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Economic Impacts of Carbon Taxes and Biomass Feedstock Usage in Southeastern United States Coal Utilities

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The Southeastern United States depends on coal to supply 60% of its electricity needs. The region leads in CO_2 emissions and ranks second in emissions of SO_2 and NO_2. Compared with coal, biomass feedstocks have lower emission levels of sulfur or sulfur compounds and can potentially reduce nitrogen oxide emissions. This study examines the economic impacts of cofiring biomass feedstocks with coal in coal-fired plants under three emission credit and two cofiring level scenarios. Economic impacts are estimated for producing, collecting, and transporting feedstock; retrofitting coal-fired utilities for burning feedstock; operating cofired utilities; and coal displaced from burning the feedstock.

Key Words: biomass, coal, cofiring, economic impacts, electricity, input-output model

JEL Classifications: Q42, R15

Electricity from coal utilities provides over 50% of the electricity generated in the United States. In 2005, 29% of the electricity in the Southeast Energy Reliability Council region, excluding Florida's panhandle, was produced from nuclear, 50% from coal, over 3% from hydroelectric, and 1.6% from wood, primarily black liquor (U.S. Department of Energy 2005).[1] Although coal-fired plants are important sources of electricity in the United States, negative environmental impacts are associated with this type of electricity generation. About two-thirds of sulfur dioxide (SO_2), one-third of carbon dioxide (CO_2), and one-fourth of nitrogen oxide (NO_x) emissions are produced by burning coal. Particulate matter is also emitted when coal is converted to electricity. The Southeastern Region of the United States leads in CO_2 emissions and ranks second in emissions of SO_2 and NO_2 (U.S. Department of Energy 1999).

When compared with coal, biomass feedstocks (agriculture residues, dedicated energy crops, forest residues, urban wood waste, and wood mill wastes) have lower emission levels of sulfur or sulfur compounds and can potentially reduce nitrogen oxide emissions. In a system where biomass crops are raised for the purposes of energy production, the system is considered carbon neutral since crops absorb carbon during their growth process.

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[1] This study includes the Southeastern states of Alabama, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, and Virginia and does not include the Florida panhandle, which the Southeastern Electricity Reliability Council includes.

Thus, the net emissions of the CO_2 are much lower compared with coal firing (Haq).

The credits to electricity providers for offsetting sulfur emissions, priced at about $100 per ton of sulfur at the time of this research, provide an incentive for cofiring biomass with coal (Comer, Gray, and Packney). Costs of conversion of power plants for cofiring are relatively modest at low percentage levels of biomass. Power companies also have the potential in the future to obtain marketable value through offsetting CO_2 and NO_x for greenhouse gas mitigation. Replacing coal with biomass offers a means for achieving CO_2 reductions while maintaining operational coal generating capacity (Comer, Gray, and Packney).[2] Cofiring when compared with 100% biomass use is not as reliant on a continuous supply of biomass because of a ready supply of coal (Demirbas).

The purpose of this study is to estimate the economic impacts of cofiring biomass feedstocks (forest residues, primary mill waste, agricultural residues, dedicated energy crops, switchgrass, and urban wood wastes) with coal in coal-fired plants in the Southeastern United States (Alabama, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, and Virginia). The impacts of using each type of feedstock are evaluated for three emission credit and two cofiring level scenarios. The potential economic impacts (total industry output, employment, value added) for producing/collecting/transporting the feedstock, retrofitting the coal-fired utilities for burning the feedstock, operating cofired utilities, and the coal displaced from burning the feedstock are estimated.

Legislation

In 2002, the Bush Administration announced legislation to implement the Clear Skies Initiative. Passage of the recent energy bill may give Congress the opportunity to further examine the market-based cap-and-trade system to reduce SO_2, NO_x, and mercury emissions from power plants in the next two decades. A summary of the projected reductions with the caps is displayed in Table 1. For the Southeast, the initiative would potentially result in a reduction of 75% in SO_2 emissions, 77% in NO_x emissions, and 74% in mercury emissions (U.S. Environmental Protection Agency).

Under the Energy Policy Act of 2005, the term biomass is defined as "any lignin waste material that is segregated from other waste materials and is determined to be nonhazardous by the Administrator of the Environmental Protection Agency and any solid, nonhazardous, cellulosic material that is derived from—(A) any of the following forest-related resources: mill residues, precommercial thinnings, slash, and brush, or nonmerchantable material; (B) solid wood waste materials, including waste pallets, crates, dunnage, manufacturing and construction wood wastes (other than pressure-treated, chemically-treated, or painted wood wastes), and landscape or right-of-way tree trimmings, but not including municipal solid waste (garbage), gas derived from the biodegradation of solid waste, or paper that is commonly recycled; (C) agriculture wastes, including orchard tree crops, vineyard, grain, legumes, sugar, and other crop by-products or residues, and livestock waste nutrients; or (D) a plant that is grown exclusively as a fuel for the production of electricity" (U.S. Congress, p. 59).

The Senate version of the Energy Policy Act of 2005 contained a renewable portfolio standard that would have required utilities selling electricity to customers to have a minimum level of renewable energy contained within their portfolio. This requirement could be met either through direct production or purchase with another utility. In 2003, Senator Jeff Bingaman, the ranking minority member of the Senate Committee on Energy and Natural Resources, requested that the U.S. Department of Energy (DOE) conduct an analysis of a nationwide renewable portfolio

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[2] Coal contracts might impact whether a plant can move toward a 2% or 15% cofire and these impacts are not incorporated into the study. However, the Energy Information Administration (EIA) indicates that these long-term contracts are becoming less prominent (U.S.DOE–EIA 2005).

Table 1. EPA's Estimate of Annual Emission for 2000 Compared with 2020 under the Clear Skies Initiative, by State[a]

State/Region	SO_2 (1,000 tons)		NO_x (1,000 tons)		Mercury (tons)	
	2000	2020	2000	2020	2000	2020
Alabama	500	75	182	31	2.53	0.38
Georgia	508	66	185	37	1.47	0.25
Kentucky	588	194	244	44	1.78	0.32
Mississippi	129	9	65	11	0.24	0.04
North Carolina	459	133	161	45	1.52	0.67
South Carolina	200	64	87	26	0.53	0.19
Tennessee	425	119	156	39	1.12	0.38
Virginia	213	81	82	32	0.64	0.30
Regional total	3,022	741	1,162	265	9.83	2.53
United States	11,818	3,900	4,595	1,700	67	18

[a] SO_2 is sulfur dioxide and NO_x includes nitrogen oxide compounds.
Source: U.S. Environmental Protection Agency, Office of Air and Radiation, Clear Skies, 2003.

standard (RPS) program. This program was proposed to amend energy legislation before the U.S. Senate. The program specified by Sen. Bingaman included:

- Extension of the renewable energy production tax credit (PTC) for electrical generation from eligible facilities entering service by December 31, 2006, but no longer indexed to inflation
- Implementation of an RPS with incremental increases in required renewable generation reaching 10% of most sales by 2020 (effectively 8.8% of all sales)
- Exemption of small utilities, those generating less than 4,000 billion kilowatt-hours per year, from holding renewable energy credits, plus exemption of all generation from existing hydroelectric and other renewables from the requirement
- Only renewable facilities commissioned after the enactment of the legislation qualify to produce renewable energy credits
- The allowance price for renewable energy credits is capped at 1.5 cents per kilowatt-hour, with no indexing for inflation (U.S. Department of Energy 2003).

By August 2005, 19 states and Washington DC had adopted renewable portfolio standards. The Southeast is notably absent in adopting this policy largely because wind and solar options are not as viable as in other parts of the nation.

Prior Studies

English, Short, and Heady examined the economic feasibility of using crop residues for direct combustion in electric generating power plants located in Iowa. They found that coal prices needed to double for residues to become economically feasible. However, if SO_2 constraints existed, a net benefit of $0.25 per million Btus in 1975 prices (about $0.0023/kWh in 2005 prices) was estimated when cofiring at a 20% residue/80% coal mix.

Mann and Spath use a life cycle assessment, where all processes are examined cradle to grave. They found both life cycle and plant emissions are reduced with cofiring from a closed-loop biomass system (biomass production dedicated for energy use) compared with coal-based electricity generation. Reductions in emissions include CO, particulates, SO_2, and NO_x. Their results showed that at rates of 5% and 15% by heat input, cofiring reduces greenhouse gas emissions on a CO_2-equivalent basis by 5.4% and 18.2%, respectively.

Morris notes that use of certain types of biomass may provide valuable waste disposal services. Morris examines the benefits from biomass use accruing from changes in air pollutants and greenhouse gases, landfill capacity use, forest and watershed improvement, rural employment, economic development, and energy diversity and security. The study found that loss of the biomass industry would result in a loss of 12,000 rural jobs.

Haq examined issues affecting uses of biomass for electricity generation in the United States. Estimates of about 590 million tons of biomass are available on an annual basis, with 20 million tons available at prices of $1.25 per million Btu or less, while the average price of coal to electric utilities was $1.23 per million Btu. Therefore, for the majority of biomass production, cost competitiveness with coal is an issue. Under a 20% nonhydroelectric renewables portfolio standard (20% RPS), about 9.6 to 14.4 million acres of land would be devoted to energy crops by 2020.

Walsh et al. found that if producers were paid $48/dry ton for switchgrass, nearly 41.9 million acres of agricultural cropland in the United States could produce bioenergy crops at a profit greater than existing agricultural uses. Also, farm income could increase by nearly $6 billion as a result of bioenergy crop production. Total annual biomass production is estimated at 188 million dry tons, equivalent to 3.07×10^{12} MJ (2.91 Quads) of primary energy, potentially displacing about 253 million barrels of oil or supplying 7.3% of U.S. electricity needs.

Gallagher et al. estimated the supply response for crop residues across various regions of the United States and types of crop residues. They found that the potential biomass supply from crop residues in the United States would range from 297 to 323 million pounds and would supply about 5% of electricity consumption.

Graham and Walsh note that the community level job creation potential increases with larger biomass facilities as labor, farmer participation, input use, and transportation and product distribution needs increase. Direct job creation associated with the conversion facility can be measured by determining the number of people (people per unit of output generally decrease in the plant operation) needed to build and operate the facility. Jobs may be created in associated supply and support industries. Increased employment will have a multiplier effect throughout the community. However, jobs may be lost if a new biomass facility displaces conversion facilities using conventional technologies. Demands (and thus costs) on local infrastructure facilities might also increase as facility size increases.

Most of the regional studies on the economic feasibility of biomass have examined the supply of biomass feedstocks. Alich and Inman conducted an initial study where the amount of different types of feedstock that existed was quantified. Epplin, Mapemba, and Tembo conducted a study in Oklahoma and found that the most economical bioenergy system would process a variety of feedstocks.

This study evaluates the cofiring of various biomass feedstocks (forest residues, primary mill waste, agricultural residues, dedicated energy crops, switchgrass, and urban wood wastes) with coal in coal-fired plants in the Southeastern United States. It contains an economic comparison between traditional feedstock (coal) and the five sources of biomass. The study not only attempts to compare the use of biomass to the use of coal as an energy feedstock, but also incorporates the regional economic impacts that such an industry would have on the region.

An input-output model (IMPLAN) is used to estimate the economic impacts of carbon taxes and emission allowances for SO_2 and NO_x on biomass feedstock use under two cofiring level scenarios. Economic impacts are estimated for producing/collecting/transporting the feedstock, retrofitting the coal-fired utilities for burning the feedstock, and operating cofired utilities. In addition, the coal displaced from burning the feedstock is estimated. Intraregional transfers of economic activity that result from cofiring and displacement of coal use are evaluated.

Methodology

Study Area

The power plants studied in this analysis were associated with the Southeastern Electric Reliability Council (SERC), the regional organi-

Table 2. State Total Potential Biofuel Demands per Year

State	Plant Capacity Modeled[a] (MW)	Estimated Electricity Generated (Million MWh)	Coal Use at 0% Cofire (Tons)	Maximum Quantity of Biofuel at: 2% Cofire (Dry Tons)	15% Cofire (Dry Tons)
Alabama	11,624	101.83	32,073,970	746,297	5,833,074
Georgia	13,155	115.24	34,187,067	821,343	6,217,369
Kentucky	12,700	111.25	41,951,990	995,816	7,629,523
Mississippi	2,228	19.52	1,283,987	27,476	233,510
N. Carolina	12,438	108.96	36,293,167	853,325	6,600,390
S. Carolina	5,777	50.61	16,266,923	381,996	2,958,354
Tennessee	8,751	76.66	28,137,147	659,303	5,117,111
Virginia	5,099	44.67	12,666,353	285,200	2,303,543
Total	71,772	629.00	202,860,604	4,770,756	36,892,874

[a] Data on individual plants modeled available upon request. The average Btu content of coal is 24.6 MMBtu/ton.

zation for the coordination of the operation and planning of the bulk power electric systems in the southeastern United States. This region includes the following areas: Alabama, Florida Panhandle, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, and Virginia. Power plants in each of these areas, except the Florida Panhandle, were identified and incorporated into the analysis[3] (Table 2). In order to conduct the regional economic impact analysis, trading regions within the eight states were identified. These regions were based on the Bureau of Economic Analysis trading areas (referred to as economic trading areas (ETAs) in this study).

The analysis uses the Oak Ridge county-level biomass supply database (ORCBS), a geographic information system (GIS)-based transportation model (Oak Ridge integrated bioenergy analysis system [ORIBAS]), the Oak Ridge competitive electricity dispatch (ORCED) model, and a regional input-output model (impact analysis for planning [IMPLAN]) (Figure 1). The ORCBS database provides county biomass quantities available at several feedstock supply price (in 2002 U.S. dollars) levels for multiple feedstock categories (forest, agricultural, and mill waste; dedicated energy crops; urban wood wastes) and subcategories (e.g., spring and winter wheat straw, corn stover for agricultural residues) for the United States. The ORIBAS[4] is a GIS-based transportation model used to estimate the delivered costs (in 2002 U.S. dollars) of biomass to power plant facilities (Graham et al.; Noon et al.). The ORCED model is a dynamic electricity distribution model that estimates the delivered feedstock price (in 2002 dollars) utilities can pay for biomass feedstocks. ORCED models the electrical system for a region by matching the supplies and demands for two seasons of a single year. The IMPLAN model uses input-output analysis to derive estimated economic impacts for constructing and operating the power plants, the transporting of the biobased feedstocks, and the growing/collecting of wastes, residues, and dedicated crops in the eight states. Input-output analysis creates a picture of a regional economy to describe flows of goods and services to and from industries and institu-

[3] Information regarding the location, capacity, capacity factor, and production of power plants used in the analysis is available from the authors upon request.

[4] ORIBAS sequentially selects biomass based on lowest to highest biomass costs delivered to the plant gate in sufficient quantities to meet power plant demand. The transportation costs incorporate costs to load and transport the material to a major highway and then costs required to deliver the material to the plant by truck.

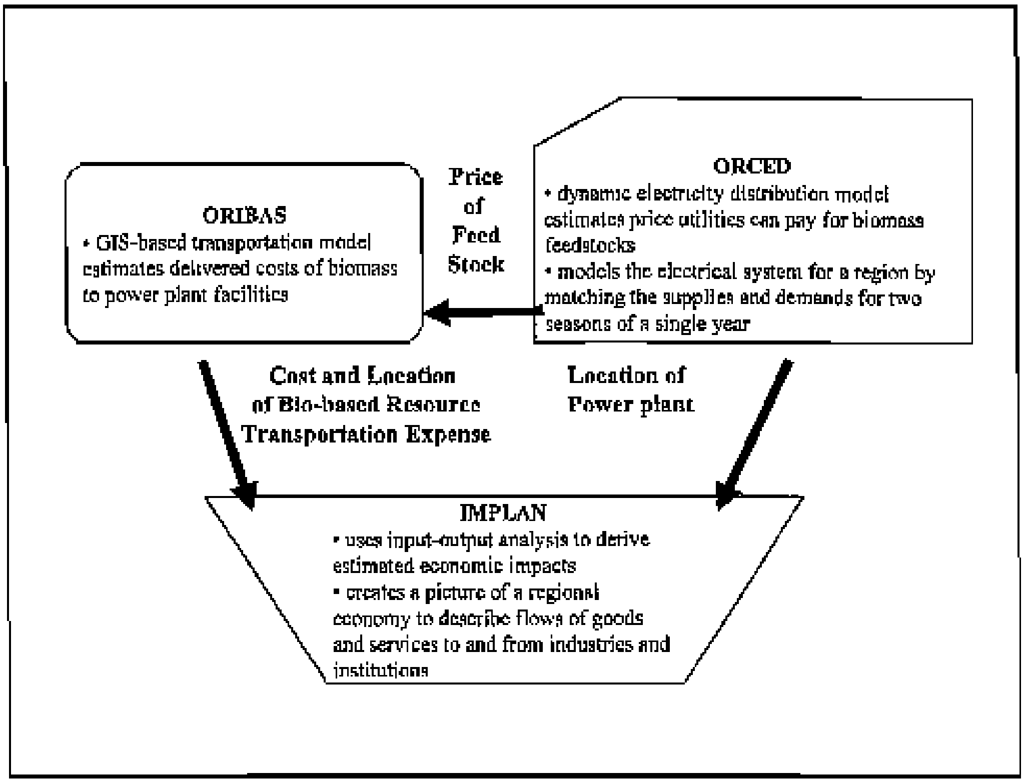

Figure 1. Flow of Information within the Analysis

tions. For this analysis, county-level IMPLAN databases were aggregated to Bureau of Economic Analysis trading areas. Each trading area within the region was used to determine the economic impacts.

For each power-generating location, ORIBAS provides the delivered cost of the biobased feedstock, the cost of transporting the feedstock from the collection point to the demand center, the feedstock supply price paid to the owner of the feedstock, and the location of the feedstock and the power plant. The delivered feedstock price that each power facility is willing to pay per delivered MMBtu is estimated by ORCED and is less than or equal to a price that will result in no increases in the cost of producing electricity via cofiring biomass compared with coal only production. Economically viable electricity production levels are identified as those in which a utility can obtain all of the biomass feedstock quantities it requires at a delivered feedstock price that is less than or equal to the maximum price the utility is willing to pay. The location, quantity, and cost of the biomass supplies are identified for each utility where biomass cofiring is economically viable.

To determine the economic feasibility of cofiring, information from the three modeling components is necessary. For each potential 1-km pixel (i), the cost and quantity of biomass ($C_{i,j}$, $Q_{i,j}$) were calculated given current land use and county supply estimates for each biomass type (j): crop residues, forest residues, mill wastes, switchgrass, and urban wood wastes (from ORCBS). A road network is used to determine the costs of transporting ($T_{i,k}$) the five different biomass sources to each plant (k) from each supply pixel. The cost function of the road network depends on road type and proximity of the pixel to a road node. The cost of supply ($C_{i,j,k}$) (growing, land use competition when examining switchgrass, nutrient replacement, harvesting/collecting, storage costs, etc.), plus transportation costs ($T_{i,k}$), equals the cost of supplying biomass from that pixel to the plant (Equation 1).

$$(1)\quad C_{i,j} + T_{i,k} = CS_{i,j,k}.$$

All $CS_{i,j,k}$ for a given state is calculated and then ranked from least cost to greatest cost.

The quantities associated with the cost of supplying biomass are summed until the quantity demanded by the plant (BD_k) is attained. Once the condition in Equation (2) is met,

$$(2)\quad \sum_j \sum_i Q_{i,j} = BD_k,$$

the $C_{i,j}$ of the highest cost pixel included is compared with the price the plant is willing to pay (estimated from ORCED). If the price the plant is willing to pay is greater than the estimated supply price, then the plant purchases the biomass and cofires. If the price the plant is willing to pay is less than the supply price, the plant is assumed to use only coal in creating electricity.

This information is then converted into direct economic impact estimates and modeled in IMPLAN. Economic or direct impacts occur when changes in policies or other actions stimulate changes in final demand for a sector's product. Indirect impacts measure the change in interindustry purchases due to the change in final demand from the industry directly affected. In addition, induced impacts measure the changes in the incomes of households and other institutions and the resulting increases/decreases in spending power as a result of the change in final demand (Olson and Lindall).

Impacts are estimated for four economic sectors. A one-time only impact in the construction sector is estimated. Annual impacts are estimated for electrical generation, growing/collecting of the biobased feedstock, and transportation sectors. In addition, the difference between the amount the power plant is assumed to pay for the residue and the cost of growing/collecting that residue is estimated. This amount is assumed to go to the original owner of the feedstock and is considered as a change in proprietary income within IMPLAN.[5] In areas where coal production is displaced by biomass cofire in the Southeast, a negative impact from the reduction of coal mining is estimated.

Table 3. Tax Level by Pollutant for the Three Scenarios Analyzed

	U.S. Dollars per Ton		
Scenario	Carbon Tax Value	Nitrogen Tax Value	Sulfur Tax Value
NoCtax	0	0	142
LowCtax	70	2,374	142
HighCtax	120	2,374	142

Cofiring Scenarios Analyzed

Two levels of cofiring are examined in the analysis: 2% or 15% (by weight) of the coal replaced by biobased feedstocks. In addition, three levels of carbon taxes are assumed: \$0 (no carbon tax [*NoCtax*]), \$70 (low carbon tax [*LowCtax*]), and \$120 (high carbon tax [*HighCtax*]) per ton of carbon within the carbon compound emitted. Further, each ton of sulfur within the sulfur compound emissions is taxed at \$142. In the positive carbon tax scenarios, each ton of nitrogen within the nitrogen compound emissions is taxed at \$2,374 (Table 3) (U.S. Department of Energy 2001).[6] Five scenarios are established and estimated: *NoCtax* 2% cofire, *LowCtax* 2% cofire, *LowCtax* 15% cofire, *HighCtax* 2% cofire, and *HighCtax* 15% cofire. A 15% cofire under the *NoCtax* scenario was evaluated; however, power plants could not attain a sufficient supply of residues at prices less than coal costs to meet the 15% demand level.

[5] Proprietary income is the income generated from economic activity to proprietorships.

[6] Based on table 11 in the referenced report—NO_x is the 2005 reference case, CO_x is the price value for 2005, and sulfur is a value from Stanton Hadley at Oak Ridge National Laboratory (reference case is \$178; used \$142).

Total Project Investment (Plant Construction)

The costs of converting power plants to cofiring differed depending on whether a 2% or 15% cofire was assumed. If a 2% cofire is assumed, the costs of conversion are estimated to equal \$50/kW (Van Dyke). Likewise, for the 15% cofire scenario, the investment cost was estimated to be \$200/kW (Van Dyke; Antares Group Inc. and Parsons Power). Each power plant was rated with a plant capacity and a capacity factor (Van Dyke). Using this information, the total costs were assigned to appropriate machinery, equipment, and construction IMPLAN sectors. When these two values are multiplied, the number of kilowatts produced is determined. The kilowatts produced multiplied by the cofire level assumed (2% or 15%) multiplied by either the \$50 or \$200 investment cost provides an estimate of the total investment required ($INVEST_{p,m}$ where p is the power plant and m is the percentage cofire assumed) (Van Dyke).

Based on the information provided by Van Dyke, a million dollar investment was proportioned through the economy and assigned to the appropriate IMPLAN industry sectors. Each ETA was then impacted with a million dollar investment for both the 2% and 15% cofiring scenarios. The impact of this million dollar investment was then divided by the direct impact to develop a multiplier for each ETA and percentage cofire, $MULT_{ETA,m}$, where m is the percentage cofire assumed.

To determine the impact of the investment stage within an ETA, the total investment required for all power plants within the ETA expressed in millions of dollars was multiplied by the multipliers for total industry output, employment, and value added. This can be represented as

$$(3) \quad IMPACT_{ETA,m} = MULT_{ETA,m} \times \sum_{p=1}^{n} INVEST_{p,m}$$

where p is the number of plants in the ETA.

Annual Operating Costs

The IMPLAN sector representing electricity production was modified to reflect an increase in annual machinery repair expenditures. Employment compensation was increased to reflect the additional labor requirements. Assuming a \$1 million change, employment compensation was increased by \$750,000 and machinery by \$250,000 (Van Dyke). Using IMPLAN results, operating multipliers were estimated for total industry output, number of jobs, and value added (Olson and Lindall). To estimate the increased amount spent per year to operate the power plant, the amount of coal replaced by biomass was multiplied by 22 million Btu's times the operating cost (\$0.09/MMBtu) (Van Dyke). The total impact on the economy in terms of output, jobs, and value added is estimated by multiplying the amount spent per year with the appropriate multiplier.

Biobased Feedstock Costs

Each of the five types of biobased feedstocks considered in the analysis had a different cost structure. The distribution of expenditures across input sectors is displayed in Table 4. These distributions were then multiplied times a million dollars and assigned to the appropriate IMPLAN sector. The nonlabor costs were used to adjust the current production function of the sector most likely to provide the output.

A new economic impact model was created for each biobased feedstock with adjusted production function coefficients reflecting the new activity in the economy. Total industry output, employment, and value-added multipliers were then generated for each biobased feedstock. These multipliers were multiplied by the cost of producing/collecting the feedstock that ORIBAS indicated would be used by the power plant. The economic impact that cofiring would have in the areas where the feedstock originated was then estimated.

Proprietary Income Impacts

The value paid for the biobased feedstock determined by ORIBAS for each scenario was subtracted from the per-acre cost to estimate impacts on proprietary income. An impact analysis on proprietary income was conducted

Table 4. Expenditures, by IMPLAN Sector, Associated with Producing $1,000,000 of each Biomass Feedstock

		1,000 Dollars				
IMPLAN Sector	Description	Agriculture Residue[a]	Forest Residue[b]	Switchgrass[c]	Mill Waste	Urban Waste
20	Seeds	0	0	30	0	0
26	Miscellaneous	160	90	40	0	0
26	Operating costs	0	0	20	0	0
202	Fertilizer	0	0	310	0	0
204	Chemicals	0	0	10	0	0
451	Fuel/lube	70	60	80	360	310
456	Depreciation	240	280	220	140	180
456	Capital	70	60	10	10	10
460	Insurance	0	10	20	10	10
482	Repair	330	170	110	130	160
	Labor	130	330	150	350	330
	Total	1,000	1,000	1,000	1,000	1,000

[a] Agriculture residue is cost for crop residues including round baling and moving to edge of field and stacking.
[b] Forest residue is costs for forest residues including felling-bunching/skidding to field edge/chipping at field edge and blowing into trailer.
[c] Switchgrass is costs for switchgrass including production costs and harvest costs of round baling, moving to edge of field, and stacking

in each ETA. The economic multiplier generated multiplied by the total change in proprietary income served as an estimate of the impacts that would occur as a result of an increase in proprietary income within the region.

Transportation Sector Impacts

Total transportation sector impacts were determined by summing costs of the biomass transported to the power-generating facility over all trips and residue types. The result was a change in total industry output. Input-output multipliers for the ETAs in which the power plants are located were then used to estimate the impact on the economy, impact on employment, and value added.

Results

Consumption of Residues by Scenario

In each of the scenarios evaluated, some residues were projected to replace coal as a fuel. With the *NoCtax*, a 2% cofire scenario generates a demand of 0.56 million tons of residue. The residue demanded consists of mill residues (213,432 dry tons [dt]) and urban wastes (319,125 dt), plus forest residues (31,350 dt). Feedstock owners are projected to receive nearly $22.00/dt for urban waste to $24.66/dt for forest residue (Table 5). At these prices, no dedicated crop or agricultural residues are purchased by the power plants. Over 561,510 dry tons of residues are used producing 8.4 trillion Btu's. Using a conversion factor of 293 kilowatt-hours per million Btu's, and an energy conversion efficiency of one-third from fuel in to electricity out, an estimated 817.6 gigawatt-hours (GWh) of electricity is produced. Demand for residue occurs in seven of the eight states with concentrations near urban areas and power-generating facilities.

In the other four scenarios, as percentage cofire increases so does the amount of residue demanded. The amount the utility is willing to pay increases as the demand for those residues increase (Table 6). However, this increase is not uniform among all units since competition among units for placing electricity on the grid changes as the cost of generating electricity changes.

Indeed, as the system moves from low carbon to a high carbon tax, less total residue is demanded in the 2% cofire solution. In the *HighCtax* 15% cofire scenario, 31.9 million - dry tons of biomass are used annually in the generation of 45,685 GWh of electricity. While the delivered feedstock price for these residues to the power plant range from $57.72/dt to $58.54/dt, the feedstock farmgate demand price averaged $55.00/dt in the 2% *LowCtax* scenario (Table 5). The delivered feedstock price of the residues to the power plant increases as the value of coal decreases. With the *NoCtax*, the delivered feedstock price ranged from $27.98 to $28.86 per dry ton. With the *HighCtax* 15% cofire scenario, the delivered feedstock price averaged $63.19/dt with the feedstock supply price ranging from a low of $61.29/dt for agriculture residues to $64.28/dt for mill waste. The difference between what a power plant can afford to pay for fuel and the amount required by feedstock owners to cover the cost of growing (for dedicated crops only), harvesting/collecting, storing, and transporting is allocated to changes in proprietors' income.

In both the 2% and 15% *HighCtax* cofire scenarios, dedicated crops play a large role in the mix of biomass. Nearly 40% of the biobased feedstock used in the cofire comes from dedicated crops in both cofire solutions (Table 6). Dedicated crops increase from a low of zero tons of use with the *NoCtax* to 1.8 million dry tons in the 2% cofire *HighCtax* and 12.1 million dry tons in the 15% cofire *HighCtax* tax scenarios. Total biomass

Table 5. Average Feedstock Demand Prices by Utilities

	U.S. Dollars per Dry Ton			
	2% Cofire		15% Cofire	
Scenario and Residue	Farmgate Feedstock Demand Price[a]	Delivered Feedstock Demand Price[b]	Farmgate Feedstock Demand Price	Delivered Feedstock Demand Price
NoCtax:				
Agriculture residues	NA[c]	NA	NA	NA
Forest	$24.66	$28.48	NA	NA
Mill waste	$23.67	$28.86	NA	NA
Dedicated crop	NA	NA	NA	NA
Urban waste	$21.96	$27.98	NA	NA
LowCtax:				
Agriculture residues	$54.79	$57.07	$46.41[d]	$58.25
Forest	$53.48	$58.46	$40.13	$60.60
Mill waste	$54.29	$57.97	$40.18	$60.63
Dedicated crop	$54.91	$55.85	$42.71	$59.29
Urban waste	$54.92	$56.07	$41.70	$59.20
HighCtax:				
Agriculture residues	$55.00	$57.72	$55.00	$61.29
Forest	$55.00	$58.46	$55.00	$64.22
Mill waste	$55.00	$58.10	$55.00	$64.28
Dedicated crop	$55.00	$58.54	$55.00	$63.71
Urban waste	$55.00	$58.30	$55.00	$62.45

[a] Farmgate feedstock demand price is the average price the utility would be willing to pay the supplier given the scenario and cost of other feedstocks and the costs involved in transporting, handling, and on-site storage.

[b] Delivered feedstock demand price determined based on information from ORIBAS and includes transportation, handling, and on-site storage costs.

[c] NA is none available at the estimated value.

[d] A much larger quantity of residues would be demanded by power plants resulting in increased transportation costs and increased investment costs resulting in a lower feedstock demand price.

Table 6. Residue Use, Energy Content, and Electricity Produced by Scenario

Feedstock	Energy Content (MMBtu/ton)	Total Residue (1,000 dry tons)	Total Energy Content (Billion Btu)	Electricity Produced (GWh)
LowCtax 2% cofire:				
Agriculture residue	13.6	19.3	263	26
Forest residue	15.0	1,025.1	15,363	1,500
Mill waste	15.0	795.6	11,923	1,165
Dedicated crop	14.1	1,825.7	25,702	2,510
Urban waste	15.0	871.2	13,056	1,275
Total		4,536.9	66,307	6,476
Percentage electricity generated by residues: 1.03%				
LowCtax 15% cofire:				
Agriculture residue	13.6	100.2	1,365	133
Forest residue	15.0	8,558.2	128,256	12,526
Mill waste	15.0	6,452.5	96,700	9,444
Dedicated crop	14.1	6,959.4	97,976	9,569
Urban waste	15.0	4,061.0	60,860	5,944
Total		26,131.4	385,157	37,616
Percentage electricity generated by residues: 5.98%				
HighCtax 2% cofire:				
Agriculture residue	13.6	20.8	284	28
Forest residue	15.0	948.1	14,208	1,388
Mill waste	15.0	776.9	11,642	1,137
Dedicated crop	14.1	1,789.9	25,198	2,461
Urban waste	15.0	824.6	12,359	1,207
Total		4,360.3	63,691	6,221
Percentage electricity generated by residues: 0.99%				
HighCtax 15% cofire:				
Agriculture residue	13.6	158.4	2,159	211
Forest residue	15.0	7,720.4	115,701	11,300
Mill waste	15.0	8,053.9	120,699	11,788
Dedicated crop	14.1	12,134.6	170,832	16,685
Urban waste	15.0	3,894.7	58,367	5,701
Total		31,962.0	467,758	45,685
Percentage electricity generated by residues: 7.27%				

use increases to 4.5 million dry tons in the 2% cofire *LowCtax* tax scenario and 26.1 and 31.9 million dry tons in the *LowCtax* and *HighCtax* tax 15% cofire scenarios, respectively. Geographic locations producing the biobased feedstocks expand as the amount of biobased feedstock produced increases.

Impacts to the Coal Industry

Using biomass instead of coal to generate electricity will result in a decrease in coal demand within the region. The amount of decrease depends on the amount of coal that would have been purchased within the region had the substitution of biobased feedstocks not occurred. This study estimated the amount of decrease for each ETA study region by taking the amount of coal displaced specified by state and multiplying that quantity by the ratio of coal mined in an ETA compared to the total coal mined in the state.

With the *NoCtax* scenario, 355 thousand tons of coal is replaced by biomass, including a decrease of 3,344 tons of sulfur emissions (Table 7). A decline of $8.4 million dollars in direct coal purchases within the region is estimated (Table 8), and a decline of 34.4 jobs in the coal industry is estimated (Table 9). This is about one-tenth of 1% of the region's direct total industry output and direct jobs from coal. This decrease in coal purchase reduces total economic activity within the region by $15.5 million and 127 jobs (Tables 8 and 9). These impacts increase as demand for coal declines. For example, under the 15% cofire *HighCtax* scenario, $440 million of coal direct total industry output (5.5% of the region's direct total industry output from coal) is replaced by residues, waste, and dedicated crops (Table 8). The direct job impact is a loss of 1,823 jobs out of the coal industry or 5.6% of jobs in the coal industry (Table 9). This decrease in coal purchases generates an $800 million reduction in economic activity including direct, indirect, and induced economic impacts (Table 8).

Total Impacts Resulting from Cofiring Bioresidues

For the *NoCtax* 2% scenario, the biobased feedstock sectors gain $11.6 million annually (forest residues, $0.7 million; mill waste, $4.59 million; and urban waste, $6.37 million) for producing, harvesting, and collecting the feedstock. In addition, for *NoCtax* 2%, $1.46 million is paid toward the transportation of the feedstock to the power-generating facilities (Table 8). An estimated $0.7 million in operating costs occur annually with an additional $4.6 million in investment required to convert the exclusive coal-burning system to cofire. Proprietors within the region would earn over $1.3 million.

Incorporating the decrease in coal demand that would occur with the substitution of biomass of $8.4 million, the region's annual increase in direct economic activity in the *NoCtax* 2% cofire scenario is estimated at $5.5 million and nearly 63 additional jobs (Tables 8 and 9). The direct, indirect, and induced impacts yield a total impact of $7.4 million annually and close to 100 jobs, with an additional one-time impact of $7.5 million as a result of increased investment for converting to cofire units.

In the 2% cofire scenarios, as the carbon tax increases, economic activity first increases and then slightly declines. A comparison of the *NoCtax* with the *LowCtax* scenarios shows total economic activity impacts measured by total industry output increases from $7.3 million to $260.5 million. The increase in total industry output occurs despite a $110 million decrease in economic activity as a result of replacing coal in the 2% *LowCtax* scenario. An estimated $6.5 million is spent operating the power plants, and $14.6 million is spent transporting the biobased feedstocks. These direct impacts result in total economic activity of $9.2 and $29.9 million for operation and transportation sectors, respectively (Table 8). Job increases within the region are projected to exceed 3,800 in both the low and high carbon tax 2% scenarios (Table 9).

In the 15% cofire scenarios, the potential impacts could be much larger. With the *LowCtax* scenario, nearly $1 billion in direct economic activity is spent on the production,

Table 7. Characteristics of Coal Replaced by Biobased Feedstocks for Alternative Scenarios

Scenario	Coal Replaced (tons)	% Sulfur (S) (%)	Coal Value[a] ($)	Sulfur Replaced (tons)
NoCtax, 2% cofire	355,412	0.94	12,487,292	3,344
LowCtax, 2% cofire	3,251,073	1.33	91,389,091	43,160
LowCtax, 15% cofire	18,198,976	1.24	525,177,225	225,992
HighCtax, 2% cofire	3,251,073	1.33	91,389,091	43,160
HighCtax, 15% cofire	23,987,425	1.32	678,951,258	317,708

[a] Coal value differs by power plant in the study and is based on annual coal expenditures.

Table 8. Estimated Total Industry Output Impact on the Economy as a Result of Increased Demand for Biobased Feedstocks by Carbon Tax and Cofire Percentage Scenario[a]

	Total Industry Output ($1,000)									
	NoCtax 2%		*LowCtax 2%*		*LowCtax 15%*		*HighCtax 2%*		*HighCtax 15%*	
	Direct	Total	Direct	Total	Direct	Total	Direct	Total	Direct	Total
Transportation	1,455	2,995	14,569	29,862	215,291	432,973	13,431	27,559	257,456	533,618
Operating	704	1,011	6,437	9,231	36,034	51,556	6,437	9,231	47,495	68,154
Coal replacement	−8,368	−15,512	−60,117	−110,063	−325,295	−596,173	−60,117	−110,063	−439,634	−805,137
Biobased feedstocks	11,663	18,854	218,340	331,425	975,436	1,516,413	217,815	330,239	1,594,662	2,458,748
Total annual impact	5,454	7,348	179,229	260,455	901,466	1,404,772	177,566	256,966	1,459,979	2,255,383
Investment (nonannual)	4,655	7,577	43,533	71,204	1,080,693	1,830,102	43,533	71,204	1,382,542	2,367,249

[a] Information at the state or Bureau of Economic Analysis region level is available upon request.

Table 9. Estimated Total Job Impact on the Economy as a Result of Increased Demand for Biobased Feedstocks by Carbon Tax and Cofire Percentage Scenario[a]

	Total Estimated Job Impacts (number of jobs created)									
	NoCtax 2%		*LowCtax 2%*		*LowCtax 15%*		*HighCtax 2%*		*HighCtax 15%*	
	Direct	Total	Direct	Total	Direct	Total	Direct	Total	Direct	Total
Transportation	14.3	34.9	142.8	342.1	2,120.50	5,042.90	131.6	315.7	2,520.8	6,095.9
Operating	3.6	8.0	33.0	71.7	187.0	407.4	33.0	71.7	243.8	530.5
Coal replacement	−34.4	−126.9	−249.4	−899.6	−1,348.3	−4,881.9	−249.4	−899.6	−1,823.0	−6,586.5
Biobased feedstocks	79.8	180.8	2,771.60	4,368.1	12,540.5	20,195.4	2,774.5	4,368.9	20,309.2	32,570.6
Total net annual jobs	63.3	96.8	2,698.0	3,882.3	13,499.7	20,763.8	2,689.7	3,856.7	21,250.8	32,610.5
Investment (nonannual)	29.8	67.8	275.0	631.0	8,720.9	19,210.4	275.0	631.0	11,057.8	24,559.1

[a] Information at the state or BEA region level is available upon request.

harvest, and/or collection of the biobased feedstocks. This amount increases to nearly \$1.6 billion under the *HighCtax* tax situation. Adding the indirect and induced impacts to the direct impacts that occurred in the feedstock sectors resulted in an estimated \$1.5 and \$2.4 billion annual total industry output impact to the region's economy. A total impact of \$430 million and \$533 million occurs as a result of increased transportation of biobased feedstocks in the 15% *LowCtax* and *HighCtax* tax scenarios, respectively. Operating costs in the power facility are estimated at \$36 and \$47 million for these same scenarios, respectively. With the added impacts that occur as a result of these expenditures, an estimated increase in economic activity of \$52 million and \$68 million is projected for the *LowCtax* and *HighCtax* tax scenarios, respectively. Finally, for both the *LowCtax* and *HighCtax* tax scenarios, less coal is purchased from the region, and this decrease in economic activity is estimated at \$600 or \$800 million, respectively.

The net number of jobs within the region will increase overall. A decrease in jobs caused by a decrease in coal demand (over −6,500 in the *HighCtax*, 15% cofire solution) is offset by the increase in employment of 6,000 as a result of changes in the transportation industry, over 500 jobs in the power industry, and over 32,000 jobs in the supply of biomass industries. Impacts are similar for all the cofire scenarios (Table 9).

Economic impacts are not consistent across trading areas in the study region. Most trading areas show a benefit; however, some coal-producing regions are impacted negatively (Figure 2). Eastern Kentucky incurs the largest losses in economic activity that occur within the study area. Trading areas that receive the majority of economic benefits typically have a major population center (i.e., Atlanta, Nashville, and Memphis) though

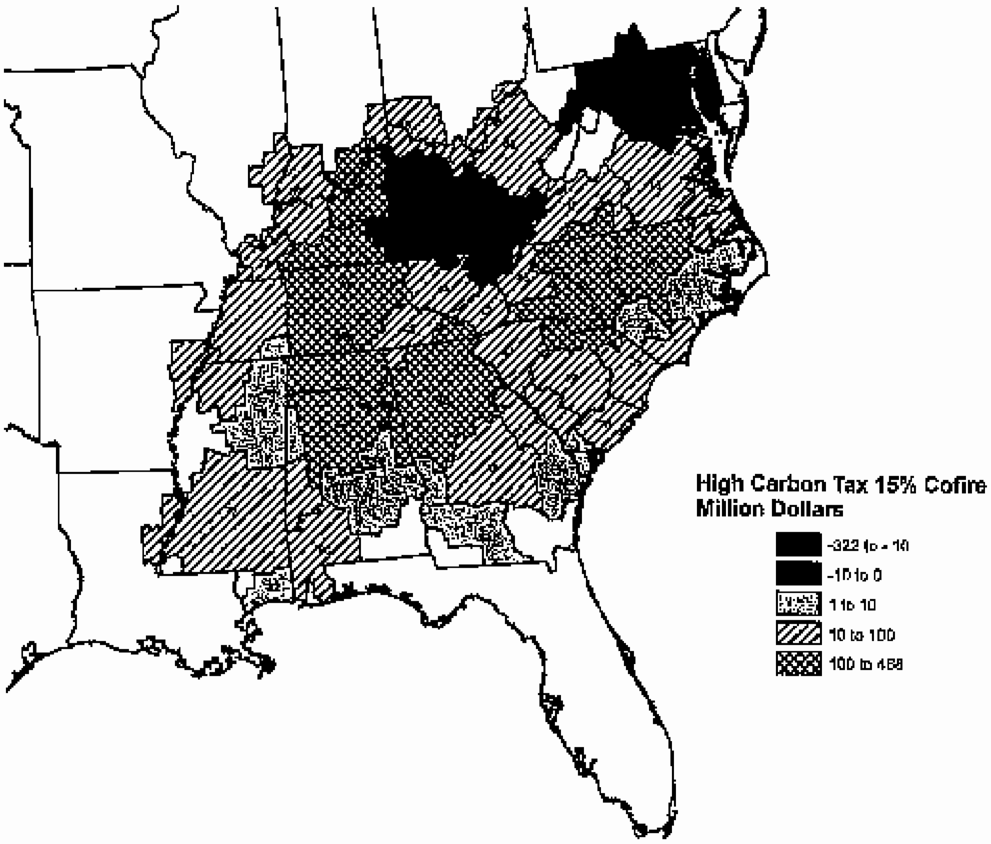

Figure 2. Regional Location of Economic Benefits and Losses, *HighCtax*, 15% Cofire Scenario

Northern Alabama and Western North Carolina also receive significant economic benefits. Proximity to a power plant increases the likelihood that a trading area will accrue significant benefits from cofiring. Transportation costs of residues, wastes, and dedicated crops are high and, as a result, the closer that you are to the demand center the more likely the trading area will benefit.

Conclusions

Cofiring does not appear economically cost competitive under the current market conditions except in certain urban/forest situations and under low cofire levels. Very small amounts of residue (2%) are economically feasible for cofire in the *NoCtax* scenario. Under a 2% cofire, some plants can find residue at a lower cost than coal plus sulfur emissions cost. However, upon examination of the 15% cofire *NoCtax* scenario, the analysis indicates paying the sulfur emissions cost is more economical than burning residue. The analysis indicates that there are areas now that would benefit from generating electricity using forest residues, mill waste, and urban waste. In fact, nearly 817 gigawatt-hours of electricity could be produced using these residues replacing 355,000 tons of coal with the *NoCtax* 2% cofire scenario.

While there is increased economic activity as a result of producing and transporting the feedstock in the region near the coal-fired power plant, there is a reduction in economic activity that occurs in coal-producing regions as the demand for coal decreases as a result of the cofire. Displacement of coal with biomass would result in SO_2 and NO_x reductions from the firing to electricity conversion process. However, it should be noted that to measure the overall effects on air emissions, the decreases in emissions resulting from transport and handling of coal along with the reduced emissions from firing would need to be compared with any increases in emissions resulting from additional production and transport of biomass feedstocks in the region near the coal-fired power plant.

There is little difference between the *LowCtax* and *HighCtax* tax scenarios under the 2% cofire level. There is a slight change in the mix of the residues. However, the power plants using the residues do not change between the two scenarios. Total industry output within the region increases by over $175 million, including a reduction in the demand for coal of $60 million. Analysis indicates that an estimated 2,700 net jobs would be created.

With the *NoCtax* scenario, increases in percentage cofire from 2% to 15% resulted in no additional residue demand, while in both the *LowCtax* and *HighCtax* emissions cost scenarios, the amount of residues consumed increase from 4.5 million dry tons in the *LowCtax* 2% cofire scenario to 26.1 (*LowCtax* 15% cofire) and 31.9 (*HighCtax* 15% cofire) million dry tons. The expansion in residue demand results in significant increases in regional economic impacts. There is an estimated $1.4 to $2.2 billion impact that occurs to the Southeast Region under the 15% cofire levels with *LowCtax* and *HighCtax* emission cost scenarios, respectively. Concurrent with this increase in economic activity is an estimated increase of 21,000 to 33,000 jobs under these emission cost scenarios.

Discussion

The cost data for conversion of the boilers to accept residues is extrapolated from a study of a single power plant (Van Dyke; Antares Group and Parsons Power). It is expected that these costs would vary between power plants and between units within power plants. The costs of producing, collecting, and/or harvesting the biobased feedstocks are estimated costs, and while road type and condition are incorporated in the analysis through ORIBAS, these costs will vary depending on the locations and infrastructure available in the region.

More residues might be demanded than indicated in the analysis. The model used in determining whether electricity could be generated from biobased feedstocks in a competitive environment assumed that the entire power-generating facility would be cofired at the 2% and 15% levels. If the amount of residue required for each level was not available at a competitive delivered feedstock price, the entire facility would continue burning 100% coal. However, most power plants consist of multiple units and cofiring could occur at the individual unit level rather than the entire facility level. Lower unit demand levels result in lower delivered feedstock costs compared with total facility demand, resulting in the potential for more cofiring than is estimated in the analysis. No attempts are made to evaluate the overall U.S. impacts, nor is the impact of increased feedstock costs as a result of the employment of environmental taxes incorporated into the analysis. The authors recognize that additional economic impacts that are not captured would occur to the rail industry (transportation of coal) and other forward linked sectors to the coal industry. In addition, loss of economic activity resulting from shifting of current cropping systems to dedicated energy crops might occur and is not included in this analysis. Further, estimation of the long-term economic benefits accruing to the region as a result of a cleaner environment is beyond the scope of this study.

This study is limited to the southern region of the United States. Certain factors make this study region unique. The region contains large amounts of forest residues and mill wastes. In addition, wood from municipal solid waste stream is also available for cofiring. The region has significant potential to produce high-yielding dedicated energy crops. In addition, other renewable sources such as wind and solar are not realistic utility scale options in the Southeast. In part due to coal quality and in part due to power plant characteristics, the southeastern region of the United States leads in CO_2 emissions and ranks second in emissions of SO_2 and NO_2. These factors limit the application of the analysis contained in this study to this region. Further research should be conducted to extend the impacts to other regions.

Finally, the analysis provides a first cut at estimating the economic benefits of substituting biobased feedstocks for coal in the generation of electricity. As conducted, the analysis estimates the amount of benefits that would occur within a trading area. Some of the leakages that occur from a transaction within the region would likely occur in the eight-state area. Thus, the actual economic impacts for the eight-state region might be greater than those presented in this analysis.

Based on EIA projections, the future demand for electricity will increase and the growth is primarily in coal-produced electricity. Therefore, the negative impacts that the study projects for the coal industry may not occur. However, the growth would likely decrease by the projected amounts.

The study provides interesting insights into intraregional transfers of economic activity that would occur with displacement of coal by other types of feedstocks. The areas adopting cofiring would not only achieve the greatest air emission reductions, they would also achieve added economic activity. The transfers of economic activity out of the Eastern Kentucky region suggest the potential need for economic development policy or programs to offset losses.

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