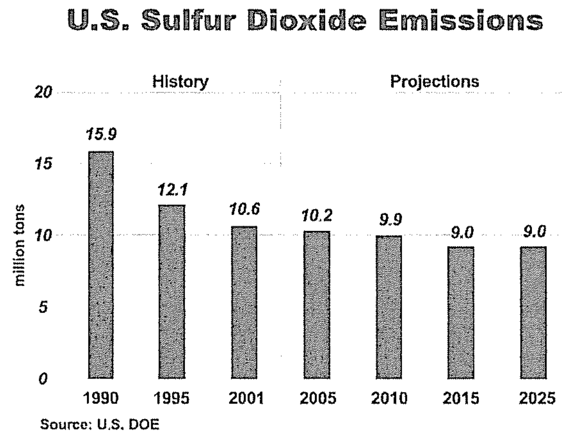


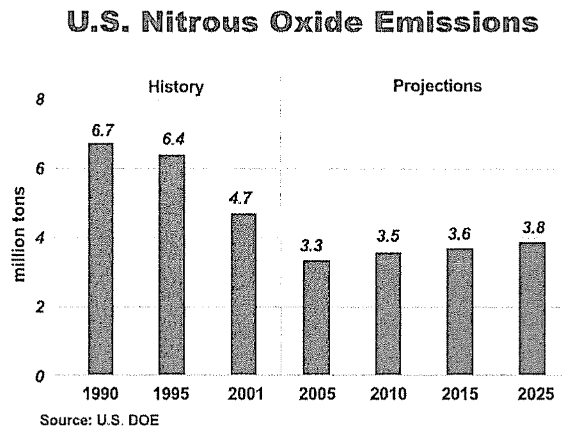
forthcoming in 2005. Carbon emissions could become targeted for reduction.

The United States has made significant strides in controlling other energy related pollutants, particularly those identified with coal-fired electricity generation. Nationwide, sulfur dioxide emissions have been reduced by 33% and nitrous oxide emissions have been reduced by 29% from 1990 levels. Both pollutants are projected to remain well below 1990 levels for the next 20 years.

Low Cost Energy: A Kentucky Asset

According to the Bureau of Labor Statistics' *Consumer Expenditure Survey*, during the period of 2000-2002, the average American family spent about $2,500 annually on "utilities, fuels and public services."[6] This accounted for about 5.5% of total family expenditures, exceeding the cost of health care each year by an average of $450. The cost of energy and public services increased by 8.2% over the period.





In 2002, Kentucky residents on average enjoyed the lowest-cost residential electricity rates in the nation[7]. Consider how Kentucky's residential electricity rates compare with surrounding states:

- 9% lower than West Virginia residents.
- 12% lower than Tennessee residents.
- 18% lower than Indiana residents.
- 20% lower than Missouri residents.
- 27% lower than Virginia residents.
- 32% lower than Ohio residents.
- 33% lower than Illinois residents.
- 33% lower than the national average.

[6] See the Consumer Expenditure Survey (2002). Bureau of Labor Statistics. www.bls.gov Note: Further disaggregation of category not available.

[7] Calculations based upon "cents per kilowatt hour." U.S. Department of Energy, Energy Information Administration, "State Electricity Price, 2002." www.doe.gov

The three largest coal producing states—Wyoming, West Virginia and Kentucky—have the three lowest electricity costs in the nation. Projections indicate that states with significant coal fired generation within their energy portfolio should, with the proper policy environment and attention to energy efficiency, continue to enjoy the benefits of low cost electricity. By the year 2025, the cost of producing electricity from petroleum or natural gas is projected to be about four times more expensive than the cost of producing electricity from steam coal.[8]

"Kentucky's abundant energy resources have placed the state in an enviable position. They offer us the opportunity to grow our economy and improve the lives of all Kentuckians. I can assure you that the Kentucky Public Service Commission will do everything in its power to help Kentucky seize that opportunity."

Mark David Goss, Chairman of the Kentucky Public Service Commission.

"Kentucky enjoys a tremendous competitive advantage in the provision of energy, natural gas and water supply. The state's large coal reserves and their resulting proximity to coal burning utility plants, its direct location on the interstate gas pipeline corridor... keep Kentucky's utility costs among the very lowest in the nation. In turn, a large number of utility providers and oversight by the Kentucky Public Service Commission continue to ensure competitive rates for the consumer."[10]

Although recent initiatives have focused on diversifying Kentucky's economic portfolio, the state remains firmly rooted in the industrial economy. According to the U.S. Bureau of Economic Analysis, in 2001—the most recent data available—25% of Kentucky's economic output came from the manufacturing sector.[11] Large industrial sectors in Kentucky include:

Industry	Employees	Average Salary
Automotive	53,000+	$50,000
Aluminum	15,000+	$50,000
Plastics	13,000+	$33,000

Furthermore, a number of Kentucky's largest manufacturing industries are very energy intensive. Kentucky's electric power cost in the industrial sector has ranked among the lowest in the nation for many years.

Mutually Inclusive Goals: Energy Development, Economic Development and Environmental Quality

According to researchers at Stanford University's Center for Environmental Science and Policy, "energy development, broadly defined to mean increased provision and use of energy resources, is an integral part of enhanced economic development."[9]

Kentucky's reliable, low-cost energy is a competitive advantage for the state. According to the Cabinet for Economic Development:

[8] Energy Information Administration, U.S. Department of Energy. www.doe.gov

[9] Toman, Michael & Jemelkova, Barbora. "Energy and Economic Development: An Assessment of the State of Knowledge." Center for Environmental Science and Policy/Program on Energy and Sustainable Development. Stanford University.

[10] Kentucky Cabinet for Economic Development. See www.thinkkentucky.com

[11] For comparison: North Carolina 21%; Tennessee 18%; U.S. Average 14%. See www.bea.gov

Kentucky's Competitor States Energy Affordability Rankings

Kentucky	1	Alabama	8
West Virginia	2	Arkansas	9
Tennessee	3	Georgia	10
Indiana	4	North Carolina	11
Virginia	5	Mississippi	12
Missouri	6	Ohio	13
South Carolina	7	Illinois	14

Source: Kentucky Cabinet for Economic Development.[12]

Energy costs are also an important factor in agricultural production costs. According to the U.S. Department of Agriculture, the "difference in the production cost per acre between high and low cost (corn and soybean producers) stems mostly from four expenditure items" which include fuel and electricity.[13] On average, energy costs account for:

- 15% of production costs for corn producers.
- 11% of production costs for soybean producers.
- 17% of production costs for wheat producers.

Livestock growers also face significant energy related costs. Kentucky's livestock farmers realize some significant advantages in low cost energy. For example, where energy costs account for 5.2% of the average Kentucky dairy farm's operating costs, those costs are 25% higher in Tennessee, 30% higher in Illinois and 46% higher in Wisconsin.[14]

"The existing industrial base of Kentucky relies on low-cost electricity to maintain its regional, national and international economic competitiveness."

Kentucky Industrial
Utility Customers

According to David Beck, Executive Vice President of the Kentucky Farm Bureau, "electric rates are a major concern for our members, many of whom are farmers who, in most instances, will use more electricity than the average household. Kentucky enjoys the lowest electric rates in the United States. This is obviously a great benefit and we would like to see this remain the case."[15]

While Kentucky's economy has grown—although at a slower rate than our competitor states—indicators suggest that air quality, a significant envi-

"Kentucky has the lowest electric rates in the United States—a major plus for industrial development. Low utility rates attract jobs and investment to the Commonwealth."

Kentucky Chamber
of Commerce

[12]Derived from data provided by the *North American Business Cost Review*, 10th Edition, Prepared by Economy.com, Inc.

[13]U.S. Department of Agriculture, Economic Research Service. See www.usda.gov

[14]U.S. Department of Agriculture, Economic Research Service. See www.usda.gov

[15]David S. Beck. *Letter from Kentucky Farm Bureau to the Commonwealth Energy Policy Task Force.*

ronmental measure, within the state has dramatically improved. Airborne pollutants—carbon monoxide, sulfur dioxide, nitrogen oxide, ozone and particulate matter—have significantly declined since 1980. According to Kentucky's Environmental and Public Protection Cabinet[16]:

- Statewide and regional sulfur dioxide levels have declining trends over the past 20 years due at least in part to successful efforts of power plants to curb emissions.

- Statewide and regional nitrogen dioxide levels show steady downward trends due to the use of pollution control devices on... power plants and industrial boilers.

Kentucky Farm Bureau Policy States: "Steps should be taken to maintain Kentucky's favorable utility rates."

Energy Efficiency: Saving Energy, Saving Money and Protecting the Environment

A sound energy policy requires balancing supply and demand forces in the market. On the demand side, efficient energy use and conservation can reduce overall energy costs and help address environmental issues.

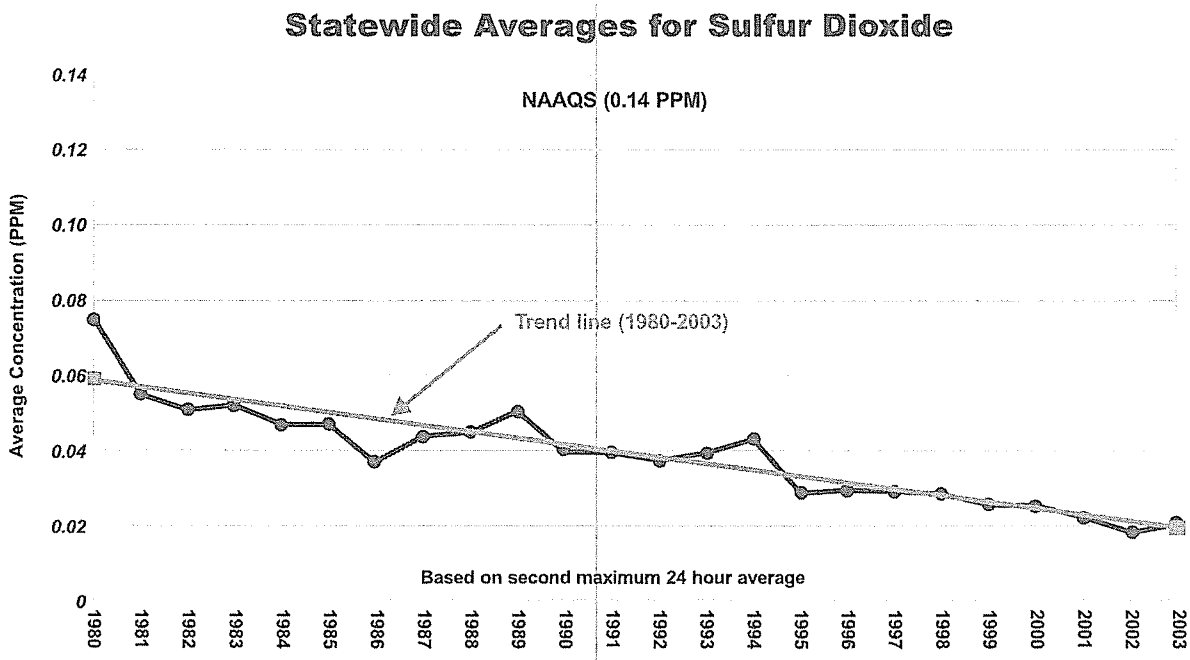
Energy efficiency means using advanced and state-of-the-art technologies to provide better quality energy services with less energy or, in more practical terms, receiving the same (or improved) results from our appliances, office equipment, and buildings while using less energy. Energy efficiency reduces utility bills, provides for more comfortable homes and buildings, increases profitability, and helps improve the quality of the environment.

The United States has made impressive gains in energy efficiency. For example, new refrigerators require just one-third the electricity as they did 30 years ago. Since 1973, the U.S. economy has grown by 126 %, while energy use has increased by only 30%. In the 1990s alone, manufacturing output expanded by 41%, while industrial electricity consumption grew by only 11%.

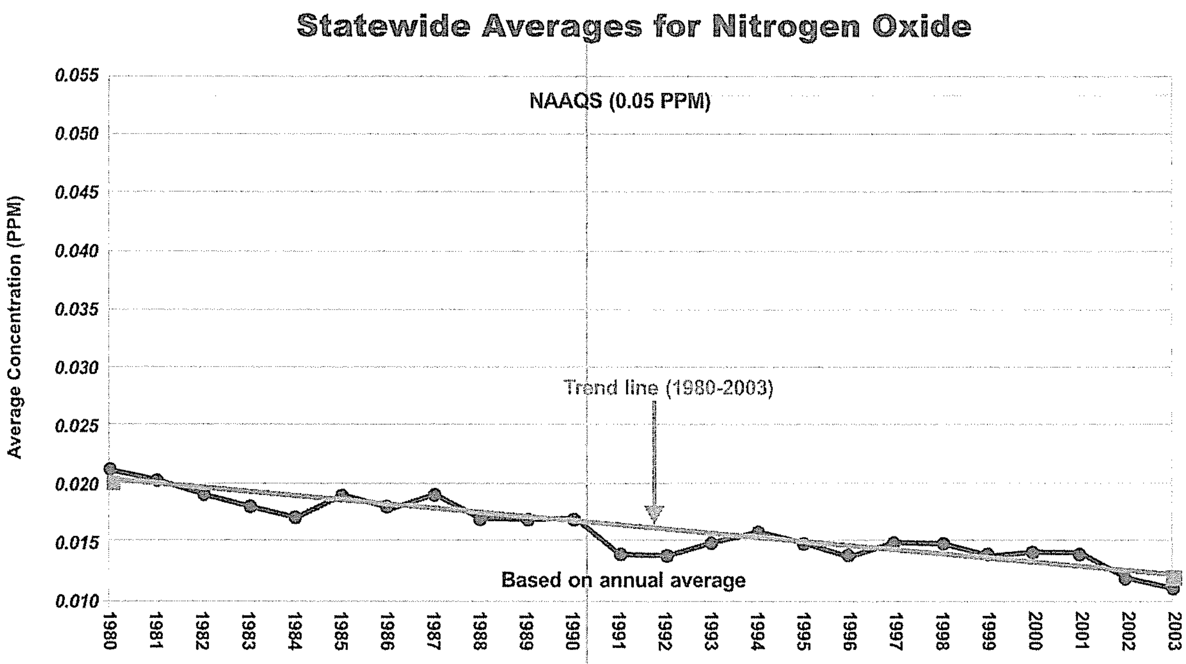
Over the years, Kentucky's low electricity rates have encouraged energy-intensive practices, processes and procedures. This historic energy intensity provides a great opportunity for energy efficiency to help lower consumption, reduce energy bills and improve the environment. Kentuckians should not only enjoy the lowest electricity rates in the nation but also the lowest electricity bills in the nation.

Since the passage of the Clean Air Act of 1970, the coal based electric industry has spent more than $50 billion nationwide to comply with environmental regulations.

[16]Kentucky Air Quality Annual Report—2003. Cabinet for Environmental and Public Protection. www.environment.ky.gov



Source: Kentucky Environmental and Public Protection Cabinet



Source: Kentucky Environmental and Public Protection Cabinet

Kentuckians can gain from improved energy efficiency. Note that:

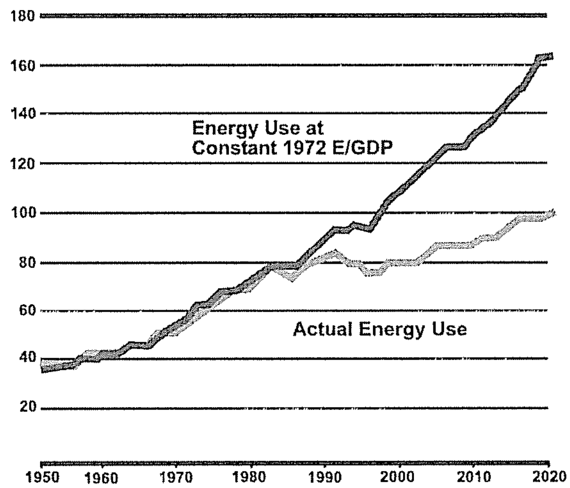
- Kentucky residents actually paid 1% more on their electric bills than West Virginia residents (even though our electricity rates are 9% lower).
- Although our electricity rates are 18% lower than Indiana's, our residents paid only 6% less on their electric bills.
- On an average monthly electric bill, Kentucky's schools spend 7% more per student than the national average
- The average Kentucky industrial bill is 123% higher than the national average.
- Kentucky's average residential electric rate is 33% less than the national average but the average residential bill is only 17% below the national average.

"Frequently overlooked, efficiency is usually our best form of 'alternative energy.' And quite often, the one most readily adaptable to every situation."

James Dontje, Department of Sustainability and Environmental Studies, Berea College

There are significant gains to be realized by increasing and promoting energy efficiency, especially in Kentucky's residential sector, which ranks eighth in the nation for electric intensity (kWh per customer). Even with its historically low electricity rates, Kentuckians have not fully realized the savings and environmental benefits associated with improved energy efficiency.

Energy Efficiency Gains in U.S. Economy



Note: If the intensity of U.S. Energy use had remained constant since 1972, consumption would have been about 74 percent higher in 1999 than it actually was.

State Government: Leading by Example

Energy costs for state government are escalating. In 2003, utility costs for state agencies were 12% higher than in the previous year. In 2004, state agencies used about 4% more energy than they did the same time the year before—with a cost increase of about $1.7 million.

"Through energy efficiency Americans saved a significant amount of energy in 2003, about 110 billion kilowatt hours (kWh) and 20,000 megawatts (MW) of peak power, the amount of energy required to power about 20 million homes. They also prevented emissions equivalent to those from 18 million automobiles - while saving $8 billion on their energy bills."

U.S. Environmental Protection Agency

2003 State Utility Expenditures

State Government Facilities	$ 41 million
Post Secondary Schools	$ 54 million
K-12 Schools	$107 million
Judicial Branch	$ 4 million
Total	$206 million

Source: Kentucky Division of Energy

These costs are manageable. Other states have demonstrated this. In Fiscal Year 2003, South Carolina public facilities saved $4.4 million in energy costs compared to fiscal year 1998 as a result of improved energy efficiency. It is estimated that Kentucky's state government could reduce energy costs by 10%—up to $20 million—with a comprehensive energy management program.

Recommendation 1:

The Commonwealth of Kentucky, through the Finance and Administration Cabinet, should dedicate staff toward implementing an aggressive and sensible utility savings initiative throughout state government and other state-funded institutions to improve energy efficiency.

Kentucky's residential customers consume 28% more electricity than the national average. Reducing our consumption to the national average would result in a 22% reduction in the average resident's bill or about $14 per month.

Recommendation 2:

The Commonwealth of Kentucky should develop and implement procurement polices that encourage sustainable practices, products and energy efficiency.

Recommendation 3:

The Commonwealth of Kentucky should encourage high performance, energy-efficient design for new construction of state facilities.

Recommendation 4:

The Commonwealth of Kentucky should require interagency cooperation to promote energy efficiency initiatives.

Consumer Outreach and Awareness

The choices we make when purchasing products, operating homes, schools and businesses, driving cars, and designing buildings can have a tremendous impact on Kentuckians' budgets and the state's environment. Energy efficiency delivers improved energy savings and an improved quality of life.

The ENERGY STAR program is a voluntary partnership between U.S. EPA, U.S. Department of Energy (DOE), product manufacturers, local utilities, state and local government agencies and retailers. ENERGY STAR works to improve the energy efficiency of products, homes, and commercial buildings and schools. As the symbol for energy efficiency, the ENERGY STAR label identifies highly efficient products for homes and commercial buildings.

Recommendation 5:

The Commonwealth of Kentucky should encourage the continued development of public-private partnerships dedicated to promoting energy efficiency through education and outreach.

Recommendation 6:

The Commonwealth of Kentucky should work with industries, businesses, schools, universities, and communities to promote and give preference to energy-efficient products and practices.

Recommendation 7:

The Commonwealth of Kentucky should support energy assessment initiatives that will help our industries and businesses improve their profitability through energy efficiency and resource management.

Recommendation 8:

The Commonwealth of Kentucky should examine its building codes and specifications to determine if enhanced energy efficiency gains are possible through progressive policy.

Educating Kentucky's Youth

Youth education is important as energy issues take on greater importance. The energy choices and challenges will become increasingly complicated as the nation and the world balance the need for energy supply with the importance of increasing energy efficiency and conservation.

The non-profit National Energy Education Development (NEED) currently works within Kentucky's schools to educate our students on the energy issues facing the state and nation. The mission of NEED is "to promote an energy conscious and educated society by creating effective networks of students, educators, business, government and community leaders to design and deliver objective, multi-sided energy education programs."[17]

Parents and community leaders should teach sound energy policy to today's youth, the leaders of tomorrow.

Recommendation 9:

The Commonwealth of Kentucky should pursue funding opportunities to strengthen K-12 energy education.

[17]National Energy Education Development. www.need.org

Kentucky should develop "programming that will cultivate an awareness of energy and energy issues, a program that will be sustainable for years to come. A program that will not only provide an energy curriculum, but one that will promote an understanding of the importance of making wise energy decisions."

Karen Reagor,
Executive Director, Kentucky NEED.

If all consumers, businesses and organizations in the United States made their product choices and building improvement decisions with ENERGY STAR over the next decade, the national annual energy bill would be reduced by about $200 billion.

Renewable Energy: A Sustainable Commitment

During the 2004 regular session of the Kentucky General Assembly, the Fletcher Administration joined with utilities, environmental groups and other stakeholders in supporting landmark net-metering legislation for the state. Kentucky became one of 34 states that allow their utility customers to benefit from a home or business-based renewable energy generating system.

The Fletcher Administration has implemented an initiative to encourage state parks, wherever feasible, to utilize biodiesel in vehicle fleets and has purchased the first hybrid electric vehicles for use by executive branch agencies.

Many of the state's universities are committed to renewable energy research. The University of Louisville is investigating how to improve ethanol production from corn, soybeans and other carbon-based natural products. The University of Kentucky is exploring methods to convert biomass resources directly into liquid transportation fuels.

Our universities are also conducting cutting-edge research on fuel cells and hydrogen technologies "that have the potential to solve several major challenges facing America today: dependence on petroleum imports, poor air quality and greenhouse gas emissions."[18]

The growth potential in renewable resources is especially strong in our transportation sector, where Kentucky is in an enviable position to take advantage of the emerging biodiesel and ethanol markets. A strong biofuels market offers myriad benefits—improved health through reduced emissions of harmful pollutants, improved air quality, and improved economic growth, particularly in agriculture. Throughout Kentucky, the use of clean transportation fuels such as natural gas, ethanol, propane, and biodiesel has increased in recent years in both public and private vehicle fleets.

Tom Fitzgerald, Kentucky Resources Council

In 2004, the federal government passed legislation that contains incentives to promote the biodiesel and ethanol markets. According to the United States Department of Agriculture, the federal incentive could add almost $1 billion to the bottom line of farm income.

A strong biofuels market offers myriad benefits—improved health through reduced emissions of harmful pollutants, improved air quality, and economic growth, particularly in agriculture.

Using biodiesel in a conventional diesel engine substantially reduces emissions of unburned hydrocarbons, carbon monoxide, sulfates, polycyclic aromatic hydrocarbons, nitrated polycyclic aromatic hydrocarbons and particulate matter.

Biodiesel fuel specifications have been written by the Finance and Administration Cabinet, enabling

[18] Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy. www.eere.energy.gov

fuel suppliers to bid on this fuel as they do standard diesel and gasoline. The state diesel fuel use annually is roughly 2.4 million gallons.

Ethanol is a clean-burning fuel that can be made from corn. Ethanol production is an ideal market for Kentucky farmers, who produce 166 million bushels of corn per year.

Ethanol is sold nationwide as a high-octane fuel that delivers improved vehicle performance while reducing emissions and improving air quality. By reducing foreign oil imports, ethanol creates American jobs and provides value-added markets to bolster agriculture and rural America.

Ethanol improves combustion of petroleum fuels, reduces carbon monoxide (CO) emissions, reduces particulate matter (PM) emissions, reduces oxides of nitrogen (NOx) emissions, reduces smog-forming volatile organic compounds (VOC) and is highly biodegradable.

Ethanol is sold nationwide as a high-octane fuel that delivers improved vehicle performance while reducing emissions and improving air quality. By reducing foreign oil imports, ethanol creates American jobs and provides value-added markets to bolster agriculture and rural America.

Research by the U.S. Department of Energy and U.S. Department of Agriculture shows that, for every 100 BTUs of energy used to make ethanol, 135 BTUs of ethanol is produced. That is a positive net energy balance of 1:1.35.

All motor vehicles manufactured since the 1970s can run on E10, a blend of 10 percent ethanol. E10, which does not require engine modifications, also significantly lowers carbon monoxide levels. E10 is required in Louisville and Northern Kentucky near Cincinnati for clean air mandates.

In 2003, two million gallons of biodiesel were produced in Kentucky, with 300,000 gallons consumed in Kentucky. In 2003, 24 million gallons of ethanol were produced in Kentucky, and 12 million gallons were consumed in Kentucky. A lack of retail distribution has impeded consumption of cleaner fuels.

Recommendation 10:

The Commonwealth of Kentucky should require its state fleet to utilize a 10% blend of ethanol (E10) and gasoline and a 2% blend of biodiesel (B2) wherever these clean fuels are available, and encourage Kentucky's post-secondary institutions to adopt similar initiatives.

Recommendation 11:

The Commonwealth of Kentucky should design and implement policy to promote the production, consumption and availability of biodiesel and ethanol within Kentucky.

Children riding on a diesel-powered school bus are exposed to four times the level of diesel exhaust as someone standing or riding beside the bus. Research shows that diesel exhaust may exacerbate asthmatic conditions. Children comprise 25% of the population, but comprise over 40% of all asthma cases.

Recommendation 12:

The Commonwealth of Kentucky should design policy to promote the utilization of a 20% blend of biodiesel in the public school bus fleet.

"We owe our students a safe and healthy ride to and from school each day."

Melissa Howell, Executive Director of the Kentucky Clean Fuels Coalition.

Kentucky's Low Cost Electricity: Strategic Investment

Libby Marshall, Municipal Electric Power Association of Kentucky

Kentucky enjoys some of the lowest rates of electricity in the nation. This provides significant benefits to Kentucky's residential consumers and is a comparative advantage in recruiting and retaining industry.

It is shortsighted, however, to think that these advantages are guaranteed. Kentucky must strategically develop its energy portfolio to ensure that the state continues to enjoy the benefits of low-cost electric.

The Strategic Blueprint

The Kentucky Public Service Commission (PSC) collects information related to the projected needs for future generations. However, there is no comprehensive assessment of statewide needs that could serve as a blueprint for strategic investment.

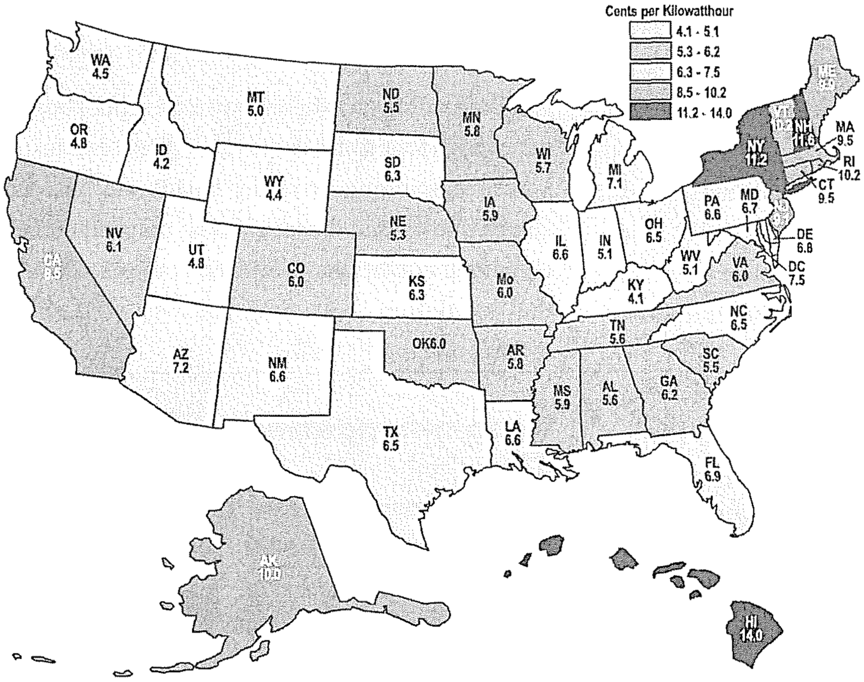
Recommendation 13:

The Commonwealth of Kentucky should develop a comprehensive statewide assessment of Kentucky's electricity infrastructure—generation, transmission and distribution—which includes reasonable projections of future electricity requirements.

Kentucky enjoys some of the lowest rates of electricity in the nation. This provides significant benefits to Kentucky's residential consumers and is an advantage in recruiting and retaining industry. It is shortsighted, however, to think that these advantages are guaranteed.

Figure 10: Kentucky's Low Cost Electric - A Comparison

Average Revenue from Electricity Sales for All Sectors, Year 2000



Source: Kentucky Public Service Commission

Recommendation 14:
The Commonwealth of Kentucky should periodically update the comprehensive statewide assessment to reflect changes in both electric infrastructure and future electricity requirements.

Recommendation 15:
The Commonwealth of Kentucky assessment should serve as a "strategic blueprint" for policy-makers to determine future investment requirements in Kentucky's electricity generation, transmission, and distribution infrastructure.

Recommendation 16:
The Commonwealth of Kentucky should utilize the "strategic blueprint" to develop policies that promote sufficient investment in electricity infrastructure—generation, transmission and distribution—to sustain Kentucky's low cost electricity into the future.

Recommendation 17:
The Commonwealth of Kentucky should identify impediments to investment in electricity generation, transmission and distribution and develop policies to promote investment while ensuring that appropriate environmental protections are maintained and local voices are heard.

"A long history of legal decisions requires that... regulated utility companies must make a reasonable profit. Nonetheless, it is critical to make sure that those rates are as low as they reasonably can be without jeopardizing the health of the regulated companies."

Dennis Howard, Assistant Attorney General, Office of the Kentucky Attorney General

"Renewable energy sources are already recognized for their potential to help develop our energy security, improve environmental conditions and public health, and control consumer energy costs. The possibility that, in addition to these indirect benefits, renewable energy sources could help spur economic development... provides an interesting and valuable option to state policy-makers."

Council of State Governments

An Enhanced Renewable Portfolio

According to the U.S. Department of Energy, renewable energy resources' contribution to electricity generation will increase by 38% by 2025. In 2002, renewables and hydroelectric generation contributed a combined total of 4.6% of Kentucky's electric generation capacity. New electric-generation technology is providing the opportunity for renewables—i.e. wood waste, landfill gasses, biomass, solar and wind—to supplement primary resources in electricity generation. These advances make significant contributions to environmental concerns. Mixing renewables with primary resources helps lower emissions.

Recommendation 18:
The Commonwealth of Kentucky should design and implement policies that promote, but do not mandate, the use of renewable energy resources in Kentucky's electricity generation portfolio.

Coal: Energy at Kentucky's Feet

A thorough discussion of Kentucky's low-cost electric must include the role played by coal. Ninety percent of Kentucky's electricity is produced from coal-fired generation.[19] Historically, coal has proven to be the least costly fuel for electric generation. The U.S. Department of Energy (DOE) projects that this will remain the case over the next 20 years.

Electric Power Prices by Year and Energy Source.
(2002 Dollars per million BTU)

	2002	2010	2015	2020	2025
Petroleum	$4.32	$4.21	$4.54	$4.67	$4.88
Natural Gas	$3.77	$4.04	$4.78	$4.85	$4.92
Steam Coal	$1.26	$1.22	$1.22	$1.20	$1.22

Source: U.S. Department of Energy, Energy Information Administration.

According to DOE, Kentucky ranked third in the United States—behind Wyoming and West Virginia—in coal production in 2002, providing 11.3% of the nation's aggregate production. Kentucky produced 131.4 million tons of bituminous coal in 2002, down from the record, of 179.4 million tons, set in 1990. Estimates indicate that there are 35.8 billion tons of remaining coal reserves in Western Kentucky and 52.3 billion tons in Eastern Kentucky.

"As coal demand grows, new coal-fired generating capacity is required to use the best available control technology (scrubbers or advanced coal technologies), which can reduce sulfur emissions by 90% or more, providing market opportunities for higher sulfur coal."

U.S. Department of Energy

Air quality emission requirements present a significant challenge to the Kentucky coal industry. Electric power plants purchased 67.5% of Kentucky's coal in 2002. According to the Energy Information Administration, "The use of western (United States) coals can result in up to 85% lower sulfur dioxide emissions than the use of many types of higher sulfur eastern (United States) coals." From 2000 to 2002, Kentucky actually *imported* 2.5 million tons from Colorado and Wyoming.

Promoting Kentucky's Coal Industry through Clean Coal Technology

According to the Department of Energy, "As coal demand... grows new coal-fired generating capacity is required to use the best available control technology (scrubbers or advanced coal technologies), which can reduce sulfur emissions by 90% or more, providing market opportunities for higher sulfur coal."[20] Therefore, the Kentucky coal industry can realize benefits from the electricity generation industry investing in "clean coal technology."

Clean-coal technology describes a new generation of energy processes that sharply reduces air emissions and other pollutants compared to older coal-burning systems. For example, power plants utilizing Integrated Gasification Combined Cycle (IGCC) generation "can significantly reduce air emissions, water consumption and solid waste production," and offer "the potential of a technical pathway for cost effective separation and capture of carbon dioxide (CO^2) emissions and for co-production of

[19] U.S. Department of Energy, *Energy Information Administration-State Electricity Profiles 2002.* See www.doe.gov

[20] Energy Information Administration. U.S. DOE. www.doe.gov

hydrogen."[21] Investments in clean coal technology will allow for low-cost Kentucky coal to continue to be utilized as a primary energy resource in the United States while significantly reducing undesirable emissions.

Recommendation 19:

The Commonwealth of Kentucky should examine its regulatory policies and traditional economic-development incentives to design and implement policies that promote investment in clean coal technology.

Recommendation 20:

The Commonwealth of Kentucky should develop policies to provide incentives for the purchase of Kentucky coal at clean-coal facilities.

Promoting New Growth in Kentucky's Coal Industry

The Surface Mining Reclamation and Control Act requires coal operators to post a reclamation bond sufficient to reclaim the mine site in the event that operators do not meet their obligation to do so. A reclamation bond must be posted before a surface mining permit can be issued.

In an effort to provide a viable bonding alternative for medium-to-small coal companies, the state legislature created the Kentucky Bond Pool Fund in 1986. The Kentucky Bond Pool is administered by the Bond Pool Commission and is required to maintain a level of funding adequate to meet the bonding commitments of the member companies.

On an industry-wide basis, bonds have become increasingly more difficult to obtain. The tightening of the bond market, coupled with a booming coal market, has placed an increased demand on the Kentucky Bond Pool. At current funding levels, the Kentucky Bond Pool faces limitations in its capacity to take on additional bond liability to keep pace with the increasing demand.

Recommendation 21:

The Commonwealth of Kentucky should ensure that the Kentucky Bond Pool Fund is sufficiently enhanced to promote the growth and productivity of Kentucky's coal mining industry.

Recommendation 22:

The Commonwealth of Kentucky should examine its current mine permitting policies and identify streamlining opportunities.

Companies are finding that it makes economic sense to construct generation capacity directly at coal sites to diminish transportation costs. The coal is then utilized to generate electricity, which may then be used to serve Kentucky's native load requirements or sold to utilities in Kentucky or other states.

One benefit of siting generation at coal sites is that it adds value to the energy resource through jobs in the mining industry and at the generation plants. Further, the proposed plants must conform to the environmental requirements of the state so environmental concerns are addressed before any construction begins.

Recommendation 23:

The Commonwealth of Kentucky should design and implement policy to promote electricity generation at Kentucky mine sites.

[21] Rosenberg et al. "Deploying IGCC in this Decade-Volume II." John F. Kennedy School of Government, Harvard University.

Other states are investing in the coal industry. For example, Illinois's Coal Infrastructure program provides grants that match private sector investment aimed at improving coal production, transportation and utilization systems. In 2003, $17 million of state grants leveraged $128 million in private investment from the industry.

Recommendation 24:

The Commonwealth of Kentucky should design policy to promote capital investment within the coal industry.

Additionally, the Department of Energy is promoting research and development into coal gasification as an alternative to conventional petroleum-based fuel. According to the Office of Fossil Energy, "Coal gasification offers one of the most versatile and cleanest ways to convert the energy content of coal into electricity, hydrogen, and other energy forms."[22] This research could provide new markets for Kentucky coal.

Recommendation 25:

The Commonwealth of Kentucky should support projects and initiatives intended to open new markets for Kentucky coal.

Investing and Protecting Kentucky's Coal Workforce

In 2002, the coal industry directly employed over 15,500 people at an average wage of $47,000 per year. According to a study by the University of Kentucky, "the $3.15 billion in receipts from coal produced and processed in Kentucky... generated additional economic activity totaling $3.69 billion and 41,407 jobs. This additional economic activity, plus coal production and processing, yielded total economic activity in Kentucky of $6.84 billion and 56,219 jobs."[23]

While Kentucky's coal industry continues to employ a significant number of people, employment has been on a downward trend since the 1970s. The recent uptick in coal demand has been complicated by the fact that the coal industry is facing a shortage of qualified miners due to retirements of the current generation and a lack of sufficient training in the next generation.

U.S. Department of Labor officials have said that "Mining is experiencing a dramatic transformation as the industry takes advantage of advanced technology." The Department of Labor is looking at initiatives "to make sure that its workers have the education and training to take advantage of new job opportunities in the mining industry."

According to an article by the Associated Press, "America is looking for coal miners." It continued, "the labor shortage isn't just a problem today; the real crunch... will occur in five to seven years, when the industry faces a massive retirement wave." Additionally, "the worker shortage is so pervasive, it has reached into the ranks of state and federal agencies... which need employees familiar with mine work."[24]

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[22] Office of Fossil Energy, U.S. Department of Energy. www.doe.gov

[23] Source: Updated from University of Kentucky Center for Business and Economic Research. Economic Impact Analysis of Coal in Kentucky, (1995) for 2000 by Haywood and Baldwin. See *Kentucky Coal Facts 2003-2004.*

[24] Sheehan, Charles. "Coal Industry Battles Worker Shortage." Associated Press, Oct. 21, 2004.

tion as the industry takes advantage of advanced technology... The Department of Labor is looking at initiatives "to make sure that their workers have the education and training to take advantage of new job opportunities in the mining industry." [25]

According to the federal Department of Labor, "the rate of fatal accidents has steadily been decreasing since 2000. The challenge now is dealing with preventable problems caused by people who are impaired by drugs or alcohol."

Recommendation 26:

The Commonwealth of Kentucky should partner with post-secondary institutions and industry to develop and invest in a program targeted at workforce development within the coal industry.

Recommendation 27:

The Commonwealth of Kentucky should partner with post-secondary institutions and industry to pursue federal resources to implement workforce development initiatives for the coal mining industry.

Recommendation 28:

The Commonwealth of Kentucky should partner with the Southern States Energy Board to develop a model workforce development initiative that can be replicated in other coal-producing states.

Even well-trained miners can face challenges on the job if they are wrestling with a substance-abuse problem. According to the federal Department of Labor, "the rate of fatal accidents has steadily been decreasing since 2000. The challenge now is dealing with preventable problems caused by people who are impaired by drugs or alcohol."[26]

[25] Employment and Training Administration, U.S. Department of Labor. www.dol.gov

[26] Biesk, Joe. "State, Federal Officials Plan Campaign Against Drugs in Mines." Associated Press, October 28, 2004. Quote from Dave Lauriski, U.S. Assistant Secretary of Labor.

Recommendation 29:

The Commonwealth of Kentucky should partner with the federal government, the mining industry, employee organizations and with other coal producing states to study the extent of the drug and alcohol problems in the mines.

Recommendation 30:

The Commonwealth of Kentucky should partner with the mining industry and employee organizations to develop policies that promote drug screening and rehabilitation within the mining industry.

Recommendation 31:

The Commonwealth of Kentucky should pursue federal funding opportunities to promote drug screening and rehabilitation within the mining industry.

Responsible Development of Kentucky's Energy Resources

The Department for Natural Resources has partnered with the University of Kentucky and the Environmental Quality Commission to promote "the planting of high-value hardwood species on mined lands."[27] As a result:

"There has been a growing interest in reforestation within the mining industry... the Department (for Natural Resources) has worked closely with UK on the development and construction of approximately 50 acres of reforestation test plots on the Starfire Mine in Breathitt County. The emphasis has been on the establishment and growth of desirable hardwood species (white oak, red oak,

[27] Source: www.surfacemining.ky.gov

white ash, black walnut, yellow poplar, royal paulownia and eastern white pine). The data indicates that surface-mined lands are very capable of supporting high-value forest if properly reclaimed."[28]

In addition to the Starfire project, and through funding from the U.S. Forest Service and U.S. Department of Energy, more than one million native hardwood trees have already been planted on approximately 1,500 acres throughout the Kentucky coal fields. When this project is complete, more than two million trees will have been planted on 3,000 acres throughout the coalfields.

The Starfire Mine site is also one of the four locations where elk have been reintroduced into eastern Kentucky. These reclaimed surface mines serve as a friendly habitat to what is becoming a thriving elk population (4,600) in eastern Kentucky.

The Appalachian Wildlife Initiative (AWI) is a recent partnership between the Department for Natural Resources, the Kentucky Department of Fish and Wildlife Resources and the Rocky Mountain Elk Foundation. The AWI ultimately should provide for the reestablishment of an improved wildlife habitat that will, for the most part, employ the reclamation techniques used to restore healthy hardwood forest on mined land. These reclaimed areas should provide a wonderful opportunity for both eco-tourism and recreational hunting. The goal of the AWI and the Kentucky Reforestation Initiative is to demonstrate that progressive reclamation techniques can balance the responsible development of Kentucky's energy resources with a commitment to environmental quality and commercial opportunity.

The data indicates that surface-mined lands are very capable of supporting high-value forest if properly reclaimed.

Recommendation 32:

The Commonwealth of Kentucky should continue to promote progressive reclamation practices through reforestation and the creation of wildlife habitats that support environmental restoration and enhanced economic development and tourism opportunities.

Recommendation 33:

The Commonwealth of Kentucky should design and implement policies that promote the recovery of the energy resources inherent to abandoned coal refuse and the proper reclamation of those properties.

Area Mining is a method of mining currently authorized by the Surface Mining Control and Reclamation Act of 1977. The issue of area mining has been discussed for many years in Kentucky. The need to support a cost-effective method of coal mining must be balanced with the environmental concerns surrounding it. Further, the method is conducive to the creation of post-mining land use for commercial, industrial, residential or agricultural development.

"Over a 5-year period, about 1,500 elk were released at eight different locations in the eastern coal fields. Now it is estimated that there are more than 4,000 elk in Kentucky and we are on our way to reaching the state's population goal of 8,000 elk over a 16 county area."

David Ledford, Rocky Mountain Elk Foundation

The Fletcher Administration has taken a number of recent actions to balance the responsible development of Kentucky energy resources with main-

[28] Source: www.surfacemining.ky.gov

taining a commitment to environmental quality. In 2004, there was only one permit issued for area mining in Kentucky. The Fletcher Administration has worked closely with the coal industry to develop mining plans that reduce the volume and acreage of hollowfills, thereby decreasing the adverse impacts on our streams. Compared to statistics for the year 2000, the average volume of hollowfills has been reduced by 57% and the average acreage of hollowfills has been reduced form 16 to 12.

In addition, the Fletcher Administration is participating in an interagency task force that is evaluating the impact of coal mining methods and hollowfills on our natural resources. Participants in this effort include the federal Office of Surface Mining, US EPA, US Army Corps of Engineers, US Fish and Wildlife Service, Kentucky Department for Fish and Wildlife Resources and the Kentucky Department of Environmental Protection.

The federal Office of Surface Mining Reclamation and Enforcement (OSM) has proposed to amend certain regulations related to area mining. The Fletcher Administration is monitoring the actions of OSM on this new proposed rule and will be developing changes to Kentucky's regulatory program to accommodate the federal rule change.

Additional consultation on area mining to determine whether common ground can be found is warranted. By bringing various groups to the table, progressive policy aimed at promoting the vitality of the coal industry and addressing environmental concerns could be developed.

Recommendation 34:
The Commonwealth of Kentucky should monitor the proposals of the Office of Surface Mining surrounding the issues of area mining and determine what appropriate changes should be made to the current state regulatory program to bring it in line with proposed federal rule changes.

Recommendation 35:
The Commonwealth of Kentucky should support dialogue between appropriate energy and environmental parties to determine the policy options related to area mining within the context of the proposed federal rule changes.

Innovative research is being conducted to transform waste into non-hazardous byproducts that, when mixed with combustible coal, lower sulfur emissions. The research could potentially take the trash out of Kentucky's landfills and create "value-added" industries.

Recommendation 36:
The Commonwealth of Kentucky should design and implement policies to promote the transformation of waste into value-added products, particularly directed at opportunities to reduce the environmental impact of coal-fired emissions.

Kentucky's Natural Gas: Untapped Potential

According to the Energy Information Administration (EIA), "total natural gas consumption (in the United States) is projected to increase" for the next 20 years.[29] Growth in demand is expected in each economic sector: residential, commercial, industrial and transportation. The EIA continues, "domestic natural gas consumption is met by domestic production and net imports. All forecasts show domestic production providing a decreasing share of total natural gas supply."[30]


Dr. Jim Cobb, Director - Kentucky Geological Survey

Kentucky has 1.9 billion cubic feet of proven natural gas reserves—or about 1% of the nation's proven reserves. In 2002, Kentucky produced over 86 million cubic feet of natural gas. If this gas was wholly consumed within the state (which it was not) Kentucky's production would have accounted for only 41% of the state's consumption. Consequently, Kentucky is a net importer of natural gas.

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Investment in Natural Gas Infrastructure

Recent complications have impeded the responsible development of Kentucky's natural gas reserves. Getting natural gas from the field to the interstate pipelines that cross the state has been made difficult due to significant infrastructure barriers. Consequently, a number—some estimates suggest up to 2,000—natural gas wells are "shut in," denying the Commonwealth the opportunity to realize the benefits of jobs in the industry and increased severance revenues.

A robust natural gas infrastructure is essential to providing reliable and cost-effective service to Kentucky's consumers. Natural gas infrastructure is capital-intensive, requiring significant investment on the front end. Storage is one tool that companies use to reduce volatility in the natural gas prices passed on to consumers. According to a report from the former Kentucky Energy Policy Advisory Board, "more gas storage in Kentucky can help flatten out seasonal price curves and lead to more stable natural gas prices."[31]

Recommendation 37:

The Commonwealth of Kentucky should develop and implement policies that encourage investment in intrastate natural gas pipelines, gathering lines and distribution capacity.

[29] Annual Energy Outlook 2004-Market Trends. Energy Information Administration. www.eia.doe.gov
[30] Annual Energy Outlook 2004-Market Trends. Energy Information Administration. www.eia.doe.gov

[31] Kentucky Energy Policy Advisory Board, *An Interim Report from the Kentucky Energy Policy Advisory Board to Governor Paul E. Patton.*

Recommendation 38:

The Commonwealth of Kentucky should determine the opportunities for increased natural gas storage capacity and, if appropriate, promote its development.

Coal-Bed Methane: An Emerging Opportunity

Coal-bed methane is a promising source of energy and economic development. Coal-bed methane is defined as "methane generated during coal formation... contained in the coal microstructure."[32] Methane is the principal component of natural gas. Coal bed methane can be added to natural gas pipelines without any special treatment.

The Kentucky Geological Survey estimates that Kentucky has 848 billion cubic feet of coal bed methane. A lack of substantial research diminishes the ability to substantiate these estimates.

Methane gas is also a byproduct of refuse decomposition. Methane is being leaked into the atmosphere at many of Kentucky's landfills. Capturing this resource would supplement the state's energy portfolio and diminish the environmental impact of landfills.

Further, methane is a component part of multiple products, particularly plastics. The need for methane as an input into industrial processes provides an opportunity for Kentucky to leverage this inherent resource to expand value-added industry.

Recommendation 39:

The Commonwealth of Kentucky should promote research to accurately determine the extent of coal-bed methane and natural gas reserves in Kentucky and its prominent locations.

Recommendation 40:

The Commonwealth of Kentucky should design and implement policies to promote the recapture of methane from the state's landfills.

Recommendation 41:

The Commonwealth of Kentucky should identify the potential of coal bed methane value-added industries and, if feasible, design economic development strategies to grow those industries around the state's coal bed methane reserves.

[32] Source: Energy Information Administration. www.eia.doe.gov

Kentucky's Energy Future: A Perpetual Commitment

Kentucky does not have a high-level government organization dedicated to energy. This has not always been the case. During the energy shortages of the 1970's, Kentucky had an Energy Cabinet. Over the years, however, the dedication to energy issues has been diminished. This creates a myriad of problems:

- Energy policy is developed in an ad-hoc manner without a coordinating body promoting the responsible development of Kentucky's energy resources.
- There is no coordinating body bringing together industry and environmental concerns to discuss issues which will lead to balancing the responsible development of Kentucky's energy resources with a commitment to environmental quality.
- There is no coordinating body to encourage collaborative research and development among Kentucky's universities.
- Kentucky is at a disadvantage competing for industry investment in its energy sectors.
- Kentucky is at a disadvantage in competing for federal resources in its energy sectors.

In order to better ensure Kentucky's low-cost energy future, there must be a perpetual commitment.

Recommendation 42:

The Commonwealth of Kentucky should place a high-level emphasis on energy policy to continue the vital work necessary to ensure Kentucky's low cost energy future, the responsible development of Kentucky's energy resources and Kentucky's commitment to environmental quality.

Recommendation 43:

The Commonwealth of Kentucky should engage federal regulatory and energy agencies to ensure that the state has a 'place at the table' while energy issues are being discussed.

Recommendation 44:

The Commonwealth of Kentucky should investigate the emerging impact of global and national policies and institutions on Kentucky's energy future.

Recommendation 45:

The Commonwealth of Kentucky should partner with post-secondary institutions and industry to develop and invest in programs targeted at workforce development within the energy industry.

Low Income Assistance

Although Kentuckians enjoy the lowest electricity rates in the nation, low income citizens, particularly those on fixed incomes, have a difficult time paying their energy bills, particularly in the wintertime when natural gas and propane prices are generally higher. There are a number of programs in place to provide assistance to low income Kentuckians, and they need to be promoted better.

"There are issues being hammered out as we speak in pleadings and meetings between stakeholders, regional transmission organizations, States and the Federal Energy Regulatory Commission. For Kentucky, it is critical that we remain active and engaged in these discussions."

Jason Bently, General Counsel, Kentucky Public Service Commission

The Kentucky Association for Community Action and its Community Actions agencies, through the state's Cabinet for Health and Family Services, manage

Kip Bowmar, Kentucky Association for Community Action

Although Kentuckians enjoy the lowest electricity rates in the nation, low income Kentuckians, particularly those on fixed incomes, have a difficult time paying their energy bills.

several state and federal programs—e.g. Low Income Home Energy Assistance Program and the Weatherization Assistance Program—to help low income Kentuckians with energy issues. The Low Income Home Energy Assistance Program helps approximately 150,000 Kentucky families pay their utility bills each winter. These initiatives are vital to ensuring that these citizens are able to keep their homes warm in the winter and cool in the summer.

"Through our support of low-income programs, we attempt to help customers who are struggling with their bills manage through high natural gas prices."

Joseph Kelly, President, Columbia Gas

Recommendation 46:

The Commonwealth of Kentucky should partner with community-action agencies and the energy industry to provide energy assistance to Kentucky's neediest citizens.

Recommendation 47:

The Commonwealth of Kentucky should promote the awareness of utility check-off programs and encourage widespread participation.

Energy Research, Development and Deployment

Billions of dollars for energy research and development are available through the federal government. Unfortunately, Kentucky has a very poor track record capturing these resources. This must change.

In 2002, the federal government launched the "Clean Coal Power Initiative (CCPI)." The initiative is described as "an innovative technology demonstration program (to foster) more efficient clean-coal technologies for use in new and existing electric power-generating facilities in the United States."[33]

The CCPI is only one of several federal initiatives that direct resources to energy research and development (R&D). Most of these initiatives require cost sharing to participate. In the past, Kentucky has not made a concerted effort to pursue these federal dollars. Such a commitment could lead to increased federal R&D dollars coming into Kentucky's universities and enhanced investments by industry in clean coal technology.

Billions of dollars for energy research and development are available through the federal government. Unfortunately, Kentucky has a very poor track record at garnering these resources. This must change.

The federal government also announced its intention

[33] *Program Fact Sheet*, U.S. DOE, Office of Fossil Energy. www.doe.gov

to partner with industry to invest over $1 billion in FutureGen—the worlds first zero-emission power plant. Other states have moved aggressively to attract this investment while Kentucky has not.

Mercury emissions... have not yet been efficiently controlled. The Mercury Emission and Control Laboratory at Western Kentucky University is one of only five labs in the nation capable of performing mercury sampling and testing at power plants."

Wei-Ping Pan, Ph.D., Western Kentucky University

Programs that focus on helping our industries become more competitive through energy efficiency help ensure that we will keep our existing industries in the Commonwealth, as well as attract new industry.

Kentucky's small and mid-sized manufacturing firms are a vital component of our economy. According to the U.S. Department of Labor, in 2003 there were 272,000 manufacturing jobs in Kentucky. A large portion of these jobs are provided by small-to mid-sized manufacturing companies. Energy and utility bills significantly affect the profitability of these companies.

Several southeastern states have university-sponsored energy efficiency assessment centers that help keep these smaller-sized manufacturing companies profitable in their respective states. Currently, Kentucky only has a limited capability to help our companies improve their profitability through energy efficiency and resources management.

The federal government sponsors substantial investment in energy efficiency and renewable energy technologies. The bulk of this funding goes to states that have worked to establish their own coordinated groups of researchers, educators, commodity groups and energy professionals, to focus on energy research, development and deployment.

Individuals and organizations that have the good ideas and initiative to develop biobased products, renewable energy or energy efficiency often have to "go it alone," because the state lacks a central clearinghouse and networking partner to help bring their ideas to market and profitability.

Recommendation 48:

The Commonwealth of Kentucky should partner with the state's universities, private industry and non-profit organizations to aggressively pursue federal research and development resources that are dedicated—but not limited—to clean-coal technology, energy efficiency, hydrogen technology and renewable energies.

Recommendation 49:

The Commonwealth of Kentucky should initiate a full-scale effort to attract and site the federal FutureGen facility in Kentucky.

"Location of the FutureGen project in Kentucky will place the state in the forefront of energy and environmental research."

Richard Schmidt, Ph. D.
Kentucky Consortium for Energy and the Environment.

Recommendation 50:

The Commonwealth of Kentucky should encourage and assist the state's universities, private industry and non-profit organizations to leverage available federal energy research and development resources.

Recommendation 51:

The Commonwealth of Kentucky should promote greater collaboration between Kentucky's universities to synergize ongoing energy research efforts at individual institutions.

Securing Kentucky's Critical Energy Infrastructure

According to the U.S. Department of Homeland Security, "energy drives the foundation of many of the sophisticated processes at work in American society. It is essential to our economy, national defense and quality of life."[34] Additionally, "it is important to remember that protection of our critical infrastructures and key assets is a shared responsibility. Accordingly, the success of our protective efforts will require close cooperation between government and the private sector at all levels."[35] Kentucky, with its critical energy infrastructure being vital to the state and national economy, must be engaged in ensuring that this national security priority is fulfilled.

Recommendation 52:

The Commonwealth of Kentucky should partner with the federal government, local governments and private industry to promote enhanced security of Kentucky's critical energy infrastructure.

Recommendation 53:

The Commonwealth of Kentucky should partner with local governments and private industry to pursue federal funding opportunities that promote enhanced security of Kentucky's critical energy infrastructure.

[34] *The National Strategy for the Physical Protection of Critical Infrastructures and Key Assets.* U.S. Department of Homeland Security. www.dhs.gov

[35] Letter from President George W. Bush within *The National Strategy for the Physical Protection of Critical Infrastructures and Key Assets.* U.S. Department of Homeland Security. www.dhs.gov

Recommendation 54:

The Commonwealth of Kentucky should partner with the federal government to enhance the nation's energy security through research and development directed at transforming Kentucky's energy resources into the resources that fuel the nation.

Conclusion: Kentucky's Energy—Opportunities for Our Future

Kentucky's energy sector is currently well positioned but that position is not guaranteed. Our challenge today is to continue to grow our economy, utilize our resources in a sustainable manner and protect and maintain our commitment to environmental quality. To accomplish these objectives, Kentucky must have a comprehensive state energy strategy.

Governor Fletcher has committed to work with the legislature in a bipartisan manner to develop and implement a comprehensive energy strategy for the benefit of all Kentuckians. As Kentuckians unite to build a Commonwealth of opportunity, the competitive advantage Kentucky enjoys in low-cost energy is an important building block. We must act now to secure a low-cost energy future through the responsible development of Kentucky's energy resources and a sustained commitment to environmental quality.

All Kentuckians hope to leave the next generation of Kentuckians with a more prosperous and more beautiful Kentucky. This strategy serves as a framework to get us there.

Printed with state funds

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KENTUCKY POWER COMPANY

INTEGRATED RESOURCE PLANNING REPORT
TO THE
KENTUCKY PUBLIC SERVICE COMMISSION

Submitted Pursuant to
Commission Regulation 807 KAR 5:058

Case No. 2002-00377
November 15, 2002

2002 national economic forecast of Economy.com (formerly RFA). The forecasts of seasonal peak demands were developed using an analysis similar to EPRI's Hourly Electric Load Model (HELM) that estimates hourly demand.

Some of the key assumptions on which the load forecast is based include:

- moderate U.S. economic growth;
- declining real (inflation-corrected) average electricity prices through 2005; constant real prices thereafter;
- generally slow growth in the Company's service-area population;
- normal weather.

Also, the forecasts for both KPCO and the AEP System reflect the exclusion, beginning in early 2002, of the peak demands of certain sales for resale customers, mainly municipals and cooperatives, who will terminate their contracts for electric power and energy from AEP.

Table 1 provides a summary of the "base" forecasts of the seasonal peak internal demands and annual energy requirements for KPCO and the Regulated AEP-East System for the years 2002 to 2016. The forecast data shown on this table do not reflect any adjustments for current DSM programs. However, inherent in the forecast are the impacts of past customer conservation and load management activities, including DSM programs already in place.

As Table 1 indicates, during the period 2002-2016, KPCO's base internal energy requirements are forecasted to increase at an average annual rate of 1.6%, while the corresponding summer and winter peak internal demands are forecasted to grow at average annual rates of 1.7% and 1.7%, respectively. KPCO's annual peak demand is expected to continue to occur in the winter season.

TABLE 1 KPCO and Regulated AEP-East System Forecast of Peak Internal Demand and Energy Requirements Before Adjusting for Expanded DSM Programs 2002-2016						
	KPCO			Regulated AEP-East System		
	Peak Internal Demand			Peak Internal Demand		
Year	Summer (MW)	Winter Following (MW)	Internal Energy Req'ts (GWh)	Summer (MW)	Winter Following (MW)	Internal Energy Req'ts (GWh)
2002	1,271	1,503	7.676	19,577	16,985	112,596
2003	1,286	1,554	7,702	10,950	11,721	66,163
2004	1,331	1,592	7,993	11,225	11,956	68,044
2005	1,363	1,586	8,150	11,455	12,133	69,169
2006	1,357	1,624	8,125	11,631	12,367	70,331
2007	1,389	1,651	8,322	11,856	12,548	71,698
2008	1,412	1,684	8,480	12,031	12,788	72,936
2009	1,440	1,709	8,620	12,263	12,982	74,108
2010	1,462	1,737	8,750	12,450	13,186	75,234
2011	1,486	1,758	8,884	12,647	13,345	76,378
2012	1,504	1,794	9,037	12,802	13,602	77,648
2013	1,535	1,823	9,189	13,049	13,824	78,899
2014	1,560	1,853	9,336	13,261	14,047	80,166
2015	1,585	1,878	9,489	13,476	14,230	81450
2016	1,606	1,911	9,640	13,651	14,483	82,735
% Average Growth Rate, 2002-2016	1.7	1.7	1.6	-2.5	-1.1	-2.2

Note: Regulated AEP-East System Peak Internal Demands indicated above include "traditional" interruptible/non-firm loads, which are assumed to aggregate to 307 MW (summer) and 306 MW (winter) throughout the forecast period. KPCO does not have such loads.

Similarly, the Regulated AEP-East System's base internal energy requirements during the forecast period are projected to increase at an average annual rate of 1.7% over the 2003-2016 period, while the corresponding summer and winter peak internal demands are projected to grow at average annual rates of 1.7% and 1.6%, respectively. The Regulated AEP-East System's annual peak demand is expected to occur in the winter season.

Table 2 shows KPCO and Regulated AEP-East System load forecast information as in Table 1 except that the peak demands and energy requirements have been reduced, where appropriate, to reflect the impact of the expanded company-sponsored DSM programs assumed to be implemented during the forecast period. A comparison of the data shown on Tables 1 and 2 indicates that the expanded DSM program effects are minor and do not affect the long-term load growth rates.

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November 15, 2002

This report was prepared under the supervision of :

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1. OVERVIEW AND SUMMARY

1. OVERVIEW AND SUMMARY

A. GENERAL REMARKS

Kentucky Power Company (KPCO), authorized to do business in Kentucky as American Electric Power (AEP), is one of the operating companies of the AEP-East System, which is planned and operated on a wholly integrated basis.[1] In this regard, KPCO's resource plans must be considered in the context of the AEP-East System.

Major structural changes are taking place in the electric utility industry. Among these is a transition away from the integrated utility generation, transmission, and distribution structure. This system is being replaced by a combination of regional transmission organizations that will have responsibility for planning and operation of the transmission system, along with a generating system that includes both utility and independent generating capacity. Along with this structure a market for generation products is developing, with the major "product" at present (in the East Central Area Reliability Coordination Agreement (ECAR) region) being energy. Simultaneously, the State of Ohio has deregulated generation, mandated corporate separation, and eliminated the concept of native load retail service in favor of competition at retail. This has necessitated the proposal of a modified AEP generation interconnection agreement that will exclude from the AEP-East System the Ohio operating companies, CSP and OPCO. The Restated and Amended Interconnection Agreement among APCo, I&M, KPCO, and the AEP Service Corporation was approved by the Federal Energy Regulatory Commission (FERC) on September 26, 2002. This agreement will not become effective until after Security Exchange Commission (SEC) approval. These three operating companies form the Regulated AEP-East System. Thus, the focus of this report when referring to "AEP System" considerations has shifted from the "old" aggregate AEP-East System in prior reports to the new Regulated AEP-East System in this report. However, historical information (i.e. pre January 1, 2003) is generally reported for the "old" aggregate AEP-East System.

This report presents the results obtained from evaluations carried out in connection with the development of integrated resource plans for the Regulated AEP-East System and KPCO. The information contained herein includes assumptions relating to overall study parameters and the integration of supply-side resources and demand-side management (DSM) programs.

The AEP System's strategy for complying with Title IV of the Clean Air Act Amendments (CAAA) of 1990, taking into consideration the inception of Phase II of those requirements in the year 2000, includes the continual evaluation of alternative fuel strategies, opportunities to purchase sulfur dioxide (SO_2) allowances, and possible post-combustion technologies in order to lower the overall cost-impact of compliance. Continued use of low and medium sulfur coal, supplemented with SO_2 allowances as needed, and low NOx combustion systems at Big Sandy

[1] 1 The operating companies are: Appalachian Power (APCo); Columbus Southern Power (CSP); Indiana Michigan Power (I&M); Kentucky Power (KPCO); Kingsport Power; Ohio Power (OPCo); and Wheeling Power. All of the AEP operating companies do business as AEP.

Plant will allow that facility to remain in compliance. Big Sandy Plant will be required to meet more stringent NOx emission limitations during the May through September ozone season beginning in May 2004. The compliance plan for Big Sandy Plant to meet this requirement includes installation of an overfire air burner modification and water injection system on Unit 1 and installation of a selective catalytic reduction (SCR) system on Unit 2. The latter installation also requires an upgrade of the Unit 2 electrostatic precipitator. On September 30, 2002 the Company filed with the Commission revisions to the Company's Environmental Compliance Plan at the Big Sandy Generating Plant and an application to recover the associated costs by way of the Environmental Surcharge.

The Integrated Resource Plan (IRP) is based on current mandatory environmental requirements (the existing SO2 reduction program under the CAAA of 1990 and the NOx SIP Call requirements for seasonal NOx reductions in the Midwestern U.S.). However, the IRP does not include the potential impacts of new air emission regulations or air emission legislation (so called 3P and 4P legislation) aimed at further significant reductions in SO2, NOx, mercury and in the case of 4P legislation CO2 emission reductions. While it is quite possible that there may be new legislation and/or new regulations governing these pollutants in the future, it is very difficult to predict future legislative and regulatory outcomes. In addition, the EPA is scheduled to propose a Mercury MACT (maximum achievable control technology) standand during 2003. However, it is uncertain the degree of reductions or type of mercury standard likely to be proposed at ths time.

With the additional supply-side resources obtained from the regional generation market and the DSM program effects reflected in the integrated resource plan presented in this report, the AEP System (including KPCO) is expected to have adequate resources to serve its customers' requirements throughout the forecast period.

The AEP System's ability to meet its customers' future electric needs will be affected by the timely completion of planned transmission reinforcement projects, including the Wyoming-Jacksons Ferry 765-kV Project. AEP continues to seek approval of this project.

The planning process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the resource expansion plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. It is not a commitment to a specific course of action, since the future, now more than ever before, is highly uncertain, particularly in light of the move to increasing competition among suppliers in the marketplace and restructuring in the industry. In this regard, there are a growing number of federal and state initiatives that address the many issues related to industry restructuring and customer choice. Along these lines, ongoing dialogues are continuing with regulators and other interested stakeholders across the AEP System to deal with such issues.

B. PLANNING OBJECTIVES

The primary objective of power system planning is to assure the reliable, adequate, and economical supply of electric power and energy to the consumer in an environmentally compatible manner. Implicit in this primary objective are related objectives, which include, in part: (1) maximizing the efficiency of operation of the power supply system, and (2) encouraging the wise and efficient use of energy. Achievement of these objectives necessarily involves consideration of supply-side options, including various types of generation resources, as well as demand-side options, involving customer load modification programs.

In the planning of power supply resources for the AEP System, consideration is given to several broad factors, including: (1) reliability, i.e., the ability of the system to provide continuous electric service not only under normal conditions but also during various contingency conditions; (2) economy, so as to minimize the cost of resources on a long-term basis; (3) environmental compatibility; (4) financial requirements; and (5) flexibility, i.e., the extent to which plans for future resources can be adjusted to meet changing conditions.

C. COMPANY OPERATIONS AND INTERRELATIONSHIP WITH THE AEP SYSTEM

KPCO serves a population of about 389,000 (173,000 retail customers) in a 3,762 square-mile area in eastern Kentucky. The principal industries served are primary metals, chemicals and allied products, petroleum refining and coal mining. The Company also sells and transmits power at wholesale to other electric utilities, municipalities, electric cooperatives, and non-utility entities engaged in the wholesale power market.

KPCO's internal load usually peaks in the winter; the all-time peak internal demand of 1,579 megawatts (MW) occurred on January 3, 2001. On August 5, 2002, an all-time summer peak internal demand of 1,326 MW was experienced. Of KPCO's total internal energy requirements in 2001, which amounted to 7,392 gigawatt-hours (GWh), residential, commercial, and industrial energy sales accounted for 31.3%, 17.3%, and 42.3%, respectively. Public street and highway lighting, sales for resale, and all other categories accounted for the remaining 9.1%.

In comparison, the "old" AEP-East System collectively serves a population of about 6.8 million (3.1 million retail customers) in a 41,000 square-mile area in parts of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. In 2001 the residential, commercial, and industrial customers accounted for 29.1%, 22.8%, and 36.1%, respectively, of the System's total internal energy requirements of 112,488 GWh. The remaining 12.0% was supplied for use in the public street and highway lighting, sales for resale, and all other categories.

The "old" AEP-East System experienced its all-time peak internal demand of 20,402 MW in the summer season of 2002, on August 1. The all-time winter peak internal demand, 19,557 MW, was experienced on February 5, 1996. If sales to non-affiliated power systems are included, the "old" AEP-East System reached its all-time peak total demand of 25,991 MW on June 24, 2002.

As of January 1, 2002, KPCO owns and operates the 1,060-megawatt, coal-fired Big Sandy Plant, consisting of an 800-MW unit and a 260-MW unit, at Louisa, Kentucky, and has a unit power agreement with AEP Generating Company, an affiliate, to purchase 390 megawatts of capacity through 2009 and 195 MW of capacity from January 2010 through December 7, 2022 or the end of the lease agreement from the Rockport Plant, located in southern Indiana. In comparison, as of January 1, 2002, the new Regulated AEP-East System's total generating capability will be 12,171 MW (or 11,921 MW, after adjusting for 250 MW of unit power sales), which includes predominantly coal-fired generating units along with conventional hydroelectric, pumped storage, and nuclear capacity.

The AEP System's major eastern operating companies, including KPCO, are electrically interconnected by a high capacity transmission system extending from Virginia to Michigan. This eastern transmission system, consisting of an integrated 765-kV, 500-kV, 345-kV, and 230-kV extra-high-voltage (EHV) network, together with an extensive underlying 138-kV transmission network, and numerous interconnections with neighboring power systems, is planned, constructed, and operated to provide a reliable mechanism to transmit the electrical output from AEP generating plants to the principal load centers and to provide open access transmission service pursuant to FERC Order No. 888.

AEP intends to transfer functional control of transmission facilities in the Eastern part of its system to the PJM Interconnection, LLC a regional transmission organization (RTO) during the first half of 2003. During that time, the PJM RTO will assume the monitoring, market operations and planning responsibilities of these facilities. In addition, PJM will assume the Open Access Same Time Information System (OASIS) responsibility including the evaluation and disposition of requests for transmission services over the AEP transmission system. PJM will also become the North American Reliability council (NERC) Reliablity Coordinator for the AEP transmission system, however, AEP will continue to maintain and physically operate all of its transmission facilities. AEP will retain operational and planning responsibility for those facilities that are not under PJM functional control, and will be involved in the various operations, and planning stakeholder processes of PJM.

D. LOAD FORECASTS

It should be noted that the load forecasts presented herein were developed in August 2002 and do not reflect the experience for the summer season of 2002 and later, or other relevant changes.[2]

KPCO's forecasts of energy consumption for the major customer classes were developed by using both short-term and long-term econometric models. These energy forecasts were determined in part by forecasts of the regional economy, which, in turn, are based on the June

[2] The load forecasts (as well as the historical loads) presented in this report reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of *connected load*, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.

2002 national economic forecast of Economy.com (formerly RFA). The forecasts of seasonal peak demands were developed using an analysis similar to EPRI's Hourly Electric Load Model (HELM) that estimates hourly demand.

Some of the key assumptions on which the load forecast is based include:

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Note: Regulated AEP-East System Peak Internal Demands indicated above include "traditional" interruptible/non-firm loads, which are assumed to aggregate to 307 MW (summer) and 306 MW (winter) throughout the forecast period. KPCO does not have such loads.						

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Table 2 shows KPCO and Regulated AEP-East System load forecast information as in Table 1 except that the peak demands and energy requirements have been reduced, where appropriate, to reflect the impact of the expanded company-sponsored DSM programs assumed to be implemented during the forecast period. A comparison of the data shown on Tables 1 and 2 indicates that the expanded DSM program effects are minor and do not affect the long-term load growth rates.

TABLE 2 KPCO and Regulated AEP-East System Forecast of Peak Internal Demand and Energy Requirements After Adjusting for Expanded DSM Programs 2002-2016						
	KPCO			Regulated AEP-East System		
	Peak Internal Demand		Internal Energy Req'ts (GWh)	Peak Internal Demand		Internal Energy Req'ts (GWh)
Year	Summer (MW)	Winter Following (MW)		Summer (MW)	Winter Following (MW)	
2002	1,270	1,502	7,674	19,576	16,984	112,594
2003	1,285	1,552	7,697	11,949	11,719	66,158
2004	1,330	1,589	7,986	11,224	11,953	68,037
2005	1,361	1,582	8,140	11,453	12,129	69,159
2006	1,355	1,620	8,114	11,629	12,363	70,320
2007	1,387	1,647	8,311	11,854	12,544	71,687
2008	1,410	1,680	8,469	12,029	12,784	72,925
2009	1,438	1,705	8,609	12,261	12,978	74,097
2010	1,460	1,733	8,739	12,448	13,182	75,223
2011	1,484	1,754	8,873	12,645	13,341	76,367
2012	1,502	1,790	9,026	12,800	13,598	77,637
2013	1,533	1,819	9,178	13,047	13,820	78,888
2014	1,558	1,849	9,325	13,259	14,043	80,155
2015	1,583	1,874	9,478	13,474	14,226	81,439
2016	1,604	1,907	9,629	13,649	14,479	82,724
% Average Growth Rate, 2002-2016	1.7	1.7	1.6	-2.5	-1.1	-2.2
Note: Regulated AEP-East System Peak Internal Demands indicated above include "traditional" interruptible/non-firm loads, which are assumed to aggregate to 307 MW (summer) and 306 MW (winter) throughout the forecast period. KPCO has no such loads.						

E. DSM PROGRAMS AND IMPACTS

AEP has offered a variety of conservation and demand-side management programs designed to encourage customers to use electricity efficiently, achieve energy conservation, and reduce the level of future peak demands for electricity. As a result of these energy efficiency programs implemented throughout the AEP jurisdictions, an annual energy savings of about 328 GWh (31 GWh by KPCO customers) and peak demand reductions of 179 MW (22 MW by KPCO customers) in winter and 71 MW (10 MW by KPCO customers) in summer have been achieved by the end of year 2001. For future years, AEP will continue to experience the load impact benefits from these traditional DSM programs, and these load impacts are "embedded" in the base load forecast of the integrated resource plan.

Although the overall effects of past AEP DSM programs will continue to be realized in the future, several recent developments in the restructuring electric utility industry, specifically in the AEP-East service area, have caused AEP to trim down the level of company-sponsored new and/or expanded DSM programs. The emerging competitive environment evolving from restructuring in the electric utility industry and in the AEP System has affected the viability of DSM programs. As a result of recent trends in the regulatory and competitive arenas, the nature of DSM's role has changed to a supplementary and complementary role in utility resources planning over the past few years. Lower supply side resource costs, as a result of competition and other factors, have diminished the economic viability of new or expanded DSM programs. Increased federally mandated energy efficiency standards, together with years of customer educational programs and utility-sponsored DSM programs have improved the energy efficiency of the customers and will continue to do so in the future. Much of the efficiency effects formerly associated with utility-sponsored DSM programs have been captured, or are embedded, in the base load forecast. In addition, while there has always been some uncertainty over projections of DSM impacts, its future has become even more uncertain due to the likelihood of impending electric utility retail competition and cost recovery issues.

The level of DSM activity in each AEP jurisdiction will vary, depending on the regulatory climate, timing of restructuring, various economic factors, such as potential program participation and cost-effectiveness, and the DSM cost recovery mechanisms in that jurisdiction. Currently, DSM programs are expanding in KPCO, but no new recruitment of DSM conservation program participants is assumed in the integrated resource planning for the Regulated AEP-East System beyond the year 2005.

KPCO is fully appreciative of the current regulatory climate and DSM potential in Eastern Kentucky. In this regard, the Company has been continually working with the KPCO DSM Collaborative (which was established in November 1994 to develop KPCO's DSM plans) to ensure that DSM programs are implemented as effectively and efficiently as possible and are helping Kentucky customers save energy. Over the years, the KPCO DSM Collaborative has worked closely in reviewing, recommending and endorsing DSM programs for Kentucky Power. Through continuously monitoring the program performance, program participation level and DSM market potential, the Collaborative has recommended the addition, deletion and modification of various DSM programs for Kentucky Power. These past and present programs, along with DSM programs proposed by the Collaborative for a 3-year extension beyond 2002, are described in detail in the KPCO DSM Collaborative Semi-Annual Status Report and Program Evaluation Reports filed with the Commission on August 14, 2002. On September 24, 2002 the Commission approved the Company's plan to continue the KPCO Collaborative DSM programs through 2005.

TABLE 3
AEP System and KPCO
Expanded DSM Programs
Residential Programs:
1. Targeted Energy Efficiency (Low-Income Weatherization)
2. Modified Energy Fitness
3. High-Efficiency Heat Pump Mobile Home
4. Mobile Home New Construction
Commercial Programs:
SMART Audit/Incentive
Note: (a) For KPCO, the Residential Modified Energy Fitness Program will be implemented in January 2003, with Commission approval.
(b) For KPCO, the Commercial SMART Audit/Incentive Programs will be discontinued at year-end 2002, with Collaborative approval.

Table 3 lists the DSM programs that are currently being offered in one or more state jurisdictions of the AEP System including Kentucky. This table includes those DSM programs that were approved by the Commission for a three-year extension beyond 2002.

Table 4 provides a summary of the estimated load impacts of implementing the expanded DSM programs for Regulated AEP-East System & KPCO for the years 2002 to 2020, based on the market penetration rates assumed. It was also assumed that there would be no new DSM program participants after the year 2005. Thus, for KPCO, the expanded DSM programs would reduce the base forecast of peak internal demand for the winter season of 2010/11 by an estimated 4 MW (0.2%). In comparison, the summer 2010 peak demand would be reduced by 2 MW. KPCO's corresponding base forecast of internal energy requirements for the year 2010 would be reduced by an estimated 11 GWh.

As Table 4 indicates, the DSM impacts generally increase through about the year 2006 and remain relatively stable until about 2016, decreasing thereafter. Thus, for KPCO, the expanded DSM impact on winter-season peak demand would be reduced from a level of 4 MW in winter 2015/16 to 0 MW in winter 2019/20. These estimated impacts reflect the assumption that new DSM program participants will continue to be added through 2005 in Kentucky.

The projected impacts shown in Table 4 reflect the effects of DSM implementation experience gained thus far while taking into account the latest results of the DSM program evaluations filed with the Commission on August 14, 2002.

The expanded DSM program impacts shown in Table 4 are in addition to the impacts of DSM program installations already in place, i.e., the DSM measures implemented prior to 2002. Such "embedded" DSM impacts are already reflected in the base load forecast. Estimates of these embedded DSM program impacts as of the end of 2001 are shown in the bottom portion of Table 4.

TABLE 4
KPCO and Regulated AEP-East System
Estimated Load Impacts of Expanded DSM Programs
2002-2020

	KPCO			Regulated AEP East System		
	Demand Reduction			Demand Reduction		
Year	Summer (MW)	Winter Following (MW)	Energy Reduction (GWh)	Summer (MW)	Winter Following (MW)	Energy Reduction (GWh)
2002	0	0	2	0	0	2
2003	1	1	5	1	1	5
2004	1	2	7	1	2	7
2005	1	3	10	1	3	10
2006	2	4	11	2	4	11
2007	2	4	11	2	4	11
2008	2	4	11	2	4	11
2009	2	4	11	2	4	11
2010	2	4	11	2	4	11
2011	2	4	11	2	4	11
2012	2	4	11	2	4	11
2013	2	4	11	2	4	11
2014	2	4	11	2	4	11
2015	2	4	11	2	4	11
2016	2	4	11	2	4	11
2017	1	4	9	1	4	9
2018	1	3	6	1	3	6
2019	1	2	4	1	2	4
2020	0	0	0	0	0	0

Note: Expanded DSM program impacts result from installations assumed to be made in the future and are not reflected in the base load forecast. Impacts of DSM program installations already in-place, i.e., embedded DSM program impacts, are reflected in the base load forecast.

As of the end of 2001, the estimated aggregate embedded DSM program impacts were as follows:

	Summer MW	Winter MW	Annual GWh
KPCO	10	22	31
AEP System	71	179	328

Since DSM program persistence is less than 100%, these embedded DSM impacts are expected to diminish gradually over the forecast period.

F. SUPPLY-SIDE RESOURCE EXPANSION

With regard to reserve planning, the ultimate objective of reserve planning is to ensure that adequate operating reserve will be available at all times. (Operating reserve provides for contingencies such as load forecast errors and unplanned generating unit outages, as well as load following and frequency control.) In the old, "single system" planning model, each utility system had to ensure that its own dedicated resources would be adequate to provide such operating reserve. This was accomplished through the provision of long-term "planning reserves," which provided for both forced and scheduled outages of generating units, unexpected system load growth, etc. Individual system resources were then added to provide adequate "planning reserves."

With the emergence of substantial non-utility generation resource additions to provide resources to the regional market, the focus of utility resource planning has changed. Each system must still provide adequate operating reserves, but "planning reserves" must now be assessed on a regional, rather than an individual system basis. Thus, individual system planning reserves, if any, reflecting only its own dedicated supply-side resources are no longer the major indicator of long-term system reliability.

The AEP System plans to purchase capacity and/or energy from the developing market to provide adequate daily operating reserves. ECAR at present requires a reserve of 4% of the projected daily peak load. AEP has obtained conditional approval from FERC to join PJM as it's RTO selection for AEP's eastern region companies, which includes KPCO. AEP will become a member of PJM and transfer functional control of it's transmission facilities to PJM for inclusion in an expanded PJM-West Region. Additionally, the AEP control area functions will be integrated into the PJM Interchange Energy Market and certain other PJM markets during the first half of 2003. AEP's integration into PJM may require changes in certain operations and planning processes and requirements to ensure reliable and efficient operations of transmission and energy markets within PJM.

Regarding the availability of capacity to be purchased from the market, significant capacity additions have been announced in the ECAR region, of which AEP is a member. The recently issued *Assessment of ECAR-Wide Capacity Margins 2002-2011* indicates that 41,615 MW of new capacity have been announced for installation within the region for the years 2003 through 2007. The study and report estimates that if only 8,734 MW of this new capacity is in service by the year 2006, adequate reliability levels will be maintained. If the announced additions were to be installed (some will most likely be delayed or cancelled) and the peak demand growth projections are accurate, ECAR could see a rise in reserve margins to about 32% by 2005.

Table 5 shows the supply-side resource plan with expanded DSM, along with the corresponding projected Regulated AEP-East System and KPCO peak demands, capabilities, and margins, for the winter and summer seasons, respectively, after adjusting the demands for DSM impacts. (The market purchases included in the reported capabilities are estimated purchases during the week of the seasonal peak, as discussed in Chapter 4.)

Table 5 Projected Peak Demands, Generating Capabilities and Margins 2003 - 2017								
	AEP – at time of winter peak (Jan.)				KPCO - at time of winter peak (Jan.)			
Year	Peak Demand(1) (MW)	Capability (MW) (2)	Reserve (MW)	Margin (%)	Peak Demand(1) (MW)	Capability (MW) (2)	Reserve (MW)	Margin (%)
2003	11,400	12,945	1,545	13.6	1,502	1,450	(52)	(3.5)
2004	11,662	13,095	1,433	12.3	1,552	1,600	48	3.1
2005	11,896	13,345	1,449	12.2	1,589	1,690	101	6.4
2006	12,072	13,545	1,473	12.2	1,582	1,690	108	6.8
2007	12,306	13,795	1,489	12.1	1,620	1,750	130	8.0
2008	12,487	13,995	1,508	12.1	1,647	1,800	153	9.3
2009	12,727	14,295	1,568	12.3	1,680	1,850	170	10.1
2010	12,921	14,500	1,579	12.2	1,705	1,845	140	8.2
2011	13,125	14,700	1,575	12.0	1,733	1,895	162	9.3
2012	13,284	14,900	1,616	12.2	1,754	1,925	171	9.7
2013	13,541	15,200	1,659	12.3	1,790	1,985	195	10.9
2014	13,763	15,450	1,687	12.3	1,819	2,025	206	11.3
2015	13,986	15,700	1,714	12.3	1,849	2,065	216	11.7
2016	14,169	15,900	1,731	12.2	1,874	2,085	211	11.3
2017	14,422	16,150	1,728	12.0	1,907	2,125	218	11.4

Note: (1) Including interruptible load curtailments..
(2) Includes generating facilities and committed and uncommitted purchases as shown in Exhibit 4-12 or 4-14.

Inasmuch as there are many assumptions, each with its own degree of uncertainty, which had to be made in carrying out the resource evaluations, changes in these assumptions could result in significant modifications in the resource plan reflected in Table 5. In this respect, sensitivity analyses indicated that the resource plan is sufficiently flexible to accommodate possible changes in key parameters, including load growth. As such changes are recognized, updated, and more refined, input information must be continually evaluated and resource plans modified as appropriate.

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5. PLAN SUMMARY

5.(1) Description of the utility, its customers, service territory, current facilities, and planning objectives.

Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") are investor-owned public utilities supplying electricity and natural gas to customers primarily in Kentucky. Both KU and LG&E are subsidiaries of LG&E Energy LLC which is a member of the E.ON AG (NYSE: EON; Frankfurt: EOA) family of companies. Effective December 30, 2003, LG&E Energy LLC, a Kentucky limited liability company, was the successor by assignment and subsequent merger of all of the assets and liabilities of LG&E Energy Corp., a Kentucky corporation. As the owners and operators of interconnected electric generation, transmission, and distribution facilities, KU and LG&E ("the Companies") achieve economic benefits through operation as a single interconnected and centrally dispatched system and through coordinated planning, construction, operation and maintenance of their facilities.

KU and LG&E have a joint net summer generation capacity of 7,610 MW as shown in Table 5.(1)-1 and serve 903,834 electricity customers over a transmission and distribution network covering some 27,000 square miles. KU supplies electric service in an area that covers approximately 6,600 non-contiguous square miles in 77 counties of Kentucky and 5 counties in southwestern Virginia that are serviced by Old Dominion Power Company ("ODP"). KU also sells electric energy at wholesale for resale to 11 municipalities in Kentucky and Berea College (a privately-owned utility serving the city of Berea). LG&E supplies electricity and natural gas to customers in the Louisville metropolitan area and 16 surrounding counties covering approximately 700 square miles.

The Companies' retail customers include all customers served under the following service classes: Residential, General Service (Small Commercial and Industrial), Large Commercial, Large Industrial (Large Power), and Street Lighting customers. Among the industries included in the service territory are coal mining, automotive and related industries, agriculture, primary metals processing, chemical processing, pipeline transportation, and the manufacture of electrical and other machinery and of paper and paper products.

The Companies' power generating system consists of 20 coal-fired units operated at 7 different steam generating stations: E. W. Brown, Cane Run, Ghent, Green River, Mill Creek, Trimble County, and Tyrone. Also, there are 2 oil-fired units operated at Tyrone. Gas-fired and/or oil-fired combustion turbines supplement the system during peak periods. The system is further augmented by hydroelectric facilities at Dix Dam and Ohio Falls. The Companies do not own any nuclear facilities. The generating units for KU and LG&E are summarized in Tables 5.(1)-1. (See Table 8.(3)(b) in Section 8 for a detailed listing.)

Table 5.(1)-1
Generating Unit Totals for KU and LG&E

Totals	2004 Summer Net Capacity (MW)	2004 Winter Net Capacity (MW)
KU Coal	2876	2874
KU CT – Gas	1499	1669
KU – Oil	58	63
KU Hydro	24	24
Total KU	**4457**	**4630**
LGE Coal	2418	2440
LGE CT – Gas	687	764
LGE Hydro	48	32
Total LGE	**3153**	**3236**
Coal	5294	5314
CT – Gas	2186	2433
Oil	58	63
Hydro	72	56
Total	**7610**	**7866**

The Companies' net summer generating capability in 2004 was 7,610 megawatts. The Companies have purchase agreements in place with Electric Energy Incorporated ("EEInc."), Owensboro Municipal Utilities ("OMU") and Ohio Valley Electric Corporation ("OVEC"). The Companies' ownership in EEInc. is 20%. The Companies receive 9.5% of the OVEC capacity and energy; the OVEC sponsorship is further described in Section 5.(4). The Companies' highest combined system peak demand of 6,513 megawatts occurred on August 5, 2002. LG&E experienced its highest system peak demand of 2,623 megawatts on that date at hour ending 15:00 EST. On that date, KU's highest peak demand was 3,899 megawatts at hour ending 16:00 EST. However, KU has superseded that day's peak with their highest system peak demand occurring on January 18, 2005 with a (non weather-normalized) demand of 4,065 megawatts at 8:00 EST.

This report is a snapshot in time of an ongoing resource planning process, which the Companies believe is fundamental to all corporate planning. The various sections of this report define ongoing and planned activities that collectively make up this process. The Companies review the planning alternatives and decisions annually as part of the ongoing resource planning process. This process is continually evolving, and as such is a dynamic effort using state-of-the-art techniques and models as well as timely and pertinent information. All planning decisions are based on certain sets of assumptions and are subject to varying degrees of risk and uncertainty. It is only through an ongoing planning process that there is assurance that the interests of the Companies' constituent groups are adequately addressed.

Meeting the needs of the Companies' customers requires the availability of sufficient resources to serve customer demand. Additional resources must also be available should there be an unexpected loss of generation, generation equipment problems, extreme weather conditions, or unanticipated load growth. Existing capacity resources consist of company-owned generating units and contracted purchased power from other generating entities. In the integrated planning process, the economics and practicality of supply-side and demand-side options are examined to determine cost-effective responses to customers' needs. The Companies' resource planning process encompasses: 1) establishment of a reserve margin criterion, 2) assessment of the adequacy of existing generating units and purchase power agreements, 3) assessment of potential purchased power market agreements, 4) assessment of demand-side options, 5) assessment of supply-side options, and 6) development of an economic plan from the available resource options. While the Integrated Resource Plan ("IRP") represents the Companies' analysis of the best options to meet customer needs at a given point in time, the action plan is reviewed and re-evaluated prior to implementation. In addition to net Present Value Revenue Requirement ("PVRR"), which establishes the ordering of the IRP options, rate impact, shareholder effects, risks and flexibility are typically considered prior to making financial commitments.

While preparing this resource assessment and acquisition plan, the Companies were in possession of the Commission Staff Report on the 2002 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company dated December 2003. This report summarizes the Commission Staff's review of the Companies' 2002 filing and offered suggestions and recommendations to be considered in subsequent filings. The Companies have addressed the suggestions and recommendations contained in the Staff report. A summary of the ways in which these suggestions and recommendations were addressed is provided in the report titled *Recommendations in PSC Staff Report on the Last IRP Filing* contained in Volume III, Technical Appendix.

5.(2) Description of models, methods, data, and key assumptions used to develop the results contained in the plan;

Demand and Energy Forecast

Robust forecasting of energy and demand is of vital importance for the prudent planning and control of the Companies' operations. The load forecast is the basis upon which the Companies make decisions on the construction of facilities such as power plants, transmission lines, and substations, all of which are necessary to provide economical and reliable service.

The modeling techniques in use within the Companies allow energy and demand forecasts to be tailored to address the unique characteristics of the KU and LG&E service territories. New forecasting approaches are continually evaluated to optimize all aspects of the exercise.

Energy forecasts for KU and LG&E are developed using the same basic methodologies. The energy forecasts from each utility are used as inputs to a consistent demand forecasting methodology that generates individual and combined company demand forecasts. The remainder of this section addresses at a summary level the models, methods, data and key assumptions in developing the energy and demand forecast for the 2005 IRP.

Models & Methods

KU's and LG&E's energy forecasting approach relies upon econometric modeling, together with the collection of specific growth outlook information from its largest customers. The econometric approach establishes the historical relationships between electric sales and the 'independent' explanatory variables that underlie sales development (e.g. output growth and household formation). This approach may be applied to forecast customer numbers, energy sales, or use-per-customer. Separate econometric models are prepared for each sales jurisdiction and each class of service. For LG&E, only one jurisdiction is modeled, Kentucky-Retail. The KU energy forecast identifies three separate jurisdictional groups: Kentucky-Retail, Virginia-Retail, and Wholesale sales (to eleven municipally-owned utilities in Kentucky and to Berea College). The distribution of KU sales by jurisdiction in 2004 was: 85.9 percent Kentucky-Retail; 4.5 percent Virginia-Retail; and 9.6 percent Wholesale. Within each jurisdiction, the forecast typically distinguishes several classes of customer including Residential, Commercial, and Industrial. The econometric models used to produce the forecast passed two critical tests. First, the explanatory variables of the models were theoretically appropriate and have been widely used in electric utility forecasting. Second, inclusion of those explanatory variables produced statistically-significant results that led to an intuitively reasonable forecast. In other words, the models were proven theoretically and empirically robust to explain the behavior of the KU and LG&E customer and sales data.

Both KU and LG&E forecasts incorporate medium- and long-term models, with the specification and length of historical data varying by class. In general, medium-term models using monthly data determine the outlook for the first five forecast years, with long-term models based on annual or seasonal data used for the remainder of the forecast horizon. A notable exception is Residential sector modeling of use-per-customer, which uses monthly data in combination with long-term structural trends interpolated to monthly data for both medium-term and long-term forecasting.

Residential energy sales modeling for both utilities incorporates elements of end-use forecasting - such as baseload, heating and cooling components of sales - which addresses expectations with regard to appliance saturation trends, efficiencies, and price or income effects.

Several large customers for both KU and LG&E are forecast using their recent history and information provided by the customers to KU/LG&E regarding their outlook. This process allows for market intelligence to be directly incorporated into the sales forecast.

Once complete, the energy forecast of each utility is converted from a billed to calendar basis and adjusted for Company use and losses. Monthly energy requirements are then associated with a typical load profile to generate hourly demand forecasts for each utility and for the combined company.

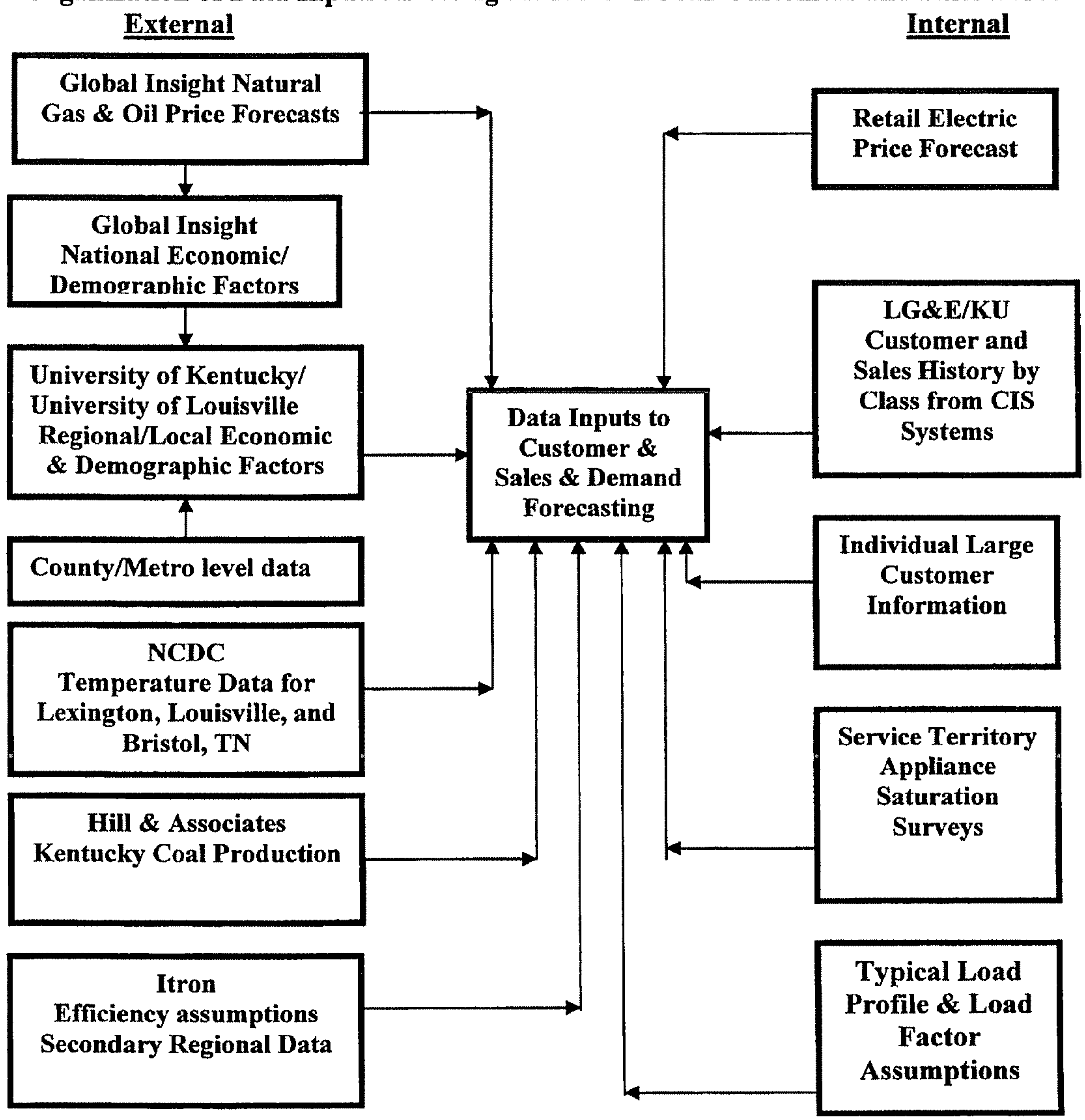
A more detailed description of the forecasting models, methods, and data used to develop the forecast is contained in Section 7 of this report and in Technical Appendices 1 and 2 of Volume II.

Data

Data inputs to the forecasting process for both KU and LG&E come from a variety of external and internal sources. The national outlook for U.S Gross Domestic Product, consumer prices, and industrial productivity are key determinants of the economic environment within which KU and LG&E must operate. Local influences are population, households, employment, personal income, weather, and the price of electricity. The utilities have contracted with Global Insight ("GI") to provide national macroeconomic data, while the Gatton Center for Business and Economic Research ("CBER") at the University of Kentucky ("UK") utilizes the GI data to generate local economic and demographic forecasts. Weather data is received from the National Climatic Data Center ("NCDC"), a branch of the National Oceanic and Atmospheric Administration of the U.S. Department of Commerce. New York Mercantile Exchange ("NYMEX") futures prices for oil and natural gas are utilized in rate class choice modeling in the KU forecast. A coal production forecast is obtained from Hill & Associates for use in modeling KU Mine Power tariff sales. Itron provides regional databases that support the modeling of appliance saturation and efficiency trends and customer choice. The retail electric price forecast, historical appliance saturations and efficiency trends, and load profile/load factor data for both utilities are determined internally.

Important information relative to growth prospects is also collected through discussions with the largest customers of KU and LG&E. These regular communications allow the Companies to directly adjust sales expectations given the first-hand knowledge of production outlook of these companies. Historical sales data on these customers and for the respective classes are obtained via extracts from KU's and LG&E's Customer Information Systems ("CIS"). Figure 5.(2)-1 illustrates the external and internal data sources used to drive the KU and LG&E forecasts.

Figure 5.(2)-1
Organization of Data Inputs Affecting the KU & LG&E Customers and Sales Forecasts



Key Assumptions

Following is a summary of key assumptions made in GI's Winter 2003 Long-Term Macro Forecast, used by the Companies as macroeconomic background for the energy sales forecast in the 2005 IRP. A copy of this forecast is attached as part of Technical Appendix 4, 'Supporting Documents,' in Volume II.

- *Trend Scenario*: GI assumed that the economy suffered no major mishaps or exogenous shocks. Economic output was forecast to grow smoothly, with actual output following potential output relatively closely.

- *Demographics*: The population projection in the GI trend scenario was consistent with the Census Bureau's 2000 "middle" projection for the U.S. population. Based on specific assumptions about immigration, fertility and mortality rates, U.S. population was forecast to achieve average annual growth of 0.9 percent from 2005 to 2019.

- *Energy*: Except for temporary spikes, GI forecasted that the average price of foreign oil would remain below $31 per barrel until 2009. In the longer term, GI projected that scarcity would begin to drive the real price of imported oil upward to $45 a barrel in 2019.

- *Output*: Growth in annual real U.S. Gross Domestic Product was projected to average 3.1 percent over the fifteen-year period from 2005 to 2019.

Economic and demographic assumptions were developed for each utility using the Kentucky State Econometric Model and the Companies' Service Territory Econometric Model ("STEM") to produce utility-specific forecast drivers. These assumptions are addressed in section 5.(3).

Resource Assessment and Acquisition Plan

In the planning decision-making process, the economics and practicality of supply-side and demand-side options are carefully examined to develop the IRP for meeting customers' expected needs. If, upon review, an alternative plan shows economic viability, a capacity expansion computer program is used to evaluate its operational characteristics and economics.

The Companies use New Energy Associates' Strategist® program for resource expansion studies. Strategist® contains several modules that can be executed in various ways to evaluate system resource expansion alternatives.

Two key assumptions and uncertainties associated with the development of the Companies' IRP are forecasted fuel prices and forecasted customer load requirements. As a part of the detailed resource assessment using Strategist®, sensitivity analyses were conducted on these variables.

Currently, three types of fuel are simulated in the resource optimization analysis: coal, oil, and natural gas. A major change in future oil, gas or coal prices can have a significant impact on the selection of new units and on the operation of existing units. Therefore, three fuel forecasts (Base, High, Low) are developed and analyzed as part of the development of the plan.

The load forecast (demand and energy forecast) is another significant factor influencing the Companies' resource plan. Each resource option is selected for optimal performance at specific levels of utilization. Alternative load growth scenarios also may have a significant impact on the selection of an optimal technology, type and size; therefore, three load forecasts are developed. The three forecasts show an expected system load growth case, a case in which system load growth exceeds expected growth, and a case in which system load growth is less than expected. The three load forecasts were analyzed as part of the IRP development.

5.(3) Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts;

Combined Company

History

Table 5.(3)-1 presents historical data on combined company customers, sales, energy requirements[1], and peak demand. On a Combined Company basis, native electric customers increased from 858,827 in 2000 to 903,834 in 2004, an average annual growth rate of 1.3 percent. Actual sales for KU and LG&E rose from 30,145 GWh in 2000 to 31,902 GWh in 2004, increasing at an average annual growth rate of 1.4 percent. On a weather-normalized basis, average sales growth was 1.6 percent over this period. Combined energy requirements grew from 32,058 GWh in 2000 to 33,796 GWh in 2004. Peak demand fluctuated over the 2000-2004 period. On an actual basis, peak demand fell from 6,317 MW in 2000 to 6,221 MW in 2001 only to increase to 6,513 MW in 2002. Further declines occurred in 2003 and 2004, which recorded peaks of 6,393 MW and 6,223 MW, respectively. However, on a weather-normalized basis, a slight increase in peak was recorded in 2003 over 2002 (6,448 MW vs. 6,429 MW) before declining to 6,362 MW in 2004. Because of the mild summer, weather-normalization added 139 MW to the 2004 peak.

1 Energy requirements represent sales plus transmission and distribution losses.

Table 5.(3)-1
Combined Company: Historical Customer Numbers, Calendar Sales, Energy Requirements and Peak Demand, 2000-2004

	2000	2001	2002	2003	2004
Customers	858,827	871,879	884,056	892,677	903,834
Sales (GWh)	30,145	29,856	31,369	30,999	31,902
Weather-Normalized Sales (GWh)	30,349	29,852	30,623	31,518	32,277
Energy Requirements (GWh) (actual)	32,058	31,749	33,254	32,778	33,796
Peak Demand (MW) [1]	6,317	6,221	6,513	6,393	6,223
Weather-Normalized Peak Demand (MW)	6,314	6,239	6,429	6,448	6,362

[1] Includes impact of Interruptible and Curtailable loads

Combined Company Forecast

All forecasts of energy sales/requirements, peak demand, and use-per-customer assume normal weather – which is based on 20 years of average daily temperatures. Table 5.(3)-2 presents the forecast for Combined Company customer numbers, sales and energy requirements, together with forecast annual growth rates. From 2005 through 2009, Combined Company customers are forecast to grow at an average annual rate of 1.2 percent, while both sales and energy requirements are forecast to average 2.1 percent. By 2019, Combined Company customers are forecast to reach 1,062,741, averaging 1.1 percent growth over the full forecast horizon. The forecast calls for sales to reach 42,685 GWh in 2019, with annual growth averaging 2.0 percent.

Table 5.(3)-2
Combined Company: Forecast Customer Numbers, Sales, and Energy Requirements

Year	Combined Company Customers	% Growth in Customers	Combined Company Sales Forecast (GWh)	% Growth in Sales	Combined Company Requirements Forecast (GWh)
2005	909,469	0.6%[1]	32,490	0.7%[2]	34,468
2006	920,949	1.3%	33,133	2.0%	35,143
2007	932,352	1.2%	33,889	2.3%	35,954
2008	943,694	1.2%	34,651	2.2%	36,797
2009	955,020	1.2%	35,316	1.9%	37,462
2010	966,347	1.2%	35,957	1.8%	38,121
2011	977,264	1.1%	36,701	2.1%	38,931
2012	988,119	1.1%	37,373	1.8%	39,644
2013	998,879	1.1%	38,153	2.1%	40,493
2014	1,009,557	1.1%	38,898	2.0%	41,285
2015	1,020,186	1.1%	39,620	1.9%	42,033
2016	1,030,821	1.0%	40,294	1.7%	42,719
2017	1,041,457	1.0%	41,035	1.8%	43,524
2018	1,052,112	1.0%	41,870	2.0%	44,424
2019	1,062,741	1.0%	42,685	1.9%	45,306

1 Based on Combined Company customers of 903,834 in 2004
2 Based on Weather-normalized sales of 32,278 GWh in 2004

Table 5.(3)-3 presents the Combined Company forecast for summer and winter season peak demand. The Combined Company demand forecast reflects the coincident peak of both utilities (KU & LG&E); the individual company peaks are not necessarily coincident. Combined Company native demand after curtailments is forecast to grow from 6,696 MW in 2005 to 7,272 MW in 2009, a growth of 576 MW with an average annual growth rate of 2.1 percent. By 2019, Combined Company demand reaches 8,794 MW for a total increase from 2005 of 2,098 MW, with growth averaging 1.9 percent per year over the full forecast period. Combined Company curtailable load is estimated to be 100 MW for each summer period during the forecast. From

2005 through 2009, the winter peak increases by 495 MW for an average growth rate of 2.1 percent. By 2019, the winter peak is forecast to increase by 1,708 MW with growth averaging 1.9 percent per year. Curtailable load impacts in winter are 38 MW per year.

Table 5.(3)-3
Combined Company Seasonal Peak Demand Forecast

Year	Combined Company Summer Peak Demand (MW) [1]	Percent Growth	Year	Combined Company Winter Peak Demand (MW) [2]	Percent Growth
2005	6,696	5.3%[3]	2004/05	5,647	3.5%[3]
2006	6,811	1.7%	2005/06	5,754	1.9%
2007	6,951	2.1%	2006/07	5,896	2.5%
2008	7,125	2.5%	2007/08	5,974	1.3%
2009	7,272	2.1%	2008/09	6,142	2.8%
2010	7,383	1.5%	2009/10	6,223	1.3%
2011	7,556	2.3%	2010/11	6,388	2.7%
2012	7,662	1.4%	2011/12	6,500	1.8%
2013	7,859	2.6%	2012/13	6,574	1.1%
2014	7,993	1.7%	2013/14	6,768	3.0%
2015	8,159	2.1%	2014/15	6,890	1.8%
2016	8,292	1.6%	2015/16	6,972	1.2%
2017	8,430	1.7%	2016/17	7,134	2.3%
2018	8,587	1.9%	2017/18	7,287	2.1%
2019	8,794	2.4%	2018/19	7,355	0.9%

1 Includes impact of Combined Company Summer Interruptible and Curtailable load of 100 MW per year.

2 Includes impact of Combined Company Winter Interruptible and Curtailable load of 38 MW per year.

3 2005 growth based on normalized 2004 peaks of 6,362 MW and 5,454 MW for summer and winter, respectively.

Kentucky Utilities

History

From 2000 to 2004, KU billed sales grew at an average annual rate of 2.2 percent on a weather-normalized basis. Recent growth has been most pronounced in the Residential class (3.3 percent on average since 2000) followed by the Industrial (2.2 percent), Commercial (1.9 percent), and Municipal (1.5 percent) classes. Within the Residential category, the All-Electric ("FERS") class experienced the highest average growth rate of 4.1 percent on a weather-normalized basis. For the balance of KY Residential sales (the "RS" class), growth over that same period was 2.4 percent. Virginia retail sales averaged 1.8 percent growth since 2000. Calendar sales by class (not weather-normalized) and recorded and weather-normalized total sales are displayed in Table 5.(3)-4.

Table 5.(3)-4
KU Recorded Sales by Class (GWh)

	2000	2001	2002	2003	2004
SYSTEM BILLED SALES:					
Recorded	18,612	18,618	19,488	19,470	20,074
Weather Normalized	18,735	18,639	19,114	19,702	20,458
SYSTEM USED SALES:					
Recorded	18,818	18,478	19,558	19,496	20,178
Weather Normalized	18,939	18,500	19,186	19,803	20,534
ENERGY REQUIREMENTS:					
Recorded	20,056	19,710	20,751	20,654	21,317
Weather Normalized	20,178	19,733	20,379	20,961	21,673
SALES BY CLASS (recorded):					
Residential Heating (FERS)	2,722	2,729	2,964	2,978	3,058
Residential Non-Heating (RS)	2,581	2,537	2,799	2,594	2,682
	--------	--------	--------	--------	--------
TOTAL RESIDENTIAL	5,303	5,266	5,763	5,572	5,740
Commercial	4,726	4,751	4,952	5,004	5,156
Industrial	5,983	5,648	5,933	6,027	6,312
Utility Use and Other	83	83	82	84	85
	--------	--------	--------	--------	--------
KENTUCKY Retail	16,095	15,748	16,730	16,687	17,293
Requirement Sales for Resale	1,843	1,842	1,926	1,903	1,959
	--------	--------	--------	--------	--------
TOTAL KENTUCKY	17,938	17,590	18,656	18,590	19,252
VIRGINIA Retail	880	888	902	906	926
TOTAL KU SALES	18,818	18,478	19,558	19,496	20,178
SYSTEM LOSSES	1,238	1,232	1,193	1,158	1,138
ENERGY REQUIREMENTS	20,056	19,710	20,751	20,654	21,317

KU Forecast

KU's long-term forecast drivers are produced by the STEM model. Key economic assumptions underlying the KU sales forecast are as follows.

Key Assumptions

- *Demographics:* The population growth rate in the KU service territory was forecast to be below the national average. Annual population growth was forecast to average 0.8 percent over the next five years and 0.9 percent nationally. This is a continuation of past trends where population growth in Kentucky has lagged the national average. Kentucky population was forecast to increase at an average rate of 0.8 percent over the fifteen-year forecast period through 2019. Furthermore, aging of the population leads to fewer people per household. The number of households was forecast to increase at a 1.3 percent annual rate for the next five years, and at a 1.1 percent rate over the fifteen-year forecast horizon.

- *Output:* Industrial value-added *(a measure of economic activity in this sector)* in the KU service territory was forecast to grow by 5.2 percent annually over the next five years. This rapid average rate of growth was particularly pronounced in 2005 and 2006 as the manufacturing industry was projected to continue to recover. Over the fifteen-year forecast horizon, Industrial value-added was forecast to increase at an average annual rate of 3.7 percent.

- *Employment:* Commercial employment was forecast to grow at 2.1 percent per year over the next five years and at a rate of 2.0 percent annually over the fifteen-year horizon.

- *Personal Income:* Real total personal income in the KU service territory was forecast to grow at a 3.4 percent average annual rate for the first five years, and at 3.6 percent annually over the fifteen-year horizon.

KU Customer Growth and Energy Sales

Total KU energy sales over the first five years (2005 to 2009) of the forecast are projected to rise at a 2.4 percent average annual rate. The forecast averages 2.0 percent growth over the fifteen-year forecast horizon. Table 5.(3)-5 shows the five and fifteen-year average annual growth rates for each class of sales along with each class's relative share of 2004 sales.

Kentucky Retail Residential sales are forecast to increase at a 1.7 percent annual rate from 2005 to 2009. Residential growth is driven by a combination of customer growth and continued growth in use-per-customer. Kentucky Retail Commercial sales are forecast to increase at a 3.2 percent annual rate from 2005 to 2009, while Kentucky Retail Industrial sales are projected to average 2.6 percent growth. Significant growth by some of the larger Industrial customers creates a relatively strong medium-term growth outlook for the Industrial sector. A relatively unfavorable outlook for total coal production in Western Kentucky results in a forecast annual growth rate for energy sales under the Mine Power rate of 0.8 percent. Wholesale sales are forecast to grow at an average rate of 2.2 percent, generally in line with but slower than Kentucky Retail sales. Virginia sales are expected to increase only moderately, with 1.3 percent average growth.

Table 5.(3)-5
KU: Sales Structure and Forecast Growth Rates By Class

Class	Percent of 2004 Sales	Percent Annual Growth 2005-2009	Percent Annual Growth 2005-2019
RETAIL	**90.4**	**2.4**	**2.1**
Kentucky	**85.9**	**2.5**	**2.1**
Residential	29.2	1.7	1.9
RS	13.6	0.5	0.9
FERS	15.5	2.8	2.7
Commercial	27.4	3.2	2.5
Industrial	26.7	2.4	1.8
General Industrial	16.1	3.5	2.8
Major Industrials	10.6	1.1	0.3
Coal Mining (MP, LMP)	2.0	0.8	0.6
Lighting (COLT, St. Lt.)	0.6	2.9	2.3
Virginia	**4.5**	**1.3**	**1.2**
WHOLESALE	**9.6**	**2.2**	**2.0**
TOTAL KU	**100.0**	**2.4**	**2.0**

Table 5.(3)-6 presents the 2005 KU forecast values for total customers and sales with their corresponding annual growth rates through 2019. Over the 2005-2009 period, sales are projected to grow at an average growth rate of 2.4 percent. Through the entire forecast horizon, annual growth is projected to be 2.0 percent.

Table 5.(3)-6
KU: Forecast Customer Numbers and Billed Sales (GWh)

Year	Customers	% Growth in Customers	Energy Sales Forecast (GWh)	% Growth in Energy Sales
2005	518,045	0.7%[1]	20,506	0.2[2]
2006	524,417	1.2%	20,945	2.1%
2007	530,617	1.2%	21,558	2.9%
2008	536,646	1.1%	22,102	2.5%
2009	542,598	1.1%	22,551	2.0%
2010	548,544	1.1%	22,968	1.8%
2011	554,169	1.0%	23,444	2.1%
2012	559,781	1.0%	23,868	1.8%
2013	565,346	1.0%	24,357	2.0%
2014	570,884	1.0%	24,829	1.9%
2015	576,422	1.0%	25,281	1.8%
2016	581,980	1.0%	25,697	1.6%
2017	587,541	1.0%	26,160	1.8%
2018	593,109	0.9%	26,687	2.0%
2019	598,697	0.9%	27,198	1.9%

1 Based on 2004 Customers of 511,514 that excludes lighting

2 Based on 2004 weather-normalized sales of 20,458 GWh

KU Peak Demand

KU's actual and weather-normalized peak demand over 2000-2004 are displayed in Table 5.(3)-7. On a weather-normalized basis and after curtailment, KU's summer and winter peaks in 2000 were 3,772[1] MW and 3,975 MW respectively. In 2004, the weather-normalized summer peak was 3,800 MW. The weather-normalized KU winter peaks have ranged from 3,975 MW in 2000 to 3,660 MW in 2002. In 2004, the winter peak was 3,771 MW.

Table 5.(3)-7
KU Recorded and Weather-Normalized Peak Load (MW)

	2000	2001	2002	2003	2004
SUMMER					
Recorded	3,775	3,699	3,899	3,810	3,744
Weather- Normalized	3.772	3,714	3,870	3,836	3,800
	99/00	**00/01**	**01/02**	**02/03**	**03/04**
WINTER					
Recorded	3,665	3,748	3,491	3,944	3,768
Weather- Normalized	3,975	3,886	3,660	3,930	3,771

KU Peak Demand Forecast

The KU summer peak demand is forecast to increase at an annual rate of 1.9 percent from 4,067 MW in 2005 to 5,393 MW in 2019, adding 1,326 MW over the period at an average of 95 MW per year. In the medium term, 2005 to 2009, the KU summer peak demand is forecast to increase from 4,067 MW to 4,472 MW (101 MW per year), which represents an average annual rate of 2.4 percent. For 2009 to 2019 the summer peak demand is forecast to increase at an

[1] Changes in weather-adjusted peaks reported in 2002 IRP are because of new normalization methodology.

average annual rate of 1.9 percent from 4,472 MW to 5,393 MW, adding 921 MW over the period at an average of 92 MW per year (Table 5.(3)-8).

Table 5.(3)-8
KU: Forecast Energy Requirements (GWh) and Peak Demand (MW)

Year	Energy Requirements (GWh)	Percent Growth	Summer Peak (MW) [2]	Percent Growth
2005	21,812	0.2%[1]	4,067	7.0% [3]
2006	22,273	2.1%	4,153	2.1%
2007	22,930	2.9%	4,275	2.9%
2008	23,530	2.6%	4,387	2.6%
2009	23,983	1.9%	4,472	1.9%
2010	24,399	1.7%	4,549	1.7%
2011	24,920	2.1%	4,646	2.1%
2012	25,376	1.8%	4,731	1.8%
2013	25,909	2.1%	4,830	2.1%
2014	26,420	2.0%	4,925	2.0%
2015	26,883	1.8%	5,012	1.8%
2016	27,298	1.5%	5,089	1.5%
2017	27,810	1.9%	5,184	1.9%
2018	28,377	2.0%	5,290	2.0%
2019	28,933	2.0%	5,393	1.9%

1 Based on 2004 weather-normalized value of 21,673 GWh

2 The peak demands include a reduction for Curtailable loads of 51 MW.

3 Based on 2004 weather normalized value of 3,800 MW

Louisville Gas & Electric

History

From 2000 to 2004, LG&E calendar sales grew at an average annual growth rate of about 1.0 percent on a weather-normalized basis. LG&E sales over this period are shown in Table 5.(3)-9.

Table 5.(3)-9
LG&E Recorded Sales by Class (GWh)

	2000	2001	2002	2003	2004
SYSTEM BILLED SALES:					
Recorded	11,209	11,360	11,798	11,448	11,698
Weather Normalized	11,289	11,335	11,456	11,655	11,735
SYSTEM USED SALES:					
Recorded	11,329	11,377	11,810	11,503	11,724
Weather Normalized	11,409	11,352	11,436	11,715	11,744
ENERGY REQUIREMENTS:					
Recorded	12,003	12,038	12,503	12,123	12,532
Weather Normalized	12,083	12,013	12,129	12,335	12,552
SALES BY CLASS:					
Residential Heating	732	724	732	723	740
Residential Non-Heating	2,990	3,058	3,303	3,111	3,184
	---------	---------	---------	---------	---------
TOTAL RESIDENTIAL	3,722	3,782	4,036	3,835	3,924
General Service	1,364	1,388	1,404	1,379	1,395
Large Commercial	2,855	2,904	2,987	2,995	3,028
Large Power	3,318	3,253	3,314	3,225	3,308
Street Lighting	70	70	69	69	69
	---------	---------	---------	---------	---------
TOTAL LG&E SALES	11,329	11,397	11,810	11,503	11,724
SYSTEM LOSSES	674	641	692	620	756
ENERGY REQUIREMENTS	12,003	12,038	12,503	12,123	12,480

LG&E Forecast

The LG&E electric sales forecast is developed from a macroeconomic background produced by the STEM. Key economic assumptions underlying the LG&E sales forecast are as follows.

Key Assumptions

- *Demographics:* Population in the Louisville area was forecast to increase at a slower rate than the national population forecast. Annual population growth was forecast to average 0.5 percent over the next five years and 0.6 percent over the fifteen-year forecast horizon. Furthermore, with the aging of the population (resulting in fewer persons per household), households numbers were forecast to increase at a faster rate than population - 0.8 percent per year on average over the next five years and over the full fifteen-year forecast horizon.

- *Output:* Industrial Value-Added was forecast to increase at a 2.3 percent average annual rate over the next five years and over the fifteen-year horizon. However, a base of large, mature Industrial customers - accounting for a significant portion of Industrial load - was forecast to exhibit much slower growth in electric consumption in response to process efficiency initiatives and excess capacity.

- Personal *Income:* Real total personal income was forecast to increase at a 3.1 percent average annual rate over the first five years, and at a 3.5 percent growth rate over the fifteen-year forecast horizon.

LG&E Customer Growth and Energy Sales

Table 5.(3)-10 presents the five and fifteen-year average annual sales growth rates for each class along with their relative share of 2004 sales. Over the first five years of the energy forecast, sales growth by sector is forecast to be strongest in the Residential and Large Commercial sectors (2.2 and 2.0 percent respectively). Similarly, Small Commercial, Industrial and Street Lighting are projected to grow annually at 1.9, 0.3 and 0.4 percent respectively. Over the fifteen-year period, sales to the Residential sector exhibit the highest sustained growth at 2.3 percent, followed by Commercial (both Large and Small) at 1.9 percent. Industrial sales are projected to increase by 1.2 percent over the 2005-2019 period.

Table 5.(3)-10
LG&E: Sales Structure (2004) and Forecast Growth Rates by Class

Class	Percent of 2004 Sales	Average Annual Growth 2005-2009	Average Annual Growth 2005-2019
Residential	33.6	2.2	2.3
Small Commercial	11.9	1.9	1.9
Large Commercial	25.8	2.0	2.0
Large Industrial	28.1	0.3	1.2
Street Lighting	0.5	0.4	0.4
LG&E Total	100.0	1.6	1.9

Total LG&E energy sales over 2005-2009 are forecast to rise at a 1.6 percent annual average rate. The forecast averages 1.9 percent growth over the fifteen-year forecast horizon.

Table 5.(3)-11 presents the 2005 LG&E Forecast for total customers and sales with their corresponding annual growth rates through 2019. Sales are projected to increase by 1.3 percent

in the medium term (2005-2009) as national and state economic conditions creates strong short-term growth, with a gradual slowdown in the longer-term trend. Sales are projected to increase by 1.2 percent over the 2005-2019 forecast horizon.

Table 5.(3)-11
LG&E: Forecast Customer Numbers and Billed Sales (GWh)

Year	Customers	% Growth in Customers	Energy Sales Forecast (GWh)	% Growth in Energy Sales
2005	391,424	0.6%[1]	11,983	2.1%[2]
2006	396,532	1.3%	12,188	1.7%
2007	401,735	1.3%	12,330	1.2%
2008	407,048	1.3%	12,549	1.8%
2009	412,422	1.3%	12,765	1.7%
2010	417,803	1.3%	12,988	1.8%
2011	423,095	1.3%	13,258	2.1%
2012	428,338	1.2%	13,506	1.9%
2013	433,533	1.2%	13,796	2.2%
2014	438,673	1.2%	14,069	2.0%
2015	443,764	1.2%	14,339	1.9%
2016	448,841	1.1%	14,597	1.8%
2017	453,916	1.1%	14,874	1.9%
2018	459,003	1.1%	15,183	2.1%
2019	464,044	1.1%	15,488	2.0%

1 Based on 2004 customer number of 389,196

2 Based on 2004 weather-normalized sales of 11,735 MWh

LG&E Peak Demand

On a weather-normalized basis and after curtailment, LG&E peak demand in 2000 was 2,542 MW. As shown in Table 5.(3)-12, LG&E's weather-normalized summer peak demand in 2004 (after curtailment) was 2,562 MW.

Table 5.(3)-12
LG&E Recorded and Weather-Normalized Peak Load (MW)

	2000	2001	2002	2003	2004
SUMMER					
Recorded	2,542	2,522	2,623	2,583	2,485
Normalized	2,542	2,525	2,559	2,612	2,562
	99/00	**00/01**	**01/02**	**02/03**	**03/04**
WINTER					
Recorded	1,670	1,818	1,660	1,824	1,750
Normalized	1,724	1,838	1,691	1,818	1,683

LG&E Peak Demand Forecast

Table 5.(3)-13 presents the LG&E summer peak demand and energy requirements forecasts. The LG&E summer peak demand is forecast to increase at an annual growth rate of 1.9 percent from 2,629 MW in 2005 to 3,401 MW in 2019, adding 772 MW over the period at an average of 55 MW per year. Between 2005 and 2009, the summer peak demand is forecast to increase from 2,629 MW to 2,800 MW, at an annual rate of 1.6 percent, adding 171 MW over the four-year period at an average of 43 MW per year. For the 2009 to 2019 period, the summer peak demand is projected to increase at an annual rate of 2.0 percent from 2,800 MW to 3,401 MW, adding 601 MW over the period at an average of 60 MW per year.

Table 5.(3)-13
LG&E: Forecast Energy Requirements and Peak Demand

Year	Energy Requirements (GWh)	Percent Growth	Summer Peak (MW)	Percent Growth
2005	12,657	1.3%[1]	2,629	2.6%[2]
2006	12,870	1.7%	2,673	1.7%
2007	13,024	1.2%	2,705	1.2%
2008	13,266	1.9%	2,756	1.9%
2009	13,478	1.6%	2,800	1.6%
2010	13,722	1.8%	2,850	1.8%
2011	14,011	2.1%	2,910	2.1%
2012	14,269	1.8%	2,964	1.9%
2013	14,584	2.2%	3,029	2.2%
2014	14,865	1.9%	3,088	1.9%
2015	15,151	1.9%	3,147	1.9%
2016	15,421	1.8%	3,203	1.8%
2017	15,713	1.9%	3,264	1.9%
2018	16,047	2.1%	3,333	2.1%
2019	16,374	2.0%	3,401	2.0%

1 Based on 2004 Energy Requirements of 12,500 GWh

2 Based on a weather-normalized 2004 summer peak of 2,562 MW

5.(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, non-utility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities;

Summary of Planned Resource Acquisitions

The Companies' resource planning process considers the economics and practicality of available options to meet customer needs at the lowest practical cost. A study was completed to determine an optimal target reserve margin criterion to be used by the Companies. This study indicates that an optimal target reserve margin in the range of 12% to 14% would provide an adequate and reliable system to meet customers' demand under a wide range of sensitivities to key assumptions. In the development of the optimal Integrated Resource Plan, the Companies used a reserve margin target of 14%. The plan resulting from the Companies' optimal Integrated Resource Plan analysis is shown below in Table 5.(4) and is detailed in a report titled, *2005 Optimal Expansion Plan Analysis* (January 2005) contained in Volume III, Technical Appendix. The in-service years for the units shown assume the Companies' Base Load Forecast.

Table 5.(4)
Recommended 2005 Integrated Resource Plan

Year	Resource
2005	1.9 MW New DSM Initiatives
2006	4.9 MW New DSM Initiatives (cumulative totals)
2007	8.8 MW New DSM Initiatives (cumulative totals)
2008	13.4 MW New DSM Initiatives (cumulative totals)
2009	18.5 MW New DSM Initiatives (cumulative totals)
2010	549 MW (75% of 732 MW) Trimble County Unit 2 Supercritical Coal 23.7 MW New DSM Initiatives (cumulative totals)
2011	28.8 MW New DSM Initiatives (cumulative totals)
2012	
2013	148 MW Greenfield CT Unit 1
2014	WV Hydro Purchase Power Agreement
2015	148 MW Greenfield CT Unit 2 148 MW Greenfield CT Unit 3
2016	148 MW Greenfield CT Unit 4
2017	148 MW Greenfield CT Unit 5
2018	148 MW Greenfield CT Unit 6
2019	750 MW Greenfield Supercritical Coal Unit

Note: Unit Ratings are Proposed Summer Net Ratings

The technological status, construction aspects, operating costs, and environmental features of various generation plant construction options were reviewed. After screening many technologies, the options recommended for further evaluation using detailed resource planning computer models included the following supply-side options:

Supercritical Pulverized Coal unit at Trimble County Station (TC2)
WV Hydro Purchase Power Agreement ("PPA")
Supercritical Pulverized Coal, High Sulfur – 750 MW
Run of River-Ohio Falls Expansion (Units 9 and 10)
Combustion Turbines at a Greenfield Site
Combined Cycle Combustion Turbine (Un-Phased)

Along with these supply-side options, DSM programs are included in the integrated analysis. The optimal Integrated Resource Plan recommends the construction of a second coal unit at Trimble County, six Greenfield combustion turbines, the Purchase Power Agreement ("PPA") with W.V. Hydro, Inc., and one supercritical Greenfield coal unit. Also, there is the implementation of five new DSM programs which ramp up to a combined amount of 28.8 MW annually in 2011.

Efficiency Improvements

The plan described in Table 5.(4) does not explicitly call for generation efficiency improvements. However, the Companies continue to evaluate economic improvements to their generation fleet. Maintenance schedules are coordinated across the entire generation system such that the outages will have the least economic impact to the customers and the Companies. Additional details are provided in Section 8.(2)(a).

Rehabilitation of Ohio Falls

The Companies have evaluated and will continue to evaluate the sustainable long-term generation and modernization needs and opportunities for the Ohio Falls Hydro generating station. This evaluation has considered several economic options and continues to be an ongoing process.

Currently, the Ohio Falls Station has a 30-year operational license granted by the Federal Energy Regulatory Commission ("FERC") which will expire November 10, 2005. LG&E filed an Application for License Renewal with FERC on October 7, 2003. The relicensing process is underway with the current relicensing schedule anticipating a FERC decision in October 2005. On March 3, 2005, LG&E officially requested that the new license from FERC have a term of 40 years.

Ohio Falls has been in service since the 1920's with no significant rehabilitation efforts having taken place. A rehabilitation project to be implemented in three phases over a number of years began in 2001 with Phase 1 and Phase 2 now complete. Phase 3 entails the most significant scope of work including the rehabilitation of the turbine/generator units. Subject to FERC approval, Phase 3 of the rehabilitation will take place during the low water season in the latter six months of each year beginning in 2005. Current plans call for one unit to be repaired each year thereafter until all eight units are complete in 2012. This rehabilitation will increase the expected capacity output of the Ohio Falls Station to 64 MW from the current planned value (time of summer peak) of 48 MW and provide a potential for 187 GWh of additional annual energy production.

The Companies continually evaluate resources available to meet load obligations, including the options at the Ohio Falls station. Current plans to rehabilitate all eight units beginning with one unit will be continually evaluated as more detailed rehabilitation estimates become available and as the Companies learn from the actual condition of the units as the rehabilitation progresses one unit at a time. Further discussion is contained in Section 6.

Demand Side Management

The plan described in Table 5.(4) includes the implementation of 5 new programs, labeled collectively as New DSM Initiatives. Additional detail on the DSM alternative in the plan is contained in the report titled *Screening of Demand-Side Management (DSM) Options* (April 2005) contained in Volume III, Technical Appendix.

Non-Utility Generation

The plan described in Table 5.(4) includes some non-utility generation. On April 1, 2003 the Companies sent out a Request for Proposals ("RFP") in conjunction with Trimble County Unit 2 ("TC2") supply alternatives. One of these proposals was a renewable resource from W.V. Hydro, Inc. with a Purchase Power Agreement ("PPA"). Their most current offer dated October 14, 2004 consists of three 80 MW hydroelectric projects based on conventional hydro technology. The average summer output during the peak month is 181 MW. Pursuing this PPA to commence in 2013 after construction of TC2 lowers the overall revenue requirements. On occasion, the Companies receive inquiries from Independent Power Producers ("IPPs") and will continue to evaluate all bid proposals received with the goal of determining the least cost generation resources for meeting the needs of customers.

Location of Exempt Wholesale Generators ("EWGs") near or within the Companies' service territory may continue as the deregulated wholesale power marketplace evolves. The Companies anticipate receiving offers on occasion from EWG's to supply capacity needs and thus will include EWG's in any Requests for Proposals for purchased power that may be issued by the Companies in the future.

New Power Plants

The plan described in Table 5.(4) calls for Trimble County Unit 2, six new Greenfield combustion turbines and one Greenfield supercritical high sulfur coal unit. Clearly, new power plants are the most significant component of the 15-year least-cost plan.

Transmission Improvements

The Companies routinely identify transmission construction projects and upgrades required for maintaining the adequacy of its transmission system to meet projected customer demands. The construction projects currently identified are included in Volume III, Technical Appendix under the section labeled *Transmission Projects*.

Bulk Power Purchase and Sales and Interchange

The Companies have purchase power arrangements with Owensboro Municipal Utilities ("OMU"), Ohio Valley Electric Corporation ("OVEC") and Electric Energy, Inc. ("EEInc.") to provide additional sources of capacity. Under the OMU agreement, the Companies purchase (on an economic basis) the output not needed by OMU's system from two coal-fired, baseload units (combined capacity of approximately 400 megawatts). For 2005, the Companies expect to receive 196 megawatts of capacity from OMU. For each year after 2005, the expected capacity available to KU is projected to decrease due to the increases in OMU's customer load.

On May 11, 2004 the City of Owensboro, Kentucky and Owensboro Municipal Utilities filed suit against Kentucky Utilities Company in Daviess County, Kentucky District Court concerning a long-term power supply contract ("OMU Agreement") between KU and OMU. The dispute involves interpretational differences regarding certain issues under the OMU Agreement, including various payments or charges between KU and OMU, rights to excess power from the Smith units above that required to serve the OMU load, the ability to terminate the OMU Agreement and allocation between KU and OMU of the NO_x emissions allowances issued by the EPA. Kentucky Utilities removed the case to federal court in the Western District of Kentucky and filed an answer in that court denying the OMU claims and presenting certain counterclaims.

OVEC was formed for the purpose of providing electric power requirements projected for the uranium enrichment complex being built near Portsmouth, Ohio. However, beginning August 31, 2001, the power and energy from these plants was released from the original purpose and became available to the sponsoring companies. The Companies currently have access to 9.5% of the capacity and energy, which is approximately 225 MW of the installed capacity or approximately 209 MW reliably during the summer peak and varying capacity during the remaining months due to unit maintenance schedules. However, the Inter-Company Power Agreement ("ICPA") was renewed in 2004 and the Companies combined sponsorship will be 8.13% beginning in April 2006. Further details about OVEC and the Companies' sponsorship are contained in Section 6.

The EEInc. Power Supply Agreement ("PSA") expires December 31, 2005. Because KU has an ownership interest of only 20 percent while Ameren has an ownership interest of 80 percent, the disposition of the PSA after the expiration date is not certain at this time. For the purpose of this analysis, the Companies assume that the PSA will be extended in its current form for the entire study period. The PSA permits KU to take its 20% share in the output of six coal-fired, baseload units with combined capacity of approximately 1,000 megawatts. The Companies continue to schedule their 20 percent contract right to the 200 megawatts from EEInc.

5.(5) Steps to be taken during the next three (3) years to implement the plan;

As part of implementing the plan over the next three years, the Companies have submitted an application to the Commission for appropriate certificates for the installation of the second coal-fired unit at Trimble County (Case No. 2004-00507). However, the Companies currently do not have the Certificate of Public Convenience and Necessity ("CCN") from the Commission. Once certification is received, and once approvals for other state agencies are secured as applicable, construction will begin on this unit. Additional measures that Demand Side Management ("DSM") will be taking are outlined below.

Demand-Side Management

The DSM alternatives included in the plan will be subjected to a much more rigorous review and program design cycle, including pilot programs, which could result in program concepts and program details being changed significantly, or programs not being implemented.

Implementation of the DSM program in the plan will then require the preparation of a multi-year DSM filing that would include any update in program design, would have the selected program by customer class, and would include the recovery of the expected cost to administer the program and the expected lost revenue for the program.

As a final step, a Request for Proposal ("RFP") will be developed and issued for an administrator/contractor for the program. Marketing representatives for the Companies would be trained on the new customer offerings. The Companies would develop a process to track data related to the program.

5.(6) Discussion of key issues or uncertainties that could affect successful implementation of the plan.

Forecast Uncertainty

The econometric modeling approach as utilized in the latest energy forecasts seeks to define the historical statistical relationships between the dependent variable (electricity consumption) and the various independent variables that influence the behavior of the dependent variable. These relationships are assumed to continue in the future and are used to develop the forecasts. The Company updates its energy sales, peak demand and customer forecasts on an annual basis to ensure that the structural relationships between explanatory and dependent variables are fully current. To address uncertainty, the Companies developed high and low scenarios to support sensitivity analysis of the various resource acquisition plans being studied. For the 2005 IRP, these scenarios were based on probabilistic simulation of the historical volatility exhibited by each utility's weather-normalized year-over-year sales trend (see KU or LG&E Technical Appendices in Volume II for a complete description).

These alternative outlooks for Combined Company energy requirements and demand are presented in Tables 5.(6)-1 and 5.(6)-2.

Table 5.(6)-1
Combined Company Base, High and Low Energy Requirements Forecast (GWh)

Year	Base Energy Requirements	High Energy Requirements	Low Energy Requirements
2005	34,468	34,731	34,087
2006	35,143	35,582	34,579
2007	35,954	36,589	35,180
2008	36,797	37,637	35,805
2009	37,462	38,485	36,283
2010	38,121	39,325	36,763
2011	38,931	40,341	37,352
2012	39,644	41,246	37,875
2013	40,493	42,309	38,489
2014	41,285	43,317	39,072
2015	42,033	44,269	39,613
2016	42,719	45,146	40,108
2017	43,524	46,163	40,698
2018	44,424	47,294	41,350
2019	45,306	48,402	41,991

Table 5.(6)-2
Combined Company Base, High and Low Peak Demand Forecasts (MW)

Year	Base Peak	High Peak	Low Peak
2005	6,696	6,748	6,623
2006	6,811	6,898	6,703
2007	6,951	7,074	6,803
2008	7,125	7,288	6,935
2009	7,272	7,471	7,044
2010	7,383	7,618	7,122
2011	7,556	7,831	7,250
2012	7,662	7,974	7,321
2013	7,859	8,215	7,470
2014	7,993	8,390	7,565
2015	8,159	8,597	7,689
2016	8,292	8,768	7,785
2017	8,430	8,947	7,882
2018	8,587	9,148	7,991
2019	8,794	9,402	8,149

Purchased Power

The unprecedented purchased power price volatility, which began in 1998, has not been repeated due to the increase in supply, i.e. new peaking capacity installed in the region in the past few years. Next-day peak power prices which reached $239/MWh in 1997 and then rose as high as $7,500/MWh in 1998 have steadily dropped to $2000/MWh in 1999, and as low as $60/MWh in 2002. However, recent trends in the last two years have contributed to an increase in next day prices in 2003 and 2004 to as high as $129/MWh. These market price trends (which are difficult to predict) are significant relative to the Companies' need to address native load growth and expansion in a cost-effective manner.

The forward prices in the market for purchased power change frequently. Such a change may initiate a corresponding revision to the plan as presented in this resource assessment.

DSM Implementation

The level of peak reduction ultimately reached in any of the DSM programs in this plan may not equal the target values listed in Table 5.(4). Several things could change that may alter the resulting peak reduction of these programs. The peak reduction for each participant could vary compared to the assumptions. The number of customers willing to participate could vary. If the willingness of customers to participate changes significantly, it may be possible to modify the marketing or redesign the program to maintain the expected level of participation.

The DSM alternatives included in the plan might not be implemented as they have been described in this report, because any DSM program will be subjected to a much more rigorous review and program design cycle, including pilot programs, which could result in program concepts and program details being changed significantly, or programs not being implemented.

Aging Units

The generating units in the Companies fleet continue to age. The two oldest steam generating units in the system are Tyrone Units 1 and 2. Each of these is over fifty years old, which is beyond the typical design life for a coal-fired unit. Some of the oldest combustion turbines are the LG&E smaller-sized combustion turbines and the KU Haefling combustion turbines. Each of these units is over 30 years of age, which is considered the typical full life expectancy for small frame combustion turbines. Table 5.(6)-4 indicates the age of the older units, otherwise referred to by the Companies as Group 3 units.

Having operated past their design lives, units run a greater risk of catastrophic failure than other units. As evaluations indicated such, Green River Units 1 and 2 were operationally retired December 31, 2003 for economic reasons. Further details of their retirement are described in Section 6 of this IRP.

The economics surrounding the continued operation of these units are periodically reviewed to ensure the efficiency of the overall system. The relatively high production costs of these units and further environmental restrictions only worsen their relative economics. It could become economic to retire many of these units even without a significant mechanical failure. This plan has a sensitivity done with these units retiring in 2010, the first year that Clean Air Interstate Rule ("CAIR") goes into effect. This is covered in more details in the *2005 Optimal Expansion Plan Analysis* (January 2005) contained in Volume III, Technical Appendix. Any decision to retire generation would change the future capacity needs.

Table 5.(6)-4
Aging Units

Type of Unit	Plant Name	Unit	Summer Capacity	In Service Year	Age (2005)
Steam	Tyrone	1	27	1947	58
Steam	Tyrone	2	31	1948	57
CT	Waterside	7	11	1964	41
CT	Waterside	8	11	1964	41
CT	Cane Run	11	14	1968	37
CT	Paddy's Run	11	12	1968	37
CT	Paddy's Run	12	23	1968	37
CT	Zorn	1	14	1969	36
CT	Haefling	1,2,3	36	1970	35

Midwest Independent Transmission System Operator

The Midwest Independent Transmission System Operator Inc. ("MISO") is in the process of developing transmission and generation resource adequacy proposals. As members of the MISO, the Companies continue to closely monitor and participate. The impact of these MISO initiatives is difficult to gauge at this time.

As described in Section 6, MISO Day 2 markets, i.e. Day Ahead and Real-Time energy markets with LMPs, will impact the very nature of the wholesale power market in the Midwest. The expected costs and benefits associated with the Companies' membership in MISO are the subject of a Commission investigation in Case No. 2003-00266 and are not explicitly incorporated as a significant change to the 2005 IRP relative to the 2002 IRP due to the on-going nature of that proceeding.

In December 2004, the Companies notified MISO of their intent to withdraw from MISO at the end of 2005. The outcome of the aforementioned proceeding and any subsequent proceedings related to the Companies' membership in MISO may ultimately impact the analyses included in the 2005 IRP. It is not possible to detail those potential impacts at this time.

Kentucky Public Service Commission

Staff Report On the

2005 Integrated Resource Plan Report

of Louisville Gas and Electric Company

and Kentucky Utilities Company

Case No. 2005-00162

February 2006

SECTION 1

INTRODUCTION

Administrative Regulation 807 KAR 5:058, promulgated in 1990 by the Kentucky Public Service Commission, ("Commission") established an integrated resource planning ("IRP") process that provides for regular review by the Commission Staff of the long-range resource plans of the six major electric utilities under its jurisdiction. The goal of the Commission in establishing the IRP process was to ensure that all reasonable options for the future supply of electrity were being examined and pursued, and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost.

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (jointly "LG&E/KU") submitted their 2005 Joint IRP to the Commission on April 21, 2005. The IRP submitted by LG&E/KU includes the plan for meeting their customers' electricity requirements for the period 2005-2019.

LG&E and KU are investor-owned public utilities that supply electricity and natural gas to customers primarily located in Kentucky. Both are subsidiaries of E.ON US, formerly LG&E Energy LLC. As owners and operators of interconnected electric generation, transmission, and distribution facilities, LG&E/KU achieve economic benefits through the operation of an interconnected and centrally dispatched system and through coordinated planning, construction, operation and maintenance of their facilities.

LG&E and KU are members of the Midwest Independent System Operator ("MISO") a regional transmission organization subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Since the issuance of the Staff Report on LG&E's and KU's Joint 2002 IRP, LG&E and KU have announced their intention to terminate their membership in MISO. LG&E/KU's request to exit MISO is presently pending in cases before both the Commission and FERC.

LG&E supplies electricity and natural gas to customers in the Louisville, Kentucky greater metropolitan area. It provides electric service to more nearly 400,000 customers in Louisville and 11 surrounding counties with a total service area covering approximately 700 square miles.

KU supplies retail electricity in 77 Kentucky counties to over 515,000 customers in a service area covering roughly 6,500 non-contiguous square miles and in 5 Virginia counties. It sells wholesale electricity to 12 Kentucky municipalities and the municipal system serving Pitcairn, Pennsylvania.

The purpose of this report is to review and evaluate the Joint IRP in accordance with the requirements of 807 KAR 5:058, Section 12(3), which requires the Commission

Staff to issue a report summarizing its review of each IRP filing made with the Commission and make suggestions and recommendations to be considered in future IRP filings. The Staff recognizes that resource planning is a dynamic ongoing process. Thus, this review is designed to offer suggestions and recommendations to LG&E/KU on how to improve their resource plan in the future. Specifically, the Staff's goals are to ensure that:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions and methodologies for all aspects of the plan are adequately documented and are reasonable; and
- The selected plan represents the leas-cost, least risk plan for the ultimate customers served by LG&E/KU, recognizing the need to achieve a balance between the interests of ratepayers and shareholders.

The report also includes an incremental component, noting any significant changes from the Companies' most recent IRP filed in 2002.

Based on a forecasted average annual growth rate of 2.0% over the 2005-2019 forecast period, LG&E/KU will require resource additions of roughly 2,400 megawatts ("MW"). Supply-side resources included in the plan include a supercritical 732 MW (the LG&E/KU share would be 549 MW) coal-fired base load plant to be located at LG&E's Trimble County Generating Station and 6 "greenfield" combustion turbines ("CTs") with a total capacity of 888 MW. The resources also include 28 MW through greater demand-side management ("DSM") savings, a hydro power purchase agreement with an average summer capacity of 181 MW, and a 750 MW supercritical coal unit for which a site was not designated.

The remainder of this report is organized as follows:

- Section 2, Load Forecasting, reviews LG&E/KU's projected load growth and load forecasting methodology.

- Section 3, Demand-Side Management, summarizes LG&E/KU's evaluation of DSM opportunities.

- Section 4, Supply-Side Resource Assessment, focuses on supply resources available to meet LG&E/KU's load requirements.

- Section 5, Integration and Plan Optimization, discusses LG&E/KU's overall assessment of supply-side and demand-side options and their integration into an overall resource plan.

SECTION 2

LOAD FORECASTING

This section reviews LG&E/KU's projected load growth and load forecasting methodology. Although much progress has been made in standardizing the forecasting processes for LG&E/KU, some differences remain, especially in how data is segmented. The value gained from this distinction will be analyzed in the near future, according to the IRP. Therefore, this IRP presents separate forecasts for LG&E and KU.

Forecasting Methodology

Forecasting energy and demand is important for both the planning and control of LG&E/KU's operations. The forecast is a tool for decisions regarding construction of facilities such as power plants, transmission lines, and substations, all of which are necessary for providing reliable service. The desired outcome of the forecasting process are reasonable estimates of LG&E/KU's future energy and load growth so that their goals of providing adequate and reliable service to their customers at the lowest reasonable cost can be attained.

LG&E/KU's energy forecasting uses econometric modeling and growth outlook information collected from their largest customers. Econometric modeling satisfies two critical forecasting requirements. First, it combines economic and demographic factors that determine sales in a rational manner. This means that national economic conditions affect regional and local economic and demographic conditions. Local economic and demographic conditions contribute their own unique characteristic trends to the outlook. Together, these provide a reasoned outlook for demographic and economic growth in LG&E/KU's service territories. This widely accepted approach establishes the basis for a base case analysis and for optimistic and pessimistic growth scenarios for sensitivity analyses of the various resource acquisition plans studied.

Second, this approach quantifies cause and effect relationships between electric sales and the national, regional, and local factors that influence their growth. The relationships will vary depending upon the jurisdiction being modeled and the class of service. For LG&E, only one jurisdiction is modeled, Kentucky-retail. KU's forecast includes three jurisdictional groups: Kentucky-retail, Virginia-retail, and wholesale sales to 11 municipal utilities in Kentucky. Typical classes modeled include Residential, Commercial, and Industrial.

According to the IRP, the models were proven theoretically and empirically robust to explain the behavior of LG&E/KU's customer and sales data. Once econometric relationships were established, the forecast was produced using standard procedures. For both LG&E and KU, the forecast incorporates both short and long term models with the specification and length of historic data varying by customer class.

The modeling processes incorporate various elements of end-use forecasting, such as base load, heating and cooling components. The extent of this modeling varies by utility and class. Energy forecasts are converted from a billed to calendar basis and inflated for company use and losses. The resulting estimate of monthly energy requirements is then associated with a typical load profile and load factor to generate annual, seasonal, and monthly peak demand forecasts for each utility and on a combined utility basis.

The first step in the forecasting process is to gather national, state and service territory economic and demographic data in order to specify models that describe customers' usage characteristics. Due to the strong link between growth forecasts for national and regional economies and estimates of future energy use, national economic forecast data are used. The national forecast data for both LG&E and KU was prepared by Global Insight ("GI"), an economic consulting firm used by many utilities.

Key Macroeconomic Assumptions in GI's forecast

Following is a brief review of GI's key assumptions in generating its trend forecast.

- After the first five years of the forecast, the national economy suffers no exogenous shocks. Economics output grows smoothly, in the sense that actual output follows potential output relatively closely.

- GI's population projection is consistent with the U.S. Census Bureau's "middle" projection for the U.S. population. The projection, based on numerous assumptions about immigration, fertility and mortality rates, projects that the US population will grow an average of 0.8% annually over the fifteen year period from 2002 to 2028.

- Except for temporary spikes, the average price of foreign crude oil is expected to remain below $30 per barrel until 2010. Between 2011 and 2020, the price of oil is projected to average $36 and then climbing steadily toward $62 per barrel by 2028. In the long run, scarcity of resources tends to bid prices up, while new technologies tend to hold them down. In the end, scarcity will have the greater effect, with the real price of imported oil expected to increase from around $21 a barrel in 2001 to approximately $27 a barrel in 2028.

- Annual real US Gross Domestic Product is expected to average 3.0 percent growth over the 2002 to 2028 period.

- Inflation over the forecast period will remain moderate. Inflation as measured by the CPI will average 3.2% over the forecast period.

The KU Forecast

For KU, GI generated national forecast data is fed into the University of Kentucky Center for Business and Economic Research's ("UK/CBER") State Econometric Model, which then generates value-added forecasts for over 30 industries and employment forecasts for nearly 70 sectors, as well as an income forecast. State forecasted data from the State Econometric Model are fed into the Service Territory Economic Model ("STEM") that UK/CBER produces to create service territory level class forecast drivers.

Demographic trends are an important part of the forecasting process. Population and number of persons per household forecasts work together in the STEM model to create a household forecast, which is a key driver in the development of a total Kentucky retail residential customer forecast. Kentucky retail residential customers are then used to explain growth in commercial customers. Virginia residential customers are forecast similarly using Virginia data from the STEM model.

KU's forecast of long term residential sales is a function of customers by class and sales per customer by class. Total residential customers are split between Full-Electric Residential Services ("FERS") customers and Residential Service ("RS") using EPRI's Residential End-Use Energy Planning System ("REEPS") model. For both FERS and RS customers, personal income from the STEM model is used as an explanatory variable to generate long term forecasts of residential customers.

Assumptions regarding electricity and competing fuel prices are an important component in the forecast of customers by class. KU develops internal forecasts of electricity price and obtains a forecast of regional gas and oil prices from GI.

Industrial sales in KU's service territory are forecast as a function of Real Gross State Product, which is an output of the STEM Model for specific industries. Commercial sales forecasts are driven by the residential customer forecast and by estimates of commercial employment. Coal mining continues to be an important industry in KU's service territory. KU forecasts mining sales using data from Hill & Associates.

Since retail price is important in forecasting for all customer classes, the model must make assumptions about the future retail price of electricity. The model assumes there will be no potential future rate increases for KU. There are adjustments made for fuel expenses and environmental cost recovery.

Finally, weather data is also an important aspect of forecasting electricity usage. A twenty year rolling average for both cooling and heating degree days from the National Climatic Data Center ("NCDC") is used in the modeling.

In addition to data gathered from other sources, KU also relies upon company collected reports and survey data to supplement the analysis. Such data allow KU to forecast the percentage of new Residential customers choosing the FERS rate by type of housing, the availability of gas at new hook-ups, the mix of residential housing type, the approximate level of various appliance saturation levels, and sales history by key industrial SIC codes.

Key Assumptions in KU's Forecast

The following key economic and demographic assumptions are the primary drivers of KU's Energy and Demand Forecast.

- KU's service area population will average 0.8% annual growth over the next five years, and 0.8% annual growth over the next fifteen years.

- Annual US Real Gross Domestic Product growth will average 3.4% over the next five years and 3.1% over the next fifteen years.

- Households in KU-served counties are predicted to increase at a 1.3% annual average rate over the next five years, and 1.1% over the next fifteen years.

- Future climate, reflected by the weather values averaged for the most recent twenty-year period, is expected to be normal over the forecast period, 2005-2019.

- In the next five years, industrial output is predicted to increase at a 4.3 % annual rate and at a 3.4% rate over the next fifteen years.

- KU service territory commercial employment is predicted to increase at an average annual rate of 2.4% for the next five years and 2.1% over the next fifteen years.

- West Kentucky coal production is predicted to decline at an average annual rate of 3.0% for the next five years and decline at an average annual rate of 2.3% for the next fifteen years.

The LG&E Forecast

For LG&E's forecast, methodologies similar to those used in the KU forecast were used. Regional economic data and forecasts were provided by GI the University of Louisville Center for Urban Economic Research ("UL/CUER"), and UK/CBER. The UL/CUER forecasts focused on the Louisville Metropolitan Area and cover each of the seven counties included in the Louisville Metropolitan Statistical Area ("MSA") and the six Kentucky counties surrounding the Louisville MSA. Customer projections were made on the basis of the regional demographic forecasts developed by UK/CBER using the STEM model. In both the UL/CUER and UK/CBER studies, GI's 20-year long term forecasts were used as inputs for national economic and demographic variables.

Weather data, utilizing NCDC data for a twenty-year rolling average for the Louisville, Kentucky weather station, were used in the forecasts. As was the case with KU, no general retail rate increase was assumed.

Key Assumptions in LG&E's Forecast

The following key economic and demographic assumptions were made for the primary drivers of LG&E's Energy and Demand Forecast:

- LG&E's service territory population will average 0.5% annual growth over the next five years and average 0.6% annual growth over the next fifteen years.

- LG&E service territory households will average 0.8% annual growth over the next five years and increase at a 0.8% annual rate over the fifteen-year forecast horizon.

- Real per capita personal income in the Louisville MSA will increase at an average annual growth rate of 3.5% through 2019.

- The forecast does not reflect any potential future rate actions, including but not limited to those associated with home energy assistance programs, demand side management programs, corporate actions, new federal or state regulations, or unforeseeable surcharges or surcredits.

- Commercial industry employment in the Louisville MSA will grow at an annual average rate of 2.3%.

- Future climate as reflected by the weather values averaged for the most recent twenty-year period is forecast to be normal over the 2005-2019 forecast period.

Results

On a combined basis, weather normalized energy requirements are forecast to grow from 34,368 GigaWatt-hours ("GWh") in 2005 to 37,462 GWh in 2009, an average annual growth rate of 2.1 percent. By 2019, combined energy requirements are expected to reach 45,306 GWh, an average growth rate of 2.0 percent per year over the forecast horizon.

Combined summer peak demand is predicted to grow from 6,696 MW in 2005 to 8,794 MW in 2019, an average increase of 150 MW per year or an average annual growth rate of 2.0 percent. The combined LG&E/KU winter peak demand is forecast to increase from 5,647 MW in 2004/05 to 7,355 MW in 2018/19 with an average annual growth rate of 1.9 percent or about 122 MW per year.

KU's weather normalized energy requirement is expected to grow from 21,812 GWh in 2005 to 23,983 GWh in 2009, averaging 2.4 percent average annual growth. Between 2009 and 2019, energy requirements are forecast to reach 28,933 GWh, with growth averaging 1.9 percent per year.

KU's summer peak demand is forecast to grow from 4,076 MW in 2005 to 5,393 MW in 2019 with an average annual growth rate of 1.9 percent. The winter peak demand is forecast to grow from 3,842 MW in 2004/05 to 5,097 MW in 2018/19 with an average annual growth rate of 2.0 percent.

LG&E's weather normalized energy requirement is forecast to grow from 12,657 GWh in 2005 to 13,478 GWh in 2009, averaging 1.6 percent average annual growth. Between 2009 and 2019, energy requirements are forecast to grow from 13,478 GWh to 16,374 GWh with growth averaging 1.9 percent per year.

LG&E's summer peak demand is forecast to grow from 2,629 MW in 2005 to 3,401 MW in 2019 with an average annual growth rate of 1.9 percent. The winter peak demand is forecast to grow from 1,805 MW in 2004/05 to 2,335 MW in 2018/19 with an average annual growth rate of 1.9 percent.

Uncertainty Analysis

For the 2005 IRP, high and low scenarios were prepared based on probabilistic simulation of the historical volatility which is exhibited by both companies' weather normalized year over year sales trends. Specifically, a probabilistic simulation is run on the historic year over year growth for each utility's as-billed, weather normalized energy sales. A lower and an upper bound is identified based upon the 33rd and 67th percentile values, respectively. For the "low growth" sales scenario, the year over year growth in the base case forecast is decreased by the percent difference between the 33rd and 50th percentile values of the historical growth rate distribution. For the "high growth" sales scenario, the bas case year over year growth rate is increased by the percent difference between the 67th and 50th percentile values. These high and low growth rates are then applied to the 2003 weather normalized actual energy sales to produce the "high" and "low" energy sales forecst cases. The distribution of the monthly sales in the low ansd high scenarios is the same as in the base case forecast.

For KU, the long-term high and low forecast of energy sales range from 28,842 GWh to 25,344 GWh in 2019 compared to a baseline forecast of 27,198 GWh. KU's high and low forecasts of peak demand range from 5,708 MW to 5,0014 MW in 2019, in contrast to the baseline forecast of 5,393 MW. In the near term period, KU's 2009 high and low forecasts of peak demand range from 4,586 MW to 4,321 MW, in contrast of the baseline forecast of 4,472 MW.

For LG&E, the long-term high and low forecast of energy sales range from 16,825 GWh to 14,285 GWh in 2019 compared to a baseline forecast of 15,488 GWh. LG&E's high and low forecasts of peak demand range from 3,694 MW to 3,135 MW in

2019, in contrast to the baseline forecast of 3,401 MW. In the near term, KU's 2009 high and low forecasts of peak demand range from 2,885 MW to 2,723 MW, in contrast of the baseline forecast of 2,800 MW.

Changes and Updates to the Forecasting Process

The forecasting process for both KU and LG&E is essentially the same. Most differences are due to data issues. For future KU forecasts, sales will no longer be segmented by SIC code. A historical data series for the Commercial and Industrial sectors that is more closely aligned to data reported on a bill code basis has been adopted. For LG&E, a Residential SAE model has been developed; in addition to the models already in use for KU. In the present IRP forecast, the REEPS end-use model served a supporting role, rather than as a direct model of Residential use-per-customer.

The 2005-2019 Demand Forecast is based upon LG&E/KU's forecasted energy requirements and the 10 year average monthly load shapes. Peak demand is derived from the hourly demand forecast. An innovation over the 2002 IRP is in the conversion of monthly energy forecasts to hourly load curves. The 2005 load forecast is an "average" normalized load duration curve based on ten years of history, which is used to distribute monthly energy across individual hours in the month. LG&E/KU report that using representative load duration curves removes the risk of replicating an anomalous pattern over the forecast period and results in a more consistent relationship between monthly peak demands. Also, the use of average values over the last ten years also captures the impact of existing trends in the system load factors.

Discussion of Reasonableness

In general, Staff is satisfied with the forecasting of LG&E/KU. In its report on the 2002 IRP of LG&E/KU, Staff made the following recommendations relative to load forecasting for consideration by LG&E/KU in preparing their next IRP:

- LG&E/KU should continue to examine and report on the potential impact of increasing competition and future environmental requirements and how these issues are incorporated into future load forecasts.

- To the extent it is appropriate, LG&E/KU should continue to pursue efforts to integrate their forecasting processes and report on these efforts in their next IRP filing.

Staff is generally pleased with LG&E/KU's response to past recommendations. Given the lack of retail competition, there is not a large impact on retail customers from wholesale competition. We urge LG&E/KU to continue monitoring this area, as well as future costs of environmental compliance. Staff is satisfied with LG&E/KU's progress in integrating their forecasts.

Intervenor Comments

The Attorney General ("AG") referred to his comments and testimony filed in LG&E/KU's certificate case for the Trimble County Unit No. 2 ("TC2") generator.[1] In that case, the AG argued that TC2 was not needed before 2012; a two year delay from the proposed TC2 implementation date. The AG argued that the historical experience and the forecasts of peak demand growth as well as a 30.7% reserve margin demonstrated that the certificate application was premature. However, the AG did not contest the forecasting methodology, the models, or the data in the 2005 IRP. The AG only criticized how the IRP results were being applied by LG&E/KU.[2]

The Staff is satisfied with the load forecasting model and its results, as well as LG&E/KU's response to questions and comments regarding the forecasts.

Recommendations

- LG&E/KU should continue to examine and report on the potential impact of increasing competition and future environmental requirements and how these issues are incorporated into future load forecasts.
- LG&E/KU should continue its efforts to further integrate the load forecasting processes and report on these efforts in their next IRP filing.
- LG&E/KU should continue to refine their load forecasting models.
- In light of the financial impacts related to the construction of TC2, LG&E/KU should consider reflecting potential future rate actions in future forecasts or explain why they should not be so reflected.

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[1] Case No. 2004-00507, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity, and a Site Compability Certificate, for the Expansion of the Trimble County Generating Station.

[2] For example, see Case No. 2005-00507 Post Hearing Brief of the Attorney General filed August 10, 2005.

SECTION 3

DEMAND SIDE MANAGEMENT

Introduction

This section summarizes the Demand-Side Management ("DSM") assessment included in LG&E/KU's 2005 IRP. According to their IRP, LG&E/KU evaluate the future electric requirements of their customers with a balanced consideration of demand-side and supply-side resource options. LG&E/KU formed an interdepartmental team, which worked to identify a broad range of DSM alternatives. Each alternative was evaluated using a two-step screening process. The first step was qualitative in nature, and consisted of evaluating each alternative based upon four criteria. The alternatives that passed the first step underwent a second step of screening that was quantitative in nature. That quantitative process was broken down into two separate phases, and the programs that passed this process were then evaluated with supply-side alternatives. The remainder of this section describes LG&E/KU's process and the results thereof.

Qualitative Screening Process

A set of criteria was defined to facilitate an objective evaluation of the broad range of DSM alternatives. Four criteria were selected, reflecting LG&E/KU's objective of providing low cost, reliable energy to their customers. LG&E/KU also considered the comments from the Staff's report on their previous IRP and input from the Air Pollution Control District of Jefferson County and the Kentucky Department of Energy. Weights or values were assigned to each of the criteria. The highest weights were assigned to the criteria judged to be the most important to develop a successful DSM program. The most important criterion for LG&E/KU was the cost effectiveness of peak demand reduction. Each potential DSM alternative was evaluated based on a scale of 1 to 4, with 4 being the best score, using the following criteria and their respective weightings: (1) Customer Acceptance - 25 percent; (2) Technical Reliability - 15 percent, (3) Cost Effectiveness of Energy Conservation - 25 percent, and (4) Cost Effectiveness of Peak Demand Reduction - 35 percent.

The DSM team identified a broad list of DSM alternatives to be evaluated, which are summarized by revenue classification in the following table.

Alternatives by Revenue Classification	KU and LG&E
Residential	36
Commercial	34
Industrial	0
Total	70

LG&E/KU's DSM Department selected 2.4, on a scale of 4.0, as the cut-off level for alternatives analyzed in the qualitative screening process. Of the 70 original DSM alternatives, 27 passed LG&E/KU's qualitative screening. Of these 27 alternatives, 17 targeted residential customers while 10 targeted commercial customers.

Quantitative Screening Results

Alternatives that passed the qualitative screening analysis were next modeled in more detail using EPRI's DSManager software package, which was developed by EPS Solutions under contract with EPRI. A screening tool determines the cost effectiveness of DSM alternatives by modeling their costs and benefits over a period of time. The program simplifies the "real world" by using 48 typical days to represent a year. There are four daily load shapes per month: (1) high weekday; (2) medium weekday; (3) low weekday; and (4) weekend. DSManager uses LG&E/KU's aggregate system load shape. It also utilizes marginal energy costs to estimate the change in production costs resulting from the implementation of each DSM option. A detailed production-costing model, PROSYM™, is utilized to determine the marginal energy costs used by DSManager.

DSManager calculates the net present value of the quantifiable costs and benefits assignable to both LG&E/KU and to customers participating in a DSM program. For each DSM initiative modeled, DSManager requires the following: administrative costs, participant's costs, life span of the technology, expected level of participation, expected level of free-riders, and rate schedules. DSManager calculates changes to the participant's bill, LG&E/KU's revenue, production costs, and the peak demand. The present value for each DSM alternative is calculated by DSManager and reported as the costs and benefits using the five generally recognized DSM tests known as the "California Tests." These include the participant test, utility cost test, ratepayer impact measure test ("RIM"), total resource cost test ("TRC"), and societal cost test. LG&E/KU used only the participant and TRC tests to screen DSM options. The participant test includes changes in all costs and benefits to the customer participating in the program. The TRC test combines the RIM and participant tests and indicates overall benefits of the DSM option to the average customer, where the RIM test considers all impacts to the non-participants. A score of 1.0 or greater indicates that a program is cost effective.

15 DSM programs passed the first phase of the quantitative screening analysis, in which administrative costs are not considered and it is assumed that the program has only 1 participant per each company (LG&E and KU). This phase is performed to remove non-cost effective programs. Of these 15 programs, 4 ultimately passed the second phase of the quantitative screening analysis in which administrative costs and the expected levels of penetration for each company are added as inputs.

Recommended DSM Programs

Of the 4 programs that passed the quantitative screening process, two are load management programs: Setback Thermostats and Smart Thermostats (special rate).

These programs are similar in some respects to LG&E/KU's existing load management program, Demand Conservation. LG&E/KU note that these programs could have a detrimental effect on the existing Demand Conservation Program; however, they believe the programs would provide customers additional choices and bring new customers into load management that would not otherwise participate. The other programs are Energy Efficient Indoor Lighting and A/C Tune-up. Descriptions of the 4 programs follows.

Setback Thermostats

As mentioned earlier, this program is similar to the existing load management program, Demand Conservation. The most significant difference between this program and the existing program is the incentive mechanism. The Demand Conservation Program credits customers' bills as an incentive whereas this program would provide the customer with a programmable set back thermostat as an incentive. The Setback Thermostat program can either change the set point on the thermostat or duty cycle the air conditioner, as does the Demand Conservation Program device. An advantage of the Setback Thermostat program is that a utility could pre-cool a home before going into a cycling or control session, and allow the customer to reduce heating and cooling costs year-round. Customers would be provided the thermostat at no cost, but would not receive the bill credit as do customers in the existing Demand Conservation Program. Based upon the estimated energy and demand savings this program is cost effective with a TRC result of 2.09 and a Participant test result of infinity.

Smart Thermostat (TOU rate)

This is a sophisticated load management and Time of Use ("TOU") rate program. The TOU rate would have three-tiers similar to other utilities, but with a fourth rate – a real-time component. The real-time component would be the highest cost period and would be invoked during system peaks (at the times that existing Demand Conservation Program switches are controlled). A Smart Thermostat would incorporate a radio receiver to react when the real-time component of the rate is invoked. Customers would set heating and cooling temperatures and turn large loads off or on, based on the price of electricity. Pilot programs and full-scale deployment of such programs at other utilities indicate that significantly larger demand savings can occur than is seen in the Demand Conservation Program. Based upon the projected energy and demand savings, the Smart Thermostat program is cost effective with a TRC result of 1.24 and a Participant test result of 2.84. LG&E/KU plan to implement a pilot of this program sometime in the near future as stated in the DSM Program Plan filed with the Commission in September of 2000 and approved in May of 2001 in Case No. 2000-00459. This pilot program has not been implemented previously because of costs; however, equipment availability has increased and costs have decreased.

Energy Efficient Indoor Lighting

Compact fluorescent lighting is a technology that has been available for over 15 years, but due to costs and availability of product for limited applications, has not proven viable. Today, costs have been significantly reduced while the product is more readily available in a great number of sizes and shapes, with higher lighting levels, and better color rendition. This program would piggyback on the existing Residential Conservation programs and provide customers with a wide selection of compact products. Based upon the estimated energy and demand savings this program is cost effective with a TRC result of 1.14 and a Participant test result of 6.91.

A/C Tune-up (Commercial)

This program would take advantage of the fact that information indicates that 50 percent or more of existing air conditioning systems operate at or below manufacturers' specified efficiency, due to over or under refrigerant charge, and/or air flow problems in the evaporator coil. This program would provide customers an analysis of existing commercial A/C systems and discounted corrective action when necessary. Based upon the estimated energy and demand savings this program is cost effective with a TRC result of 1.20 and a Participant test result of 5.53.

Another commercial program, Polarized Refrigerant Oxidant Agent, also passed the second phase of the quantitative screening analysis with a TRC result of 1.13 and a Participant test result of 2.59. This product increases the efficiency of heat transfer in refrigerant systems such as heat pumps and air conditioners. LG&E/KU would offer this technology to customers through the existing Commercial Conservation Program.

Summary Discussion of DSM

LG&E/KU pointed out that DSM alternatives that are ultimately selected through this evaluation process may not necessarily be implemented as they are described in the IRP. The DSM alternatives that are ultimately proposed will, according to LG&E/KU, be subjected to a much more rigorous program design cycle, which could result in program concepts and program details being changed significantly or in some programs not being implemented at all.

Discussion of Reasonableness

In its report on LG&E/KU's 2002 IRP, Staff made the following recommendations relative to DSM for consideration in preparing LG&E/KU's next IRP filing:

- The Companies next IRP filing should use all five of the California DSM tests. The five tests include the participant, utility cost, ratepayer impact measure (RIM), total resource cost (TRC), and societal cost tests.

- In their next IRP filing, the Companies should reasonably expand the number of DSM technologies that receive a complete evaluation to determine if they would be cost effective.

- In their next IRP filing, the Companies should report on their efforts to evaluate and support Local Integrated Resource Planning, cogeneration and distributed generation, and statewide and regional market transformation initiatives of the type advocated by Kentucky Department of Energy.

Staff is encouraged by LG&E/KU's efforts in pursuing DSM programs. The number of DSM alternatives which LG&E/KU included in the quantitative evaluation was expanded from the 2002 IRP and a larger number of alternatives passed the second phase of that evaluation. However, Staff continues to believe that LG&E/KU should use all 5 California tests in the next IRP. Staff also continues to believe that LG&E/KU should include for quantitative evaluation a limited number of DSM alternatives that, by a small margin (i.e. 10%), fail to pass the qualitative screening process.

Recommendations

Relative to the DSM efforts of LG&E/KU as reflected in the 2005 IRP, Staff makes the following recommendations:

- LG&E/KU should use all five "California tests", the participant test, utility cost test, ratepayer impact measure test, total resource cost test, and societal cost test, to review DSM alternatives in the next IRP filing.

- In the next IRP filing, consistent with the Commission's findings in Administrative Case No. 2005-00090,[3] LG&E/KU should place a greater emphasis on DSM and attempt to expand the number of DSM technologies that receive a complete evaluation to determine if they would be cost effective.

- In their next IRP filing, LG&E/KU should continue to consider and evaluate a variety of DSM technologies, including those applicable to low income customers, that would be cost effective.

- If any DSM technology applicable to commercial customers passes the qualitative and quantitative screening, LG&E/KU should approach those customers to determine if there is an interest in pursuing the programs. It may be beneficial for LG&E/KU to contact commercial customers engaged in new construction rather than those involved in renovations or retrofits of existing structures.

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[3] Administrative Case No. 2005-00090, An Assessment of Kentucky's Electric Generation, Transmission and Distribution Needs, Order dated September 15, 2005.

SECTION 4

SUPPLY-SIDE RESOURCE ASSESSMENT

Introduction

This section summarizes, reviews, and comments on LG&E/KU's evaluation of existing and future supply-side resources, and includes a discussion of environmental compliance planning.

Existing Capacity

LG&E/KU have generating units at 14 generating stations. Most of their capacity is coal-fired steam generation; 7 stations have CTs; and 2 stations have hydroelectric units.[4] The newest generation is TC2, a coal-fired unit being constructed at LG&E's Trimble County station. The 2004 summer net capacity for LG&E/KU was 7,610 MW. In addition, LG&E/KU have purchase power agreements in place with Ohio Valley Electric Corporation and Owensboro Municipal Utilities ("OMU"). Table 4-1 shows LG&E/KU's existing electric generating facilities.

Several of LG&E/KU's CTs have been in operation for over 30 years. Some of the coal-fired units are over 50 years old. These generating units could become uneconomical due to their high production costs, future nitrogen oxide ("NO_X") restrictions, or the risk of their failure due to age. LG&E/KU indicate that retiring some units might be economical even without a significant mechanical failure. LG&E/KU review the economic value of aging units periodically to determine when, or if, they should be retired. Table 4-2 shows the LG&E/KU units that might be considered for retirement due to their age.

Reliability Criteria

LG&E/KU indicate that a target reserve margin in the range of 12-14% will be adequate to meet their customers' future demand in a reliable manner. LG&E/KU's reserve margin of 14% is being used for the purpose of developing an optimal integrated resource plan. A reserve margin is needed to have sufficient capacity available to allow for (1) unexpected loss of generation, (2) reduced generation capacity due to equipment problems, (3) unanticipated load growth, (4) variances in load due to extreme weather conditions, and (5) disruptions in contracted purchase power. A utility's required reserve capacity can be supplied via its own generation, purchased power, or a combination thereof. "Reserve margin" and "capacity margin" are derived as shown immediately after Table 4-2.

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[4] At the time this IRP was filed, LG&E/KU had 3 hydro facilities. Since that filing, KU was authorized to transfer its interest in the Lock 7 hydro facility on the Kentucky River to a non-regulated entity (See Case No. 2005-00405).

Table 4-1
KU and LG&E Combined Existing Generating Facilities

1	2	3	4	5	6	7		8		9	10	11
Plant Name	Unit No.	Location in Kentucky	Status	Operation Date	Facility Type	Net Capability (MW) Winter	Net Capability (MW) Summer	Entitlement KU	Entitlement LGE	Fuel Type	Fuel Storage Cap/SO2 Content	Scheduled Upgrades Derates, Retirements
Cane Run	4	Louisville	Existing	1962	Steam	155	155		100%	Coal (Rail)	250,000 Tons (6.0# SO2)	None
	5			1966		168	168					
	6			1969		240	240					
	11			1968	Turbine	14	14			Gas/Oil	100,000 Gals	
Dix Dam	1-3	Burgin	Existing	1925	Hydro	24	24	100%		Water	None	None
E. W. Brown Coal	1	Burgin	Existing	1957	Steam	102	101	100%		Coal (Rail)	360,000 Tons (~2.2# SO2)	FGD Derate - 2009
	2			1963		169	167					
	3			1971		433	429					
E.W. Brown-ABB 11N2	5			2001	Turbine	143	135	47%	53%	Gas	2,200,000 Gals	None
E.W. Brown-ABB GT24	6			1999		168	154	62%	38%	Gas/Oil		None
	7			1999		168	154					
E.W. Brown-ABB 11N2	8			1995		140	126	100%				None
	9			1994		140	126					
	10			1995		140	126					
	11			1996		140	126					
Ghent	1	Ghent	Existing	1974	Steam	468	475	100%		Coal (Barge)	310,000 Tons (6# SO2)	None
	2*			1977		466	484				1,000,000 Tons (1.1# SO2 & PRB)	FGD Derate - 2008
	3			1981		495	493					FGD Derate - 2007
	4			1984		495	493					FGD Derate - 2009
Green River	3	Central City	Existing	1954	Steam	71	68	100%		Coal	170,000 Tons	None
	4*			1959		102	95					
Haefling	1*	Lexington	Existing	1970	Turbine	14	12	100%		Gas/Oil	630,000 Gals	None
	2*			1970		14	12					
	3*			1970		14	12					
Lock 7	1-3	Burgin	Existing	1927	Hydro	Run of River Plant		Lease		Water	None	None
Mill Creek	1*	Louisville	Existing	1972	Steam	303	303		100%	Coal (Barge & Rail)	750,000 Tons	None
	2*			1974		299	301					
	3*			1978		397	391					
	4*			1982		492	477					
Ohio Falls	1-8	Louisville	Existing	1928	Hydro	Run of River Plant (32/48)			100%	Water	None	Rehab begins Fall 2005
Paddy's Run	11	Louisville	Existing	1968	Turbine	13	12		100%	Gas	None	None
	12			1968		28	23					
Paddys Run-Siem/West V84.3a	13			2001		175	158	47%	53%		Unknown at this time	
Tyrone	1	Versailles	Existing	1947	Steam	30	27	100%		Oil (Truck)	514,000 Gals	None
	2			1948		33	31					
	3			1953		73	71			Coal (Trk)	30,000 Tons (1.4# SO2)	
Trimble County Coal (75%)	1	Near Bedford	Existing	1990	Steam	514 (386)	511 (383)	0%	75%	Coal (Barge)	500,000 Tons (6.0# SO2)	None
Trimble County-GE7FA	5			2002	Turbine	180	160	71%	29%	Gas		
	6			2002		180	160					
	7			2004		180	160	63%	37%			
	8			2004		180	160					
	9			2004		180	160					
	10			2004		180	160					
Waterside	7	Louisville	Existing	1964	Turbine	13	11		100%	Gas	None	None
	8			1964		13	11					
Zorn	1	Louisville	Existing	1969	Turbine	16	14		100%	Gas	None	None

Table 4-2: Aging Units Considered For Retirement

TYPE OF UNIT	PLANT NAME	UNIT	SUMMER CAPACITY	IN SERVICE YEAR	AGE (2005)
Steam	Tyrone	1	27	1947	58
Steam	Tyrone	3	31	1948	57
CT	Waterside	7	11	1964	41
CT	Waterside	8	11	1964	41
CT	Cane Run	11	14	1968	37
CT	Paddy's Run	11	12	1968	37
CT	Paddy's Run	12	23	1968	37
CT	Zorn	1	14	1969	36
CT	Haefling	1, 2, 3	36	1970	35

Reserve Margin % = (Total Supply Capability – Peak Load)/ Peak Load

Capacity Margin % = (Total Supply Capability – Peak Load)/ (Total Supply Capability).

Key variables incorporated into the reserve margin analysis are: (1) number and length of planned generating unit outages and maintenance outages; (2) generating unit forced/equivalent outage rates; (3) the availability of purchased power; (4) customers' perceived cost of unserved/emergency energy; and (5) expected system load and load factor. Forced outages require that a unit to be removed from service unexpectedly and immediately. Forced outage rates are the total number of forced outage hours/(total forced outage hours + total number of service hours). Equivalent forced outage rates are similar to forced outage rates but include hours when a unit can operate but unable to operate at full load. The Strategist computer model was used in the evaluation, and the minimizing present value of revenue requirements ("PVRR") was the decision factor.

Supply-Side Evaluation

Black & Veatch supplied LG&E/KU with the majority of data used to evaluate 47 technologies. Alternatives were screened through a levelized analysis in which total costs were calculated for each alternative, at various levels of utilization, over a 30-year period and levelized to reflect uniform payment streams in each year. Levelized costs of each alternative at varying factors were then compared and the least-cost technologies for each capacity factor increment throughout the planning period were developed. Table 4-3 shows the technologies included in the screening analysis.

Table 4-3: Technologies Screened

Tech. ID	Technology Description	Category	Sub-Category
6.1	Pumped Hydro Energy Storage - 500 MW	Storage	Hydro
6.2	Lead-Acid Battery Energy Storage - 5 MW	Storage	Battery
6.3	Compressed Air Energy Storage - 500 MW	Storage	Compressed Air
2.1.1	Simple Cycle GE LM6000 CT - 31 MW	Natural Gas	SCCT
2.1.2	Simple Cycle GE 7EA CT - 73 MW	Natural Gas	SCCT
2.1.3	Simple Cycle GE 7FA CT - 148 MW	Natural Gas	SCCT
2.2.1	Combined Cycle GE 7EA CT - 119 MW	Natural Gas	CCCT
2.2.2	Combined Cycle GE 7FA CT - 235 MW	Natural Gas	CCCT
2.2.3	Combined Cycle 2x1 GE 7FA CT - 484 MW	Natural Gas	CCCT
2.1.4	W 501F CC CT - 258 MW	Natural Gas	CCCT
2.5.1	Spark Ignition Engine - 5 MW	Natural Gas	Reciprocating Engine
2.5.2	Compression Ignition Engine - 10 MW	Natural Gas	Reciprocating Engine
3.1.1	Wind Energy Conversion - 50 MW	Renewable	Wind
3.2.1	Solar Thermal, Parabolic Trough - 100 MW	Renewable	Solar
3.2.2	Solar Thermal, Parabolic Dish - 1.2 MW	Renewable	Solar
3.2.3	Solar Thermal, Central Receiver - 50 MW	Renewable	Solar
3.2.4	Solar Thermal, Solar Chimney - 200 MW	Renewable	Solar
3.3	Solar Photovoltaic - 50 kW	Renewable	Solar
3.4.1	Biomass (Co-Fire) - 27.5MW	Renewable	BioMass
3.5	Geothermal - 30 MW	Renewable	Geotherm
3.6	Hydroelectric - New - 30 MW	Renewable	Hydro
102	WV Hydro	Renewable	Hydro
4.1	MSW Mass Burn - 7 MW	Waste To Energy	MSW
4.2	RDF Stoker-Fired - 7 MW	Waste To Energy	RDF
4.3	Landfill Gas IC Engine - 5 MW	Waste To Energy	LFG
4.4	TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	Waste To Energy	TDF
4.5	Sewage Sludge & Anaerobic Digestion - .085 MW	Waste To Energy	SS
5.1.1	Humid Air Turbine Cycle CT - 450 MW	Natural Gas	CT
5.1.2	Kalina Cycle CC CT - 275 MW	Natural Gas	CCCT
5.1.3	Cheng Cycle CT - 140 MW	Natural Gas	CCCT
5.2.1	Pressurized Fluidized Bed Combustion - 250 MW	Coal	Fluidized Bed Combustion
5.3.1	IGCC - 267 MW	Coal Gasification	IGCC
5.3.2	IGCC - 534 MW	Coal Gasification	IGCC
5.4	Fuel Cell - 0.2 MW	Storage	Fuel Cell
5.5.1	Peaking Microturbine - 0.03 MW	Natural Gas	CT
5.5.2	Baseload Microturbine - 0.03 MW	Natural Gas	CT
2.3.1	Supercritical Pulverized Coal - 500 MW	Coal	Pulverized Coal
2.3.2	Supercritical Pulverized Coal, High Sulfur - 500 MW	Coal	Pulverized Coal
2.3.3	Supercritical Pulverized Coal - 750 MW	Coal	Pulverized Coal
2.3.4	Subcritical Pulverized Coal - 250 MW	Coal	Pulverized Coal
2.3.5	Subcritical Pulverized Coal - 500 MW	Coal	Pulverized Coal
2.3.6	Subcritical Pulverized Coal, High Sulfur - 500 MW	Coal	Pulverized Coal
2.3.7	Supercritical Pulverized Coal, High Sulfur - 750 MW	Coal	Pulverized Coal
2.4.1	Circulating Fluidized Bed - 250 MW	Coal	Fluidized Bed Combustion
2.4.2	Circulating Fluidized Bed - 500 MW	Coal	Fluidized Bed Combustion
100	Ohio Falls 9 and 10	Renewable	Hydro
101	TC2 732 MW Supercritical Pulverized Coal	Coal	Pulverized Coal

In order to quantify the impact of uncertainties on their estimates of supply-side costs, LG&E/KU conducted a sensitivity analysis as part of the screening process. The screening analysis considered the following: (1) capital cost; (2) heat rate; (3) fuel cost; and (4) environmental costs pertaining to NO_X, sulfur dioxide (SO_2), and carbon dioxide (CO_2) as uncertainties.

Based on the results of the screening analysis, the following supply-side technologies were recommended for further evaluation in the integrated resource optimization analysis:

- Trimble County 2 Supercritical Pulverized Coal Unit
- Supercritical Pulverized Coal, High Sulfur 750 MW Unit
- WV Hydro – Purchase Power Agreement
- GE 2x1 7FA Combined Cycle Combustion Turbine
- Ohio Falls Units 9 and 10
- GE 7FA Simple Cycle Combustion Turbine

Table 4-4 shows LG&E/KU's planned electric generation facilities. The TC2 unit, to be located at LG&E's Trimble County site and scheduled for operation in 2010, is presently under construction. Subsequent to filing their IRP, LG&E/KU received a Certificate of Public Convenience and Necessity ("CPCN") to construct TC2 in Case No. 2004-00507.

Table 4-4: Future Units

Future Units												
Trimble County Coal (75%)	2	Near Bedford	Proposed	2010	Steam	750 (563)	732 (549)	61%	14%	Coal	Unknown at this time	None
Greenfield CT	1	Unknown	Planned	2013	Turbine	181	148	Unknown		Gas	None	None
	2			2015		181	148					
	3			2015		181	148					
	4			2016		181	148					
	5			2017		181	148					
	6			2018		181	148					
W.V. Hydro (PPA)		Smithland/Cannelton	Proposed	2014	Hydro	99	181	Unknown		Water	None	None
Greenfield Coal Unit	1	Unknown	Proposed	2019	Steam	750	750	Unknown		Coal	Unknown at this time	None

Compliance Planning

LG&E/KU performed a study in January 2005 of various NO_X compliance options to determine whether their previously recommended plan is still the most effective plan. Some of the changes since the last study include the addition of early reduction credits ("ERC"), retirement of Green River 1-2 and the update of NO_X emission rates for existing units. LG&E/KU indicate that they will have sufficient NO_X allowances through the end of 2009 and would be dependent on purchasing 152,000 NO_X allowances over the 2010-2025 timeframe to comply. The construction of an SCR at KU's Ghent Unit 2 will mitigate the dependency on purchasing allowances. LG&E/KU are keeping a close watch on legislative activities, technology enhancements, regulatory rulings and judicial actions in order to meet the emissions reduction requirements in a prudent and least-cost manner.

Regarding SO_2 compliance options, LG&E/KU will have sufficient allowances through 2007. More than 2.7 million tons of allowances will be needed over the 2008-2025 timeframe. The construction of wet Flue Gas Desulfurization Units on Ghent Units 2, 3, and 4 and E.W. Brown Units 1, 2, and 3, the simultaneous switching of the units to high sulfur coal, and purchase of SO_2 allowances is offred by LG&E/KU as the most reasonable and least cost plan for continued environmental compliance.

Intervenor Comments.

The AG questioned the need for TC2 in 2010 and argued that new generation would not be needed until 2012. This is the same position that the AG advanced in Case No. 2004-00507. The AG also suggested that the purchase of 240 MW from WV Hydro Inc. should be pursued prior to TC2 but no earlier than 2012 as well. Due to its smaller size, in a period of uncertainty about future load growth, the AG stated that purchased power is less risky to ratepayers if load growth fails to materialize. The AG did not comment on any aspect of the IRP except the proposed addition of generating capacity.

On November 1, 2005 the Commission granted LG&E/KU a CPCN to construct a 750 MW super-critical pulverized-coal based load unit, TC2, at LG&E's Trimble County Generating Station in Trimble County, Kentucky, subject to LG&E/KU monitoring the accuracy of their forecasts and advising the Commission immediately if they notice any material divergence between their energy and peak forecasts and actual usage that could call into question the advisability of further pursuit of construction of TC2. This decision, by the Commission, renders moot the need for Staff comments on the issue of the need for, and timing of, TC2.

Recommendation

LG&E/KU's December 22, 2005 letter regarding the termination of KU's purchase power contract with EEI stated that the loss of the 200 MW available under this contract would have no near term (2006-2007) impact on KU's capacity plans. As LG&E/KU's next IRP is not scheduled to be filed with the Commission until 2008, Staff recommends that KU provide a summary of its longer range capacity plans as part of the annual filings it makes pursuant to Commission Orders in Administrative Case No. 387, A Review of the Adequacy of Kentucky's Generation Capacity and Transmission System.

SECTION 5

INTEGRATION AND PLAN OPTIMIZATION

The final step in the IRP process is the integration of supply-side and demand-side options to arrive at the optimal integrated resource plan. This section will discuss the integration process and the resulting LG&E/KU plan.

The Integration Process

LG&E/KU developed their ultimate resource assessment and acquisition plan based on minimizing expected PVRR over a 30-year planning horizon. Differences were evaluated by changing assumptions and calculating the total PVRR based on the changes with a smaller PVRR as the objective.

LG&E/LU's planning analysis was performed using modules of the STRATEGIST computer model. The plan includes analyses of reserve margin requirements, supply-side resources and demand-side resources. It includes sensitivities of 6 areas: (1) first year available for base load addition; (2) load; (3) fuel cost; (4) unit retirements; (5) capital cost of the coal units; and (6) gas transportation for CTs and combined cycle units.

LG&E/KU's optimal target reserve margin study indicates that a target reserve margin from 11 to 14% would be optimal and adequately and reliably meet customers' current and future demand needs. The study recommended that a 14% target reserve margin be used in LG&E/KU's long-range planning studies, which is the reserve margin used in the development of the optimal long-range resource plan. This represents a slight change from LG&E/KU's 2002 IRP, in which the reserve margin range was 13 to 15% and 14% was recommended as the target reserve margin for planning purposes.

LG&E/KU's supply-side analysis screened 47 supply-side technologies to arrive at 6 options for analysis within STRATEGIST. Those 6 options are as follows:

Simple cycle combustion turbines (CTs - 148 MW each)

Trimble County 2 – Supercritical pulverized Coal (549 MW – 75% of total)

Ohio Falls 9 and 10 - Run of River Expansion (2 MW each)

Supercritical pulverized Coal unit at a Greenfield Site (750 MW)

WV Hydro – Power purchase agreement (potential 240 MW)

Combined cycle combustion turbines (CC – 484 MW)

The detailed analysis of the supply-side options reflected cost/performance data for the CTs and combined cycle units based on data provided by Black & Veatch.

Cost/performance data for the Trimble County coal unit was based on data provided by Burns & McDonnell. Cost/performance data for the Ohio Falls option is based on data provided by Voith-Siemens Hydro. The first year available for each of the options is based on LG&E/KU's experience with permitting and constructing similar projects.

Summary of Results

Iterations of the "base case" analysis show a need for the TC2 coal unit in 2010, six CTs and the WV Hydro option in the middle and later years of the forecast period, and the Greenfield coal unit in 2019, the last year of the forecast period. The base case analysis shows that this plan for adding supply-side resources, in conjunction with the DSM programs that passed the quantitative screening, produces the lowest PVRR ($17.635 billion over 30 years).

Specifics of the Supply-Side Analyses

LG&E/KU performed several sensitivity analyses to determine how other factors might influence the selection of an optimal resource plan. The first sensitivity analysis, using low and high load forecasts has (1) the WV Hydro capacity being added in 2011, (2) TC2 pushed back to 2013 and (3) several of the CTs and the Greenfield coal unit being eliminated in the low load forecast scenario; in the high load forecast scenario (1) 2 of the CTs are moved up to 2009, (2) TC2 remains at 2010 and (3) the Greenfield coal unit is moved up to 2015. A second sensitivity analysis using low and high coal prices was performed to evaluate how different coal prices would impact the plan. This analysis did not impact the timing of adding TC2, but did substitute 2 Ohio Falls hydro units for CTs and moved the Greenfield coal unit up to 2017.

LG&E/KU have no current plans to retire any existing generating units; however, they have a number of older units, i.e. 35 years-plus. These units' relatively high production costs and the stricter emissions limits forthcoming under the Clean Air Interstate Rule ("CAIR") in 2010 will negatively impact the economics of operating these units. Hence, there is some potential that retiring some of these older units might become economical, depending on future events. For this reason, a sensitivity analysis was performed based on retiring approximately 180 MW in 2010. Compared to the base case, the results of this analysis call for adding an additional CT, which would come on line earlier than in the base case, and adding 1 Ohio Falls unit in the later years of the forecast period.

A sensitivity analysis was also conducted based on a 5% increase in the capital cost of TC2. Cost estimates provided by the firm of Cummins & Barnard reflected a cost of $1,314 per Kw of capacity. An increase of 5% increased the PVRR by $105 million, but did not impact the in-service date compared to the results in the base case.

A final sensitivity analysis, based on eliminating firm natural gas transportation costs for the CT and CC options, reduces the PVRR compared to the base case by

$180 million, but does not alter the in-service dates of any of the generation facilities included in the base case.

Specifics of the DSM Analysis

LG&E/KU's qualitative DSM analysis screened 70 DSM measures. The results of this qualitative screening suggested that 27 measures should be evaluated further in a quantitative analysis. The present value for each DSM alternative was calculated in this analysis based on the 5 "California Tests" which have been employed historically in the evaluation of DSM alternatives. The 5 tests are the participant test, the utility cost test, the ratepayer impact measure, the total resource cost test, and the societal cost test. The results of this quantitative analysis indicated that 5 programs, Setback Thermostats, Smart Thermostat, A/C Tune-Up, Energy Efficient Indoor Lighting, and Polarized Refrigerant Oxidant Agent, should be considered in the integrated analysis, where DSM programs are evaluated together with supply-side alternatives.

Overall Plan Integration

Based on its analyses, LG&E/KU determined that the optimal expansion plan consists of TC2 in 2010, 1 CT in 2013, the WV Hydro purchase in 2014, 2 CTs added in 2015, single CTs added in each year from 2016 through 2018, and the Greenfield coal unit in 2019.

After developing this optimal expansion plan, LG&E/KU modeled the plan with the DSM programs added to determine whether the addition of the program affected the PVRR. Based on the 30-year analysis, adding the programs to the optimal expansion plan reduces the PVRR by over $23 million. Based on that result, LG&E/KU modified the plan described above to add the DSM programs over the first 7 years of the forecast period. The estimated cumulative effect of the DSM programs is a demand reduction of 28.8 MW. While this reduces the PVRR to $17.611 billion, it does not alter the timing of any of the supply-side resource additions.

Discussion of Reasonableness

In its report on LG&E/KU's 2002 IRP, Staff made the following recommendations relative to the integration process for consideration in the preparation of LG&E/KU's next scheduled IRP.

- In the next IRP, a decision to retire any generating unit(s) should be supported by a feasibility study regarding the decision to retire the unit(s).

- In the next IRP, LG&E/KU should ensure that their planning adequately reflects the impact of future CO_2 emission restrictions.

In response to the first of these recommendations, LG&E/KU cited the report on the "Phase II Evaluation of the Economic Viability of Green River Units 1 and 2" which supported the decision to retire those units and which was filed with the Commission in Case No. 2004-00434. In response to the second recommendation, LG&E/KU offered the analysis of CO_2 issues included in the section of the IRP headed "Analysis of Supply-Side Technology Alternatives."

Staff is generally satisfied with LG&E/KU's responses and the information contained therein. It believes these responses adequately address the previous recommendations. Staff has the following recommendations which it believes should be addressed in the next LG&E/KU IRP filing.

<u>Recommendations</u>

This report includes Staff's observations on both LG&E/KU's aging generating units and their existing purchase power agreements. Staff's recommendations on those issues for LG&E/KU's next IRP are as follows:

- Given the future implications of the CAIR, LG&E/KU should include a sensitivity analysis in the next IRP based on the possible retirement of a level of capacity much larger than the 180 MW included in the sensitivity analysis performed for this IRP.

- Since the filing of this IRP, LG&E/KU have provided information in other proceedings concerning the status of KU's purchase power agreement with OMU. In the next IRP, LG&E/KU should include a detailed report on the status of this purchase power agreement.

- In the next IRP filing, consistent with the Commission's findings in Administrative Case No. 2005-00090, LG&E/KU are encouraged to fully investigate the potential for incorporating renewable energy into their portfolio of supply-side resources.

Staff will also repeat its recommendations from the prior report, as follows:

- In the next IRP, a decision to retire any generating unit(s) should be supported by a feasibility study regarding the decision to retire the unit(s).

- In the next IRP, LG&E/KU should ensure that their planning adequately reflects the impact of future CO_2 emission restrictions.