CEED
Center for Energy and Economic Development

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VIA E-MAIL & FEDERAL EXPRESS

Commissioner Jeff Byron
Commissioner John Geesman
California Energy Commission
Docket Unit
Attn: Docket No. 06-OIR-1
1516 Ninth Street, MS-4
Sacramento, California 95814-5512
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Re: CEED Comments Regarding Docket No. 06-OIR-1, Greenhouse Gases Emission Performance Workshop

Dear Commissioners Byron and Geesman:

Pursuant to the California Energy Commission's ("CEC" or the "Commission") Notice of Electricity Committee Workshop on Greenhouse Gases Emission Performance Standard for Implementing Senate Bill 1368 (the "Notice"), the Center for Energy and Economic Development ("CEED") respectfully submits its Comments regarding the Commission's proposed development and adoption of a greenhouse gas ("GHG") emissions performance standard ("EPS") and implementing regulations pursuant to Senate Bill 1368. In addition to, and in support of, its Comments, CEED refers to and incorporates by reference the following documents:

1. A technical evaluation of the California Public Utilities Commission's ("CPUC") Draft Staff Proposal prepared by Energy Ventures Analysis, Inc., an energy industry consulting firm specializing in energy and environmental market analysis and forecasting for natural gas, coal, electricity, oil, NO_x, SO_2, and CO_2 (the "EVA Technical Evaluation") (attached hereto as Attachment 1);

2. An article by Professor M. Harvey Brenner, "Health Benefits of Low-Cost Energy: An Econometric Case Study," Journal of the Air & Waste Management Association, Nov. 2005 ("Brenner Article") (Attachment 3), together with a summary of Dr. Brenner's research (Attachment 2);

3. A paper by Professor Adam Z. Rose and Dan Wei, "The Economic Impacts of Coal Utilization and Displacement in the Continental United States, 2015," ("Rose & Wei Paper") (Attachment 5), together with a summary of Dr. Rose's and Mr. Wei's research (Attachment 4) and additional supporting calculations (Attachment 6); and

4. An article published by Americans for Balanced Energy Choices, "Energy Cost Burdens on American Families," ("Balanced Energy Report") (Attachment 7).

I. INTRODUCTION

CEED is a non-profit organization formed by the nation's coal-producing companies, railroads, a number of electric utilities, equipment manufacturers, and related organizations for the purpose of educating the public, including public-sector decision-makers, about the benefits of affordable, reliable, and environmentally compatible coal-fueled electricity. CEED has several member-companies who are doing business in both California and in neighboring western states. CEED has participated in the CPUC rulemaking proceeding regarding the development and adoption of a GHG emissions cap, participated in the Workshops in the CPUC proceedings, and has participated in previous CEC public hearings on climate and clean coal technology issues. CEED also submitted detailed comments to Governor Schwarzenegger's Climate Action Team.

CEC staff notes in the issue paper, *Implementation of SB 1368 Emission Performance Standard*, November 27, 2006, CEC-700-2006-011 (the "CEC Issue Paper"), that S.B. 1368 requires CEC's emissions standard to be "consistent with the standard adopted by [CPUC] for load-serving entities," but recognizes that the standard proposed by CPUC should not simply be adopted by CEC without modification. CEC Issue Paper at 10. CEED shows by these comments that the emissions performance standard currently proposed by CPUC in its October 2, 2006 Final Workshop Report (the "CPUC Proposal") (the CPUC Proposal is available on the internet at www.cpuc.ca.gov/published/REPORT/60350.htm) does not meet several goals that the implementation of S.B. 1368 must achieve. S.B. 1368 cites to California's Energy Action Plan II, stating that the plan "establishes a policy that the state will rely on clean and efficient fossil fuel fired generation, and will 'encourage the development of cost-effective, highly-efficient, and environmentally-sound supply resources to provide reliability and consistency with the state's energy priorities.'" S.B. 1368 § (1)(d).

Despite a legislative focus on encouraging advanced technology, and containing costs, the CPUC Proposal sets an unrealistically low GHG emissions standard (even for Combined Cycle Gas Turbine ("CCGT")[1] generation), that will preclude any currently available coal-fueled power from California's market, and thereby prohibits a large portion of California's existing out-of-state power suppliers from competing in baseload California power markets. The CPUC Proposal eliminates or creates disincentives for continued development of cleaner coal-fueled electric generation. The CPUC Proposal also eliminates cost containment measures to protect ratepayers, and increases California's already high dependence on natural gas to supply its power needs. Moreover, the CPUC Proposal violates provisions of the U.S. Constitution, including the Commerce Clause.

[1] CCGT technology is alternatively referred to as Natural Gas Combined Cycle ("NGCC") in these comments and in the incorporated EVA Technical Evaluation.

CEED encourages the CEC to carefully consider the flaws in the CPUC Proposal in establishing its own emissions performance standard. The CEC should not impose the CPUC Proposal without significant revision, or at a minimum, additional analysis of the proposal's costs.

II. ARGUMENT

A. The CPUC Proposal Fails to Analyze the Costs Associated with its Requirements, and Lacks an Adequate Record to Provide Such Analysis.

As noted in the EVA Technical Evaluation, the CPUC Proposal contains no analysis or discussion of costs imposed on ratepayers resulting from the CPUC Proposal, nor does it contain any analysis of the reliability concerns raised by homogenizing California's energy supply to rely upon natural gas.[2]

> The [CPUC Proposal] attempts to address reliability concerns by allowing reliability exemptions on a case-by-case basis, but misses the much larger policy issue created by eliminating most new resource options and forcing the state to become increasingly dependent upon natural gas. *At the minimum, the Draft Report should contain a discussion of anticipated compliance costs and reliability impacts and how (if at all) the proposed approach minimizes ratepayer costs and risks.*

EVA Technical Evaluation at 3-4 (emphasis in original) (referencing CPUC Proposal at 45, § 5(h)).

1. The CPUC Proposal Fails to Address the General Assembly's Mandate to Minimize the Costs of the EPS to California Ratepayers.

The California General Assembly requires in S.B. 1368 that the EPS minimize costs to the ratepayer. S.B. 1368 § (1)(d) ("Energy Action Plan II establishes a policy that the state will rely on clean and efficient fossil fuel fired generation and will 'encourage the development of cost-effective, highly-efficient, and environmentally-sound supply resources to provide reliability and consistency with the state's energy priorities.'"); *id*. at § (1)(g) ("It is vital . . . to reduce California's exposure to costs associated with future federal regulation of these emissions."); *id*. at § 8341(e)(7) ("In adopting and implementing the greenhouse gases emission performance standard, the Energy Commission, in consultation with the Independent System Operator, shall consider the effects of the standard on system reliability and overall costs to electricity customers.").

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[2] The EVA Technical Report was prepared in response to the CPUC Draft Workshop Report, and is equally applicable to the Final CPUC Proposal. Where appropriate, the references to the Draft Report have been modified to refer to the identical language of the Final Proposal.

Despite such statutory mandates, the CPUC Proposal lacks cost containment provisions, and lacks analysis of the costs associated with implementing the CPUC Proposal. By eliminating all cost containment provisions from the EPS, and in failing to address the costs to ratepayers, the CPUC Proposal neglects its obligation to protect ratepayers from the costs of the EPS. As the EVA Technical Report states:

> The California legislature and governor have expressed interest in controlling compliance costs to minimize impacts on the state economy in both SB 1368 and AB 32. SB 1368 specifically requires the Energy Commission to consider the ratepayer costs in its development and implementation of a GHG emission standard (Section 8341(d)(6), Section 8341(e)(7)). This was reiterated in AB 32 that requires that the state agencies establish a GHG emissions cap "in an efficient and cost-effective manner." (Section 38561(a)).
>
> To provide the flexibility needed to be "efficient and cost effective," AB 32 authorizes use of "alternative compliance mechanisms" that allow offsets to provide for an equivalent reduction in greenhouse gases. AB 32 also permits the state to establish a GHG cap & trade system. *At the minimum, the commission should follow the governor's and legislature's lead on cost containment measures and permit offsets and portfolio averaging. The proposal should also establish carbon price caps to protect the California ratepayer.*

EVA Technical Evaluation at 4-5 (emphasis in original). A.B. 32 specifically refers to the use of offsets as a mechanism for reducing system costs of compliance, and such a program should be applied to the EPS as well.

The EVA Technical Evaluation reaches the same conclusion, and proposes three potential methods to mitigate the cost risk to California ratepayers:

> **Emission offsets**: Gives an economic incentive to businesses capable of reducing/capturing CO_2 in a cost effective manner, but otherwise have no reason to do so. Most existing state CO_2 control programs permit companies with higher emitting alternatives the flexibility to use purchased carbon offsets for compliance. Overall, the decreased carbon emissions from qualifying offset programs in combination with power source emissions will result in the same net emissions to the environment as a qualifying source (as defined by current draft staff proposal). This cost-containment measure would ensure the reduction targets are met in a cost-effective manner, while expanding supplier competition. The Draft Report currently prohibits such use of offsets.

> **Portfolio averaging**: Portfolio averaging also provides needed flexibility to control costs by averaging emissions across multiple diverse facilities to comply with the environmental performance standard. This option would encourage companies to invest in zero emitting technology options (e.g. nuclear, renewable) to offset their cheaper, but higher carbon emitting, technologies. Overall, with portfolio averaging, there would be no net emission change to the environment while allowing the suppliers flexibility to offer a lower-priced product. Currently the Draft Report recommendation would prohibit portfolio averaging.
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> **Price caps**: The only true method to protect the ratepayer would be to establish a price cap for CO_2 emissions. This approach is commonly applied in state renewable portfolio standards when they set a maximum price premium. A price cap approach is also applied in new power plant CO_2 control programs in Massachusetts (\$1/ton CO_2), Oregon (\$0.85/ton CO_2) and Washington (\$1.60/metric ton carbon). Several congressional GHG control proposals (e.g. Climate and Economy Insurance Act of 2005) have also contained carbon price caps. The California draft proposal contains no price caps. The governor and state legislature in recent legislation that cost is an important issue. The Draft Report should address how much California ratepayers should be willing to pay to avoid CO_2 emissions and that would not adversely affect the state economy. To assure that this price is not exceeded, the Commission should set a price cap at or below this level.

EVA Technical Evaluation at 5-6 (footnotes omitted).

Several methods exist to build cost controls into the proposed EPS. Incorporating such methods allows the CEC EPS to comply with its statutory mandate to minimize costs of the EPS to California ratepayers.

2. The Displacement of Coal-Fueled Electric Generation Will Harm California's Economy, and Will Disproportionately Impact Lower-Income California Families.

The higher electricity rates resulting from the CPUC Proposal will have the same effect as a regressive tax. Higher energy prices disproportionately affect families living on lower and fixed incomes.[3] Thus, everyone in society has a stake in keeping energy costs affordable. More

[3] In 2005, energy costs accounted for only 5% of the gross incomes of families with household incomes of greater than \$50,000. In the same year, energy costs consumed 48% of the budgets of U.S. families with incomes of less

(footnote continued on next page)

money spent on electricity means less money is available for housing, food, education, and other necessities that improve quality of life. Therefore, it is an unwise and unjust policy to raise energy prices so that consumers use less.

a. **Rose & Wei Research: The Displacement of Coal-Fueled Electric Generation Will Negatively Impact California's Economic Output, Household Income, and Jobs.**

Adam Z. Rose, Ph.D., and Dan Wei[4] conducted research to estimate the economic impacts of displacing coal-fueled electricity generation. *See* Rose & Wei Paper (Attachment 5); *see also* Summary of same (Attachment 4); Supporting Data (Attachment 6); and Balanced Energy Report (Attachment 7). Dr. Rose and Mr. Wei calculated that U.S. coal-fueled electric generation will contribute $1.05 trillion in gross economic output, $362 billion in annual household incomes, and 6.8 million jobs in 2015. *See* Rose & Wei Paper at 4. Based upon these calculations, Dr. Rose and Mr. Wei concluded that displacement of 33% of coal-fueled electric generation (nationwide) would result in a loss of $166 billion in gross economic output, a $64 billion reduction in annual household incomes, and 1.2 million job losses. *Id*. at 5. But the report further calculated the net economic losses of such displacement of coal-fueled electric generation in California alone. *See* Summary of Rose & Wei Paper at 8-9 (Attachment 4). A 33% displacement of coal-fueled electric generation would result in a $10 billion net loss in economic output, $4.1 billion in lost household income, and 65,300 lost jobs in California. A 66% displacement would cost California $22.9 billion in lost economic output, $9.3 billion in lost household income, and 148,300 lost jobs. These losses illustrate the interdependence of major segments of the economy, and show that the CPUC Proposal's EPS cannot be judged in terms of expected environmental effects alone. The additional effects of the proposed EPS must be assessed by the Commission before implementing an EPS.

b. **Brenner Research: Higher-Cost Energy Results in Reduced Household Income, Increased Unemployment, and Premature Death.**

M. Harvey Brenner, Ph.D.,[5] conducted research regarding the relationship between energy, the environment, and health. *See* Brenner Article (Attachment 3); *see also* Summary of same (Attachment 2). After applying his econometric model of public health to a hypothetical

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than $10,000. *See* EVA Technical Evaluation at 16-18; Balanced Energy Report (Attachment 7 to CEED's September 8, 2006 Comments on the Draft Workshop Report) at 1-6.

[4] Dr. Rose is Professor of Energy, Environmental, and Regional Economics at the Pennsylvania State University. Mr. Wei is a Graduate Assistant at the same university.

[5] Dr. Brenner is Professor of Health and Policy Management at the Johns Hopkins University Bloomberg School of Public Health and Senior Professor of Epidemiology at the Berlin University of Technology.

scenario in which higher-cost fuels displace U.S. coal to generate electricity (like the CPUC Proposal will do for California), Dr. Brenner discovered that such displacement will result in staggering adverse impacts, including reduced household income, increased unemployment, and premature deaths. *See* Brenner Article at 30 (Table 1). Such premature deaths are directly attributable to "decreased household income and increased unemployment associated with a shift to higher cost energy supply options, absent any direct mitigation programs that effectively prevented or offset these effects." *Id.* at 32. By increasing the costs of goods and services such as electricity, and, in doing so, reducing disposable income, government regulation can inadvertently harm individuals' socioeconomic status and contribute to poor health and premature death. *Id.* at 28.

Dr. Brenner's caution to public policy makers applies directly to the Commission here: "Governmental programs intended to protect public health and the environment should take into account potential income and employment effects of required compliance measures." *Id.* In short,

> [t]he economic growth that continuously improves human life expectancy requires access to affordable energy. In this fundamental sense, any policy change that reduces growth or raises the level of unemployment should therefore be defined and addressed as a public health issue requiring an economic policy response that limits or offsets these results.

Id. at 33. Dr. Brenner's research cautions the Commission to recognize the costs and potential unintended consequences that the proposed EPS will have on employment, income, and public health.

B. <u>The CPUC Proposal Precludes Coal-Fueled Power Plants from Supplying Baseload Generation to California, and Increases California's Dependence on Natural Gas to Supply Its Power Needs.</u>

CEC staff notes in the CEC Issue Paper that "Staff is not aware of any fuel oil-, coal-, or petroleum coke-fired base loaded power generation units that could achieve or even approach the effective heat rates shown above." CEC Issue Paper at 11. CEC staff is correct, and directly addresses the point the CPUC Proposal skirts – no coal-fueled power plant can meet the EPS proposed in the CPUC Proposal, and, accordingly, the EPS blatantly excludes coal-fueled generation from California's baseload power markets.

The answer to **CEC Staff's Question 4.1** (could any coal-fired or advanced coal-fueled technologies meet the EPS?) is that no current coal-fueled technology can meet the EPS as proposed by CPUC. Advanced technologies may be able to meet the CPUC Proposal's EPS in the future, but by excluding coal from the California market entirely, the CPUC Proposal creates no incentive to develop such technologies.

The EVA Technical Evaluation confirms that the CPUC Proposal's 1,100 lb CO_2/MWh EPS precludes <u>all</u> power plants that use oil, coal, petroleum coke, and most waste fuels from supplying baseload power to California investor-owned utilities. Any generation derived from higher carbon content fuels, such as petroleum coke, coal, waste fuels, and oil, face "impossible technology hurdles since such facilities must offset their higher fuel carbon content without any energy efficiency advantage (often a disadvantage)" when judged based upon the proposed CCGT standard. EVA Technical Evaluation at 6-7. *No coal or other carbon chain fuel (including natural gas, in some instances) can currently meet the proposed CO_2 performance limit of 1,100 lbs CO_2/MWh*. *Id.* at 7.

1. **The CPUC Proposal Results in Greater Vulnerability to Natural Gas Market Reliability Risks.**

Power plants that use oil, clean coal, petroleum coke, and most waste fuels are precluded from supplying baseload power to California investor-owned utilities under the CPUC Proposal. By limiting baseload generation competition in this way, the CPUC Proposal leaves California with fewer and higher-cost baseload generation options. Moreover, as the EVA Technical Evaluation observes:

> Given the [CPUC P]roposal['s] limitations, the CEC Net System emission average for unspecified resource contracts would likely exceed the EPS limit. The CEC calculation would include older fossil fuel plants and plants using longer carbon chain fuels may be far above the [1,100 lb/MWh] limit that would likewise yield a system average much greater than 1,500 lb CO_2/MWh. In summary, the [CPUC P]roposal, as written, would prohibit California utilities from signing any long-term unspecified resource contracts.

EVA Technical Evaluation at 15.

When coal, oil, petroleum coke, waste fuel, older CCGT, and unspecified generation options are excluded from baseload California power contracts, utilities must depend upon additional new CCGT plants, nuclear units, and renewable resources to meet California's growing energy demand. *Id*. If California is reluctant to support nuclear power, it is left with little diversity in its energy portfolio – only natural gas and renewable energy options.

The North American Electric Reliability Council ("NERC") 2006 Long-Term Reliability Assessment[6] plainly recognizes this flaw in California's resource adequacy and diversity assessment, stating that:

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[6] NERC 2006 Long-Term Reliability Assessment, October 16, 2006, at 120, *available at* ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2006.pdf (citing the Energy Action Plan II report, *available at* http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF).

> California is highly reliant on gas-fired generation and has very little alternate fuel capability for these plants. California is also highly reliant on natural gas imports so gas supply is of concern to area energy planners, including the California Energy Commission. The Commission's September 21, 2005 Energy Action Plan II Implementation Roadmap For Energy Policies identifies eight key actions to address natural gas supply, demand, and infrastructure.

A portfolio of limited energy sources is inherently a high-risk portfolio, and the CPUC Proposal creates unjustifiably high supply and market risks for California ratepayers. *Id*. Given the volatility of natural gas prices, as well as the higher cost of natural gas, the proposed EPS places California ratepayers in an inherently risky position. *See* Balanced Energy Report (Attachment 7) at 3-4 (Charts 1 and 2 – electricity fuel cost indices by energy source).

NERC's 2006 Long-Term Reliability Assessment Report analyzes the adequacy of electricity supply and transmission reliability in North America through 2015, and the report calls for actions to improve system reliability. NERC 2006 Long-Term Reliability Assessment at 6-10. NERC expects demand for electricity to increase over the next ten years by nineteen percent in the U.S., but expects confirmed power capacity to increase by only six percent. *Id.* at 11-14. Accordingly, capacity margins are projected to drop below minimum target levels in the western U.S. *Id*. In Western Electricity Coordinating Council ("WECC") territory specifically, "[d]ue to a slight decrease in existing generating capacity and a significant decrease in reported generation additions, capacity margins . . . are reported as declining throughout the ten-year assessment period." *Id.* at 19. NERC predicts summer electricity supply shortages relative to study planning margins as early as 2009 assuming no resource additions beyond those presently under active construction. *Id*. Such drops alert NERC to the increased potential for shortages in electricity due to fuel disruptions, particularly for natural gas: "The supply and delivery of gas to electric generators can be disrupted when electric generation demands for gas coincide with high gas demands for other customers. In some cases, even firm gas contracts for electric generation can be curtailed in favor of residential heating needs during extreme cold weather." *Id*. at 9. By shifting California's energy portfolio to natural gas – the reallocation of resources that the CPUC Proposal will cause – California places itself in a position of increased system reliability risk, and instead of increasing system capacity as NERC recommends, is taking action which will serve to reduce available system capacity.

Further, heavy reliance upon renewable energy options is currently a high-risk and unrealistic option for California:

> First, it is unlikely that renewable energy can meet this large demand without a significant price impacts. Renewable power has been and continues to be far more expensive than convention generation options.

> The California Public Utility Commission (CPUC) report entitled *Achieving a 33% Renewable Energy Target* (November 2005) failed to study the resource availability and cost impact of the combination of California expanded renewable demand with other western state demand triggered by their renewable portfolio standards. Four western states (Arizona, Colorado, New Mexico, Nevada) have also adopted renewable portfolio requirements totaling 20 TWh by 2020 that plan to draw upon these same renewable resources. Other western states are also considering adopting similar standards that would push demand above 140 TWh. How much renewable resources can be developed and at what cost?
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> CPUC's analysis assumed that most of this increased renewable energy demand would be supplied by wind projects. To meet this demand, the CPUC report assumes that the wind capacity factors will increase from 37 percent today to 43 percent by 2017. However, according to EIA Form 906 data, only one California wind project and eight in the entire nation report such a high capacity factor. In fact, the average 2003 California capacity factor was less than 23%, so the CPUC projection may vastly over-estimate both current and future potential wind power contribution and significantly underestimate the wind production cost. A GHG performance standard would make wind a larger player in the energy market, a role wind technology does not appear ready to play.
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> Secondly, wind can also contribute to system reliability issues. In a recent article in *Power Markets Week*, the California ISO provided data for the July 2006 energy crunch in California. During this critical period, wind power operated at less than 5 percent of its rated capacity at peak demand periods. This makes wind a highly unreliable source during critical high peak periods when power is needed the most.

EVA Technical Evaluation at 15-16.

2. The CPUC Proposal Sets a Standard That Even CCGT Facilities Cannot Meet.

The intent of S.B. 1368 in directing the creation of an EPS is to capture California's baseload generation using a capacity factor greater than 60%. S.B. 1368, 8340(a); *see also* CPUC Proposal at 44. The EVA Technical Evaluation presents, at Table 1, the data reported on EIA Form 906 by in-state California facilities with a 2005 capacity factor greater than 60%. *See* EVA Technical Evaluation at 9. From these data, it appears likely that all but three facilities will be in violation of the EPS. No facilities using longer chain carbon fuels currently meet the proposed standard, and only three of fourteen combined cycle facilities are in compliance. The CPUC Proposal advances an unrealistic standard that many existing and future CCGT plants will be unable to achieve. The CEC Issue Paper recognizes this flaw in the CPUC Proposal, noting that the 800 lbs CO_2/MWhr can be achieved only by "the most efficient modern combustion turbine combined cycle plant[s]," and that 1,400 lbs CO_2/MWhr is a standard that "might envelope the majority of natural gas burning technologies (e.g., steam cycle boiler, simple cycle combustion turbine, reciprocating engine, and a range of combustion turbine combined cycle units)." CEC Issue Paper at 10. The CPUC Proposal, then, is unrealistic, *even for the majority of natural gas burning technologies*.

As the EVA Technical Evaluation notes, the proposed emissions limit may also prohibit future baseload contracts with natural gas combined cycle applications (1) located in higher elevations, (2) using air-cooled technologies, or (3) using older, less energy efficient combined cycle generation technologies. EVA Technical Evaluation at 7. By prohibiting less energy efficient CCGT applications, the staff standard would come in direct conflict with the provisions of the recently adopted S.B. 1368. S.B. 1368, § 8341(d)(1) ("All combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission performance standard.") The CPUC Proposal's emissions standard must be raised to include all existing CCGT applications (in-state and out-of-state) located in high elevations, using air-cooled technologies and using older combined cycle generation technologies, as S.B. 1368 requires. *See id.*; EVA Technical Evaluation at 7.

3. The CPUC Proposal Hinders Advanced Clean Coal Technology Development.

S.B. 1368 plainly states California's policy of encouraging advanced technology, *see* S.B. 1368 § (1)(d), but the CPUC Proposal works against this goal. While the CPUC Proposal contains a case-by-case research and development facility exemption, *see* CPUC Proposal at 45, the case-by-case exemption requires suppliers to demonstrate that the commitment would make a significant future contribution towards developing a lower-emitting resource mix, an administratively burdensome review process that more likely will discourage and hinder such advanced technology development.

> [CPUC's goal of encouraging advanced technology] would be better achieved if some predefined R&D projects such as carbon capture ready [Integrated Gasification Combined Cycle ("IGCC")] projects and ultra-supercritical pulverized coal units that provide potentially low CO_2 options were automatically exempted from the EPS and not subject to an expensive or drawn out approval process. Projects such as the Xcel Pawnee (PRB fired IGCC plant with carbon capture) and AEP Hempstead (PRB fired ultra-supercritical plant) projects should be encouraged.

> Not only would the approval process be burdensome, but the qualification criteria may also be too restrictive as contained in the Draft Report's illustrative example on page 22 [*see also* CPUC Proposal at 27]. In its description of a qualifying facility, the staff suggests that only an IGCC plant with equal to or better heat rate efficiency than average IGCC plants should be eligible for an R&D exemption. If this average is calculated based upon the existing bituminous coal demonstration units, it is highly unlikely that any IGCC plant using the higher moisture sub-bituminous western coals could ever qualify for an exemption because of their higher moisture penalty. Carbon capture processes would also reduce plant efficiency. *If the example criterion were applied, California would not support either an IGCC or ultra-supercritical plant like Pawnee or Hempstead. In summary, California may discourage the very plants that it seeks to encourage.*

EVA Technical Evaluation at 14 (emphasis in original). A case-by-case exemption discourages investment in advanced technologies due to the uncertainty of the review process. If certain advanced technologies were pre-approved by rule, the Commission would encourage investment in advanced technologies.

The CEC Issue Paper touches on this issue, asking, at **Question 4.2**, would a demonstration project for advanced coal-fired technologies and/or CO_2 sequestration need to operate at more than a 60 percent capacity factor or for more than five years, requiring the unit(s) to meet the EPS? Due to the financial realities of securing financing for the construction of a power plant, the answer to the CEC's question is, "Yes." Power plants are unlikely to be able to secure financing for operations of less than 60 percent capacity factor, or for guaranteed operational terms of less than five years.

But advanced technologies should be encouraged by the EPS, and investment in such new technologies will only be encouraged if the CEC dispenses with a burdensome, case-by-case administrative review, as proposed by the CPUC, in favor of pre-approval for carbon capture ready Integrated Gasification Combined Cycle projects and ultra-supercritical pulverized coal units. As Governor Schwarzenegger appropriately put it in a speech announcing a hydrogen power plant fueled by hydrogen generated from petroleum coke:

> I want to thank you for choosing California. This will be the first plant of its kind in the whole country and I think it is a perfect fit for our state. With our Strategic Growth Plan, a commitment to Air Quality, *and innovative projects* like this hydrogen plant, I know we can have clear skies, improve our quality of life and build a stronger, more vibrant economy for California.

Governor Schwarzenegger, Address at Carson, California Project Announcement (February 10, 2006) (quoted in Press Release, BP Global, *BP and Edison Mission Group Plan Major*

Hydrogen Power Project for California (February 10, 2006) (*available at* http://www.bp.com/genericarticle.do?categoryId=2012968&contentId=7014858)) (emphasis added).

C. The CPUC Proposal's Load-Based GHG Emissions Performance Standard Violates the Commerce Clause of the U.S. Constitution.

The CPUC Proposal effectively precludes coal, oil, petroleum coke, waste fuel, and even older natural gas fueled generation from competition in California power markets. The proposal plainly "blocks the flow" of such generation at the California border, and in doing so, violates the Commerce Clause of the U.S. Constitution.

1. Carbon Capture and Sequestration Technology Is Not Yet Sufficiently Developed to Allow Fossil-Fueled Generation to Meet the Proposed GHG Emissions Standard.

As the CEC Issue Paper itself recognizes, currently, no cost-effective technology exists to allow CO_2 capture from flue gas streams and to store or sell the captured product. CEC Issue Paper at 11 ("[s]taff is not aware of any . . . coal- . . . fired base loaded power generation units that could achieve or even approach the effective heat rates shown above."). Current CO_2 capture and sequestration technology options are both highly energy intensive and far too expensive to be commercially implemented in order to satisfy the proposed EPS.

> There are only four powerplants in the U.S. that capture a small portion of CO_2 from their flue gas streams. . . . These facilities were designed to treat less than 15 percent of their flue gas, and these facilities consume large quantities of energy in the process. Based upon their current performance, EVA calculates that to treat 100 percent of the flue gas would require roughly 75 percent of the plant's total output energy. However, to capture only the amount of CO_2 needed to meet a gas combined cycle emission rate (per MWh unit output basis) would consume roughly 63 percent of the plant output energy. Cost to capture and compress CO_2 would increase the production cost of coal-based electricity using conventional PC and CFB technologies by 184 percent. To treat the coal-fired generation currently coming-in to California alone would cost more than $5 billion/year. This would be far greater than the undocumented and arbitrary Climate Action Team (CAT) $117 million estimate. Such costs would make the higher carbon containing fuel alternatives far more costly than nuclear power and gas combined cycle alternatives that do not incur the carbon penalty.

EVA Technical Evaluation at 8, 10 (footnotes omitted).

Some utilities have proposed the development of "carbon capture ready" IGCC facilities[7]. *See id*. at 10. The U.S. Department of Energy ("DOE") hopes to improve the energy efficiency and performance of carbon capture and sequestration technologies for coal-based alternatives, such as those technologies proposed in DOE's FutureGen project. *See id*. at 11. But, while such technologies are very promising, their CO_2 removal abilities are currently modest. *Id*. Because no technology currently exists to allow fossil-fueled generation to meet the proposed GHG emissions standard, the CPUC Proposal blocks such generation from entering California.

2. The CPUC Proposal Will Preclude Out-of-State Suppliers from Competing in California's Markets.

California is currently the largest power importing state in the nation.[8] With its mix of mostly higher cost generating resources, few in-state power plants (mostly nuclear and co-generator facilities) operate at or above the CPUC Proposal's 60 percent baseload capacity factor. EVA Technical Evaluation at 11. California has turned to much cheaper power imports to supply a large portion of its baseload power needs.[9] Because the 60 percent capacity factor exempts the majority of California's in-state generators from the EPS, the reality of California's energy market dictates that the CPUC Proposal will primarily preclude out-of-state suppliers from competing in California markets.

> Under the [Final] [P]roposal, import power suppliers would need to demonstrate compliance with the proposed EPS to be eligible to compete for future baseload California power contracts. The proposed eligibility criterion would exclude a large portion of the existing import power suppliers from being able to compete for future California baseload power contracts. First, it would prohibit all coal-fired powerplants because of coal's much higher carbon content and lower energy efficiency (than combined cycle). Second, it would also exclude all natural gas and oil fired steam generating units (higher carbon content, lower efficiency) from competition. Such exclusions would significantly inhibit all future inter-state power trading . . . .

EVA Technical Evaluation at 12.

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7 For example, Xcel Energy's Pawnee facility. Such facilities seek to remove CO_2 from syngas before combustion for a far lower price than the flue gas capture approaches currently available.

8 In 2005, the state reported retail sales of 254 TWh versus in-state generation of only 196 GWh (Source: DOE Electric Power Monthly March 2006.

9 California ISO Summer 2006 forecast (May 2006).

3. The CPUC Proposal Violates the Commerce Clause of the U.S. Constitution.

The U.S. Supreme Court has stated that "where simple economic protectionism is effected by state legislation, a virtually *per se* rule of invalidity has been erected. The clearest example of such legislation is a law that overtly blocks the flow of interstate commerce at a State's borders." *City of Philadelphia v. New Jersey*, 437 U.S. 617, 624 (1978) (internal citations omitted) (state may not ban importation of solid waste while allowing disposal of in-state waste). The U.S. Supreme Court finds it equally clear that electric power raises interstate commerce concerns: "it is difficult to conceive of a more basic element of interstate commerce than electric energy, a product used in virtually every home and commercial or manufacturing facility."[10] "A state cannot block imports from other states, nor exports from within its boundaries, without offending the Constitution."[11] CPUC's EPS will necessarily limit the amount of coal-fueled electricity imported into California, and accordingly, the EPS discriminates against interstate commerce.[12] As Decision 06-02-032, Opinion on Procurement Incentives Framework, dated Feb. 16, 2006 (the "Order") itself concedes, "non-California generators . . . must adjust their behavior" to comply with CPUC's GHG cap.[13]

In *Pike v. Bruce Church*, 397 U.S. 137 (1970), the Supreme Court articulated the balancing test used to determine whether state laws and regulations are valid under the Commerce Clause:

> Where the statute regulates evenhandedly to effectuate a legitimate local public interest, and its effects on interstate commerce are only incidental, it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits…. If a legitimate local purpose is found, then the question becomes one of degree. And the extent of the burden that will be tolerated will of course depend on the nature of the local interest involved, and on whether it could be promoted as well with a lesser impact on interstate activities.

Id. at 142 (internal citations omitted).

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[10] *Federal Energy Regulatory Comm'n v. Mississippi*, 456 U.S. 742, 757 (1982).

[11] *City of Philadelphia v. New Jersey*, *supra*, 437 U.S. at 620.

[12] Yvonne Gross, "Kyoto, Congress, or Bust: The Constitutional Invalidity of State CO2 Cap-and-Trade Programs," manuscript at 19, Thomas Jefferson Law Review, Vol. 28, No. 205, 2005 Available at SSRN: http://ssrn.com/abstract=883687.

[13] Order at 23.

a. **The Performance Standard Has a Discriminatory Effect on Interstate Commerce.**

Various U.S. Supreme Court decisions have struck down regulatory enactments that required particular economic activity to be performed within the jurisdiction.[14] The discrimination in each of these cases was based on geographic origin. In each case, the regulating jurisdiction (state, county, or city) drew a line around itself and treated those inside the line more favorably than those outside the line. These arrangements are protectionist, either in purpose or practical effect, and amount to virtually *per se* discrimination.

Under the proposed EPS, the ability of out-of-state coal-fueled generation plants to export their electricity into California will be severely limited, if not foreclosed altogether. The limitation of CO_2 emissions described by CPUC effectively precludes in-state utilities and other load-serving entities from the purchase and importation of coal-fueled generation. The EPS, and the cap to follow, discriminate against coal-fueled energy in interstate commerce, and accordingly, offend the Commerce Clause of the U.S. Constitution.

In example, in *United States v. Wrightwood Dairy Co.*, 315 U.S. 110 (1942), the Supreme Court held that, because milk produced and sold wholly within a state competes with and impacts the price of milk shipped in from out-of-state, the U.S. Department of Agriculture properly regulates the pricing of milk produced and sold wholly within a state. Like the milk at issue in *Wrightwood Dairy*, electricity generated in other states competes with electricity generated in California. Limiting California's ability to include coal-fueled generation in energy procurement discriminates against the interstate trade of electric generation, and in doing so, depresses the price of electricity in the exporting state by reducing the level of demand it might otherwise satisfy, thereby imposing a burden on out-of-state generators.[15]

Moreover, by closing off the California market, CPUC's announced EPS and GHG cap places heightened financial burdens on the construction of new coal-fueled power plants in neighboring states. The initial capital required to construct a power plant is typically secured with pre-construction contracts for the output of the unit. If California is effectively closed to coal-fueled power due to the EPS, reduced potential market breadth makes securing financing for construction of new coal-fueled power plants in all Western states more difficult. In obtaining financing for new construction, California-based electric generators have a significant

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[14] *See*, *e.g.*, *Dean Milk Co. v. Madison*, 340 U.S. 349 (1951) (unconstitutional for city to require milk to be pasteurized within five miles of the city); *Fort Gratiot Sanitary Landfill, Inc. v. Michigan Dept. of Natural Resources*, 504 U.S. 353 (1992) (unconstitutional for county to prevent a landfill owner from accepting for disposal solid waste produced outside of the county); *Minnesota v. Barber*, 136 U.S. 313 (1890) (unconstitutional for state to require meat sold within the state to be examined by state inspector); *Foster- Fountain Packing Co. v. Haydel*, 278 U.S. 1 (1928) (unconstitutional for state to require that shrimp heads and hulls must be removed before shrimp can be removed from the state); *South-Central Timber Development, Inc. v. Wunnicke*, 467 U.S. 82 (1984) (unconstitutional for state to require all timber to be processed within the state prior to export).

[15] Gross, *supra* note 12, manuscript at 20.

competitive advantage over out-of-state, independent developers of coal-fueled generation facilities, and consequently, the CPUC GHG regulatory scheme offends the Commerce Clause.[16]

b. **The Performance Standard Has an Extraterritorial Effect on Interstate Commerce**

The U.S. Supreme Court has ruled that it is a *per se* violation for one state to regulate conduct in another state. For example, the Supreme Court found in a series of cases that States cannot adopt regulations that tie in-state liquor prices to out-of-state liquor prices.[17] The EPS effectively precludes access to the California market, and its proposed regulations would have a negative effect on out-of-state generators. The Supreme Court has held that a law may have an impermissible extraterritorial scope even when, technically, it applies only to conduct within the state: "The critical inquiry is whether the practical effect of the regulation is to control conduct beyond the boundaries of the State."[18] Here, the Commission's GHG policy cannot avoid having the practical and actual effect of regulating the GHG emissions of out-of-state generators selling into the California market, thus unlawfully controlling commercial conduct beyond the borders of California.

In fact, the mere announcement of CPUC's adoption of a GHG cap has already had just such an extraterritorial effect. As noted in two recent newspaper articles, Sempra Energy has halted (or downsized) the development of its Granite Fox power plant near Gerlach, Nevada. As stated by a Sempra spokesperson, California's new regulations forbidding the importation of coal-generated power is the "biggest reason for changing the plant design."[19]

c. **CEC Counsel Has Previously Cautioned Against Adoption of Exactly the Type of Regulation Proposed by the CPUC Proposal's GHG Emissions Limit.**

At its August 18, 2005 "Public Workshop," the CEC received a briefing on federal constitutional issues associated with the CEC's proposal to develop "Procurement Criteria." CEED specifically provided verbal comments with respect to this issue. In addition, Assistant Chief Counsel to the California Energy Commission, Jonathan Blees, gave an audio-visual

[16] *Id.*, manuscript at 20-21 (citing Thomas C. Hayes, Bottom-Fishing in the Gas Patch, N.Y. Times, May 19, 1991, at 3 (noting that "without ironclad guarantees for fifteen years or more of supply, lenders have refused to finance the construction of gas-fired power plants for utilities," and likewise, a long-term contract for the output of a power plant is usually required for financing of independent power producers and coal plants)).

[17] *Healy v. Beer Inst.*, 491 U.S. 324, 332 (1989); *Brown-Forman Distillers Corp. v. N.Y. State Liquor Auth.*, 476 U.S. 573 (1986).

[18] *Healy*, 491 U.S. 336; *accord Brown-Forman*, 476 U.S. 583.

[19] Susan Voyles, *Sempra Energy Halts Gerlach Project Study*, Reno Gazette-Journal, March 8, 2006, *available at* http://news.rgj.com/apps/pbcs.dll/article?AID=/20060308/NEWS10/603080363/1002; *see also* Shayla Ashmore, *Granite Fox Power Plant May Not Happen*, Lassen County Times, March 14, 2006, *available at* http://www.lassennews.com/News_Story.edi?sid=3184.

presentation entitled, "An Overview of Constitutional Limitations on Out-of-State Procurement Criteria."[20] Mr. Blees's presentation began by framing the following issue:

> To what degree should procurement decisions for out-of-state electricity consider and/or require mitigation for: emissions of criteria and toxic air pollutants; greenhouse gas emissions; and water and waste impacts?

Blees Presentation at 2.

Mr. Blees's slide presentation rightly included a caution that any CEC energy procurement criteria, which specified environmental controls or required mitigation (*e.g.* emissions offsets), were "probably constitutionally-invalid extra-territorial regulation; even if criteria applied equally to in-state and out of state plants." *Id*. at 3. The CEC was further advised not to say "Wyoming coal" or even "coal-fired plants" because such actions would constitute both express and in effect discrimination against interstate commerce. *Id*. at 9. Mr. Blees suggested that the CEC's best course would be to use an "environmental performance standard (*e.g.* tons/MWh)" with the express caution, though, that *such standards should not be set at a level which will discriminate against out of state in effect (e.g. too stringent for out-of-state plants to meet)*." *Id*. at 15 (emphasis added).

The CEC must follow Mr. Blees's cautions in the current rulemaking. The CPUC Proposal contains no substantive "record of California's interest in the [GHG EPS] criteria," as Mr. Blees advised that such a regulation should. In order to be defensible, Mr. Blees counseled the CEC to develop a credible record demonstrating "What environmental, safety, economic, etc. harms does California suffer from purchases of out-of-state plants (and in-state plants that have various levels of CO_2, acid rain, water use, etc?". Adopting the CPUC Proposal disregards Mr. Blees's advice, as the CPUC Proposal, itself, lacks the defensible record to support the proposed EPS.

To meet the requirements of the Commerce Clause, a regulation must satisfy the *Pike* test. *Pike,* 397 U.S. at 142, discussed *supra* at 15. Under the *Pike* test, even if a regulation is evenhanded, it must effectuate a *legitimate local public interest*. *Id*. The plain fact is, however, that California's reduction of GHG to 1990-levels will itself achieve little, if any, climate change. *See, e.g.*, Benjamin Zycher, *California Focus: Another Enviro-Scare Campaign*, California Republic & Orange County Register, August 29, 2006 (noting that if California were to achieve 1990 CO_2 emissions levels, "the predicted decline in world temperatures in the year 2100 would be thirteen one-thousandths of a degree Celsius," and that if the entire United States achieved such reductions, "the decline would be sixteen one-hundredths of a degree Celsius.").

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[20] Mr. Blees's presentation is available at http://www.energy.ca.gov/2005_energypolicy/documents/2005-08-17+18_workshop/presentations-081805/Blees_Jonathan_Revised.pdf (the "Blees Presentation").

III. CONCLUSION

The CEC should not adopt the CPUC Proposal without significant revision, or at a minimum, additional analysis of the costs of the proposal. In its current form, the CPUC Proposal (1) sets an unrealistically low GHG emissions standard, (2) eliminates cost containment measures to protect ratepayers, (3) increases California's already high dependence on natural gas to supply its power needs, (4) prohibits a large portion of California's existing out-of-state power suppliers from competing in baseload California power markets, and (5) eliminates or creates disincentives for continued development of cleaner coal-fueled electric generation. In doing so, the proposal contained in the CPUC Proposal violates the Commerce Clause of the U.S. Constitution.

Sincerely,

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Attachment 1

to
CEED COMMENTS

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COALCAST

FUELCAST

Evaluation of August 2006 Draft Staff Proposal for California Greenhouse Gas Emissions Performance Standard for Electric Resource Procurement—R.06-04-009

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I. INTRODUCTION

The Draft Workshop Report (the "Draft Report") issued August 21, 2006 outlines a staff proposal for implementing an interim greenhouse gas emissions environmental performance standard for future California electric resource procurements. Based upon the report's qualification criteria and utility data submissions, the draft proposal is estimated to apply to roughly 18 percent of all California power procurements by 2012[1]. The Draft Report's proposed environmental performance standard would prohibit all future power purchase contracts with any powerplants using oil, coal, petroleum coke and most waste fuels from supplying baseload power to California investor owned utilities. Since California relies heavily upon imports for much of its baseload power needs, these proposed rules will have profound impacts on future inter-state power trading by restricting eligibility of out-of-state supply sources. By significantly limiting future contract power purchase choices, the draft proposal will significantly increase California ratepayer costs and force utilities to become increasingly reliant upon natural gas to meet their growing demand.

Despite stating that their program goal is to minimize cost and future compliance risk to ratepayers, the draft report does not discuss or evaluate any cost or competitive market risk issues. By ignoring cost and market risk implications, California appears to have forgotten their stated goals and the hard lessons learned from utility deregulation.

The staff's challenge is to achieve true Greenhouse Gas ("GHG") emission reductions without significantly increasing ratepayer cost and to avoid placing California industry at an even greater energy price disadvantage. To meet its stated objectives, the proposal should provide mechanisms that would increase competition, generation diversity and new innovation that are essential to controlling ratepayer costs. Specifically, the proposal should permit the use of

[1] According to CEC and utility data request submissions, PGE, SCE and SDGE are projected to have an total power demand of 199,207 GWh by 2012. Of this amount, the three utilities estimate that 36,149 GWh would be supplied under long term (>5 yr) future baseload power procurements from resources with capacity factors greater than 60%.

emission offsets, set safety value price caps, allow generation portfolio averaging, and increase the GHG emission rate target.

This evaluation addresses concerns regarding the Draft Report and the proposed interim emissions performance standard ("EPS"). Specific concerns with the staff proposal are:

- The proposed EPS does not address program design goals on minimizing ratepayer cost and risk.
- The GHG emissions standard conflicts with the current requirements of SB 1368 that explicitly defines that all natural gas combined cycle plants in operation or received a final permit to operate before June 30, 2007 shall be deemed as being in compliance with the GHG emission performance standard. To be consistent with this definition, the staff must raise its GHG emission standard to include all existing NGCC applications (in-state and out-of-state) located in high elevations, use air-cooled technologies and use older combined cycle generation technologies.
- The Draft Report eliminates all ratepayer cost containment measures by prohibiting the use of emission offsets, portfolio averaging, and safety valve cost caps.
- The lack of cost containment measures, in combination with the 1,000 lb CO_2/MWh emission performance standard, prohibits all power plants that use oil, coal, petroleum coke and most waste fuels from supplying baseload power to California investor owned utilities because no cost-competitive CO_2 capture and sequestration technologies exist that will allow longer non-natural gas fossil fuels, such as coal, to compete in the California power markets in the foreseeable future.
- The proposed EPS prohibits a large portion of California's existing out-of-state power suppliers from competing for baseload California power contracts

because of their fuel use (e.g. coal) and/or their energy efficiency (e.g. fossil-fired steam).

- While the proposed EPS provides an R&D exemption on a case-by-case basis, its qualification criteria may not be suitable for potential California suppliers.
- By eliminating baseload power options from coal, having continuing concerns with nuclear power and given resource limitations for renewable power production, California will likely become increasingly dependent upon natural gas for power supplies. Ratepayer cost impacts would be significant.
- Rapid increasing and unstable energy costs would create a larger burden on low-income families.

Each of these concerns is discussed below.

II. THE PROPOSED EPS IS IN DIRECT CONFLICT WITH SEVERAL STATED DESIGN GOALS.

The staff proposal for an interim EPS set the following program design goals:

- Prevent major "backsliding";
- Minimize costs to rate payers ;
- Minimize the risk of long-term commitments that will raise future compliance costs;
- Addresses reliability concerns including prevention of shut-down of essential facilities ; and
- Encourage (as well as not hinder) advanced technology development (*See, e.g.*, Draft Report at 68.)

With the above stated goals, it is surprising that the Draft Report does **not** contain any analysis or discussion about ratepayer costs and risks. The Draft Report attempts to address reliability concerns by allowing reliability exemptions on a case-by-case basis, but misses the much larger policy issue created by eliminating most new resource options and forcing the state to become increasingly dependent upon natural gas. *At the minimum, the Draft Report should contain a* *discussion of anticipated compliance costs and reliability impacts and how (if at all) the proposed approach minimizes ratepayer costs and risks.*

By setting the EPS at 1,000 lbs CO_2/MWh for future long-term baseload power contract procurement, the Draft Report's proposal will discriminate against all supply options that use higher carbon containing fuels such as coal, oil, waste fuels and petroleum coke. Further, by prohibiting offset purchases, portfolio averaging and ratepayer price caps, these facilities are left with no choice but to shutdown or divert their power output to markets outside California. While carbon capture technologies exist, they remain far too expensive and energy inefficient to allow the higher carbon chain fuel sources to compete in the baseload California market now or in the foreseeable future[2]. Many low cost California suppliers may be forced to close– a result contrary to at least one stated EPS design goal. The draft proposal would also result in less competition with greater dependence on natural gas that will ultimately force higher power prices with greater volatility risk—all in direct conflict with two other stated program goals.

III. THE DRAFT REPORT ELIMINATES USE OF RATEPAYER COST CONTAINMENT MEASURES – MEASURES THAT SHOULD BE INCLUDED IN THE PROPOSED EPS.

The California legislature and governor have expressed interest in controlling compliance costs to minimize impacts on the state economy in both SB 1368 and AB 32. SB 1368 specifically requires the Energy Commission to consider the ratepayer costs in its development and implementation of a GHG emission standard (Section 8341(d)(6), Section 8341(e)(7)). This was reiterated in AB 32 that requires that the state agencies establish a GHG emissions cap "in an efficient and cost-effective manner."(Section 38561(a))

To provide the flexibility needed to be "efficient and cost effective", AB 32 authorizes use of "alternative compliance mechanisms" that allow offsets to provide for an equivalent reduction in

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[2] "Engineering Feasibility and Economics of CO_2 Capture on an Existing Coal-fired Power Plant," Alstom Power, ABB Lummus Global and AEP (June 2001) prepared for USDOE contract DE-FC26-99FT40576.

greenhouse gases. AB 32 also permits the state to establish a GHG cap & trade system. *At the minimum, the commission should follow the governor's and legislature's lead on cost containment measures and permit offsets and portfolio averaging. The proposal should also establish carbon price caps to protect the California ratepayer.*

The following are measures that would mitigate the risk of the utility companies and the ratepayers without compromising the environmental integrity of the program:

- **Emission offsets**: Gives an economic incentive to businesses capable of reducing/capturing CO_2 in a cost effective manner, but otherwise have no reason to do so. Most existing state CO_2 control programs permit companies with higher emitting alternatives the flexibility to use purchased carbon offsets for compliance[3]. Overall, the decreased carbon emissions from qualifying offset programs in combination with power source emissions will result in the same net emissions to the environment as a qualifying source (as defined by current draft staff proposal). This cost-containment measure would ensure the reduction targets are met in a cost-effective manner, while expanding supplier competition. The Draft Report currently prohibits such use of offsets.

- **Portfolio averaging**: Portfolio averaging also provides needed flexibility to control costs by averaging emissions across multiple diverse facilities to comply with the environmental performance standard. This option would encourage companies to invest in zero emitting technology options (e.g. nuclear, renewable) to offset their cheaper, but higher carbon emitting, technologies. Overall, with portfolio averaging, there would be no net emission change to the environment while allowing for the suppliers flexibility to offer a lower-priced product. Currently the Draft Report recommendation would prohibit portfolio averaging.

[3] Power industry carbon control programs that permit use of offsets include Regional Greenhouse Gas Initiative states (CT, DE, ME, NH, NJ, NY, and VT), Maryland, Massachusetts, Oregon and Washington.

- **Price caps**: The only true method to protect the ratepayer would be to establish a price cap for CO_2 emissions. This approach is commonly applied in state renewable portfolio standards when they set a maximum price premium. A price cap approach is also applied in new power plant CO_2 control programs in Massachusetts (\$1/ton CO_2), Oregon (\$0.85/ton CO_2) and Washington (\$1.60/metric ton carbon). Several congressional GHG control proposals (e.g. Climate and Economy Insurance Act of 2005) have also contained carbon price caps. The California draft proposal contains no price caps. The governor and state legislature in recent legislation that cost is an important issue. The Draft Report should address how much California ratepayers should be willing to pay to avoid CO_2 emissions and that would not adversely affect the state economy. To assure that this price is not exceeded, the Commission should set a price cap at or below this level.

To further contain costs and be consistent with SB 1368, the Draft Report qualification criteria should be revised to exempt utilities with California service territories with less than 75,000 retail end use customers but mostly serve customers in other states (Section 8341(d)(9)). These utilities have very limited emissions benefit given their small California demand but may incur steep compliance costs with only a very limited California customer base to recover them.

IV. THE PROPOSED EPS PROHIBITS MOST BASELOAD GENERATION OPTIONS, INCLUDING ALL LONGER CARBON FUEL OPTIONS.

The Draft Report's lack of cost containment measures, in combination with the 1,000 lb CO_2/MWh emission performance standard, prohibits **all** power plants that use oil, coal, petroleum coke and most waste fuels from supplying baseload power to California investor owned utilities. Higher carbon containing fuels such as petroleum coke, coal, waste fuels and oil face impossible technology hurdles since they must offset their higher fuel carbon content[4]

[4] The longer the fuel carbon chain, the greater the amount of CO_2 created per unit heat generated. This relationship was quantified in the emission factors provided by the California Energy Commission in a publication entitled, "Unit Conversions, Emission Factors, and Other Reference Data," November 2004.

without any energy efficiency advantage[5] (often a disadvantage) over the NGCC standard. To date, **<u>no</u>** coal or other carbon chain fuel (other than natural gas) project can meet the proposed CO_2 performance limit of 1,000 lbs CO_2/MWh.

This fixed performance standard may also prohibit future baseload contracts with natural gas combined cycle applications located in high elevations (less dense air->lower output->lower efficiency), use air-cooled technologies (less energy efficient than more common water cooled applications) and use older less energy efficient combined cycle generation technologies. By prohibiting these less energy efficient NGCC applications, the staff standard would come in direct conflict with the requirements of the recently adopted SB 1368 legislation. Section 8341(d)(1) of this California legislation explicitly defines that <u>all</u> natural gas combined cycle plants that are in operation or have received a final permit to operate before June 30, 2007 shall be deemed as being in compliance with the GHG emission performance standard. To be consistent with this definition, the staff must raise its GHG emission standard to include all existing NGCC applications (in-state and out-of-state) located in high elevations, use air-cooled technologies and use older combined cycle generation technologies.

The Draft Report does not ask, nor did the utilities provide, data on how site and technology variations can adversely affect heat rate efficiencies. To set its original proposed limit, the Draft Report relies upon utility data submissions that were reported as “full load” heat rate efficiencies, but may not have accounted for the fact that “average” annual heat rate efficiencies would be much higher. The Draft Report must address the standard by which power procurement decisions will be judged – either “full load” or “average” heat rates. This determination has implications on the CEC net system average calculations that likely use average annual heat rates, not fully loaded heat rates.

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[5] Combined cycle plants are more energy efficient than steam electric power plants since they can produce power through both (1) burning fuel to drive combustion turbines and (2) producing steam from the heat produced to pass through a steam turbine. Steam electric power plants produce power from a simple cycle that collects heat from fuel combustion to generate steam that is pass through a steam turbine.

The stated intent of the proposed interim EPS is to capture California's baseload generation using a capacity factor greater than 60 percent. Table 1 presents the data reported on EIA Form 906 by in-state California facilities with a 2005 capacity factor greater than 60 percent. However, if the interim EPS is implemented, it would appear likely that all but three facilities, or 42 percent of the generation, will be in violation of the EPS. Not one facility using longer chain carbon fuels currently meets the proposed standard and only 3 of 14 combined cycle facilities are in compliance. *The staff proposal has exceeded the CPUC's and S.B. 1368's directives by proposing a standard that many existing and future NGCC plants will be unable to achieve. The staff should reset its base proposed standard to at least 1,700 lbs/MWh to incorporate the full range of existing baseload NGCC plants. This change in combination with offsets, averaging, and price caps (as discussed above) would encourage greater competition and reduce ratepayer costs.*

V. NO COST-EFFECTIVE CARBON CAPTURE AND SEQUESTRATION MEASURES EXIST TO MEET PROPOSED STANDARD NOR WILL ANY EXIST IN FORESEEABLE FUTURE.

Some proponents argue that longer carbon chain fuel options can comply with the proposed standard if they were to capture CO_2 and sequester it without emitting it. Unfortunately, *no cost-effective technology methods exist to capture CO_2 from flue gas streams and to store or sell the captured product. Current CO_2 capture/sequestration technology options are both highly energy intensive and far too expensive.*

Currently, there are only four powerplants in the U.S. that capture a small portion of CO_2 from their flue gas streams[6]. These facilities use monoethanolamine (MEA) reagent based scrubber to capture up to 90 percent of CO_2 from a flue gas slip stream. In most cases, the recaptured CO_2 is then compressed to produce a product that is sold (e.g. dry ice, food packaging, fire extinguishers,

[6] AES Warrior Run (MD), AES Shady Point (OK), Bellingham (MA) and Trona (CA).

TABLE 1. California 2005 Baseload Generation Facilities (Excludes Nuclear)

Utility	Plant Name	State	Unit Type	Fuel	Capacity (MW)	Heatrate (Btu/kWh)	Capacity Factor (%)	2004 CO_2 Emission Rate-#CO_2/MWh	2005 CO_2 Emission Rate-#CO_2/MWh
Sempra	Elk Hills Power	CA	CC	NG	580	6,952	70.5%	791	813
Delmarva Operating	Delta Energy	CA	CC	NG	818	7,328	74.6%	857	857
Calpine	Los Medanos Energy Facility	CA	CC	NG	532	7,365	77.0%	837	862
Modesto Irrigation Dist	Woodland	CA	GT	NG	49	8,869	84.5%	1,021	1,038
Foster Wheeler Power Sys Inc	Foster Wheeler Martinez Inc	CA	CC	NG	99	10,200	77.1%	NA	1,193
Valero Refining Co California	Valero Cogeneration Unit 1	CA	GT	Other Gas	51	10,356	74.3%	1,195	1,243
United Cogen Inc	United Cogen	CA	CC	NG	31	10,966	55.0%	1,232	1,283
Cardinal Cogen	Cardinal Cogen	CA	CC	NG	53	11,332	80.0%	1,337	1,326
LA County Sanitation Districts	Puente Hills Energy Recovery	CA	Other	Biogas	53	11,488	89.4%	1,414	1,356
Midway-Sunset Cogeneration Co	Midway Sunset Cogen Co	CA	CC	NG	234	11,830	90.0%	1,395	1,384
Arco Products Company	Watson Cogen Co	CA	CC	NG	398	12,233	86.7%	1,428	1,431
Tosco Corporation	Los Angeles Refinery Wilmington Pl	CA	CC	Other Gas	69	11,951	60.1%	NA	1,434
Kern River Cogeneration Co	Sycamore Cogen Co	CA	CC	NG	312	12,272	98.5%	1,441	1,436
Kern River Cogeneration Co	Kern River Cogen Co	CA	CC	NG	300	12,457	87.7%	1,445	1,457
Chevron USA Inc	Richmond Cogen Project	CA	GT	NG	125	13,257	77.5%	1,641	1,551
Tosco Corporation	Tosco SFAR Rodeo Refinery	CA	CC	Other Gas	51	17,246	81.0%	1,682	2,070
Mt Poso Cogeneration Co	Mt Poso Cogen	CA	Coal	WBit	62	11,370	87.3%	2,410	2,331
Ogden Energy/Constellation	Rio Bravo Poso	CA	Coal	BIT	38	12,044	85.7%	2,564	2,469
Ogden Energy/Constellation	Rio Bravo Jasmin	CA	Coal	BIT	38	12,265	83.2%	2,496	2,514
ACE Cogeneration Co	ACE Cogen Co	CA	Coal	WBit	108	12,275	78.0%	2,775	2,516
Stockton Cogen Co	Stockton CoGen Co	CA	Coal	WBit	55	12,759	95.7%	2,575	2,616
POSDEF Power Company LP	Port of Stockton District Energy Fa	CA	Coal	WBit	50	13,597	65.3%	2,603	2,787
Hanford L P	Hanford	CA	Pet Coke	Pet Coke	27	12,531	84.2%	3,028	2,819
Colmac Energy Inc	Mecca Plant	CA	Other	Wood	56	15,290	70.2%	2,761	2,982
BP Wilmington Calciner	BP Wilmington Calciner	CA	Pet Coke	Pet Coke	34	13,558	90.5%	3,136	3,051
Delano Energy Co Inc	Delano Energy Co Inc	CA	Other	Wood	57	16,229	59.6%	3,361	3,165
Burney Forest Products	Burney Forest Products	CA	Other	Wood	31	18,419	83.4%	3,676	3,592
Wheelabrator Environmental Sys	Wheelabrator Shasta	CA	Other	Wood	55	19,035	72.1%	3,755	3,712
SERRF Joint Powers Authority	Southeast Resource Recovery	CA	Other	Refuse	36	20,222	64.6%	NA	4,044
Pacific Lumber Co	The Pacific Lumber Company	CA	Other	Wood	25	21,556	104.7%	3,887	4,203
U S West Financial Service Inc	TXI Riverside Cement Power House	CA	Coal	Coal	24	40,724	67.7%	9,329	8,348
North American Chemical Co	Argus Cogen Plant	CA	Coal	WBit	55	41,194	73.1%	9,130	8,445

Source: EIA Form 906

and trona manufacture) but could have alternatively been injected for sequestration. These facilities were designed to treat less than 15 percent of their flue gas, and these facilities consume large quantities of energy in the process. Based upon their current performance, EVA calculates that to treat 100 percent of the flue gas would require roughly 75 percent of the plant's total output energy. However, to capture only the amount of CO_2 needed to meet a gas combined cycle emission rate (per MWh unit output basis) would consume roughly 63 percent of the plant output energy. Cost to capture and compress CO_2 would increase the production cost of coal-based electricity using conventional PC and CFB technologies by 184 percent. To treat the coal-fired generation currently coming-in to California alone would cost more than $5 billion/year. This would be far greater than the undocumented and arbitrary Climate Action Team (CAT) $117 million estimate[7]. Such costs would make the higher carbon containing fuel alternatives far more costly than nuclear power and gas combined cycle alternatives that do not incur the carbon penalty. The bottom line is that California would be forced to become increasing dependent upon nuclear and high cost natural gas for its energy needs.

Some utilities have proposed to build "carbon capture ready" IGCC facilities (e.g. Xcel Energy-Pawnee) that will be capable of removing CO_2 from the syngas before combustion. Given the higher temperature of syngas, higher pressure and CO_2 concentration, technology vendors believe (but have not yet commercially demonstrated) that the CO_2 can be separated from the syngas for a far lower price than the flue gas capture approaches such as MEA outlined above. While very promising, the potential CO_2 removal is very modest (less than 20 percent) since existing technologies are designed to maximize combustible carbon monoxide (not CO_2) in their syngas stream to improve overall power energy efficiency (almost all syngas' carbon monoxide is converted to CO_2 during its subsequent combustion in gas turbines). Therefore, even these "carbon-capture" IGCC projects using Western sub-bituminous coals, emission rates may

[7] Documentation of Inputs to Macroeconomic Assessment of the Draft Climate Action Team Report to the Governor and Legislature (January 2006) California Action Team- Document estimates carbon policy compliance costs of just $27 million/year (pg 24) and $90 million per year (pg 18) for in 2020 for IOU electric sector and municipal utility sectors respectively.

eventually reach 1,600-1,800 lb CO_2/MWh--fall far short of the 1,000 lbCO_2/MWh standard proposed in the Draft Report.

With future research, the U.S. Department of Energy (DOE) hopes to improve the energy efficiency and performance of carbon capture/sequestration technologies for coal-based alternatives. In its FutureGen project[8], DOE hopes to support the development of a hydrogen based IGCC process that would convert more of the coal carbon content to CO_2 in the syngas steam and allow for greater CO_2 syngas capture/removal. These advancements and improvements may take several years to intensive research to discover and their effect on future performance and cost is highly uncertain. However, it is certain that they will unlikely be commercially available before 2020[9]. The Draft Report risks California's ability to utilize such future technologies.

VI. THE DRAFT REPORT'S PROPOSAL INHIBITS INTER-STATE POWER TRADING.

To meet its growing power needs, California has become the largest power importing state in the nation.[10] With its mix of mostly higher cost generating resources, few in-state power plants (mostly nuclear and co-generator facilities) operate at or above the Draft Report's assumed 60 percent baseload capacity factor. California has turned to much cheaper power imports to supply a large portion of its baseload power needs[11]. Given these market conditions, *the draft staff proposal will be primarily applied to out-of-state suppliers while exempting the vast majority of in-state power generators (because of 60% capacity factor criterion)*.

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8 Source:; http://www.fossil.energy.gov/news/techlines/2005/tl_futuregen_signing.html.

9 Source: http://www.fossil.energy.gov/programs/powersystems/futuregen/.

10 In 2005, the state reported retail sales of 254 TWh versus in-state generation of only 196 GWh (Source: DOE Electric Power Monthly March 2006.

11 Source: California ISO Summer 2006 forecast (May 2006).

Under the Draft Report's proposal, import power suppliers would need to demonstrate compliance with the proposed EPS to be eligible to compete for future baseload California power contracts. The proposed eligibility criterion would exclude a large portion of the existing import power suppliers from being able to compete for future California baseload power contracts. First, it would prohibit all coal-fired powerplants because of coal's much higher carbon content and lower energy efficiency (than combined cycle). Second, it would also exclude all natural gas and oil fired steam generating units (higher carbon content, lower efficiency) from competition. Such exclusions would significantly inhibit all future inter-state power trading as discussed below.

As is shown in Figure 1, the effects of the proposed performance standard would also vary widely geographically. Baseload power imported from the Southwest would be far harder hit than generation from the Pacific Northwest. Both major importing areas would be hit much harder than in-state California plants.

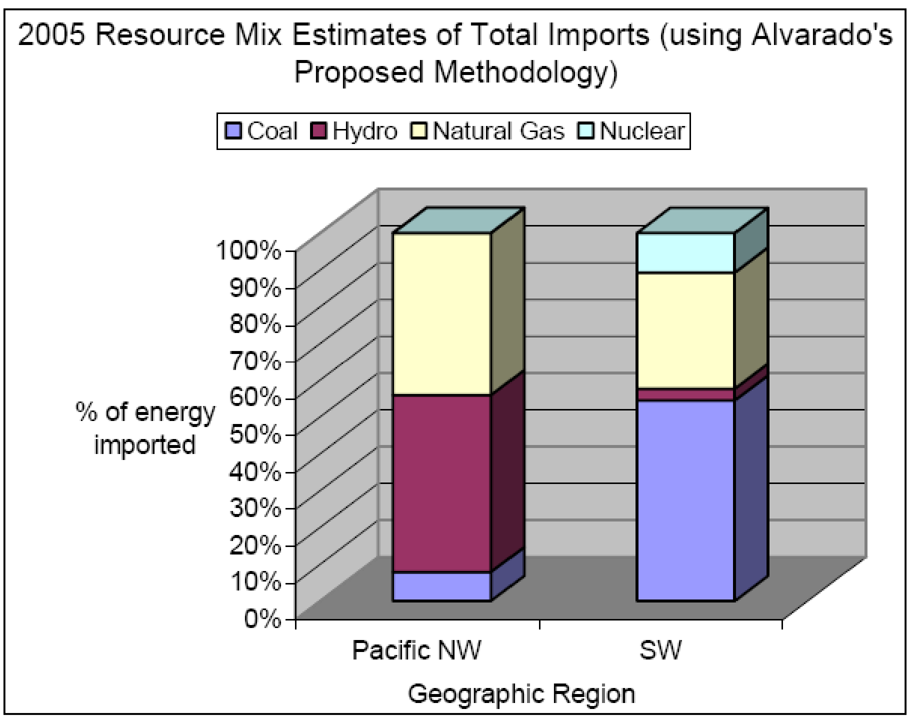

FIGURE 1

Using the methodology proposed by Al Alvarado in his May 2006 staff paper entitled *Proposed Methodology to Estimate the Generation Resource Mix of California Electricity Imports*, coal would account for 7.9 percent of total Pacific Northwest electricity imports; hydro accounts for 48 percent, while natural gas makes up 44.1 percent. Between 8-52 percent (depending upon natural gas heat rates and capacity factors) of the existing Pacific Northwest imports would not meet the draft EPS standard.

The composition of overall imports in the Southwest is entirely different. Coal has a 54.4 percent share, while natural gas, nuclear, and hydroelectric account for 31.6 percent, 10.7 percent, and 3.2 percent, respectively, of electricity imports. As a result, a higher portion of between 54-86 percent of the existing Southwest power imports may not meet the standard.

Given their power import purchases, one would expect a large portion of Southern California's electricity to be from coal-fired plants, while Northern California to very little electricity from coal. Since the performance standard discriminates against coal, Southern California may be most affected by prohibiting new baseload coal contracts. On the other hand, Northern California purchases and consumes more hydroelectric power, which at an average purchase price of $35.62 per MW was the least expensive of any purchased power source in 2005.

VII. THE PROPOSAL'S R&D EXEMPTION CRITERIA MAY BE TOO RESTRICTIVE FOR CALIFORNIA OPTIONS.

One stated goal for the EPS standard was to "encourage (as well as not hinder) advanced technology development." *See* Draft Report at 68. The Draft Report attempts to satisfy this objective by allowing suppliers to apply for a research & development facility exemption that would be granted on a case-by-case basis. Suppliers would have to demonstrate that the commitment would make a significant contribution towards developing a lower-emitting resource mix in the future.

While we strongly support the goal of encouraging advanced technology development, the Draft Report's proposed framework sets an administratively burdensome review process that will more likely discourage and hinder such technology development. We agree with Southern California Edison and PacifiCorp that the CPUC goal would be better achieved if some predefined R&D projects such as carbon capture ready IGCC projects and ultra-supercritical pulverized coal units that provide potentially low CO_2 options were automatically exempted from the EPS and not subject to an expensive or drawn out approval process. Projects such as the Xcel Pawnee (PRB fired IGCC plant with carbon capture) and AEP Hempstead (PRB fired ultra-supercritical plant) projects should be encouraged.

Not only would the approval process be burdensome, but the qualification criteria may also be too restrictive as contained in the Draft Report's illustrative example on page 22. In its description of a qualifying facility, the staff suggests that only an IGCC plant with equal to or better heat rate efficiency than average IGCC plants should be eligible for an R&D exemption. If this average is calculated based upon the existing bituminous coal demonstration units, it is highly unlikely that any IGCC plant using the higher moisture sub-bituminous western coals could ever qualify for an exemption because of their higher moisture penalty. Carbon capture processes would also reduce plant efficiency. *If the example criterion were applied, California would not support either an IGCC or ultra-supercritical plant like Pawnee or Hempstead. In summary, California may discourage the very plants that it seeks to encourage.*

VIII. REDUCED COMPETITION RESULTING FROM THE PROPOSED EPS WILL RESULT IN HIGHER RATEPAYER COSTS AND GREATER VULNERABILITY TO NATURAL GAS MARKET RISKS.

As outlined above, the combination of the 1,000 lb CO_2/MWh standard and prohibition of cost control measures (offsets, portfolio averaging and price caps) will prohibit all power plants that use oil, clean coal, petroleum coke and most waste fuels from supplying baseload power to California investor owned utilities. By setting the limit based upon applying new NGCC technology in optimal site conditions, a large majority of the existing resource options would be unable to compete for future baseload contracts. By limiting baseload generation competition, the utilities are left with fewer and higher cost options. The consequence of the more limited competition would be an increasing dependence upon natural gas based options.

Given the draft proposal limitations, the CEC Net System emission average for unspecified resource contracts would likely exceed the EPS limit. The CEC calculation would include older fossil fuel plants and plants using longer carbon chain fuels may be far above the 1,000 lb/MWh limit that would likewise yield a system average much greater than 1,500 lb CO_2/MWh. In summary, the draft proposal, as written, would prohibit California utilities from signing any long-term unspecified resource contracts.

If coal, oil, petroleum coke, waste fuel, older NGCC and unspecified generation options are no longer eligible for baseload California power contracts, utilities are left with depending upon building more new NGCC, renewable and nuclear units to fill-in the gap and meet new growing demand. If California is reluctant to support nuclear power, it is left with only a portfolio of natural gas and renewable energy options. A portfolio of energy sources of this nature would create a high supply and market risk for California ratepayers.

First, it is unlikely that renewable energy can meet this large demand without a significant price impacts. Renewable power has been and continues to be far more expensive than convention generation options. How can California increase its purchase of these more expensive power sources without a wholesale power price impact? It simply can't nor can it be certain that sufficient renewable resources may exist.

The California Public Utility Commission (CPUC) report entitled *Achieving a 33% Renewable Energy Target* (November 2005) failed to study the resource availability and cost impact of the combination of California expanded renewable demand with other western state demand triggered by their renewable portfolio standards. Four western states (Arizona, Colorado, New Mexico, Nevada) have also adopted renewable portfolio requirements totaling 20 TWh by 2020 that plan to draw upon these same renewable resources. Other western states are also considering adopting similar standards that would push demand above 140 TWh. How much renewable resources can be developed and at what cost?

CPUC's analysis assumed that most of this increased renewable energy demand would be supplied by wind projects. To meet this demand, the CPUC report **assumes** that the wind capacity factors will increase from 37 percent today to 43 percent by 2017. However, according to EIA Form 906 data, only one California wind project and eight in the entire nation report such a high capacity factor. In fact, the average 2003 California capacity factor was less than 23%, so the CPUC projection may vastly over-estimate both current and future potential wind power contribution and significantly underestimate the wind production cost. A GHG performance standard would make wind a larger player in the energy market, a role wind technology does not appear ready to play.

Secondly, wind can also contribute to system reliability issues. In a recent article in *Power Markets Week*, the California ISO provided data for the July 2006 energy crunch in California. During this critical period, wind power operated at less than 5 percent of its rated capacity at peak demand periods. This makes wind a highly unreliable source during critical high peak periods when power is needed the most.

With renewable expansion expensive and possibly limited, this leaves California increasingly dependent upon natural gas for its power supplies. With this growing dependence, the state comes increasingly vulnerable to natural gas price volatility. Instead of diversifying energy sources to decrease price risk, the draft proposal manages only to concentrate future power supplies and increase their market risk. These risks were not discussed in the Draft Report.

IX. THE PROPOSED EPS PLACES A DISPROPORTIONATE COST BURDEN ON LOW INCOME FAMILIES.

A.B. 32 directs state agencies in implementing its GHG control program to "ensure that activities undertaken to comply with the regulations do not disproportionately impact low income communities" (Section 38562(b)(2). This provision will be difficult to accomplish with the Draft Report plan that provides no cost containment measures. As outlined above, the Draft Report would limit competition, increase risk and increase rates. The resulting higher electricity rates would have the same effect as a regressive tax. Higher energy prices disproportionately affect families living on lower and fixed incomes as is shown in Figure 2. Thus, we all have a stake in keeping energy costs affordable. More money spent on electricity means less money is available for housing, food, education, and other necessities that improve quality of life. It is an unwise and unjust policy to raise energy prices so that consumers use less.

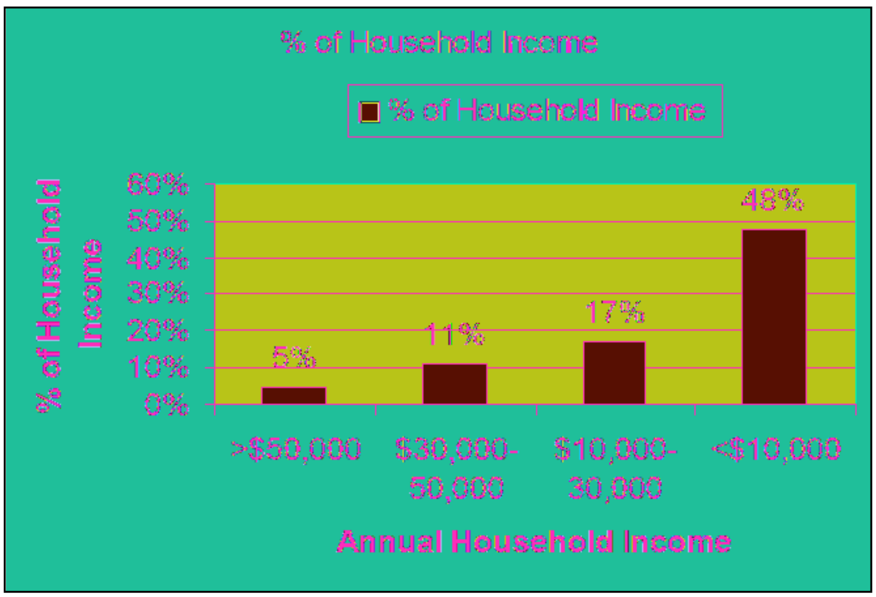

Figure 2. Annual Household Expenditures on Energy (as Percent of Household Income)[12]

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[12] *See http://www.balancedenergy.org/docs/ABEC%20Member%20Documents/Energy%20Price%20Impact%20Study.pdf (*citing *data on residential energy consumption patterns are from U.S. Department of Energy, Energy Information Administration, 2001 Survey of Residential Energy Consumption (RECS);*

http://www.eia.doe.gov/emeu/recs/contents.html. Data for 2001 energy consumption by fuel type were updated to estimated 2005 values based on consumer energy cost projections in EIA's Short Term Energy Outlook (September 2005, Hurricane Katrina "middle recovery" case), http://www.eia.doe.gov/emeu/steo/pub/contents.html. The most recent data on U.S. household income by income categories (2003) are from U.S. Bureau of the Census, "Income, Poverty, and Health Insurance Coverage in the United States, 200,";

http://www.census.gov/hhes/www/income/income.html. Total and average household incomes by income category and race are from the distribution of household income in U.S. Bureau of the Census, "Money Income in the United States, 2001," (September 2002), http://www.census.gov/prod/2002pubs/p60-218.pdf.

In 2005, energy costs accounted for only 5 percent of the gross incomes of families with household incomes of greater than $50,000. In the same year, energy costs consumed 48 percent of the budgets of U.S. families with incomes of less than $10,000. More income has been shown to increase the likelihood one lives a safe, healthy, long life. With more income, individuals spend more on health care for themselves and their children, purchase more safety equipment, eat a more nutritious diet, and take other actions that decrease the likelihood of premature death by illness or accident. Consistent with this fact, individual reductions in disposable income tend to increase health and safety risks and the resulting deaths.

The proposed GHG emissions performance standard has the intent of reducing certain life- load" or "average" heat rates. This determination has implications on the CEC net system average calculations that likely use average annual heat rates, not fully loaded heat rates.
threatening risks, but the economic costs of this regulation could worsen individual health or safety and shorten lifetimes. A key question is whether net benefits or net losses in health and safety result from these opposing forces.

THOMAS A. HEWSON JR. is a Principal of Energy Ventures Analysis, Inc., a position he has held since 1981. Mr. Hewson is responsible for power industry market studies, and provides regular power industry forecasts of future electricity demand growth, generation mix, environmental compliance and production cost changes for Fuelcast subscribers and individual client studies. Mr. Hewson has completed numerous studies examining the effect of future environmental regulation and utility deregulation on fuel prices, supplier capacity decisions (new, repower, retire), generation/environmental technology choice, wholesale electric prices and emission allowance values, and has provided market assessments for new fuel, generation and pollution control technologies. Mr. Hewson has also directed an industrial utility group examining repowering technology options, costs and risks, and has completed studies on renewable power options, costs, incentives and price impacts, and assessed electricity demand, energy conservation potential and alternative energy charge frameworks for power consumers.

Mr. Hewson has also been responsible for corporate emission allowance forecasts and assessments, provided ongoing forecasts of emission trading market prices and fundamentals of existing Acid Rain SO_2 market, seasonal NO_x market, CAIR, RGGI and individual state new source offset markets, assessed future market trading values for mercury and carbon dioxide, evaluated a wide range of state legislative multi-pollutant proposals and their effect on regional production costs, state GDP, and environmental benefits, and has developed new rules and regulations to expand existing emission allowance trading markets to include non-traditional sources (e.g. mobile sources). Mr. Hewson directs technical feasibility and environmental permitting studies, is expert in electric utility repowering technologies, fuel upgrading and environmental control technologies, and has analyzed repowering and FGD scrubber retrofits for all major coal and oil fired utility stations.

Mr. Hewson has presented and published several papers on the electric utility industry and emission allowance markets, and has co-authored two papers on innovative wastewater treatment technologies.

Mr. Hewson holds a B.S.E. in Civil Engineering from Princeton University. He currently serves as Vice Chairman of the Alexandria Environmental Policy Commission.

Attachment 1

to
CEED COMMENTS

EVA Technical Evaluation

Energy Ventures Analysis, Inc.
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COALCAST

FUELCAST

Evaluation of August 2006 Draft Staff Proposal for California Greenhouse Gas Emissions Performance Standard for Electric Resource Procurement—R.06-04-009

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September 6, 2006

I. INTRODUCTION

The Draft Workshop Report (the "Draft Report") issued August 21, 2006 outlines a staff proposal for implementing an interim greenhouse gas emissions environmental performance standard for future California electric resource procurements. Based upon the report's qualification criteria and utility data submissions, the draft proposal is estimated to apply to roughly 18 percent of all California power procurements by 2012[1]. The Draft Report's proposed environmental performance standard would prohibit all future power purchase contracts with any powerplants using oil, coal, petroleum coke and most waste fuels from supplying baseload power to California investor owned utilities. Since California relies heavily upon imports for much of its baseload power needs, these proposed rules will have profound impacts on future inter-state power trading by restricting eligibility of out-of-state supply sources. By significantly limiting future contract power purchase choices, the draft proposal will significantly increase California ratepayer costs and force utilities to become increasingly reliant upon natural gas to meet their growing demand.

Despite stating that their program goal is to minimize cost and future compliance risk to ratepayers, the draft report does not discuss or evaluate any cost or competitive market risk issues. By ignoring cost and market risk implications, California appears to have forgotten their stated goals and the hard lessons learned from utility deregulation.

The staff's challenge is to achieve true Greenhouse Gas ("GHG") emission reductions without significantly increasing ratepayer cost and to avoid placing California industry at an even greater energy price disadvantage. To meet its stated objectives, the proposal should provide mechanisms that would increase competition, generation diversity and new innovation that are essential to controlling ratepayer costs. Specifically, the proposal should permit the use of

[1] According to CEC and utility data request submissions, PGE, SCE and SDGE are projected to have an total power demand of 199,207 GWh by 2012. Of this amount, the three utilities estimate that 36,149 GWh would be supplied under long term (>5 yr) future baseload power procurements from resources with capacity factors greater than 60%.

emission offsets, set safety value price caps, allow generation portfolio averaging, and increase the GHG emission rate target.

This evaluation addresses concerns regarding the Draft Report and the proposed interim emissions performance standard ("EPS"). Specific concerns with the staff proposal are:

- The proposed EPS does not address program design goals on minimizing ratepayer cost and risk.
- The GHG emissions standard conflicts with the current requirements of SB 1368 that explicitly defines that all natural gas combined cycle plants in operation or received a final permit to operate before June 30, 2007 shall be deemed as being in compliance with the GHG emission performance standard. To be consistent with this definition, the staff must raise its GHG emission standard to include all existing NGCC applications (in-state and out-of-state) located in high elevations, use air-cooled technologies and use older combined cycle generation technologies.
- The Draft Report eliminates all ratepayer cost containment measures by prohibiting the use of emission offsets, portfolio averaging, and safety valve cost caps.
- The lack of cost containment measures, in combination with the 1,000 lb CO_2/MWh emission performance standard, prohibits all power plants that use oil, coal, petroleum coke and most waste fuels from supplying baseload power to California investor owned utilities because no cost-competitive CO_2 capture and sequestration technologies exist that will allow longer non-natural gas fossil fuels, such as coal, to compete in the California power markets in the foreseeable future.
- The proposed EPS prohibits a large portion of California's existing out-of-state power suppliers from competing for baseload California power contracts

because of their fuel use (e.g. coal) and/or their energy efficiency (e.g. fossil-fired steam).

- While the proposed EPS provides an R&D exemption on a case-by-case basis, its qualification criteria may not be suitable for potential California suppliers.

- By eliminating baseload power options from coal, having continuing concerns with nuclear power and given resource limitations for renewable power production, California will likely become increasingly dependent upon natural gas for power supplies. Ratepayer cost impacts would be significant.

- Rapid increasing and unstable energy costs would create a larger burden on low-income families.

Each of these concerns is discussed below.

II. THE PROPOSED EPS IS IN DIRECT CONFLICT WITH SEVERAL STATED DESIGN GOALS.

The staff proposal for an interim EPS set the following program design goals:

- Prevent major "backsliding";

- Minimize costs to rate payers ;

- Minimize the risk of long-term commitments that will raise future compliance costs;

- Addresses reliability concerns including prevention of shut-down of essential facilities ; and

- Encourage (as well as not hinder) advanced technology development (*See, e.g.*, Draft Report at 68.)

With the above stated goals, it is surprising that the Draft Report does **<u>not</u>** contain any analysis or discussion about ratepayer costs and risks. The Draft Report attempts to address reliability concerns by allowing reliability exemptions on a case-by-case basis, but misses the much larger policy issue created by eliminating most new resource options and forcing the state to become increasingly dependent upon natural gas. *<u>At the minimum, the Draft Report should contain a</u>*

discussion of anticipated compliance costs and reliability impacts and how (if at all) the proposed approach minimizes ratepayer costs and risks.

By setting the EPS at 1,000 lbs CO_2/MWh for future long-term baseload power contract procurement, the Draft Report's proposal will discriminate against all supply options that use higher carbon containing fuels such as coal, oil, waste fuels and petroleum coke. Further, by prohibiting offset purchases, portfolio averaging and ratepayer price caps, these facilities are left with no choice but to shutdown or divert their power output to markets outside California. While carbon capture technologies exist, they remain far too expensive and energy inefficient to allow the higher carbon chain fuel sources to compete in the baseload California market now or in the foreseeable future[2]. Many low cost California suppliers may be forced to close– a result contrary to at least one stated EPS design goal. The draft proposal would also result in less competition with greater dependence on natural gas that will ultimately force higher power prices with greater volatility risk—all in direct conflict with two other stated program goals.

III. THE DRAFT REPORT ELIMINATES USE OF RATEPAYER COST CONTAINMENT MEASURES – MEASURES THAT SHOULD BE INCLUDED IN THE PROPOSED EPS.

The California legislature and governor have expressed interest in controlling compliance costs to minimize impacts on the state economy in both SB 1368 and AB 32. SB 1368 specifically requires the Energy Commission to consider the ratepayer costs in its development and implementation of a GHG emission standard (Section 8341(d)(6), Section 8341(e)(7)). This was reiterated in AB 32 that requires that the state agencies establish a GHG emissions cap "in an efficient and cost-effective manner."(Section 38561(a))

To provide the flexibility needed to be "efficient and cost effective", AB 32 authorizes use of "alternative compliance mechanisms" that allow offsets to provide for an equivalent reduction in

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[2] "Engineering Feasibility and Economics of CO_2 Capture on an Existing Coal-fired Power Plant," Alstom Power, ABB Lummus Global and AEP (June 2001) prepared for USDOE contract DE-FC26-99FT40576.

greenhouse gases. AB 32 also permits the state to establish a GHG cap & trade system. *At the minimum, the commission should follow the governor's and legislature's lead on cost containment measures and permit offsets and portfolio averaging. The proposal should also establish carbon price caps to protect the California ratepayer.*

The following are measures that would mitigate the risk of the utility companies and the ratepayers without compromising the environmental integrity of the program:

- **Emission offsets**: Gives an economic incentive to businesses capable of reducing/capturing CO_2 in a cost effective manner, but otherwise have no reason to do so. Most existing state CO_2 control programs permit companies with higher emitting alternatives the flexibility to use purchased carbon offsets for compliance[3]. Overall, the decreased carbon emissions from qualifying offset programs in combination with power source emissions will result in the same net emissions to the environment as a qualifying source (as defined by current draft staff proposal). This cost-containment measure would ensure the reduction targets are met in a cost-effective manner, while expanding supplier competition. The Draft Report currently prohibits such use of offsets.

- **Portfolio averaging**: Portfolio averaging also provides needed flexibility to control costs by averaging emissions across multiple diverse facilities to comply with the environmental performance standard. This option would encourage companies to invest in zero emitting technology options (e.g. nuclear, renewable) to offset their cheaper, but higher carbon emitting, technologies. Overall, with portfolio averaging, there would be no net emission change to the environment while allowing for the suppliers flexibility to offer a lower-priced product. Currently the Draft Report recommendation would prohibit portfolio averaging.

[3] Power industry carbon control programs that permit use of offsets include Regional Greenhouse Gas Initiative states (CT, DE, ME, NH, NJ, NY, and VT), Maryland, Massachusetts, Oregon and Washington.

- **<u>Price caps</u>**: The only true method to protect the ratepayer would be to establish a price cap for CO_2 emissions. This approach is commonly applied in state renewable portfolio standards when they set a maximum price premium. A price cap approach is also applied in new power plant CO_2 control programs in Massachusetts ($1/ton CO_2), Oregon ($0.85/ton CO_2) and Washington ($1.60/metric ton carbon). Several congressional GHG control proposals (e.g. Climate and Economy Insurance Act of 2005) have also contained carbon price caps. The California draft proposal contains no price caps. The governor and state legislature in recent legislation that cost is an important issue. The Draft Report should address how much California ratepayers should be willing to pay to avoid CO_2 emissions and that would not adversely affect the state economy. To assure that this price is not exceeded, the Commission should set a price cap at or below this level.

To further contain costs and be consistent with SB 1368, the Draft Report qualification criteria should be revised to exempt utilities with California service territories with less than 75,000 retail end use customers but mostly serve customers in other states (Section 8341(d)(9)). These utilities have very limited emissions benefit given their small California demand but may incur steep compliance costs with only a very limited California customer base to recover them.

IV. THE PROPOSED EPS PROHIBITS MOST BASELOAD GENERATION OPTIONS, INCLUDING ALL LONGER CARBON FUEL OPTIONS.

The Draft Report's lack <u>of cost containment measures, in combination with the 1,000 lb CO_2/MWh emission performance standard, prohibits **all** power plants that use oil, coal, petroleum coke and most waste fuels from supplying baseload power to California investor owned utilities</u>. Higher carbon containing fuels such as petroleum coke, coal, waste fuels and oil face impossible technology hurdles since they must offset their higher fuel carbon content[4]

[4] The longer the fuel carbon chain, the greater the amount of CO_2 created per unit heat generated. This relationship was quantified in the emission factors provided by the California Energy Commission in a publication entitled, "Unit Conversions, Emission Factors, and Other Reference Data," November 2004.

without any energy efficiency advantage[5] (often a disadvantage) over the NGCC standard. To date, **no** coal or other carbon chain fuel (other than natural gas) project can meet the proposed CO_2 performance limit of 1,000 lbs CO_2/MWh.

This fixed performance standard may also prohibit future baseload contracts with natural gas combined cycle applications located in high elevations (less dense air->lower output->lower efficiency), use air-cooled technologies (less energy efficient than more common water cooled applications) and use older less energy efficient combined cycle generation technologies. By prohibiting these less energy efficient NGCC applications, the staff standard would come in direct conflict with the requirements of the recently adopted SB 1368 legislation. Section 8341(d)(1) of this California legislation explicitly defines that <u>all</u> natural gas combined cycle plants that are in operation or have received a final permit to operate before June 30, 2007 shall be deemed as being in compliance with the GHG emission performance standard. To be consistent with this definition, the staff must raise its GHG emission standard to include all existing NGCC applications (in-state and out-of-state) located in high elevations, use air-cooled technologies and use older combined cycle generation technologies.

The Draft Report does not ask, nor did the utilities provide, data on how site and technology variations can adversely affect heat rate efficiencies. To set its original proposed limit, the Draft Report relies upon utility data submissions that were reported as "full load" heat rate efficiencies, but may not have accounted for the fact that "average" annual heat rate efficiencies would be much higher. The Draft Report must address the standard by which power procurement decisions will be judged – either "full load" or "average" heat rates. This determination has implications on the CEC net system average calculations that likely use average annual heat rates, not fully loaded heat rates.

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[5] Combined cycle plants are more energy efficient than steam electric power plants since they can produce power through both (1) burning fuel to drive combustion turbines and (2) producing steam from the heat produced to pass through a steam turbine. Steam electric power plants produce power from a simple cycle that collects heat from fuel combustion to generate steam that is pass through a steam turbine.

The stated intent of the proposed interim EPS is to capture California's baseload generation using a capacity factor greater than 60 percent. Table 1 presents the data reported on EIA Form 906 by in-state California facilities with a 2005 capacity factor greater than 60 percent. However, if the interim EPS is implemented, it would appear likely that all but three facilities, or 42 percent of the generation, will be in violation of the EPS. Not one facility using longer chain carbon fuels currently meets the proposed standard and only 3 of 14 combined cycle facilities are in compliance. *The staff proposal has exceeded the CPUC's and S.B. 1368's directives by proposing a standard that many existing and future NGCC plants will be unable to achieve. The staff should reset its base proposed standard to at least 1,700 lbs/MWh to incorporate the full range of existing baseload NGCC plants. This change in combination with offsets, averaging, and price caps (as discussed above) would encourage greater competition and reduce ratepayer costs.*

V. NO COST-EFFECTIVE CARBON CAPTURE AND SEQUESTRATION MEASURES EXIST TO MEET PROPOSED STANDARD NOR WILL ANY EXIST IN FORESEEABLE FUTURE.

Some proponents argue that longer carbon chain fuel options can comply with the proposed standard if they were to capture CO_2 and sequester it without emitting it. Unfortunately, *no cost-effective technology methods exist to capture CO_2 from flue gas streams and to store or sell the captured product. Current CO_2 capture/sequestration technology options are both highly energy intensive and far too expensive.*

Currently, there are only four powerplants in the U.S. that capture a small portion of CO_2 from their flue gas streams[6]. These facilities use monoethanolamine (MEA) reagent based scrubber to capture up to 90 percent of CO_2 from a flue gas slip stream. In most cases, the recaptured CO_2 is then compressed to produce a product that is sold (e.g. dry ice, food packaging, fire extinguishers,

[6] AES Warrior Run (MD), AES Shady Point (OK), Bellingham (MA) and Trona (CA).

TABLE 1. California 2005 Baseload Generation Facilities (Excludes Nuclear)

Utility	Plant Name	State	Unit Type	Fuel	Capacity (MW)	Heatrate (Btu/kWh)	Capacity Factor (%)	2004 CO_2 Emission Rate- #CO_2/MWh	2005 CO_2 Emission Rate- #CO_2/MWh
Sempra	Elk Hills Power	CA	CC	NG	580	6,952	70.5%	791	813
Delmarva Operating	Delta Energy	CA	CC	NG	818	7,328	74.6%	857	857
Calpine	Los Medanos Energy Facility	CA	CC	NG	532	7,365	77.0%	837	862
Modesto Irrigation Dist	Woodland	CA	GT	NG	49	8,869	84.5%	1,021	1,038
Foster Wheeler Power Sys Inc	Foster Wheeler Martinez Inc	CA	CC	NG	99	10,200	77.1%	NA	1,193
Valero Refining Co California	Valero Cogeneration Unit 1	CA	GT	Other Gas	51	10,356	74.3%	1,195	1,243
United Cogen Inc	United Cogen	CA	CC	NG	31	10,966	55.0%	1,232	1,283
Cardinal Cogen	Cardinal Cogen	CA	CC	NG	53	11,332	80.0%	1,337	1,326
LA County Sanitation Districts	Puente Hills Energy Recovery	CA	Other	Biogas	53	11,488	89.4%	1,414	1,356
Midway-Sunset Cogeneration Co	Midway Sunset Cogen Co	CA	CC	NG	234	11,830	90.0%	1,395	1,384
Arco Products Company	Watson Cogen Co	CA	CC	NG	398	12,233	86.7%	1,428	1,431
Tosco Corporation	Los Angeles Refinery Wilmington Pl	CA	CC	Other Gas	69	11,951	60.1%	NA	1,434
Kern River Cogeneration Co	Sycamore Cogen Co	CA	CC	NG	312	12,272	98.5%	1,441	1,436
Kern River Cogeneration Co	Kern River Cogen Co	CA	CC	NG	300	12,457	87.7%	1,445	1,457
Chevron USA Inc	Richmond Cogen Project	CA	GT	NG	125	13,257	77.5%	1,641	1,551
Tosco Corporation	Tosco SFAR Rodeo Refinery	CA	CC	Other Gas	51	17,246	81.0%	1,682	2,070
Mt Poso Cogeneration Co	Mt Poso Cogen	CA	Coal	WBit	62	11,370	87.3%	2,410	2,331
Ogden Energy/Constellation	Rio Bravo Poso	CA	Coal	BIT	38	12,044	85.7%	2,564	2,469
Ogden Energy/Constellation	Rio Bravo Jasmin	CA	Coal	BIT	38	12,265	83.2%	2,496	2,514
ACE Cogeneration Co	ACE Cogen Co	CA	Coal	WBit	108	12,275	78.0%	2,775	2,516
Stockton Cogen Co	Stockton CoGen Co	CA	Coal	WBit	55	12,759	95.7%	2,575	2,616
POSDEF Power Company LP	Port of Stockton District Energy Fa	CA	Coal	WBit	50	13,597	65.3%	2,603	2,787
Hanford L P	Hanford	CA	Pet Coke	Pet Coke	27	12,531	84.2%	3,028	2,819
Colmac Energy Inc	Mecca Plant	CA	Other	Wood	56	15,290	70.2%	2,761	2,982
BP Wilmington Calciner	BP Wilmington Calciner	CA	Pet Coke	Pet Coke	34	13,558	90.5%	3,136	3,051
Delano Energy Co Inc	Delano Energy Co Inc	CA	Other	Wood	57	16,229	59.6%	3,361	3,165
Burney Forest Products	Burney Forest Products	CA	Other	Wood	31	18,419	83.4%	3,676	3,592
Wheelabrator Environmental Sys	Wheelabrator Shasta	CA	Other	Wood	55	19,035	72.1%	3,755	3,712
SERRF Joint Powers Authority	Southeast Resource Recovery	CA	Other	Refuse	36	20,222	64.6%	NA	4,044
Pacific Lumber Co	The Pacific Lumber Company	CA	Other	Wood	25	21,556	104.7%	3,887	4,203
U S West Financial Service Inc	TXI Riverside Cement Power House	CA	Coal	Coal	24	40,724	67.7%	9,329	8,348
North American Chemical Co	Argus Cogen Plant	CA	Coal	WBit	55	41,194	73.1%	9,130	8,445

Source: EIA Form 906

and trona manufacture) but could have alternatively been injected for sequestration. These facilities were designed to treat less than 15 percent of their flue gas, and these facilities consume large quantities of energy in the process. Based upon their current performance, EVA calculates that to treat 100 percent of the flue gas would require roughly 75 percent of the plant's total output energy. However, to capture only the amount of CO_2 needed to meet a gas combined cycle emission rate (per MWh unit output basis) would consume roughly 63 percent of the plant output energy. Cost to capture and compress CO_2 would increase the production cost of coal-based electricity using conventional PC and CFB technologies by 184 percent. To treat the coal-fired generation currently coming-in to California alone would cost more than $5 billion/year. This would be far greater than the undocumented and arbitrary Climate Action Team (CAT) $117 million estimate[7]. Such costs would make the higher carbon containing fuel alternatives far more costly than nuclear power and gas combined cycle alternatives that do not incur the carbon penalty. The bottom line is that California would be forced to become increasing dependent upon nuclear and high cost natural gas for its energy needs.

Some utilities have proposed to build "carbon capture ready" IGCC facilities (e.g. Xcel Energy-Pawnee) that will be capable of removing CO_2 from the syngas before combustion. Given the higher temperature of syngas, higher pressure and CO_2 concentration, technology vendors believe (but have not yet commercially demonstrated) that the CO_2 can be separated from the syngas for a far lower price than the flue gas capture approaches such as MEA outlined above. While very promising, the potential CO_2 removal is very modest (less than 20 percent) since existing technologies are designed to maximize combustible carbon monoxide (not CO_2) in their syngas stream to improve overall power energy efficiency (almost all syngas' carbon monoxide is converted to CO_2 during its subsequent combustion in gas turbines). Therefore, even these "carbon-capture" IGCC projects using Western sub-bituminous coals, emission rates may

[7] Documentation of Inputs to Macroeconomic Assessment of the Draft Climate Action Team Report to the Governor and Legislature (January 2006) California Action Team- Document estimates carbon policy compliance costs of just $27 million/year (pg 24) and $90 million per year (pg 18) for in 2020 for IOU electric sector and municipal utility sectors respectively.

eventually reach 1,600-1,800 lb CO_2/MWh--fall far short of the 1,000 lbCO_2/MWh standard proposed in the Draft Report.

With future research, the U.S. Department of Energy (DOE) hopes to improve the energy efficiency and performance of carbon capture/sequestration technologies for coal-based alternatives. In its FutureGen project[8], DOE hopes to support the development of a hydrogen based IGCC process that would convert more of the coal carbon content to CO_2 in the syngas steam and allow for greater CO_2 syngas capture/removal. These advancements and improvements may take several years to intensive research to discover and their effect on future performance and cost is highly uncertain. However, it is certain that they will unlikely be commercially available before 2020[9]. The Draft Report risks California's ability to utilize such future technologies.

VI. THE DRAFT REPORT'S PROPOSAL INHIBITS INTER-STATE POWER TRADING.

To meet its growing power needs, California has become the largest power importing state in the nation.[10] With its mix of mostly higher cost generating resources, few in-state power plants (mostly nuclear and co-generator facilities) operate at or above the Draft Report's assumed 60 percent baseload capacity factor. California has turned to much cheaper power imports to supply a large portion of its baseload power needs[11]. Given these market conditions, *the draft staff proposal will be primarily applied to out-of-state suppliers while exempting the vast majority of in-state power generators (because of 60% capacity factor criterion)*.

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[8] Source:; http://www.fossil.energy.gov/news/techlines/2005/tl_futuregen_signing.html.

[9] Source: http://www.fossil.energy.gov/programs/powersystems/futuregen/.

[10] In 2005, the state reported retail sales of 254 TWh versus in-state generation of only 196 GWh (Source: DOE Electric Power Monthly March 2006.

[11] Source: California ISO Summer 2006 forecast (May 2006).

Under the Draft Report's proposal, import power suppliers would need to demonstrate compliance with the proposed EPS to be eligible to compete for future baseload California power contracts. The proposed eligibility criterion would exclude a large portion of the existing import power suppliers from being able to compete for future California baseload power contracts. First, it would prohibit all coal-fired powerplants because of coal's much higher carbon content and lower energy efficiency (than combined cycle). Second, it would also exclude all natural gas and oil fired steam generating units (higher carbon content, lower efficiency) from competition. Such exclusions would significantly inhibit all future inter-state power trading as discussed below.

As is shown in Figure 1, the effects of the proposed performance standard would also vary widely geographically. Baseload power imported from the Southwest would be far harder hit than generation from the Pacific Northwest. Both major importing areas would be hit much harder than in-state California plants.

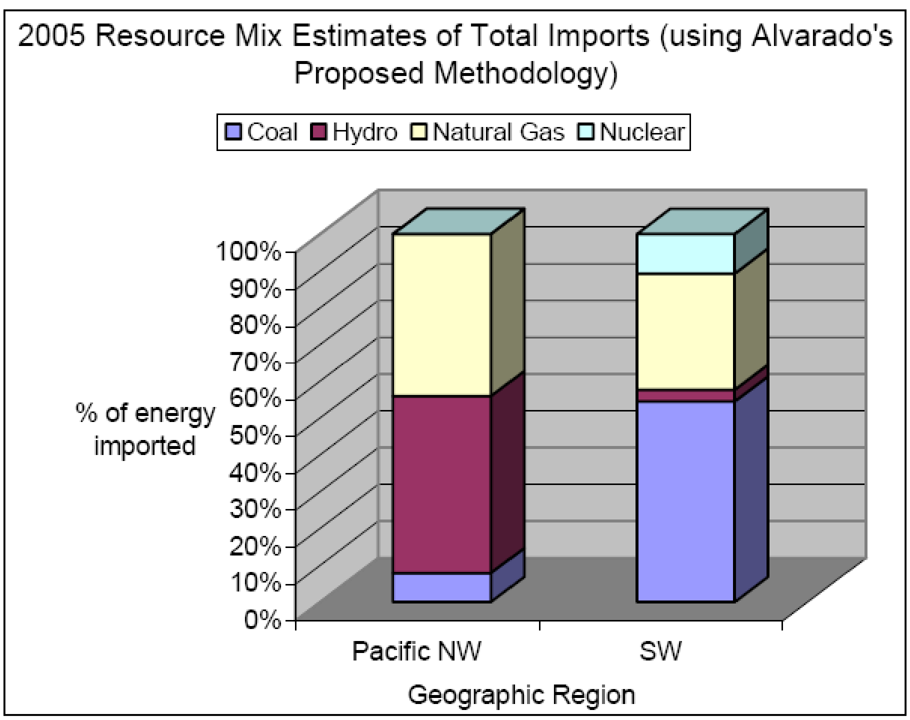

FIGURE 1

Using the methodology proposed by Al Alvarado in his May 2006 staff paper entitled *Proposed Methodology to Estimate the Generation Resource Mix of California Electricity Imports*, coal would account for 7.9 percent of total Pacific Northwest electricity imports; hydro accounts for 48 percent, while natural gas makes up 44.1 percent. Between 8-52 percent (depending upon natural gas heat rates and capacity factors) of the existing Pacific Northwest imports would not meet the draft EPS standard.

The composition of overall imports in the Southwest is entirely different. Coal has a 54.4 percent share, while natural gas, nuclear, and hydroelectric account for 31.6 percent, 10.7 percent, and 3.2 percent, respectively, of electricity imports. As a result, a higher portion of between 54-86 percent of the existing Southwest power imports may not meet the standard.

Given their power import purchases, one would expect a large portion of Southern California's electricity to be from coal-fired plants, while Northern California to very little electricity from coal. Since the performance standard discriminates against coal, Southern California may be most affected by prohibiting new baseload coal contracts. On the other hand, Northern California purchases and consumes more hydroelectric power, which at an average purchase price of $35.62 per MW was the least expensive of any purchased power source in 2005.

VII. THE PROPOSAL'S R&D EXEMPTION CRITERIA MAY BE TOO RESTRICTIVE FOR CALIFORNIA OPTIONS.

One stated goal for the EPS standard was to "encourage (as well as not hinder) advanced technology development." *See* Draft Report at 68. The Draft Report attempts to satisfy this objective by allowing suppliers to apply for a research & development facility exemption that would be granted on a case-by-case basis. Suppliers would have to demonstrate that the commitment would make a significant contribution towards developing a lower-emitting resource mix in the future.

While we strongly support the goal of encouraging advanced technology development, the Draft Report's proposed framework sets an administratively burdensome review process that will more likely discourage and hinder such technology development. We agree with Southern California Edison and PacifiCorp that the CPUC goal would be better achieved if some predefined R&D projects such as carbon capture ready IGCC projects and ultra-supercritical pulverized coal units that provide potentially low CO_2 options were automatically exempted from the EPS and not subject to an expensive or drawn out approval process. Projects such as the Xcel Pawnee (PRB fired IGCC plant with carbon capture) and AEP Hempstead (PRB fired ultra-supercritical plant) projects should be encouraged.

Not only would the approval process be burdensome, but the qualification criteria may also be too restrictive as contained in the Draft Report's illustrative example on page 22. In its description of a qualifying facility, the staff suggests that only an IGCC plant with equal to or better heat rate efficiency than average IGCC plants should be eligible for an R&D exemption. If this average is calculated based upon the existing bituminous coal demonstration units, it is highly unlikely that any IGCC plant using the higher moisture sub-bituminous western coals could ever qualify for an exemption because of their higher moisture penalty. Carbon capture processes would also reduce plant efficiency. *If the example criterion were applied, California would not support either an IGCC or ultra-supercritical plant like Pawnee or Hempstead. In summary, California may discourage the very plants that it seeks to encourage.*

VIII. REDUCED COMPETITION RESULTING FROM THE PROPOSED EPS WILL RESULT IN HIGHER RATEPAYER COSTS AND GREATER VULNERABILITY TO NATURAL GAS MARKET RISKS.

As outlined above, the combination of the 1,000 lb CO_2/MWh standard and prohibition of cost control measures (offsets, portfolio averaging and price caps) will prohibit all power plants that use oil, clean coal, petroleum coke and most waste fuels from supplying baseload power to California investor owned utilities. By setting the limit based upon applying new NGCC technology in optimal site conditions, a large majority of the existing resource options would be unable to compete for future baseload contracts. By limiting baseload generation competition, the utilities are left with fewer and higher cost options. The consequence of the more limited competition would be an increasing dependence upon natural gas based options.

Given the draft proposal limitations, the CEC Net System emission average for unspecified resource contracts would likely exceed the EPS limit. The CEC calculation would include older fossil fuel plants and plants using longer carbon chain fuels may be far above the 1,000 lb/MWh limit that would likewise yield a system average much greater than 1,500 lb CO_2/MWh. In summary, the draft proposal, as written, would prohibit California utilities from signing any long-term unspecified resource contracts.

If coal, oil, petroleum coke, waste fuel, older NGCC and unspecified generation options are no longer eligible for baseload California power contracts, utilities are left with depending upon building more new NGCC, renewable and nuclear units to fill-in the gap and meet new growing demand. If California is reluctant to support nuclear power, it is left with only a portfolio of natural gas and renewable energy options. A portfolio of energy sources of this nature would create a high supply and market risk for California ratepayers.

First, it is unlikely that renewable energy can meet this large demand without a significant price impacts. Renewable power has been and continues to be far more expensive than convention generation options. How can California increase its purchase of these more expensive power sources without a wholesale power price impact? It simply can't nor can it be certain that sufficient renewable resources may exist.

The California Public Utility Commission (CPUC) report entitled *Achieving a 33% Renewable Energy Target* (November 2005) failed to study the resource availability and cost impact of the combination of California expanded renewable demand with other western state demand triggered by their renewable portfolio standards. Four western states (Arizona, Colorado, New Mexico, Nevada) have also adopted renewable portfolio requirements totaling 20 TWh by 2020 that plan to draw upon these same renewable resources. Other western states are also considering adopting similar standards that would push demand above 140 TWh. How much renewable resources can be developed and at what cost?

CPUC's analysis assumed that most of this increased renewable energy demand would be supplied by wind projects. To meet this demand, the CPUC report **assumes** that the wind capacity factors will increase from 37 percent today to 43 percent by 2017. However, according to EIA Form 906 data, only one California wind project and eight in the entire nation report such a high capacity factor. In fact, the average 2003 California capacity factor was less than 23%, so the CPUC projection may vastly over-estimate both current and future potential wind power contribution and significantly underestimate the wind production cost. A GHG performance standard would make wind a larger player in the energy market, a role wind technology does not appear ready to play.

Secondly, wind can also contribute to system reliability issues. In a recent article in *Power Markets Week*, the California ISO provided data for the July 2006 energy crunch in California. During this critical period, wind power operated at less than 5 percent of its rated capacity at peak demand periods. This makes wind a highly unreliable source during critical high peak periods when power is needed the most.

With renewable expansion expensive and possibly limited, this leaves California increasingly dependent upon natural gas for its power supplies. With this growing dependence, the state comes increasingly vulnerable to natural gas price volatility. Instead of diversifying energy sources to decrease price risk, the draft proposal manages only to concentrate future power supplies and increase their market risk. These risks were not discussed in the Draft Report.

IX. THE PROPOSED EPS PLACES A DISPROPORTIONATE COST BURDEN ON LOW INCOME FAMILIES.

A.B. 32 directs state agencies in implementing its GHG control program to "ensure that activities undertaken to comply with the regulations do not disproportionately impact low income communities" (Section 38562(b)(2). This provision will be difficult to accomplish with the Draft Report plan that provides no cost containment measures. As outlined above, the Draft Report would limit competition, increase risk and increase rates. The resulting higher electricity rates would have the same effect as a regressive tax. Higher energy prices disproportionately affect families living on lower and fixed incomes as is shown in Figure 2. Thus, we all have a stake in keeping energy costs affordable. More money spent on electricity means less money is available for housing, food, education, and other necessities that improve quality of life. It is an unwise and unjust policy to raise energy prices so that consumers use less.

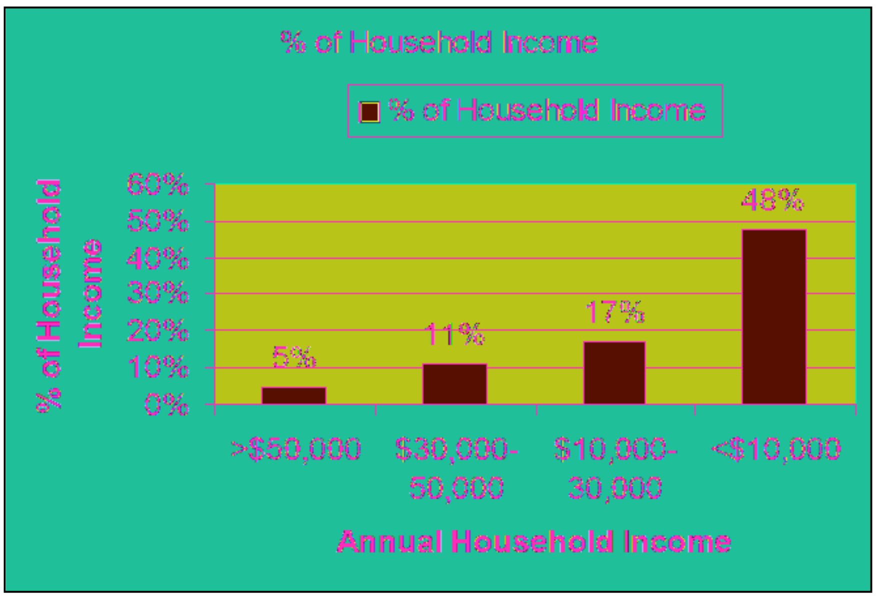

Figure 2. Annual Household Expenditures on Energy (as Percent of Household Income)[12]

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[12] *See http://www.balancedenergy.org/docs/ABEC%20Member%20Documents/Energy%20Price%20Impact%20Study.pdf* (citing *data on residential energy consumption patterns are from U.S. Department of Energy, Energy Information Administration, 2001 Survey of Residential Energy Consumption (RECS);*

http://www.eia.doe.gov/emeu/recs/contents.html. Data for 2001 energy consumption by fuel type were updated to estimated 2005 values based on consumer energy cost projections in EIA's Short Term Energy Outlook (September 2005, Hurricane Katrina "middle recovery" case), http://www.eia.doe.gov/emeu/steo/pub/contents.html. The most recent data on U.S. household income by income categories (2003) are from U.S. Bureau of the Census, "Income, Poverty, and Health Insurance Coverage in the United States, 200,";

http://www.census.gov/hhes/www/income/income.html. Total and average household incomes by income category and race are from the distribution of household income in U.S. Bureau of the Census, "Money Income in the United States, 2001," (September 2002), http://www.census.gov/prod/2002pubs/p60-218.pdf.

In 2005, energy costs accounted for only 5 percent of the gross incomes of families with household incomes of greater than $50,000. In the same year, energy costs consumed 48 percent of the budgets of U.S. families with incomes of less than $10,000. More income has been shown to increase the likelihood one lives a safe, healthy, long life. With more income, individuals spend more on health care for themselves and their children, purchase more safety equipment, eat a more nutritious diet, and take other actions that decrease the likelihood of premature death by illness or accident. Consistent with this fact, individual reductions in disposable income tend to increase health and safety risks and the resulting deaths.

The proposed GHG emissions performance standard has the intent of reducing certain life- load" or "average" heat rates. This determination has implications on the CEC net system average calculations that likely use average annual heat rates, not fully loaded heat rates.
threatening risks, but the economic costs of this regulation could worsen individual health or safety and shorten lifetimes. A key question is whether net benefits or net losses in health and safety result from these opposing forces.

THOMAS A. HEWSON JR. is a Principal of Energy Ventures Analysis, Inc., a position he has held since 1981. Mr. Hewson is responsible for power industry market studies, and provides regular power industry forecasts of future electricity demand growth, generation mix, environmental compliance and production cost changes for Fuelcast subscribers and individual client studies. Mr. Hewson has completed numerous studies examining the effect of future environmental regulation and utility deregulation on fuel prices, supplier capacity decisions (new, repower, retire), generation/environmental technology choice, wholesale electric prices and emission allowance values, and has provided market assessments for new fuel, generation and pollution control technologies. Mr. Hewson has also directed an industrial utility group examining repowering technology options, costs and risks, and has completed studies on renewable power options, costs, incentives and price impacts, and assessed electricity demand, energy conservation potential and alternative energy charge frameworks for power consumers.

Mr. Hewson has also been responsible for corporate emission allowance forecasts and assessments, provided ongoing forecasts of emission trading market prices and fundamentals of existing Acid Rain SO_2 market, seasonal NO_x market, CAIR, RGGI and individual state new source offset markets, assessed future market trading values for mercury and carbon dioxide, evaluated a wide range of state legislative multi-pollutant proposals and their effect on regional production costs, state GDP, and environmental benefits, and has developed new rules and regulations to expand existing emission allowance trading markets to include non-traditional sources (e.g. mobile sources). Mr. Hewson directs technical feasibility and environmental permitting studies, is expert in electric utility repowering technologies, fuel upgrading and environmental control technologies, and has analyzed repowering and FGD scrubber retrofits for all major coal and oil fired utility stations.

Mr. Hewson has presented and published several papers on the electric utility industry and emission allowance markets, and has co-authored two papers on innovative wastewater treatment technologies.

Mr. Hewson holds a B.S.E. in Civil Engineering from Princeton University. He currently serves as Vice Chairman of the Alexandria Environmental Policy Commission.

Attachment 2

to
CEED COMMENTS

Summary of Brenner Article

The Linkage of Economic Prosperity and Low-cost Energy to Improved Public Health

Federal, state, and local policymakers concerned about the relationship between energy, the environment, and health should become familiar with the work of M. Harvey Brenner, PhD., an internationally noted expert in the fields of economics and public health. Dr Brenner's research demonstrates that macroeconomic factors—and energy costs—play a leading role in human health. In 2005, Dr. Brenner published two important articles based on his update of research he originally conducted for the Congressional Joint Economic Committee. These articles are summarized below.

International Journal of Epidemiology**,** July 2005

In his article, "Economic Growth Is the Basis of Mortality Rate Decline in the 20th Century," Dr. Brenner noted, "It is now among the firmest of epidemiological findings, across industrial societies, that socioeconomic status is inversely related to health status." In other words, higher income reduces the odds of premature death; lower income increases morbidity and mortality.

Since 1984, at least seventeen European and U.S. studies have found higher income, employment security, and improved "socioeconomic status" can reduce an individual's risk of disease and premature death. Brenner's work contributes significantly to this body of research. According to Brenner, "Economic growth, cumulatively over at least a decade, is the central factor in mortality rate decline in the U.S. over the 20th century."

However, he noted, "volatility of changes in that growth was – in the very short-term – a source of increased mortality." Such volatility, which can lead to longer-term unemployment and place the unemployed at risk for a downturn in socioeconomic status, introduces significant risk to health and life expectancy through "increased exposure to alcoholism and use of other psychotropic substances such as tobacco and less expensive/nutritious foods."

Brenner concluded, "It is crucial to place the health impact of the small oscillations represented by annual changes in economic growth into the broader context of the principal…trends of economic development," however, "…the net effect of increased unemployment is a substantial increase in mortality."

***EM*, November 2005**

EM (the Air and Waste Management Association's journal for environmental managers) published a case study relating Dr. Brenner's work to the cost of energy. In "Health Benefits of Low-Cost Energy: An Econometric Case Study." Dr. Brenner stated that key economic factors leading to improvements in the national economy mean longer life and reduced rates of mortality. Conversely, he found strong evidence that decreased per capita income and greater unemployment contribute to increased mortality. The key macro-economic factors Brenner identified in his research are 1) real GDP per capita, 2) the employment ratio, 3) unemployment rate, and 4) the interaction between GDP and unemployment as coincident and lagging business cycle indicators.

In particular, Brenner stated "the damaging effects of increased unemployment and acute business cycle disturbances" are key drivers of overall mortality trends and are as robust and statistically significant as the benefits of higher income and stable employment.

Brenner acknowledged that health-risk factors (such as obesity, tobacco consumption, cholesterol levels, and family history) are also important predictors of human health and mortality. He found, however, that "while known risk factors to health, such as high consumption of tobacco, alcohol, and fatty foods, are additionally significant predictors of mortality, they are subordinate to the main economic predictors [the four macro-economic factors above] that routinely influence mortality."

As a consequence, when Brenner applied his econometric model to a hypothetical regulatory case study in which higher-cost fuels displace U.S. coal to generate electricity, he discovered the adverse impact on household income and unemployment could result in 195,000 additional premature deaths annually. That figure is on the low end of a range between 171,000 and 369,000 deaths.

According to Brenner, his case study results can be applied to specific policies affecting coal-fueled electricity generation. For example, the U.S. Department of Energy estimated that certain climate change policies proposed in the U.S. Congress could result in up to 78% of U.S. coal-based generation being replaced by higher-cost energy sources. In that instance, Brenner believes that "increased mortality rates would result from decreased household income and increased unemployment associated with a shift to higher cost energy supply options, absent any direct mitigation programs that effectively prevented or offset these effects."

Brenner added, "The technological bases of long-term economic growth continue to involve the harnessing of energy supplies to enable humans to produce more per unit of labor or capital investment. The economic growth that continuously improves human life expectancy requires access to affordable energy. In this fundamental sense, any policy change that reduces economic growth or raises the level of unemployment should be defined and addressed as a public health issue requiring an economic policy response that limits or offsets these results."

This led Dr. Brenner to conclude that "growth in real per capita income is the backbone of declines in the U.S. mortality rate." His research showed that, by increasing the costs of goods and services such as energy - and decreasing disposable income, government regulation can inadvertently harm individuals' socioeconomic status "and thereby contribute to poor health and premature death." Therefore, according to Brenner, "Governmental programs intended to protect public health and the environment should take into account potential income and employment effects of required compliance measures."

Implications for Policy Makers

Brenner's work shows that a combination of smart individual health practices, along with changes in regulatory standards for air and water quality, are not necessarily sufficient to maintain or improve individual health. Public policy makers must recognize the costs and potential unintended consequences that regulatory programs can have on employment and income. These costs and unintended consequences particularly affect the health of lower income Americans.

In this context, public policy makers should focus clearly on the importance of low-cost energy. "Energy is among the most indispensable ingredients of human existence," Brenner writes. Making energy more expensive decreases per-capita income and employment, and might, in effect, bring about a net increase in population mortality, according to Brenner.

* * *

M. Harvey Brenner is Professor of Health Policy and Management at the Johns Hopkins University Bloomberg School of Public Health (Baltimore, Maryland) and Senior Professor of Epidemiology at the Berlin University of Technology (Berlin, Germany).

Dr. Brenner's coal case study reported in *EM* was supported by a research grant from the Center for Energy and Economic Development (CEED). The research and conclusions referenced above are his own. CEED is a national, non-profit organization dedicated to providing information and research to policy makers and opinion leaders about the importance of affordable, reliable, and environmentally compatible coal-fueled electricity.

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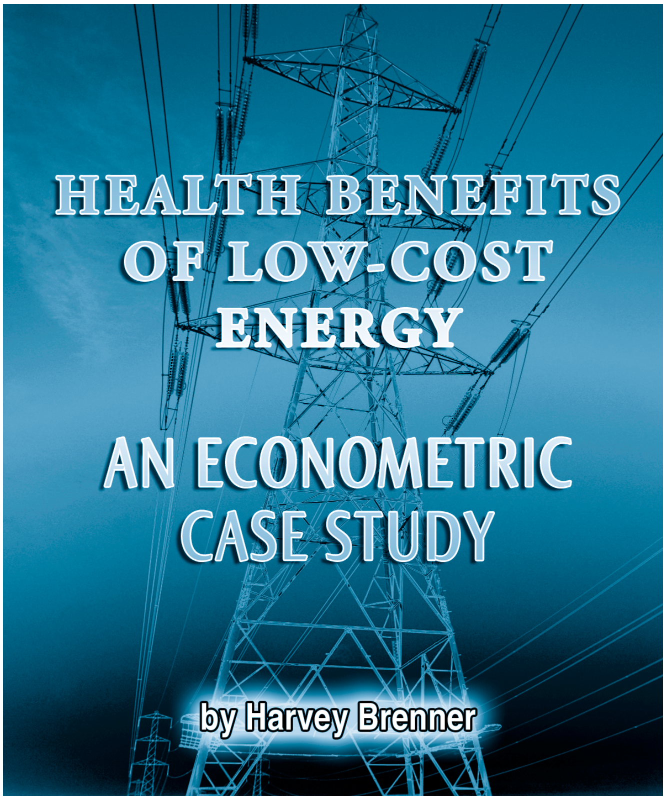
Attachment 3

to
CEED COMMENTS

Brenner Article



HEALTH BENEFITS OF LOW-COST ENERGY

AN ECONOMETRIC CASE STUDY

by Harvey Brenner

> Forum invites authors to share their opinions on environmental issues with *EM* readers. Opinions expressed in Forum are those of the author(s), and do not reflect official A&WMA policy. *EM* encourages your participation by either responding directly to this Forum or addressing another issue of interest to you.

M. Harvey Brenner, Ph.D., is a professor at Johns Hopkins University, School of Public Health, Baltimore, MD, and senior professor of epidemiology at Berlin University of Technology, Berlin, Germany. E-mail: hbrenner@ifg.tu-berlin.de.
Disclaimer: The research described in this article was supported by a grant from the Center for Energy & Economic Development Inc. The author accepts sole responsibility for the findings, conclusions, and opinions expressed herein.

Numerous studies conducted in the past 10–15 years have indicated that economic factors, such as income, employment, and socioeconomic status, affect disease and death.[1] The case study research described in this article shows how a large-scale econometric model—the application of statistical methods to the study of economic data and problems—can accurately predict long-term U.S. mortality trends based on variables such as per-capita income and unemployment rates (see Figure 1). In addition, it demonstrates that even short-term, year-to-year fluctuations in economic indicators can accurately predict year-to-year fluctuations in population mortality rates (see Figure 2). These results leave little doubt that the statistically significant relationships between socioeconomic indicators and population mortality rates identify principal risk factors to a population's health.

AN ECONOMETRIC MODEL

An econometric model was applied to a hypothetical regulatory case study, whereby U.S. coal was replaced by alternative higher-cost fuels such as natural gas for the purpose of electricity generation. The model was used to estimate the premature mortality associated with increased unemployment and reduced personal income. The adverse impacts on household income and unemployment due to the substitution of higher-cost energy sources were estimated to result in 195,000 additional premature deaths annually (see Table 1).

The results from this hypothetical case study may be scaled to apply to specific policy initiatives affecting the U.S. coal-based electricity generation sector. For example, the U.S. Department of Energy's Energy Information Administration (EIA) estimates that climate change bills currently before the U.S. Congress—such as Senate Amendment No. 2028, rejected by the Senate in 2003 and again in June 2005—could result in the displacement of up to 78% of U.S. coal-based electricity generation with higher-cost energy sources.[2] The methodology employed here suggests that, absent any direct mitigation measures to offset expected decreases in employment and income,[3] implementation of such measures could result in an annual increase of premature mortality rates by more than 150,000.

> Governmental programs intended to protect public health and the environment should take into account potential income and employment effects of required compliance measures.

These predicted mortality trends are an order of magnitude greater than recent estimates of the premature mortality benefits associated with implementation of the U.S. Environmental Protection Agency's 8-hr ozone standard (approximately 1000–3000 premature deaths avoided annually)[4] and fine particulate ($PM_{2.5}$) standard (approximately 15,000 premature deaths avoided annually).[5] In this context, a major implication of this research is that governmental programs intended to protect public health should take into account potential income and employment effects of required compliance measures. By increasing the costs of goods and services such as energy, and decreasing disposable incomes, regulation can inadvertently harm the socioeconomic status of individuals and, thereby, contribute to poor health and premature death.

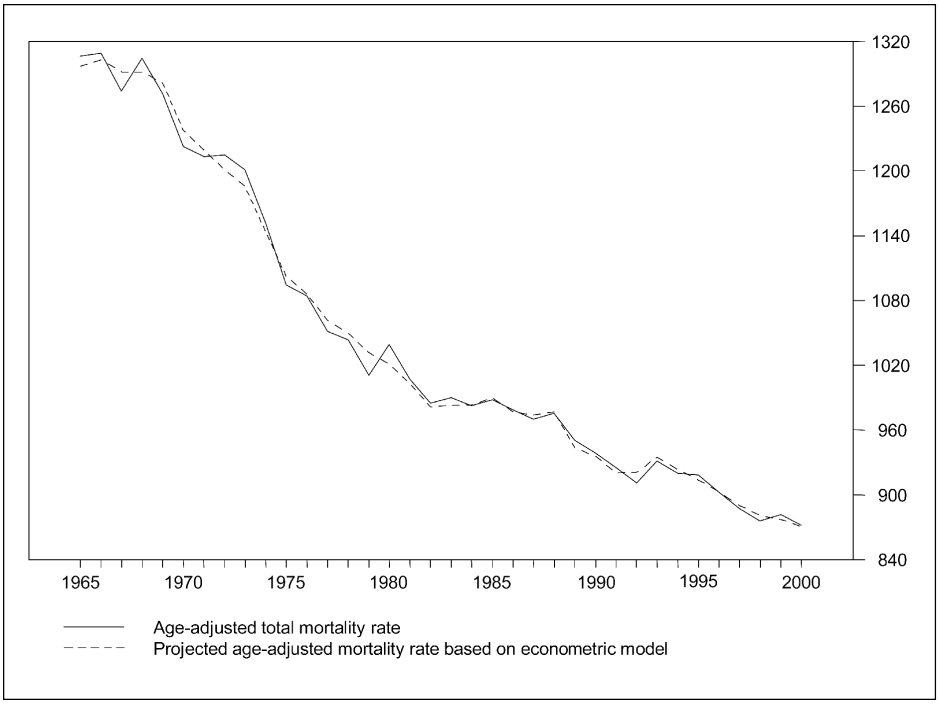


Figure 1. U.S. total mortality rate, real and projected, 1965–2000 (Level model; age-adjusted per 100,000 population).

ENERGY AND HEALTH

Energy is among the most indispensable ingredients of human existence. Like most advanced industrial economies, the United States depends primarily on carbon-based (and carbon-emitting) energy. In 2003, U.S. energy users consumed a total of 98 quadrillion British Thermal Units (quads) of energy, including 39 quads of petroleum, 23 quads of natural gas, and 23 quads of coal. Nuclear, hydro, and other non-carbon-emitting energy sources supplied the remaining 14 quads, or 15% of total energy consumption.[6] Emissions from coal-based electricity generation plants alone represented one-third of U.S. carbon dioxide (CO_2) emissions in 2002.[7]

A substantial body of literature has developed examining the potential impacts of proposed restrictions on greenhouse gas emissions on the national gross domestic product (GDP), energy prices, income, and employment.[8] It has been estimated, for example, that global climate change initiatives requiring expanded use of high-cost, lower-carbon energy alternatives such as natural gas would increase the cost of energy to the point that per-capita income and employment rates would decrease in a quantitatively predictable manner. Assuming these estimates to be approximately correct, and given the epidemiological findings on socioeconomic status and health,[1,3,9-11] it follows that these proposed policies might, in effect, bring about a net increase in population mortality.

LINKS BETWEEN HEALTH AND INCOME

The socioeconomic-status findings show that changes in the economic status of individuals produce subsequent changes in the health and life span of those individuals. Unfortunately, traditional epidemiological literature has not dealt with the issue of change in socioeconomic status in relation to changes in health status. However, another body of research shows that decreased real income per capita and increased unemployment have consequences that lead to increased mortality in U.S. and European populations.[3,9-11] This literature uses econometric analyses of time-series data to measure the relationship between changes in the economy and changes in health outcomes.

The econometric approach to health impact assessments was developed initially in two studies for the Joint Economic Committee (JEC) of the U.S. Congress in 1979[9] and 1984.[10]

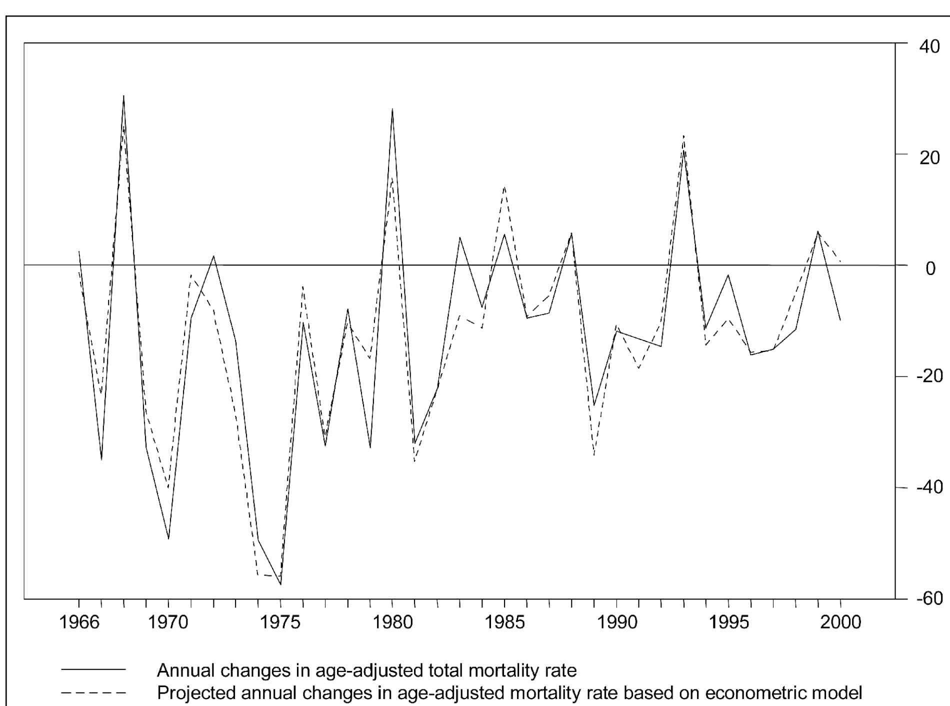


Figure 2. Annual changes of U.S. total mortality rate, real and projected, 1966–2000 (First difference model using error correction method [ECM]; age-adjusted per 100,000 population).

Table 1. Estimates of premature mortality impacts in 2010 of hypothesized elimination of coal utilization for electricity generation.

Year	U.S. Population	Annual Growth
2000	282,125,000	
2010	310,013,000	0.95%

Model Types		Base (2010)	Mortality Rates[a] Final	Delta	Base	Final	Number of Deaths Low SD (95% confidence)[b]	Delta	High SD (95% confidence)[b]	Delta Growth (%)[c]
Model 1 – Unemployment Rate (UR)	Level model	797	852	55	2,470,804	2,641,311	166,505	170,507	174,510	6.9
	First difference model	811	870	59	2,514,205	2,697,113	178,282	182,908	187,533	7.3
Model 2 – Employment Rate (ER)	Level model	885	947	62	2,743,615	2,935,823	188,555	192,208	195,861	7
	First difference model	915	976	61	2,836,619	3,025,727	185,620	189,108	192,596	6.7
Model 3 – GDP per capita (GDPP)	Level model	1392	1,504	112	4,315,381	4,662,596	342,597	347,215	351,832	8
	First difference model	1463	1,582	119	4,535,490	4,904,406	364,252	368,915	373,579	8.1
Model 4 – Model # 3 level with Model #2 first difference	First difference model	1406	1469	63	4,358,783	4,554,091	193,181	195,308	197,435	4.5
Average		**1096**	**1171**	**76**	**3,396,414**	**3,631,581**	**231,285**	**235,167**	**239,049**	**6.9**

Model Type	Mortality Rate	Weights[d]	Number of Deaths
Model 4	**Delta**		
First difference model	195,308		
UR		0.246	48,079
ER		0.266	52,037
GDPP		0.487	95,192
Total		**1.000**	**195,308**

[a]Base = 2010 forecast; Final = 2010 forecast with coal utilization impact. The impact on UR is the average of the DRI[14] and Rose and Yang[15] estimates for job loss % change from the 4% assumed 2010 base level. The impact on ER is assumed to be a minus 2% change from the 2010 base level. The impact on GDPP is the average of the DRI[14] and Rose and Yang[15] estimates for personal income % change the 2010 base level; Delta = 2010 forecast, no population assumption needed. [B]Error forecast standard deviation (SD). [c]Delta mortality rate divided by the 2010 base forecast. [d]Weights calculation = Step 1: GDPP weight is estimated as 1 minus Delta from Model 2 first difference divided by Delta from Model 3 first difference; Step 2: UR weight is estimated as 1 minus GDPP weight divided by 2 multiplied by Delta from Model 1 first difference divided by Delta from Model 2 first difference; Step 3: ER weight is estimated as 1 minus GDPP weight minus UR weight; by definition weights sum to 1.

These studies demonstrated that declines in real income per capita and increases in unemployment led to elevated mortality rates over a subsequent period of six years. For example, the 1984 JEC study found that a one-percentage-point increase in the unemployment rate (e.g., from 5% to 6%) would lead to a 2% increase in the age-adjusted mortality rate. The growth of real income per capita also showed a significant correlation to decreases in mortality rates (except for suicide and homicide), mental hospitalization, and property crimes. Over the past four years, the European Commission has supported similar research showing comparable results throughout the European Union.[11]

UPDATED MODEL RESULTS

The research described in this article updates the 1984 JEC analysis. U.S. data for the period 1965–2000 were employed to estimate mortality rates and other health effects of changes in economic conditions. The econometric model combined four predictive factors in the explanation of U.S. mortality trends and fluctuations:

1. real GDP per capita (beneficial impact on mortality);
2. employment ratio (beneficial impact);
3. unemployment rate (harmful impact); and
4. the interaction between GDP and unemployment as coincident and lagging business-cycle indicators (harmful impact).

At the national level, the findings confirmed that the hypothesized benefits of real income per capita and employment were strong and statistically significant, while the damaging effects of increased unemployment and acute business-cycle disturbances were similarly robust and statistically significant. Figure 1 demonstrates the model's projection of U.S. mortality rates.

As in the 1984 JEC study, the upward trends in real

In sum, growth in real income per capita is the backbone of decreases in the U.S. mortality rate.

income per capita represented the most important factor in decreased U.S. mortality rates since the 1960s. Also, the unemployment rate continued to bear a significant correlation to increased mortality rates, such that an increase of 1% in the unemployment rate eventuates in an approximately 2% increase in the age-adjusted mortality rate, estimated cumulatively over at least the subsequent decade.

In sum, growth in real income per capita is the backbone of decreases in the U.S. mortality rate. There are several reasons for this. First, with respect to physical health, economic growth is fundamental in meeting basic population needs, such as nutrition, housing, health insurance,[12] medical care, sanitation, electricity, transportation, and climate control. In addition, economic growth enables increased industrial investment in pollution control technologies and safer work environments, with minimal adverse workplace exposures to chemicals, noise, and unsanitary conditions.

Year-to-year fluctuations in mortality rates are largely explained by annual changes in the behavior of variables in the model (see Figure 2). This means that a decline in the mortality rate from one year to the next (e.g., between 1981 and 1982) is related to increased real income per capita and declining unemployment rates during that same year's change (1981–1982) and the (approximately) 10 years prior to that same year's mortality decline.

State and Regional Analyses

If the economic model explaining mortality changes in the overall United States applied to all of its regions, or to a large number of states, then it would necessarily follow that the historical pattern of mortality rate changes in the regions and states would resemble one another. If true, this would be remarkable, in that there is no existing literature indicating that the trends and fluctuations in mortality rates are similar among the major regions of the United States.

Regional and state modeling to test the robustness of the national model constituted a major effort of the present analysis.

The U.S. national-level model was applied to the explanation of mortality rate changes in five populous and geographically diverse states: California, Texas, New York, Florida, and Illinois. The results were remarkably similar in that the overall U.S. model applied quite precisely to each of those five states. The model's principal predictive variables all showed statistically robust relations to the age-adjusted mortality rate. It should be pointed out that the coefficients, representing the extent of change in mortality related to changes in the economic variables, were not identical from state to state. Nevertheless, it is important to note that the same economic model described historical changes in mortality rates of states thousands of miles from one another, with vastly different economies, patterns of urbanization, and a host of lifestyle, social, and environmental factors. Similar findings resulted from application of the model to regional data for the United States.

All statistical tests traditionally used in time-series analysis, as well as the forecasting capacity of the model, demonstrate that each of the variables in the model plays a highly significant role and that the entire model is of great statistical significance. The overall results, prevalent throughout the United States, demonstrate (1) long-term declining mortality rates related to patterns of economic growth, and (2) short-term fluctuations in mortality rates associated with recessions, structural unemployment rates, and the lag of unemployment rates behind changes in real GDP per capita (a standard feature of the business cycle).

CASE STUDY: MORTALITY EFFECTS OF ENERGY SUPPLY CHANGES

The national econometric model was applied to a case study to quantify the increased mortality rate that could result from potential decreased real income per capita and increased unemployment rates due to regulatory constraints on U.S. coal utilization. Numerous policy proposals to reduce greenhouse gas emissions have called for restrictions of carbon emissions by the U.S. electricity-generating sector. [13]

Under the hypothetical scenario that coal production and related electricity generation were eliminated in favor of lower-carbon, higher-cost alternatives such as natural gas combined-cycle generation, an additional 195,000 premature deaths were estimated to occur by the year 2010 (see Table 1). This is a conservative estimate based on a tight construction of the assumptions of the future behavior of the study variables (e.g., real income per capita, unemployment rates) to 2010.

The case study used inputs from two analyses of the impacts of reduced coal utilization on U.S. income and employment data, each offering disaggregated state-level estimates of income and employment effects. Standard & Poor's DRI (1998)[14] and Rose and Yang of The Pennsylvania State University (2001)[15] used alternative macroeconomic and input–output models, respectively, to estimate the reductions of income and employment associated with large-scale displacement of coal use. The findings from these studies were scaled to approximate the effects of a hypothetical 100% replacement of coal. Thus adjusted, the estimated increased unemployment in 2010 ranged from 3.2 million (Rose and Yang) to 4.6 million jobs (DRI). The reduction in household income was estimated in a range of $166 billion (Rose and Yang, 1999$) to $363 billion (DRI, 1992$).

This upward scaling provided the basis for an assessment of policy proposals that could result in specific energy supply changes. For example, in a recent study, EIA estimates that the climate change proposals currently before the U.S. Congress could lead to the displacement of 59–78% of U.S. coal-based electricity generation by higher-cost natural gas and other alternative generation sources.[2]

The results from this hypothetical case study demonstrate that increased mortality rates would result from decreased household income and increased unemployment associated with a shift to higher cost energy supply options, absent any direct mitigation programs that effectively prevented or offset these effects. The estimated increased mortality in the year 2010, based on four different variations of the econometric model, ranges from an additional 170,507 to 368,915 deaths for the displacement of 100% of coal-based generation. A moderately conservative estimate based on an annual change model would be an additional 195,308 deaths. This point estimate has a 95% confidence interval of 193,181–197,435 individual deaths.

Given an estimated potential displacement of 78% of U.S. coal generation based on EIA's study of proposed climate

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change initiatives, the indicated premature mortality from reduced income and increased unemployment would exceed 150,000 deaths annually, absent any direct and effective mitigation programs.[3] The effects of other policy measures entailing significant, near-term disruption of energy supply markets could be estimated with a similar linear interpolation of these model results. However, the model does not reliably lend itself to estimation of mortality effects associated with relatively minor shifts in regional coal production or electricity generation (e.g., 10–15%). In many instances, such production shifts tend to be offsetting, as production decreases in one region are offset by gains elsewhere.

Effects of Lagged Relationships

The relationship between change in the economic circumstances of people's lives and their subsequent health status unfolds over time. In the case of sharp stress reactions to financial or employment catastrophes, the reaction patterns may be very rapid, that is, within a single year. This is clearly the case when suicide rates are factored in, as these rates typically rise sharply within several months of increases in national unemployment rates. Chronic diseases such as cardiovascular diseases, on the other hand, are known to respond to many different health risk factors within years, if not decades.

In addition to the potential health effects of income loss and unemployment, one has the problem of judging at what point to begin the estimation of the impact of increased unemployment. The difficulty here is that in classic analyses of business cycles, national income—specifically, GDP per capita—is a "coincident" business cycle indicator, meaning that changes in it tend to coincide with the timing of business cycles. Unemployment rates, on the other hand, are "lagging" business cycle indicators. This means that, despite even robust economic growth, during much of the initial year of recovery from a recession, unemployment rates may still remain high.

If one does not take into account these basic relationships between income and unemployment change on one hand and mortality on the other over at least a decade, it is possible to arrive at the misinterpretation that without lag there might be a negative relation between unemployment and mortality. This could imply that unemployment (in the very short term) is related to decreased mortality.[16] This type of error becomes more likely if one does not control for the usual impact of traditional risk factors on mortality, such as the effects of tobacco and saturated fat consumption on cardiovascular mortality rates over at least a decade.

In virtually all of the studies on unemployment and health, unemployment (especially long-term) is definitively associated with higher illness and mortality rates at the individual level of analysis.[17] But perhaps the most powerful evidence that economic growth is the fundamental source of life-span longevity improvement is that, as shown in the present study, the trends of decline in mortality rates across diverse states and regions of the United States are related to those in real GDP per capita cumulated for at least 10 years.

Influence of Other Health Factors

The model described here was evaluated to determine whether control for principal epidemiological risk factors to health would render the predictive variables insignificant. The result was that, while known risk factors to health, such as high consumption of tobacco, alcohol, and fatty foods, are additionally significant predictors of mortality, they are subordinate to the main economic predictors of the model that routinely influence mortality.

Since the late 1960s, increasing real income per capita in the United States is no longer positively related to consumption of tobacco, alcohol, and fatty foods. Indeed, after 1970, in the United States and much of Europe, these health risk factors ceased to be found more frequently in higher income segments of society and came to be linked instead to the lifestyles of lower socioeconomic groups. Thus, the population groups that generally have benefited least from economic growth and have been most vulnerable to problems of structural and cyclical losses of employment are most likely to suffer from the risks of dietary and addictive "lifestyle" health risks.

CONCLUSIONS

This study demonstrates the fundamental importance of sustained economic growth to health and improved life span for the U.S. population. The technological bases of long-term economic growth continue to involve the harnessing of energy supplies to enable humans to produce more per unit of labor or capital investment. The economic growth that continuously improves human life expectancy requires access to affordable energy. In this fundamental sense, any policy change that reduces growth or raises the level of unemployment should therefore be defined and addressed as a public health issue requiring an economic policy response that limits or offsets these results. The implication of the research described in this article provides an important basis for future studies of energy and health. **em**

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13. For example, S.139 calls for a two-phase reduction of U.S. carbon dioxide emissions, achieving stabilization of emissions at 2000 levels by 2010, and a return to 1990 emission levels by 2020. The scaled-down version of this bill (S.A. 2028) rejected by the U.S. Senate in 2003 sought to achieve stabilization of carbon emissions at 2000 levels by 2010.
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Attachment 4

to
CEED COMMENTS

Summary of Rose & Wei Research

Electricity from coal:
Powering our energy future

A report on research by Dr. Adam Rose,
Professor of Energy, Environment and Regional Economics
and Dan Wei, Graduate Research Assistant,
The Pennsylvania State University

Economic Impacts of Coal Utilization and Displacement in the Continental United States, 2015 (July 2006)

Electricity from coal:
Powering our energy future

For decades, Americans took affordable energy for granted. Recent energy price increases are now squeezing family budgets and reducing income available for food, medical care, and other necessities.

Today, over half of the electricity generated in the U.S. comes from coal. Coal is an abundant domestic energy resource, with enough proven reserves to last 250 years at current rates of usage. Even in an era of rising energy costs, coal-fueled electric power remains one of the lowest-cost sources of energy for consumers and industries.

Economic benefits of coal use

In their 2006 study, *Economic Impacts of Coal Utilization and Displacement in the Continental United States*, Professor Adam Rose and Dan Wei of Pennsylvania State University examine the prospective effects of coal-generated electricity on state economies. Their study estimates that coal will add more than $1 trillion to U.S. economic output in 2015, along with 4.6 to 9.0 million jobs.

Using coal to generate electricity provides affordable energy to millions of Americans. Coal will add more than $1 trillion to the U.S. economy in 2015.

The Penn State study also considers the potential adverse economic consequences of reduced coal utilization on state and regional economies. Policies restricting coal use, such as proposed government-mandated measures to reduce greenhouse gas emissions, could cost millions of jobs and reduce family incomes by billions of dollars annually as a direct result of higher energy costs. For the first time in a study of this type, the positive offsetting benefits of alternative investments in natural gas and renewable energy sources, such as wind and biomass, were factored into the calculations.

Using a range of future energy price projections, the economists estimated that U.S. coal-based electricity generation in 2015 will provide:

- ✓ $714 billion to $1.38 trillion in increased economic output;
- ✓ $242 to $482 billion in increased household earnings; and
- ✓ 4.6 to 9.0 million additional U.S. jobs.

These significant benefits reflect the close interdependence of major segments of the U.S. economy. Because virtually all businesses rely on electricity to produce and sell goods and services, the economic power of coal-based energy extends far beyond the generation and sale of electricity. The availability of low-cost electricity produces powerful ripple effects that benefit the American economy as a whole.

Because reliance on coal as a fuel source for generating electricity varies from region to region, the economic benefits are not evenly spread across the U.S.

Even though electricity costs vary from state to state, coal-generated electricity is among the lowest-cost power produced in the U.S. The consumer cost-savings realized from using coal to generate electricity increase the disposable incomes of working families. This income, when used to buy other goods and services, creates additional economic benefits.

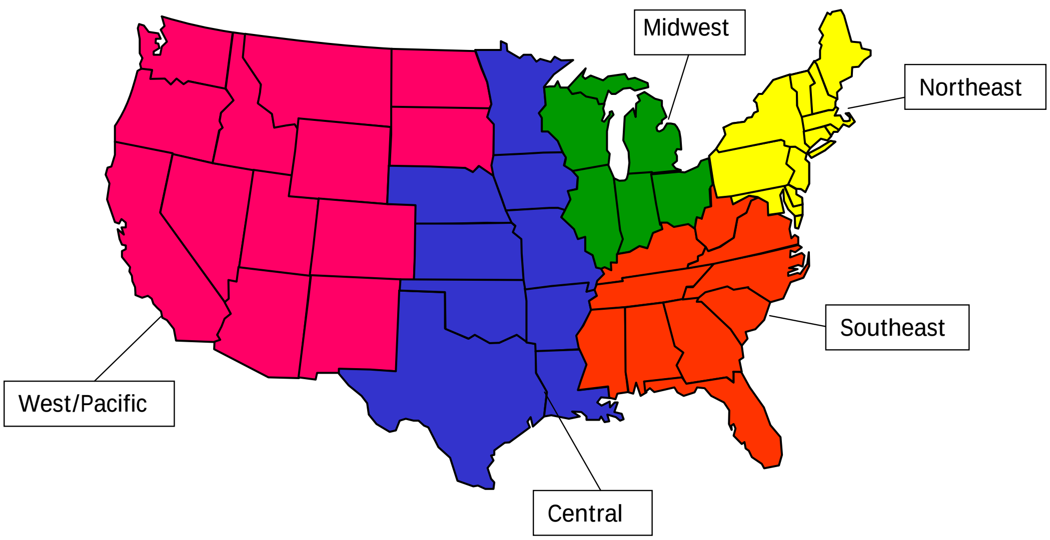
The study assessed three cases

Rose and Wei developed three cases to estimate the economic benefits of coal utilization and the potential costs of displacing coal using higher cost energy sources. The first case measures the overall "existence value" of coal by estimating the economic effects of completely replacing U.S. coal-based electric generation with higher-cost alternative fuels. The "existence value" case is intended to measure the aggregate economic and job benefits that the availability of coal-based electricity provides to the U.S. economy as a low-cost energy source.

Rose and Wei then simulated cases where alternative energy supplies (including natural gas, nuclear, and a 10 percent mix of renewables) displace coal-based electricity generation at levels of *66 percent* and *33 percent*. The two displacement scenarios utilize low, high, and average alternative energy cost projections.

They then divided the nation into five regions and calculated results for the three cases at state and regional levels. Rose and Wei found that, for all five regions – and for nearly every state individually – displacement of coal at these levels would have net negative economic impacts *even factoring in the positive offsetting multiplier impacts of replacement fuels and technologies*.

Penn State Study Regions



Regional results are summarized in the following table based on averages of the study's low and high energy price projections. These results show the overall <u>benefits</u> of the availability of coal as a low-cost electric energy resource along with the potential net <u>costs</u> of displacing coal-based power with higher-cost energy sources.

Summary of Penn State study results
(Billions of 2005 $ and millions of jobs)

Region	Overall coal generation benefits	Net costs of 33% coal displacement	Net costs of 66% coal displacement
Northeast			
Economic Output	$105	-$18	-$39
Household Income	$40	-$7	-$16
Jobs	0.6	-0.1	-0.3
Southeast			
Economic Output	$238	-$30	-$68
Household Income	$80	-$12	-$27
Jobs	1.6	-0.3	-0.6
Midwest			
Economic Output	$304	-$54	-$120
Household Income	$101	-$19	-$43
Jobs	1.8	-0.3	-0.7
Central			
Economic Output	$227	-$39	-$85
Household Income	$78	-$15	-$32
Jobs	1.5	-0.3	-0.6
West			
Economic Output	$174	-$25	-$59
Household Income	$63	-$10	-$24
Jobs	1.2	-0.2	-0.5
48 States			
Economic Output	$1,047	-$166	-$371
Household Income	$362	-$64	-$142
Jobs	6.8	-1.2	-2.8

Tables 1, 2, and 3 (see pages 7-9) provide state-by-state results for the three cases, based on an average of the study's low and high energy price projections.

The study concludes that coal-based electricity provides substantial economic benefits for large and small states alike. For example, Illinois, Indiana, Ohio, Texas, and Pennsylvania *each* stand to benefit from $42 billion to $84 billion in increased economic output because of using coal-based electricity. Smaller states also share in the advantages: New Hampshire, Connecticut, South Carolina, Oregon, and South Dakota are *each* projected to gain between $1 billion and $7 billion in expanded annual output.

In *all* states, there was a negative net effect from displacing coal-based electricity under the high-price scenario. In nearly all states, the net effect was negative even under the low-price scenario.

The Penn State research also demonstrates that states that rely on coal for a substantial portion of electric generation, but do not produce coal, obtain significant benefits. For example, North Carolina and Georgia stand to realize $31 billion and $39 billion in higher state economic output, respectively, because of coal-based generation. California, which relies on "coal-by-wire" (imported electricity generated in other western states) for about 20% of its electricity, will gain $58 billion in increased state output. These results largely reflect the beneficial price differential effects of low-cost coal generation on state economies.

The study provides empirical proof of substantial economic advantages created by coal-based electricity, and the potential costs of displacing coal with higher-cost energy supplies.

Coal provides a balanced energy future

The Penn State study provides empirical proof of the substantial economic advantages created by the coal-fueled electricity industry. Low-cost electricity from coal is a mighty economic engine that powers a growing American economy and empowers millions of American consumers and businesses.

The Penn State research was supported by a grant from the Center for Energy and Economic Development (CEED). CEED believes that the lesson from this research is simple: *electricity from coal is the key to a balanced energy portfolio*. Thanks to advances in technology, CEED also believes that Americans will not have to choose between affordable and reliable electricity or a clean environment. When it comes to electricity from coal, America can have both.

Study methodology

In *The Economic Impacts of Coal Utilization and Displacement in the Continental United States, 2015*, Pennsylvania State University's Adam Z. Rose and Dan Wei use the IMPLAN input-output model to estimate the direct and indirect economic multiplier effects of coal-based electricity generation. Projecting to the year 2015, the study provides state-by-state estimates of the economic output, household income, and jobs attributable to electricity generated using coal.

The study also estimates the effect of higher electricity prices on state economies in the event that utilities switch from coal to more costly alternatives, such as natural gas or renewables. In examining these impacts, the study's authors examine two scenarios, one in which alternative fuels displace 33 percent of projected production and utility consumption of coal. Another assumes 66 percent displacement. The mix of replacement energy sources varies by region, reflecting projected patterns of electricity generation. All cases assume that renewable energy alternatives such as wind and biomass account for 10 percent of state generation portfolios. Summary results are displayed in Tables 1-3, based on an average of the study's low and high energy price projections. The high and low price results for all three cases are reported in the full study.

Rose and Wei's model is based on *minimum backward linkages* plus *price differential impacts*.

A demand-side multiplier provides the backward linkage. It encompasses all direct and indirect inputs of materials, labor, and equipment for coal-based generation, coal production, and coal transportation. It also takes into account increased government expenditures that result from growing tax revenues which, in turn, further enhance the multiplier effect of coal-based electricity.

The price differential impacts measure the effects of higher electricity prices on state economies based on a conservative estimate of the price elasticity of demand for electricity.

A copy of the full Penn State study is available online at:
http://www.ceednet.org/ceed/index.cfm?cid=7505

Table 1.
Economic benefits due to coal-based generation, 2015
(Mid-range estimates in billions of 2005 $ and thousands of jobs)

State	Economic output ($Bil.)	Household income ($Bil.)	Jobs (000)
Alabama	$16.3	$5.2	101.2
Arizona	$12.8	$4.4	86.0
Arkansas	$5.2	$1.6	35.6
California	$58.4	$21.9	338.8
Colorado	$19.0	$6.9	109.4
Connecticut	$2.8	$1.1	15.2
Delaware	$4.6	$1.5	27.9
Florida	$26.6	$9.8	218.7
Georgia	$38.9	$13.6	242.6
Illinois	$66.5	$25.4	328.5
Indiana	$66.3	$20.0	410.3
Iowa	$21.7	$6.6	157.4
Kansas	$26.3	$8.6	194.0
Kentucky	$49.3	$16.2	340.3
Louisiana	$11.3	$4.4	99.2
Maine	$0.4	$0.1	3.4
Maryland	$18.9	$8.4	132.1
Massachusetts	$8.7	$3.4	47.2
Michigan	$54.8	$17.6	292.9
Minnesota	$32.6	$11.4	201.0
Mississippi	$5.5	$1.9	45.7
Missouri	$47.0	$16.6	317.1
Montana	$4.5	$1.5	44.1
Nebraska	$19.6	$6.9	95.0
Nevada	$7.7	$3.0	69.2
New Hampshire	$1.3	$0.4	8.3
New Jersey	$10.1	$3.9	53.0
New Mexico	$14.4	$5.5	131.6
New York	$16.3	$6.4	81.6
North Carolina	$30.8	$10.0	217.4
North Dakota	$8.5	$2.7	64.2
Ohio	$83.7	$27.1	528.0
Oklahoma	$16.9	$5.8	132.4
Oregon	$1.5	$0.5	11.7
Pennsylvania	$42.0	$14.3	263.9
South Carolina	$7.2	$2.3	49.1
South Dakota	$2.6	$0.8	18.5
Tennessee	$27.7	$9.2	172.7
Texas	$46.4	$16.4	289.5
Utah	$32.4	$11.8	245.6
Virginia	$14.3	$5.6	90.3
Washington	$4.8	$1.8	28.9
West Virginia	$20.9	$6.8	160.6
Wisconsin	$32.6	$10.6	216.8
Wyoming	$7.1	$2.5	55.5
Total	$1,047	$362	6,800

Table 2.
Net economic costs of 33% coal generation displacement, 2015
(Mid-range estimates in billions of 2005 $ and thousands of jobs)

State	Economic output ($Bil.)	Household income ($Bil.)	Job losses (000)
Alabama	-$1.6	-$0.6	-14.7
Arizona	-$0.6	-$0.4	-7.5
Arkansas	-$0.2	-$0.1	-3.0
California	-$10.0	-$4.1	-65.3
Colorado	-$4.0	-$1.7	-27.5
Connecticut	-$0.5	-$0.2	-2.7
Delaware	-$0.7	-$0.2	-4.6
Florida	-$2.6	-$1.2	-32.6
Georgia	-$5.6	-$2.2	-41.3
Illinois	-$14.5	-$6.0	-73.0
Indiana	-$8.2	-$2.7	-55.9
Iowa	-$3.3	-$1.1	-27.7
Kansas	-$5.2	-$1.8	-43.6
Kentucky	-$3.9	-$1.6	-35.2
Louisiana	-$1.5	-$0.7	-17.1
Maine	-$0.1	Negl.	-0.4
Maryland	-$3.8	-$1.9	-30.6
Massachusetts	-$1.0	-$0.4	-6.0
Michigan	-$11.6	-$3.8	-64.4
Minnesota	-$8.5	-$3.1	-54.5
Mississippi	-$0.6	-$0.3	-6.9
Missouri	-$8.7	-$3.4	-63.2
Montana	-$0.4	-$0.2	-6.2
Nebraska	-$5.1	-$1.9	-24.9
Nevada	-$1.0	-$0.5	-2.2
New Hampshire	-$0.1	Negl.	-0.9
New Jersey	-$2.1	-$0.8	-11.5
New Mexico	-$1.3	-$0.6	-17.2
New York	-$2.4	-$1.1	-13.2
North Carolina	-$5.2	-$1.9	-44.0
North Dakota	Negl.	Negl.	-10.6
Ohio	-$14.2	-$4.8	-95.1
Oklahoma	-$0.5	-$0.3	-9.6
Oregon	-$0.2	-$0.1	-1.9
Pennsylvania	-$7.0	-$2.6	-50.3
South Carolina	-$0.7	-$0.3	-7.0
South Dakota	-$0.3	$163	-1.9
Tennessee	-$6.7	-$2.3	-43.9
Texas	-$6.2	-$2.5	-47.5
Utah	-$5.8	-$2.2	-45.8
Virginia	-$2.8	-$1.3	-21.0
Washington	-$1.0	-$0.4	-6.4
West Virginia	-$0.1	-$0.1	-5.5
Wisconsin	-$5.7	-$1.9	-40.4
Wyoming	-$0.3	-$0.3	-6.1
Total	-$166	-$64	-1,200

Table 3.
Net economic costs of 66% coal generation displacement, 2015
(Mid-range estimates in billions of 2005 $ and thousands of jobs)

State	Economic output ($Bil.)	Household income ($Bil.)	Job losses (000)
Alabama	-$3.6	-$1.5	-33.4
Arizona	-$1.7	-$0.9	-18.6
Arkansas	-$0.3	-$0.2	-5.4
California	-$22.9	-$9.3	-148.3
Colorado	-$6.4	-$2.8	-45.8
Connecticut	-$1.0	-$0.4	-6.3
Delaware	-$1.7	-$0.6	-11.2
Florida	-$5.4	-$2.6	-69.4
Georgia	-$12.7	-$5.0	-93.4
Illinois	-$31.0	-$12.8	-156.2
Indiana	-$19.9	-$6.5	-135.1
Iowa	-$7.6	-$2.4	-62.6
Kansas	-$10.9	-$3.8	-90.8
Kentucky	-$10.4	-$4.2	-90.6
Louisiana	-$3.3	-$1.6	-38.4
Maine	-$0.1	Negl.	-1.1
Maryland	-$8.3	-$4.1	-65.8
Massachusetts	-$2.6	-$1.1	-15.6
Michigan	-$25.0	-$8.3	-138.1
Minnesota	-$17.3	-$6.3	-111.0
Mississippi	-$1.3	-$0.6	-14.9
Missouri	-$19.0	-$7.3	-137.1
Montana	-$1.3	-$0.5	-16.6
Nebraska	-$10.7	-$4.0	-52.2
Nevada	-$2.5	-$1.1	-18.0
New Hampshire	-$0.3	-$0.1	-2.3
New Jersey	-$4.6	-$1.8	-25.4
New Mexico	-$3.4	-$1.6	-43.7
New York	-$5.7	-$2.5	-30.9
North Carolina	-$11.1	-$4.0	-93.2
North Dakota	-$1.7	-$0.6	-26.0
Ohio	-$31.4	-$10.7	-210.3
Oklahoma	-$1.9	-$1.1	-27.4
Oregon	-$0.5	-$0.2	-4.6
Pennsylvania	-$15.1	-$5.6	-108.3
South Carolina	-$1.3	-$0.5	-13.5
South Dakota	-$0.7	-$0.2	-5.1
Tennessee	-$13.3	-$4.7	-88.0
Texas	-$13.6	-$5.5	-105.8
Utah	-$14.1	-$5.3	-111.7
Virginia	-$5.4	-$2.6	-40.8
Washington	-$2.1	-$0.9	-13.9
West Virginia	-$3.0	127.3	-32.6
Wisconsin	-$12.8	-$4.4	-91.1
Wyoming	-$1.8	-$0.9	-19.8
Total	-$371	-$142	-2,800

Prepared by:

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July 2006

Attachment 5

to
CEED COMMENTS

Rose & Wei Paper

The Economic Impacts of Coal Utilization and Displacement in the Continental United States, 2015

by

Adam Z. Rose, Ph.D. and Dan Wei

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Report Prepared for
The Center for Energy and Economic Development, Inc.
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The Economic Impacts of Coal Utilization and Displacement
in the Continental United States, 2015

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The Economic Impacts of Coal Utilization and Displacement in the Continental United States, 2015

by

Adam Z. Rose, Ph.D., and Dan Wei[1]

Executive Summary

Our analysis shows that, in 2015, U.S. coal production, transportation and consumption for electric power generation will contribute more than $1 trillion (2005 $) of gross output directly and indirectly to the economy of the lower-48 United States. Based on an average of two energy price scenarios summarized below, we calculate that $362 billion of household income and 6.8 million U.S. jobs will be attributable to the production, transportation and use of domestic coal to meet the nation's electric generation needs.

The United States relies heavily on coal to produce electric power. Domestic coal production has expanded from 560 million tons in 1950 to 1.13 billion tons in 2005, while coal consumption for electric generation has increased from 92 million tons to 1.04 billion tons in this period. Historically, coal has provided the lowest cost source of fossil energy in the U.S. Electricity is one of the most prominent commodities traded in the United States, second only to food in annual sales volume.

We based our analysis on state-specific "IMPLAN" input-output tables -- a widely utilized source of data on the composition of state economic activity -- to estimate the basic direct and indirect "multiplier" effects of coal utilization for electric generation. These multiplier effects include the economic impacts of coal mining and of government spending of taxes paid by coal mining for electricity generation, by companies that transport coal, and by coal-fueled electricity generation companies. We calculated results at the state level and compiled regional summaries by dividing the nation into five geographic regions (see Figure S1, below).

The study first presents estimates of the positive economic output, household income, and jobs attributable to projected levels of coal production and utilization in 2015. We used a 2015 base case because electric generation and other projections for this year were readily available from U.S. DOE and U.S. EPA. These estimates measure the "existence" value of coal as the key fuel input into U.S. electricity generation. The analysis includes estimates of the impact of higher electricity rates on individual state economies if utilities were required to utilize fuel sources and generating technologies more costly than coal-based electricity.

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Two Basic Scenarios

Our first scenario includes backward linkage, or demand-side multiplier, effects for coal-fueled electricity generation. Tax payments from coal production, utilization, and transportation subsequently result in government expenditures, which also generate multiplier effects. The analysis also includes the impacts of the favorable price differential attributable to coal-based electricity. This calculation measures the economic activity attributable to relatively cheaper coal in contrast to more expensive alternatives at upper-range ("high") prices for alternative generation sources.

Our second scenario is the same as the first in terms of backward linkages, but we calculated the price differential effects on the basis of lower-range estimates of the prices of alternative fuels and technologies.

The study relied on U.S. DOE Energy Information Administration (DOE/EIA) and other projections of electric generation and delivered coal prices to estimate the impact on energy prices of replacing 100% of projected coal-fueled electricity generation. We estimated the impact of higher energy prices on state economies using a price elasticity estimate of 0.10, meaning that a 10% change in energy costs would induce a 1.0% change in state economic output.

Regional results of the basic "Coal Existence" scenarios are summarized in Table S1 below. Assigning equal weight to each of the two energy price scenarios, we estimate that U.S. coal-fueled electric generation in 2015 will contribute:

- **$1.05 trillion (2005 $) in gross economic output;**
- **$362 billion in annual household incomes, and**
- **6.8 million jobs.**

We also estimated the prospective net economic impacts of the "displacement" of coal-fueled electricity generation at assumed levels of 66% and 33% from a projected 2015 base. These levels of displacement are consistent with some of the potential impacts of major environmental policy initiatives in climate change or other areas. In these cases, we again calculated backward linkage and price differential effects to determine potential negative impacts on each state's economy. Additionally, we calculated potential positive economic benefits due to the operation of replacement electricity generation of various types. In all states, the net effect of displacing coal-based electricity was negative for the "high-price" scenarios, and in nearly all states, the net effect was negative for the "low-price" scenarios.

Regional results of the "Displacement/Replacement" scenarios are presented in Tables S2 and S3. Assigning equal weight to the high- and low-price scenarios, we estimate the average impacts of displacing 66% of coal-fueled generation in 2015 at:

- **$371 billion (2005 $) reduction in gross economic output;**
- **$142 billion reduction of annual household incomes; and**
- **2.7 million job losses.**

Assigning equal weight to the high- and low-price scenarios, we estimate the average impacts of displacing 33% of coal-based generation in 2015 at:

- **$166 billion (2005 $) reduction in gross economic output;**
- **$64 billion reduction of annual household incomes; and**
- **1.2 million job losses.**

These findings are discussed in more detail in the state and regional analyses of the main report. Appendix C contains detailed state and regional results for each of the three displacement cases, including alternative impact estimates for the low and high energy price scenarios.

Figure S1
U.S. Regions Analyzed

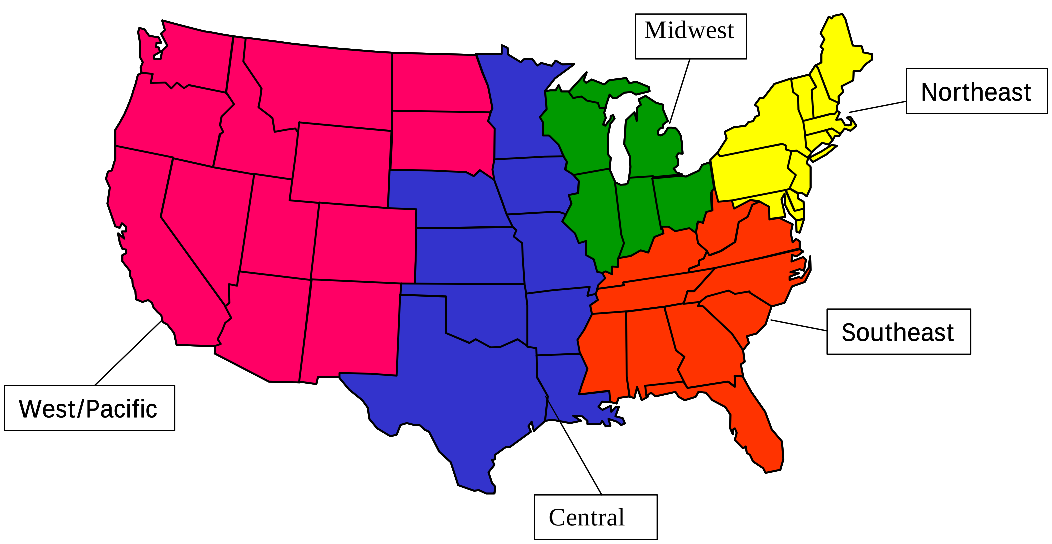

Table S1
Regional Summary of the "Existence" Value of U.S. Coal Utilization in Electric Generation, 2015
(in billions of 2005 dollars and millions of jobs)

Region	*High-Price Alternatives*	*Low-Price Alternatives*	*Average*
Southeast			
Output	$309	$166	$238
Earnings	$106	$55	$80
Jobs	2.2	1.1	1.6
Northeast			
Output	$145	$65	$105
Earnings	$56	$24	$40
Jobs	0.9	0.4	0.6
Midwest			
Output	$409	$199	$304
Earnings	$137	$65	$101
Jobs	2.4	1.2	1.8
Central			
Output	$305	$149	$227
Earnings	$106	$50	$78
Jobs	2.1	1.0	1.5
West			
Output	$213	$135	$174
Earnings	$78	$48	$63
Jobs	1.5	0.9	1.2
48 States			
Output	$1,381	$714	$1047
Earnings	$482	$242	$362
Jobs	9.0	4.6	6.8

Table S2
Regional Summary of the Net Economic Costs of 66% Displacement of Coal-fueled Electric Generation in the U.S., 2015
(in billions of 2005 dollars and millions of jobs)

Region	*High-Price Alternatives*	*Low-Price Alternatives*	*Average*
Southeast			
Output	$116	$20	$68
Earnings	$44	$10	$27
Jobs	0.9	0.2	0.6
Northeast			
Output	$66	$13	$39
Earnings	$27	$6	$16
Jobs	0.4	0.1	0.3
Midwest			
Output	$189	$51	$120
Earnings	$67	$19	$43
Jobs	1.1	0.3	0.7
Central			
Output	$136	$33	$85
Earnings	$51	$14	$32
Jobs	1.0	0.3	0.6
West			
Output	$86	$33	$59
Earnings	$34	$14	$24
Jobs	0.7	0.3	0.5
48 States			
Output	$594	$148	$371
Earnings	$223	$62	$142
Jobs	4.2	1.2	2.8

Table S3
Regional Summary of the Net Economic Costs of 33% Displacement of Coal-fueled Electric Generation in the U.S., 2015
(in billions of 2005 dollars and millions of jobs)

Region	*High-Price Alternatives*	*Low-Price Alternatives*	*Average*
Southeast			
Output	$55	$5	$30
Earnings	$21	$3	$12
Jobs	0.4	0.07	0.3
Northeast			
Output	$31	$4	$18
Earnings	$13	$2	$7
Jobs	0.2	0.03	0.1
Midwest			
Output	$89	$19	$54
Earnings	$31	$7	$19
Jobs	0.5	0.1	0.3
Central			
Output	$66	$13	$39
Earnings	$24	$5	$15
Jobs	0.5	0.1	0.3
West			
Output	$39	$11	$25
Earnings	$16	$5	$10
Jobs	0.3	0.1	0.2
48 States			
Output	$279	$52	$166
Earnings	$105	$23	$64
Jobs	2.0	0.4	1.2

The Economic Impacts of Coal Utilization and Displacement in the Continental United States, 2015

by

Adam Z. Rose, Ph.D. and Dan Wei*

I. Introduction

This study projects the extent of the likely impacts of coal utilization for electricity generation on the economies of the forty-eight contiguous states in the year 2015. The projection period covers both current coal-related economic benefits and those that may result from the construction of new coal-fueled electric generating capacity.

We first estimate the overall economic benefits associated with the availability of coal as a relatively low-cost fuel resource. This "existence" value reflects the increased economic output, earnings, and employment associated with projected coal utilization for electric generation in 2015. We also estimate the net economic impacts of displacing 33% and 66% of projected coal generation by alternative energy resources, taking into account the positive economic effects associated with alternative investments in oil/gas, nuclear, and renewable energy supplies.

We performed our analysis with the aid of an interindustry, or input-output, model. Specifically, we analyzed how coal-based electric generation affects production (output), household income, and employment in other sectors of each state and the continental U.S. as a whole under three alternative displacement scenarios. Our results indicate that the combination "multiplier" and "price-differential" effects are sizeable, amounting to $1.05 trillion ($2005) in total 48-state economic output for the "existence" of coal as a relatively inexpensive fuel for electricity generation. The results illustrate that government policies and private industry decisions affecting coal-based electric generation potentially can affect every major aspect of the American economy.

The methodology underlying the study is summarized in Section II below, as well as in Appendix A, which also presents major assumptions and some basic computations underlying the analysis. The results for the five regions analyzed are summarized in Section III, with tables of basic data presented in Appendix B and simulation results presented in Appendix C.

We simulated cases where coal-based electricity generation is displaced at levels of 66% and 33% by alternative energy supplies, including natural gas, nuclear, and a 10% mix of renewables, reflecting potential Renewable Portfolio Standards (RPS) that could be in place by 2015. The results indicate that for the nation, and for nearly every state individually, this displacement -- even factoring in positive offsetting multiplier impacts of replacement fuels and technologies -- would have a net negative economic impact. We project that national gross output would decline by $371 billion for the 66% case, and by $166 billion for the 33% case.

II. Methodology

A. Measuring Economic Interdependence

With a broad base and high level of technological advancement, the U.S. economy exhibits a great deal of interdependence. Each business enterprise relies on many others for inputs into its production process and provides inputs to them in return. This means that the coal and coal-based electric utility industries' contributions to the nation's economy extend beyond their own production to include demand arising from a succession of "upstream" inputs from their suppliers and "downstream" deliveries to their customers. The economic value of these many rounds of derived demands and commodity allocations is some multiple of the value of direct production itself. Hence, the coal and coal-based electric utility industries generate "multiplier" effects throughout the U.S. economy.

The first round of demand impacts is obvious--the direct inputs to electricity generation, including coal and primary factors (labor and capital). Subsequent rounds, or indirect demands for goods and services used by the providers of these inputs, however, thread their way through the economy in subtle ways, eventually stimulating every other sector in some way. Likewise, they generate income that is transformed into consumer spending on still more products. All of this economic activity also generates local, state, and federal tax revenues, which, when spent by all three levels of government, creates still more multiplier effects.[1]

B. Measuring Locational Attractiveness

We omitted forward linkages, or supply-side multipliers, from our analysis in this study in contrast to the one performed by Rose and Yang (2002). The premise of the supply-side multiplier is that economic activity is stimulated by "locational attractiveness" characteristics for a state or region, such as the availability of relativity inexpensive coal-fueled electricity. This effect has been documented for electricity and other key inputs (see Blair and Premus, 1987). However, the supply-side multiplier has received significant criticism (cf. Oosterhaven, 1988; Rose and Allison, 1989). The main criticism is that this form of multiplier represents a further extension of a discredited economic theory called Say's Law, which states that supply creates its own demand.[2] Therefore, we omitted supply-side impacts from this study.

Another way to capture the locational attractiveness of a good or service is not to claim the entirety of output of its direct and indirect users, but only an amount relating to the price advantage of the input over its competitors. In this case, we calculate a "price differential" between coal and alternative fuels in electricity production, and then calculate how much economic activity is attributable to this cost saving. For this purpose, we use an economy-wide elasticity of output with respect to energy prices. This measures the percentage change in economic activity with respect to a 1.0 percent change in price. We analyzed a variety of sources of information to arrive at a value of 0.10, meaning that the availability of coal-fueled electricity at a price 10 percent lower than that of its nearest competitor is responsible for increasing total state or regional economic activity by 1.0 percent (see, e.g., Anderson 1982; Hewson and Stamberg, 1996).[3]

III. Economic Impacts of Coal on State and Regional Economies, 2015

To assess the importance of coal to state and regional economies in 2015, we first estimated the level of coal-based electricity generation in each state in 2015 based on projections by DOE/EIA (2006) and EPA (2005). We also assumed that the technological structure of the economy, embodied in individual state input-output tables, would remain unchanged over the projection period to 2015.

We evaluated coal-related impacts according to various assumptions embodied in our scenarios (see Appendix B for further explanation of assumptions).

Scenario Set 1: <u>"Coal Existence" Scenarios</u>

This set of scenarios calculates the positive regional economic output, household income, and jobs attributable to the projected levels of coal-fueled electricity in 2015. These scenarios estimate the "existence" value of coal as the key fuel input into electricity generation in the U.S. The economic impacts of coal that we calculated include two components: 1) the backward linkage, or demand-side multiplier, effects for coal-fueled electricity generation, and 2) the effects of the favorable price differential attributable to the relatively cheaper cost of coal-based electricity.

We first use the 2002 IMPLAN input-output tables to estimate the direct and indirect (multiplier) economic output, household income, and jobs created by coal-fueled electricity generation in each state. In this study, we measure only the minimum backward linkage effects for the "multiplier" effects. This method excludes all forward linkages (all the production that uses coal-fueled electricity directly or indirectly) and focuses only on the factor inputs of coal-based electricity generation, such as fuel and electric generating equipment.

Tax payments from coal mining, coal transportation services, and coal-fueled electricity generation result in government expenditures, which also generate multiplier effects of the conventional demand-driven type. We calculated total personal income and employment impacts of government expenditures by multiplying these total sectoral output changes by their corresponding income and employment coefficients, rather than by direct application of multipliers.

We then evaluated the impacts of a favorable price differential attributable to coal-based electricity. Essentially, we are measuring the economic activity attributable to relatively cheaper coal in contrast to what would take place if a state were dependent on more expensive alternatives, which we assume would be a combination of oil/gas, renewable, and nuclear electricity. Here we perform two calculations: 1) an upper-range ("high") price scenario, and 2) a lower-range ("low") price scenario. These two scenarios have the same backward linkages effects, but different price differential effects based on their different energy price assumptions. We estimated the impact of higher electricity prices on state economies using a price elasticity estimate of 0.10, meaning that a 10% differential in electricity prices causes a 1.0% change in regional economic activity.

Finally, we assigned equal weight to each of the two price scenarios to obtain the average "existence" impacts of coal-fueled electricity generation in 2015. The results of this set of scenarios for each state and region in the year 2015 are presented in the summary tables in Appendix C. An example of the detailed derivation of the price differential effect is presented in Appendix Table B2.

Table 1 summarizes our regional findings for the "existence" value of coal in 2015 for the low and high energy price scenarios, as well as an average of the two price scenarios.

Table 1
Regional Summary of the "Existence" Value of U.S. Coal Utilization in Electric Generation, 2015
(in billions of 2005 dollars and millions of jobs)

Region	*High-Price Alternatives*	*Low-Price Alternatives*	*Average*
Southeast			
Output	$309	$166	$238
Earnings	$106	$55	$80
Jobs	2.2	1.1	1.6
Northeast			
Output	$145	$65	$105
Earnings	$56	$24	$40
Jobs	0.9	0.4	0.6
Midwest			
Output	$409	$199	$304
Earnings	$137	$65	$101
Jobs	2.4	1.2	1.8
Central			
Output	$305	$149	$227
Earnings	$106	$50	$78
Jobs	2.1	1.0	1.5
West			
Output	$213	$135	$174
Earnings	$78	$48	$63
Jobs	1.5	0.9	1.2
48 States			
Output	$1,381	$714	$1047
Earnings	$482	$242	$362
Jobs	9.0	4.6	6.8

Scenario Set 2: <u>66% "Coal Displacement/Replacement" Scenarios</u>

In this set of scenarios, we calculate the net economic impacts of "displacement" of coal-based electricity generation at a level of 66% from the projected 2015 level, and "replacement" by alternative fuel sources and generating technologies. We calculated both the backward linkage and price differential effects as in the "Coal Existence" scenarios. However, in contrast to the first set of scenarios, which only calculate the backward linkage multiplier effects of coal-fueled generation, we include the positive economic impacts due to the operation of replacement electricity generation of various types, i.e., gas/oil-fueled electricity, nuclear electricity, and an electricity generation mix from renewables.

For the 66% coal displacement/replacement level, we perform one scenario that calculates the price differential effects based on upper-range price assumptions. The second scenario has the same backward linkage multiplier effects on both the displacement and replacement sides, but price differential effects based on lower-range price assumptions.

We again assign equal weight to each of these two scenarios. The detailed state and regional results of this set of scenarios for the year 2015 are presented in Appendix C. Table 2 summarizes regional results for the 66% displacement cases.

Table 2
Regional Summary of the Net Economic Costs of 66% Displacement of Coal-fueled Electric Generation in the U.S., 2015
(in billions of 2005 dollars and millions of jobs)

Region	*High-Price Alternatives*	*Low-Price Alternatives*	*Average*
Southeast			
Output	$116	$20	$68
Earnings	$44	$10	$27
Jobs	0.9	0.2	0.6
Northeast			
Output	$66	$13	$39
Earnings	$27	$6	$16
Jobs	0.4	0.1	0.3
Midwest			
Output	$189	$51	$120
Earnings	$67	$19	$43
Jobs	1.1	0.3	0.7
Central			
Output	$136	$33	$85
Earnings	$51	$14	$32
Jobs	1.0	0.3	0.6
West			
Output	$86	$33	$59
Earnings	$34	$14	$24
Jobs	0.7	0.3	0.5
48 States			
Output	$594	$148	$371
Earnings	$223	$62	$142
Jobs	4.2	1.2	2.8

Scenario Set 3: <u>33% "Coal Displacement/Replacement" Scenarios</u>

In this set of scenarios, we calculate the impacts of "displacement" of coal-based electricity generation by 33% from the projected 2015 level, and its "replacement" by alternative generating technologies. The methodologies of calculating the backward linkage multiplier effects and the price differential effects (again, one scenario for the high-price case and one scenario for the lower-price case) are similar to the 66% “Coal Displacement/Replacement” scenarios.

The state and regional results of this set of scenarios are presented in Appendix C. Summary results for the five U.S. regions are shown in Table 3.

Table 3
Regional Summary of the Net Economic Costs of 33% Displacement of Coal-fueled Electric Generation in the U.S., 2015
(in billions of 2005 dollars and millions of jobs)

Region	*High-Price Alternatives*	*Low-Price Alternatives*	*Average*
Southeast			
Output	$55	$5	$30
Earnings	$21	$3	$12
Jobs	0.4	0.07	0.3
Northeast			
Output	$31	$4	$18
Earnings	$13	$2	$7
Jobs	0.2	0.03	0.1
Midwest			
Output	$89	$19	$54
Earnings	$31	$7	$19
Jobs	0.5	0.1	0.3
Central			
Output	$66	$13	$39
Earnings	$24	$5	$15
Jobs	0.5	0.1	0.3
West			
Output	$39	$11	$25
Earnings	$16	$5	$10
Jobs	0.3	0.1	0.2
48 States			
Output	$279	$52	$166
Earnings	$105	$23	$64
Jobs	2.0	0.4	1.2

IV. Conclusion

Coal-based electricity generation provides a significant stimulus to the U.S. economy by increasing output, income, and employment in all sectors through direct and indirect (multiplier) effects. It also increases the purchasing power of the consumer, and enhances the competitiveness of U.S. exports, by avoiding increased reliance on higher-priced fuels and electricity-generating technologies. Even when we take into account the positive economic effects of capital investments and operation of alternative energy generation sources, the replacement of coal-based electricity by relatively more expensive fuels or generating technologies would have a net negative economic impact on every region and on nearly every state. In general, these results reflect the large economic benefits associated with coal's favorable price differential effect relative to alternative fuels.

Note on Study Scope and Limitations

Our analysis is not intended to measure the impacts of any specific policy that could result in decreased coal production or utilization. The impacts of specific policy proposals on coal production and related electric generation should be determined on a case-by-case basis. However, the findings of our coal displacement scenarios provide preliminary insights into the potential magnitude of state, regional and national economic impacts of policy initiatives that could result in significant decreases in coal production and utilization.

This study has not addressed the several important "externalities" associated with coal used in electricity generation. On the down-side are various types of environmental pollution and the emissions of greenhouse gases. On the up-side are the creation of saleable by-products of combustion, and coal's major contribution to lowering our dependence on foreign oil. Public health benefits also may result from increased employment and higher levels of personal income associated with lower energy costs (see, e.g., Brenner, 2005). All of these external impacts are, however, beyond the scope of this study.

Endnotes

*The authors are, respectively, Professor of Energy, Environmental and Regional Economics, and Graduate Assistant in the Department of Geography at the Pennsylvania State University. The authors wish to acknowledge the funding of the Center for Energy and Economic Development (CEED). We are most grateful to Eugene Trisko for providing the data and feedback on various earlier drafts. The methodology employed in this report is an extension of that developed in an analysis by Adam Rose and Ram Ranjan in the "The Economic Impacts of Coal Production and Utilization in the Southern Appalachian Mountain Region" (June 2001), and by Adam Rose and Bo Yang in the "The Economic Impact of Coal Utilization in the Continental U.S. (January 2002) also prepared with the support of the Center for Energy and Economic Development. Dr. William Schaffer of Georgia Tech served as a consultant to and reviewer of the 2002 study. The methodology employed in the current study reflects in principle Dr. Schaffer's constructive comments on this previous work, including the suggested elimination of more speculative "forward-linkage" calculations.

[1] Note that this and subsequent multipliers used in this study are Type II multipliers, which include the stimulus from household income and spending (see Appendix A for further discussion of multipliers). Tax multiplier effects are calculated separately.

[2] Thus, supply-side multipliers do not have the solid footing of demand-side multipliers. In the latter, production definitely requires material inputs; hence the analogy of pulling an object with a rope will guarantee that the object will come forth. The supply-side analysis suggests that just the attractiveness of an input will cause it to be used; the analogy here is that pushing on a rope doesn't necessarily move the object.

[3] A 0.14 estimate first appeared in an unpublished National Economic Research Associates report by K. P. Anderson in 1982. More recent studies for the state of Georgia and the United Kingdom yield similar results. Also, the output elasticity is directly related to the ordinary price elasticity of demand for electricity, which more studies indicate to be in the range of 0.05 to 0.25. Under normal conditions, the output elasticity and price elasticity of demand are equivalent. We chose to use the more conservative value of 0.10 in this study to place our results on as solid a footing as possible

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Appendix A

Input-Output Analysis

An input-output (I-O) table is a valuable tool that provides insights into economic interdependence. The table is composed of a set of accounts representing purchases and sales between all of the sectors of an economy. Official versions of this table at the national level, prepared by the U.S. Department of Commerce, are based on an extensive collection of data from nearly all of the business establishments in the United States.

I-O accounts can serve as the foundation for more formal models, the most basic of which assumes a linear relationship between inputs and the outputs they are used to produce. This structural model enables analysts to trace linkages between sectors and to estimate the economy-wide effects of changes in activity in any one sector.

Input-output analysis was pioneered in the 1930s by Professor Wassily Leontief. Since that time, Leontief and hundreds of other researchers have extended I-O theory, constructed tables for countries and regions around the world, and used these tables to perform a broad range of economic impact analysis. I-O analysis is considered to be such an important achievement that Leontief was awarded the Nobel Prize in economics in 1973. (For further insight into input-output analysis, see Leontief, 1986; Miller and Blair, 1985; and Rose and Miernyk, 1989.)

In addition to the national I-O table, based on a census of business establishments, tables have been constructed for many regions of the U.S., based on adjustments of national data and/or a regional sample of firms. One of the preeminent sets of regional input-output tables are those of the Impact Analysis for Planning System, or IMPLAN, developed and maintained by the U.S. Forest Service in conjunction with several other government agencies. IMPLAN consists of national and regional economic databases and methodologies to construct, update, and modify I-O tables, and to apply them in impact studies (MIG, 2005). In this study, we used the latest IMPLAN I-O Tables for the forty-eight contiguous states, which are updated to 2002 (MIG, 2005).

Due to the enormous amount of data collection and reconciliation that goes into constructing the official U.S. Table, a considerable lag typically exists between the year in which data are gathered and the date of availability of the table. It is therefore standard practice to use an I-O table that is somewhat dated and this is, of course, inevitable when making future projections as in this report. We have satisfied ourselves that we are utilizing the best available model, and that any errors in estimating coal-related impacts are likely to be small. For example, although the Florida economy has grown and changed since 1998, and will continue to do so, the structural relationships (ratios of input to outputs), upon which the model is based, have been found to be relatively stable over short time periods (around 10 years).

The standard IMPLAN multipliers are now Type II multipliers. In general, a multiplier is a ratio of total impacts divided by direct impacts. Versions of multipliers differ according to the calculation of total impacts. Type I multipliers only include indirect impacts (interindustry demands) and are rarely used because they omit a major component of economic interdependence. Type II multipliers include indirect effects and induced effects (those stemming from income payments and their expenditure). Type III multipliers also include both indirect and induced effects, but are based on marginal propensities to consume (spend) out of additional income, instead of average propensities to consume. Since marginal propensities are slightly lower than average propensities, Type III multipliers are a bit more conservative than standard Type II multipliers. We used Type II multipliers in our analysis because IMPLAN recently ceased the calculation of Type III multipliers.

Appendix B

Key Assumptions

We have embodied several key assumptions in our analysis. These assumptions are needed due to limitations of data, and for computational manageability. We have taken special care, however, to ensure that the assumptions are as realistic as possible.

A. General Assumptions

1. Economic growth is proportional across all sectors and is the same in 2015 as in 2002.
2. Intraregional trade patterns are constant over time.
3. Interregional trade patterns are constant over time.
4. Technology (except for electricity generation) is constant over time.
5. Relative prices (except for fuels and electricity) are constant over time.
6. Coal heat rate is 10,250 btu/kwh and natural gas heat rate is 7,200 btu/kwh in 2015.

B. Energy-Specific Assumptions

1. We based costs of fuels and prices of electricity generation on estimates from U.S. EIA or EPA as presented in Table B1.

a. We assumed a 10-percent minimum renewable target in each state. In states, where this target was exceeded (primarily due to the presence of extensive hydroelectricity), we based our projections on actual values.

b. We used our best judgment in determining low and high price ranges for different fuels and technologies. Specifically, for nuclear and renewable electricity generation, high price estimates were 25% above the average in Table B1, and low price estimates were 25% below Table B1 estimates for all 3 cases.

For delivered natural gas prices:

33% displacement scenario -- $5/mcf for low and $9/mcf for high

66% displacement scenario -- $6/mcf and $10/mcf

100% “existence” case -- $8/mcf and $12/mcf

2. Projected electricity generation in each state is based on estimates from U.S. DOE/EIA and EPA. Specifically, we used EIA's 2015 regional electricity generation projections as control totals, and used EPA's projections of state to regional proportions for 2015 to calculate the projected electricity generation for each state.

C. Other Assumptions

1. The 100% Displacement ("Coal Existence") case does not include the impacts of replacement fuels or technologies.

2. The 66% and 33% Displacement cases do include the impacts of replacement fuels and technologies.

We made an adjustment in these simulations in the price differential effect of exporting coal-fueled electricity. The price differential effect is applied in each state to the amount of coal-fueled electricity generated and used in that state. We were not able to compute the effect of this relatively lower-priced generation on the economies of the states that import it (to do so, we would ideally need to know the origin and destination of all coal-fueled electricity exports).

For the 66% and 33% coal "Replacement" cases, the situation differs. If coal were replaced by higher-priced generation, the alternative replacement electricity could not compete in regional markets (if each state unilaterally replaced coal-fueled generation with alternatives). We assumed this would cut coal-fueled electricity generation exports to zero from each state. We then adjusted the coal displacement and coal replacement columns for each state accordingly. However, it is not appropriate to also include the price differential effect on importing states, since these states are no longer importing coal-fueled electricity (because those quantities have been replaced by higher-price alternative generation that is not competitive), nor is it appropriate to add the price differential effect of coal exports to the exporting states (since it would not impact their economies even if the exports were maintained).

Appendix Table B1. Prices of Electricity by Various Technologies and Fuels in Pennsylvania, Example Projected to 2015 (in 2003 cents per kwh)

Technology		COM TRB[1]	Nuclear[2]	Wind Turbines	Solar Thermal	Solar PV	Hydro	Geothermal	Biomass	Average Mix Price
Energy Source	Coal	Gas	Uranium	Wind	Sunlight	Sunlight	Water	Brine/Steam	Landfill or Wood	
Existing Capacity in 2015[3]										
Generation	2.24									
Transmission	0.41									
Distribution	2.36									
Total	5.01									
New Capacity in 2015[4]										
Generation and Transmission		8.34[5]	6.19	6.03		22.43	4.88[6]		5.72	5.33
Distribution		2.36	2.36	2.40	n.a.[7]	2.40	2.40	n.a.[7]	2.40	2.36
Total		10.70	8.55	8.43		24.83	7.28		8.12	7.69

Sources:

EIA. 2005a. *EIA Annual Energy Outlook 2005*. Tables 60-72. Electricity Power Projections for Electricity Market Module Regions.

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[1] COM TRB: Combustion turbine, including both conventional and advanced combustion turbine (pollution control equipment unspecified).
[2] Listed as “Advanced Nuclear” for year 2015 from EIA (2005b).
[3] The projected generating cost is from EPA (2005) for the MACW Region. The total projected electricity price is computed by adding the EPA generating cost and the projected transmission and distribution costs from EIA (2005a) for the Mid-Atlantic Region.
[4] All entries are projections from EIA (2005a and 2005b) for the Mid-Atlantic Region in Year 2015 unless otherwise noted. The total projected electricity prices are computed by adding the electricity levelized costs (including generation and transmission costs) from EIA (2005b) and the distribution costs from EIA (2005a).
[5] Average cost of “conventional combustion turbine” and “advanced combustion turbine” technologies.
[6] Data from NCOE (2005) for Year 2000 U.S. dollars adjusted to 2003 U.S. dollars.
[7] There is no solar thermal generation or geothermal electricity generation in EIA 2015 projections for the Mid-Atlantic Region.

Appendix Table B2. Example Calculation of Price Differential Effect (Pennsylvania)

Row				
	Basic fuel price			
1	Price of coal ($/million BTU)		1.73	1
2	Price of gas ($/thousand cubic feet)		12.00	2
3	Price of gas ($/million BTU)		11.70	3
	Fuel cost differential			
4	Total amount of coal consumed in electric power sector (million BTU)	[Calculated by the authors][a]	1,046,733,435.57	4
5	Total amount of electricity coal displaced by gas (million BTU)	[Calculated by the authors][b]	279,410,551.74	5
6	Total cost of coal displaced by gas (million $)	[Row 5 X Row 1]	482.65	6
7	Total physical amount when gas is used (million BTU)	[Row 5 X 0.70 (Conversion Factor)]	195,587,386.22	7
8	Total cost of gas (million $)	[Row 7 X Row 3]	2,287.57	8
9	Cost differential of coal and gas (million $)	[Row 8 - Row 6]	1,804.92	9
	Electricity price differential			
10	Displaced coal-fired electricity (excluding the part displaced by gas) (million kwh)	[From "APPENDIX A" Table 1]	74,137.85	10
11	Price of coal-fired electricity (2005cents/kwh)	[From "APPENDIX A" Table 4]	5.35	11
12	Total value of displaced coal-fired elec (excluding part displaced by gas) (million $)	[Row 10 X Row 11]	3,969.02	12
13	Displacement generation by renewables (million kwh)	[From "APPENDIX A" Table 1]	13,589.94	13
14	Weighted average price of renewable electricity (2005cents/kwh)	[25% higher than the price from "APPENDIX A" Table 4]	10.52	14
15	Total value of displacement renewable electricity (million $)	[Row 13 X Row 14]	1,429.40	15
16	Displacement generation by nuclear (million kwh)	[From "APPENDIX A" Table 1]	60,547.91	16
17	Price of nuclear electricity (2005cents/kwh)	[25% higher than the price from "APPENDIX A" Table 4]	11.44	17
18	Total value of displacement nuclear electricity (million $)	[Row 16 X Row 17]	6,924.77	18
19	Total value of the displacement renewable and nuclear electricity (million $)	[Row 15 + Row 18]	8,354.17	19
20	Total value differential of electricity with displacement (million $)	[Row 19 - Row 12 + Row 9]	6,190.07	20
21	Total electricity generation (million kwh)	[From "APPENDIX A" Table 1]	205,050.91	21
22	Average mix price of electricity after displacement (2005cents/kwh)	[From "APPENDIX A" Table 4]	7.59	22
23	Total value of electricity generation (million $)	[Row 21 X Row 22]	15,561.27	23
24	Price differential averaged over all electricity in the state (%)	[(Row 20 / Row 21) X 100]	39.78	24
	Impact Differential			
25	Elasticity of regional economic activity	[From Text]	-0.10	25
26	Impact differential factor (%)	[Row 24 X Row 25]	-3.98	26
	Impact Results			
	Output			
27	Total base gross output (million $)	[Calculated by the Authors]	1,184,626.90	27
28	Gross output change induced by price differential (million $)	[Row 26 X Row 27]	-47,122.95	28
	Income			
29	Total base income generated (million $)	[Calculated by the Authors]	423,310.39	29
30	Income change (million $)	[Row 26 X Row 29]	-16,838.75	30
	Employment			
31	Total employment	[Calculated by the Authors]	7,946,201.85	31
32	Employment change (person years)	[Row 26 X Row 31]	-316,089.82	32

Notes: a. This is calculated by multiplying the EIA regional projection of electricity coal consumption in 2015 by the EPA projected ratio of state coal-fired
b. This is calculated by multiplying the number in Row 4 by the percentage of gas-fired electricity in total displacement electricity.

Appendix C

State and Regional Summary Tables

SUMMARY TABLES FOR SOUTHEAST REGION

Southeast Table 1A. Estimates of the Statewide Output Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

($2005 million)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Alabama	-$20,844	-$11,832	-$16,338
Florida	-$34,134	-$19,080	-$26,607
Georgia	-$51,674	-$26,160	-$38,917
Kentucky	-$60,222	-$38,444	-$49,333
Mississippi	-$7,118	-$3,950	-$5,534
North Carolina	-$44,661	-$17,028	-$30,845
South Carolina	-$8,625	-$5,763	-$7,194
Tennessee	-$40,188	-$15,182	-$27,685
Virginia	-$17,527	-$11,166	-$14,346
West Virginia	-$24,140	-$17,687	-$20,913
Total	-$309,134	-$166,292	-$237,713

Southeast Table 1B. Estimates of the Statewide Personal Income Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

($2005 million)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Alabama	-$6,740	-$3,642	-$5,191
Florida	-$12,786	-$6,813	-$9,800
Georgia	-$18,184	-$8,941	-$13,563
Kentucky	-$19,877	-$12,472	-$16,174
Mississippi	-$2,449	-$1,300	-$1,875
North Carolina	-$14,648	-$5,330	-$9,989
South Carolina	-$2,759	-$1,777	-$2,268
Tennessee	-$13,406	-$4,916	-$9,161
Virginia	-$6,996	-$4,295	-$5,646
West Virginia	-$7,897	-$5,615	-$6,756
Total	-$105,742	-$55,102	-$80,422

Southeast Table 1C. Estimates of the Statewide Employment Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

(jobs)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Alabama	-133,263	-69,100	-101,182
Florida	-289,553	-147,923	-218,738
Georgia	-326,643	-158,495	-242,569
Kentucky	-418,442	-262,106	-340,274
Mississippi	-60,110	-31,290	-45,700
North Carolina	-323,124	-111,687	-217,406
South Carolina	-60,351	-37,886	-49,119
Tennessee	-252,608	-92,739	-172,673
Virginia	-111,876	-68,710	-90,293
West Virginia	-190,125	-130,984	-160,554
Total	-2,166,094	-1,110,920	-1,638,507

Southeast Table 2A. Estimates of the Statewide Output Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

($2005 million)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Alabama	-$6,629	-$668	-$3,649	-$3,063	-$64	-$1,564
Florida	-$10,511	-$228	-$5,370	-$5,447	$204	-$2,622
Georgia	-$21,133	-$4,245	-$12,689	-$9,822	-$1,306	-$5,564
Kentucky	-$17,693	-$3,191	-$10,442	-$7,596	-$155	-$3,876
Mississippi	-$2,376	-$252	-$1,314	-$1,189	-$80	-$635
North Carolina	-$20,213	-$2,033	-$11,123	-$9,749	-$744	-$5,246
South Carolina	-$2,463	-$224	-$1,343	-$1,349	-$71	-$710
Tennessee	-$21,628	-$5,124	-$13,376	-$10,802	-$2,550	-$6,676
Virginia	-$8,107	-$2,789	-$5,448	-$4,389	-$1,225	-$2,807
West Virginia	-$5,112	-$788	-$2,950	-$1,187	$1,071	-$58
Total	-$115,863	-$19,542	-$67,702	-$54,593	-$4,921	-$29,757

Southeast Table 2B. Estimates of the Statewide Personal Income Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

($2005 million)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Alabama	-$2,491	-$442	-$1,467	-$1,155	-$124	-$640
Florida	-$4,683	-$603	-$2,643	-$2,369	-$127	-$1,248
Georgia	-$8,038	-$1,920	-$4,979	-$3,738	-$653	-$2,196
Kentucky	-$6,637	-$1,705	-$4,171	-$2,874	-$344	-$1,609
Mississippi	-$945	-$175	-$560	-$463	-$61	-$262
North Carolina	-$7,037	-$906	-$3,972	-$3,389	-$353	-$1,871
South Carolina	-$938	-$170	-$554	-$509	-$70	-$289
Tennessee	-$7,501	-$1,898	-$4,700	-$3,747	-$945	-$2,346
Virginia	-$3,688	-$1,430	-$2,559	-$1,986	-$643	-$1,315
West Virginia	-$1,949	-$420	-$1,185	-$547	$251	-$148
Total	-$43,906	-$9,670	-$26,788	-$20,778	-$3,069	-$11,923

Southeast Table 2C. Estimates of the Statewide Employment Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

(jobs)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Alabama	-54,666	-12,230	-33,448	-25,402	-4,054	-14,728
Florida	-117,734	-20,997	-69,365	-59,213	-6,049	-32,631
Georgia	-149,000	-37,700	-93,350	-69,315	-13,192	-41,254
Kentucky	-142,623	-38,514	-90,568	-61,874	-8,457	-35,165
Mississippi	-24,568	-5,253	-14,911	-11,960	-1,870	-6,915
North Carolina	-162,747	-23,643	-93,195	-78,418	-9,520	-43,969
South Carolina	-22,290	-4,714	-13,502	-12,042	-2,003	-7,022
Tennessee	-140,742	-35,229	-87,985	-70,293	-17,537	-43,915
Virginia	-58,850	-22,768	-40,809	-31,704	-10,235	-20,969
West Virginia	-52,375	-12,749	-32,562	-15,858	4,828	-5,515
Total	-925,596	-213,797	-569,696	-436,079	-68,088	-252,084

SUMMARY TABLES FOR NORTHEAST REGION

Northeast Table 1A. Estimates of the Statewide Output Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

($2005 million)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Connecticut	-$4,337	-$1,291	-$2,814
Delaware	-$5,890	-$3,358	-$4,624
Maryland	-$27,103	-$10,767	-$18,935
Massachusetts	-$11,128	-$6,244	-$8,686
Maine	-$503	-$316	-$409
New Hampshire	-$1,641	-$952	-$1,297
New Jersey	-$14,964	-$5,185	-$10,074
New York	-$22,321	-$10,243	-$16,282
Pennsylvania	-$57,580	-$26,337	-$41,959
Total	-$145,467	-$64,692	-$105,080

Northeast Table 1B. Estimates of the Statewide Personal Income Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

($2005 million)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Connecticut	-$1,718	-$462	-$1,090
Delaware	-$1,968	-$1,112	-$1,540
Maryland	-$12,174	-$4,579	-$8,376
Massachusetts	-$4,403	-$2,387	-$3,395
Maine	-$175	-$107	-$141
New Hampshire	-$575	-$313	-$444
New Jersey	-$5,787	-$1,935	-$3,861
New York	-$8,955	-$3,911	-$6,433
Pennsylvania	-$19,909	-$8,744	-$14,327
Total	-$55,664	-$23,551	-$39,607

Northeast Table 1C. Estimates of the Statewide Employment Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

(jobs)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Connecticut	-23,935	-6,408	-15,171
Delaware	-35,807	-20,010	-27,909
Maryland	-192,852	-71,418	-132,135
Massachusetts	-61,119	-33,359	-47,239
Maine	-4,221	-2,506	-3,363
New Hampshire	-10,941	-5,719	-8,330
New Jersey	-79,520	-26,566	-53,043
New York	-112,861	-50,345	-81,603
Pennsylvania	-368,645	-159,069	-263,857
Total	-889,901	-375,400	-632,650

Northeast Table 2A. Estimates of the Statewide Output Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

($2005 million)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Connecticut	-$2,076	-$15	-$1,045	-$1,014	$92	-$461
Delaware	-$2,567	-$840	-$1,703	-$1,168	-$222	-$695
Maryland	-$13,677	-$2,889	-$8,283	-$6,541	-$1,139	-$3,840
Massachusetts	-$4,198	-$950	-$2,574	-$1,805	-$145	-$975
Maine	-$176	-$52	-$114	-$72	-$10	-$41
New Hampshire	-$490	-$35	-$263	-$202	$26	-$88
New Jersey	-$7,860	-$1,294	-$4,577	-$3,759	-$391	-$2,075
New York	-$9,723	-$1,751	-$5,737	-$4,421	-$435	-$2,428
Pennsylvania	-$25,488	-$4,807	-$15,148	-$12,253	-$1,824	-$7,039
Total	-$66,254	-$12,632	-$39,443	-$31,235	-$4,047	-$17,641

Northeast Table 2B. Estimates of the Statewide Personal Income Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

($2005 million)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Connecticut	-$874	-$24	-$449	-$425	$31	-$197
Delaware	-$883	-$299	-$591	-$402	-$82	-$242
Maryland	-$6,575	-$1,560	-$4,068	-$3,148	-$636	-$1,892
Massachusetts	-$1,813	-$473	-$1,143	-$785	-$99	-$442
Maine	-$66	-$21	-$44	-$27	-$5	-$16
New Hampshire	-$196	-$23	-$109	-$83	$4	-$40
New Jersey	-$3,139	-$552	-$1,845	-$1,499	-$172	-$835
New York	-$4,188	-$859	-$2,524	-$1,910	-$246	-$1,078
Pennsylvania	-$9,367	-$1,976	-$5,672	-$4,496	-$769	-$2,632
Total	-$27,101	-$5,787	-$16,444	-$12,774	-$1,974	-$7,374

Northeast Table 2C. Estimates of the Statewide Employment Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

(jobs)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Connecticut	-12,246	-383	-6,314	-5,945	420	-2,762
Delaware	-16,601	-5,824	-11,213	-7,545	-1,639	-4,592
Maryland	-105,876	-25,687	-65,781	-50,701	-10,543	-30,622
Massachusetts	-24,849	-6,386	-15,617	-10,745	-1,306	-6,026
Maine	-1,723	-591	-1,157	-716	-150	-433
New Hampshire	-4,001	-555	-2,278	-1,719	4	-857
New Jersey	-43,222	-7,665	-25,444	-20,629	-2,393	-11,511
New York	-51,565	-10,305	-30,935	-23,501	-2,871	-13,186
Pennsylvania	-177,621	-38,894	-108,257	-85,246	-15,285	-50,265
Total	-437,704	-96,289	-266,996	-206,746	-33,762	-120,254

SUMMARY TABLES FOR MIDWEST REGION

Midwest Table 1A. Estimates of the Statewide Output Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

($2005 million)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Illinois	-$95,392	-$37,686	-$66,539
Indiana	-$82,113	-$50,407	-$66,260
Michigan	-$75,140	-$34,452	-$54,796
Ohio	-$112,434	-$55,018	-$83,726
Wisconsin	-$43,485	-$21,719	-$32,602
Total	-$408,564	-$199,282	-$303,923

Midwest Table 1B. Estimates of the Statewide Personal Income Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

($2005 million)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Illinois	-$36,956	-$13,941	-$25,449
Indiana	-$24,932	-$15,182	-$20,057
Michigan	-$24,212	-$10,997	-$17,605
Ohio	-$36,538	-$17,603	-$27,071
Wisconsin	-$14,194	-$6,990	-$10,592
Total	-$136,833	-$64,713	-$100,773

Midwest Table 1C. Estimates of the Statewide Employment Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

(jobs)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Illinois	-472,111	-184,972	-328,541
Indiana	-511,683	-308,906	-410,294
Michigan	-403,210	-182,568	-292,889
Ohio	-713,994	-341,917	-527,956
Wisconsin	-291,017	-142,659	-216,838
Total	-2,392,015	-1,161,021	-1,776,518

Midwest Table 2A. Estimates of the Statewide Output Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

($2005 million)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Illinois	-$49,946	-$12,025	-$30,986	-$23,853	-$5,137	-$14,495
Indiana	-$30,565	-$9,251	-$19,908	-$13,791	-$2,565	-$8,178
Michigan	-$38,409	-$11,547	-$24,978	-$18,357	-$4,913	-$11,635
Ohio	-$50,482	-$12,389	-$31,436	-$23,830	-$4,492	-$14,161
Wisconsin	-$19,998	-$5,595	-$12,797	-$9,293	-$2,037	-$5,665
Total	-$189,400	-$50,808	-$120,104	-$89,124	-$19,143	-$54,134

Midwest Table 2B. Estimates of the Statewide Personal Income Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

($2005 million)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Illinois	-$20,369	-$5,246	-$12,808	-$9,717	-$2,252	-$5,984
Indiana	-$9,826	-$3,272	-$6,549	-$4,425	-$973	-$2,699
Michigan	-$12,630	-$3,904	-$8,267	-$6,037	-$1,670	-$3,853
Ohio	-$17,018	-$4,455	-$10,736	-$8,029	-$1,651	-$4,840
Wisconsin	-$6,773	-$2,006	-$4,389	-$3,149	-$747	-$1,948
Total	-$66,616	-$18,883	-$42,750	-$31,356	-$7,294	-$19,325

Midwest Table 2C. Estimates of the Statewide Employment Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

(jobs)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Illinois	-250,522	-61,834	-156,178	-119,582	-26,449	-73,015
Indiana	-203,241	-66,933	-135,087	-91,806	-20,010	-55,908
Michigan	-210,979	-65,309	-138,144	-100,873	-27,971	-64,422
Ohio	-333,726	-86,869	-210,297	-157,760	-32,441	-95,100
Wisconsin	-140,143	-41,973	-91,058	-65,165	-15,707	-40,436
Total	-1,138,612	-322,918	-730,765	-535,186	-122,578	-328,882

SUMMARY TABLES FOR CENTRAL REGION

Central Table 1A. Estimates of the Statewide Output Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

($2005 million)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Arkansas	-$5,787	-$4,541	-$5,164
Iowa	-$28,434	-$14,894	-$21,664
Kansas	-$36,552	-$16,146	-$26,349
Louisiana	-$14,349	-$8,154	-$11,251
Minnesota	-$48,120	-$17,154	-$32,637
Missouri	-$63,824	-$30,163	-$46,994
Nebraska	-$29,741	-$9,505	-$19,623
Oklahoma	-$19,943	-$13,780	-$16,861
Texas	-$58,320	-$34,517	-$46,418
Total	-$305,070	-$148,854	-$226,962

Central Table 1B. Estimates of the Statewide Personal Income Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

($2005 million)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Arkansas	-$1,782	-$1,375	-$1,579
Iowa	-$8,655	-$4,472	-$6,564
Kansas	-$11,990	-$5,134	-$8,562
Louisiana	-$5,655	-$3,067	-$4,361
Minnesota	-$16,881	-$5,887	-$11,384
Missouri	-$22,680	-$10,462	-$16,571
Nebraska	-$10,617	-$3,277	-$6,947
Oklahoma	-$6,995	-$4,704	-$5,849
Texas	-$20,766	-$11,950	-$16,358
Total	-$106,020	-$50,328	-$78,174

Central Table 1C. Estimates of the Statewide Employment Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

(jobs)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Arkansas	-40,347	-30,892	-35,619
Iowa	-208,837	-105,890	-157,363
Kansas	-273,630	-114,374	-194,002
Louisiana	-129,606	-68,828	-99,217
Minnesota	-298,349	-103,699	-201,024
Missouri	-433,836	-200,399	-317,118
Nebraska	-144,287	-45,783	-95,035
Oklahoma	-158,953	-105,794	-132,373
Texas	-369,816	-209,171	-289,494
Total	-2,057,661	-984,830	-1,521,246

Central Table 2A. Estimates of the Statewide Output Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

($2005 million)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Arkansas	-$878	$265	-$307	-$566	$163	-$202
Iowa	-$12,028	-$3,073	-$7,551	-$5,564	-$1,058	-$3,311
Kansas	-$17,601	-$4,165	-$10,883	-$8,565	-$1,893	-$5,229
Louisiana	-$5,349	-$1,220	-$3,285	-$2,530	-$406	-$1,468
Minnesota	-$27,513	-$7,076	-$17,295	-$13,604	-$3,385	-$8,494
Missouri	-$30,131	-$7,883	-$19,007	-$14,331	-$3,161	-$8,746
Nebraska	-$17,324	-$4,054	-$10,689	-$8,342	-$1,834	-$5,088
Oklahoma	-$3,921	$157	-$1,882	-$1,497	$556	-$470
Texas	-$21,739	-$5,517	-$13,628	-$10,600	-$1,735	-$6,167
Total	-$136,484	-$32,567	-$84,525	-$65,598	-$12,753	-$39,176

Central Table 2B. Estimates of the Statewide Personal Income Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

($2005 million)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Arkansas	-$390	-$17	-$204	-$235	$3	-$116
Iowa	-$3,818	-$1,052	-$2,435	-$1,768	-$376	-$1,072
Kansas	-$6,086	-$1,572	-$3,829	-$2,960	-$719	-$1,839
Louisiana	-$2,434	-$709	-$1,572	-$1,144	-$256	-$700
Minnesota	-$9,883	-$2,628	-$6,255	-$4,887	-$1,260	-$3,073
Missouri	-$11,358	-$3,282	-$7,320	-$5,400	-$1,346	-$3,373
Nebraska	-$6,364	-$1,551	-$3,957	-$3,064	-$703	-$1,883
Oklahoma	-$1,811	-$296	-$1,053	-$731	$32	-$349
Texas	-$8,552	-$2,544	-$5,548	-$4,140	-$857	-$2,499
Total	-$50,696	-$13,649	-$32,173	-$24,329	-$5,481	-$14,905

Central Table 2C. Estimates of the Statewide Employment Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

(jobs)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Arkansas	-9,754	-1,091	-5,423	-5,799	-274	-3,037
Iowa	-96,719	-28,630	-62,675	-44,836	-10,578	-27,707
Kansas	-143,214	-38,353	-90,784	-69,689	-17,622	-43,656
Louisiana	-58,667	-18,153	-38,410	-27,501	-6,655	-17,078
Minnesota	-175,242	-46,772	-111,007	-86,659	-22,425	-54,542
Missouri	-214,264	-59,976	-137,120	-101,951	-24,484	-63,218
Nebraska	-84,531	-19,939	-52,235	-40,708	-9,032	-24,870
Oklahoma	-45,015	-9,844	-27,429	-18,438	-726	-9,582
Texas	-160,540	-51,058	-105,799	-77,460	-17,638	-47,549
Total	-987,945	-273,816	-630,881	-473,042	-109,434	-291,238

SUMMARY TABLES FOR WESTERN/PACIFIC REGION

Western Table 1A. Estimates of the Statewide Output Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

($2005 million)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Arizona	-$15,373	-$10,242	-$12,807
California	-$74,935	-$41,882	-$58,408
Colorado	-$20,758	-$17,183	-$18,971
Montana	-$5,317	-$3,614	-$4,466
Nevada	-$9,382	-$6,103	-$7,743
New Mexico	-$17,166	-$11,714	-$14,440
North Dakota	-$9,881	-$7,028	-$8,454
Oregon	-$1,808	-$1,185	-$1,497
South Dakota	-$3,151	-$2,030	-$2,591
Utah	-$40,038	-$24,796	-$32,417
Washington	-$6,307	-$3,287	-$4,797
Wyoming	-$8,470	-$5,814	-$7,142
Total	-$212,585	-$134,879	-$173,732

Western Table 1B. Estimates of the Statewide Personal Income Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

($2005 million)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Arizona	-$5,314	-$3,428	-$4,371
California	-$28,259	-$15,540	-$21,900
Colorado	-$7,540	-$6,191	-$6,866
Montana	-$1,840	-$1,228	-$1,534
Nevada	-$3,682	-$2,359	-$3,021
New Mexico	-$6,637	-$4,391	-$5,514
North Dakota	-$3,160	-$2,215	-$2,687
Oregon	-$620	-$403	-$512
South Dakota	-$913	-$587	-$750
Utah	-$14,639	-$9,012	-$11,825
Washington	-$2,366	-$1,209	-$1,788
Wyoming	-$2,979	-$1,925	-$2,452
Total	-$77,950	-$48,488	-$63,219

Western Table 1C. Estimates of the Statewide Employment Impact of Coal-Fueled Electricity Generation for the 100% Displacement (Existence) Case

(jobs)

State	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Arizona	-105,323	-66,600	-85,962
California	-438,164	-239,492	-338,828
Colorado	-120,198	-98,649	-109,424
Montana	-53,467	-34,798	-44,133
Nevada	-78,607	-49,759	-69,215
New Mexico	-159,775	-103,413	-131,594
North Dakota	-82,479	-55,952	-64,183
Oregon	-14,319	-9,163	-11,741
South Dakota	-22,545	-14,400	-18,473
Utah	-304,341	-186,933	-245,637
Washington	-38,285	-19,477	-28,881
Wyoming	-67,423	-43,659	-55,541
Total	-1,484,929	-922,295	-1,203,612

Western Table 2A. Estimates of the Statewide Output Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

($2005 million)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Arizona	-$3,409	-$5	-$1,707	-$1,501	$227	-$637
California	-$33,815	-$12,000	-$22,907	-$15,435	-$4,527	-$9,981
Colorado	-$8,553	-$4,319	-$6,436	-$5,743	-$2,253	-$3,998
Montana	-$1,831	-$707	-$1,269	-$681	-$119	-$400
Nevada	-$3,626	-$1,461	-$2,544	-$1,542	-$460	-$1,001
New Mexico	-$5,228	-$1,583	-$3,406	-$2,212	-$321	-$1,266
North Dakota	-$2,663	-$780	-$1,721	-$503	$439	-$32
Oregon	-$700	-$288	-$494	-$298	-$93	-$196
South Dakota	-$1,099	-$360	-$730	-$457	-$88	-$272
Utah	-$19,177	-$9,068	-$14,122	-$8,325	-$3,197	-$5,761
Washington	-$3,133	-$1,140	-$2,137	-$1,471	-$475	-$973
Wyoming	-$2,690	-$929	-$1,809	-$746	$146	-$300
Total	-$85,923	-$32,641	-$59,282	-$38,915	-$10,720	-$24,818

Western Table 2B. Estimates of the Statewide Personal Income Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

($2005 million)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Arizona	-$1,511	-$260	-$885	-$671	-$36	-$353
California	-$13,517	-$5,122	-$9,319	-$6,192	-$1,994	-$4,093
Colorado	-$3,606	-$2,009	-$2,807	-$2,349	-$1,032	-$1,690
Montana	-$700	-$296	-$498	-$273	-$72	-$173
Nevada	-$1,567	-$694	-$1,130	-$674	-$238	-$456
New Mexico	-$2,388	-$887	-$1,637	-$1,027	-$248	-$637
North Dakota	-$893	-$269	-$581	-$177	$135	-$21
Oregon	-$256	-$113	-$184	-$110	-$38	-$74
South Dakota	-$312	-$97	-$205	-$129	-$22	-$75
Utah	-$7,185	-$3,452	-$5,319	-$3,127	-$1,233	-$2,180
Washington	-$1,234	-$470	-$852	-$581	-$199	-$390
Wyoming	-$1,218	-$520	-$869	-$438	-$84	-$261
Total	-$34,387	-$14,187	-$24,287	-$15,747	-$5,059	-$10,403

Western Table 2C. Estimates of the Statewide Employment Impact of Coal-Fueled Electricity Generation for the Displacement/Replacement Cases

(jobs)

State	66% Displacement/Replacement			33% Displacement/Replacement		
	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average	High Alternative-Price Scenario	Low Alternative-Price Scenario	Average
Arizona	-31,451	-5,759	-18,605	-13,988	-943	-7,465
California	-213,835	-82,712	-148,274	-98,065	-32,503	-65,284
Colorado	-58,565	-33,046	-45,806	-37,989	-16,949	-27,469
Montana	-22,739	-10,418	-16,578	-9,296	-3,135	-6,216
Nevada	-35,506	-9,232	-17,986	-15,373	2,123	-2,254
New Mexico	-62,516	-24,832	-43,674	-26,994	-7,439	-17,216
North Dakota	-26,740	-16,466	-25,986	-6,631	-5,853	-10,613
Oregon	-6,344	-2,941	-4,642	-2,747	-1,045	-1,896
South Dakota	-7,838	-2,462	-5,150	-3,247	-559	-1,903
Utah	-150,590	-72,715	-111,652	-65,580	-26,076	-45,828
Washington	-20,116	-7,703	-13,909	-9,464	-3,258	-6,361
Wyoming	-27,713	-11,959	-19,836	-10,098	-2,118	-6,108
Total	-663,954	-280,243	-472,099	-299,472	-97,754	-198,613

Attachment 6

to
CEED COMMENTS

Supporting Calculations for Rose & Wei Paper

CA Table 3A. Backward Linkage Impacts of 100% Coal-Fired Electricity Displacement, 2015
(in millions of 2005 dollars, and in person-years)

Impact Components	Output	Personal Income	Employment
Coal			
1. Direct Coal-Fired Electricity Generation Displacement[a]	-$3,920	-$825	-4,390
Electricity Demand Multiplier	1.916	2.663	6.694
Subtotal	-$7,512	-$2,196	-29,383
2. Indirect Business Taxes[b]	-$481	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	-$928	-$474	-9,092
Displacement Grand Total	-$8,440	-$2,670	-38,475

Notes:

a. Value computed by multiplying average price of coal-fired generation in surrounding region in 2015 (from EPA, 2005b) by projection of coal-fired generation in 2015 (from EPA, 2005a).

b. Includes taxes paid by all coal-fired electricity generation, by coal mining for electricity generation, and by railroad transportation of coal (to the electricity generation sector).

c. Total impacts determined by special calculation (see text).

CA Table 3B. Backward Linkage Impacts of 66% Coal-Fired Electricity Replacement, 2015

(in millions of 2005 dollars, and in person-years)

Impact Components	Output	Personal Income	Employment
Coal			
1. Direct Coal-Fired Electricity Generation Displacement[a]	-$2,587	-$544	-2,897
Electricity Demand Multiplier	1.916	2.663	6.694
Subtotal	-$4,958	-$1,449	-19,393
2. Indirect Business Taxes[b]	-$317	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	-$612	-$313	-6,001
Displacement Grand Total	-$5,570	-$1,763	-25,394
Oil/Gas			
1. Direct Oil/Gas Electricity Generation Replacement[d]	$4,419	$930	4,949
Electricity Demand Multiplier	1.466	1.819	4.232
Subtotal	$6,477	$1,691	20,941
2. Indirect Business Taxes[e]	$512	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	$988	$505	9,687
Total	$7,465	$2,196	30,628
Nuclear			
1. Direct Nuclear Electricity Generation Replacement[d]	$1,385	$291	1,551
Electricity Demand Multiplier	1.429	1.765	4.065
Subtotal	$1,979	$514	6,305
2. Indirect Business Taxes[e]	$159	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	$307	$157	3,009
Total	$2,286	$671	9,314

Biomass			
1. Direct Biomass Electricity Generation Replacement[d]	$0	$0	0
Electricity Demand Multiplier	1.916	2.663	6.694
Subtotal	$0	$0	0
2. Indirect Business Taxes[e]	$0	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	$0	$0	0
Total	$0	$0	0
Hydro			
1. Direct Hydro Electricity Generation Replacement[d]	$0	$0	0
Electricity Demand Multiplier	1.429	1.765	4.065
Subtotal	$0	$0	0
2. Indirect Business Taxes[e]	$0	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	$0	$0	0
Total	$0	$0	0
Wind			
1. Direct Wind Electricity Generation Replacement[d]	$0	$0	0
Electricity Demand Multiplier	1.429	1.765	4.065
Subtotal	$0	$0	0
2. Indirect Business Taxes[e]	$0	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	$0	$0	0
Total	$0	$0	0
Solar			
1. Direct Solar Electricity Generation Replacement[d]	$0	$0	0
Electricity Demand Multiplier	1.429	1.765	4.065
Subtotal	$0	$0	0
2. Indirect Business Taxes[e]	$0	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	$0	$0	0
Total	$0	$0	0
Replacement Grand Total	$9,751	$2,867	39,942

Notes:

a. Value computed by multiplying average price of coal-fired generation in surrounding region in 2015 (from EPA, 2005b) by projection of coal-fired generation in 2015 (from EPA, 2005a).

b. Includes taxes paid by all coal-fired electricity generation, by coal mining for electricity generation, and by railroad transportation of coal (to the electricity generation sector).

c. Total impacts determined by special calculation (see text).

d. Value computed by multiplying average price of the corresponding electricity generation in surrounding region in 2015 (from EIA, 2005b) by projection of the corresponding electricity generation in 2015 (from EPA, 2005a and EIA, 2005c).

e. Includes taxes paid by all corresponding electricity generation, by mining or processing (where applicable), and by transportation or distribution (where applicable).

CA Table 3C. Backward Linkage Impacts of 33% Coal-Fired Electricity Replacement, 2015
(in millions of 2005 dollars, and in person-years)

Impact Components	Output	Personal Income	Employment
Coal			
1. Direct Coal-Fired Electricity Generation Displacement[a]	-$1,293	-$272	-1,449
Electricity Demand Multiplier	1.916	2.663	6.694
Subtotal	-$2,479	-$725	-9,696
2. Indirect Business Taxes[b]	-$159	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	-$306	-$157	-3,000
Displacement Grand Total	-$2,785	-$881	-12,697
Oil/Gas			
1. Direct Oil/Gas Electricity Generation Replacement[d]	$2,209	$465	2,474
Electricity Demand Multiplier	1.466	1.819	4.232
Subtotal	$3,238	$845	10,471
2. Indirect Business Taxes[e]	$256	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	$494	$253	4,843
Total	$3,732	$1,098	15,314
Nuclear			
1. Direct Nuclear Electricity Generation Replacement[d]	$692	$146	776
Electricity Demand Multiplier	1.429	1.765	4.065
Subtotal	$989	$257	3,152
2. Indirect Business Taxes[e]	$80	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	$154	$78	1,505
Total	$1,143	$336	4,657

Biomass			
1. Direct Biomass Electricity Generation Replacement[d]	$0	$0	0
Electricity Demand Multiplier	1.916	2.663	6.694
Subtotal	$0	$0	0
2. Indirect Business Taxes[e]	$0	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	$0	$0	0
Total	$0	$0	0
Hydro			
1. Direct Hydro Electricity Generation Replacement[d]	$0	$0	0
Electricity Demand Multiplier	1.429	1.765	4.065
Subtotal	$0	$0	0
2. Indirect Business Taxes[e]	$0	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	$0	$0	0
Total	$0	$0	0
Wind			
1. Direct Wind Electricity Generation Replacement[d]	$0	$0	0
Electricity Demand Multiplier	1.429	1.765	4.065
Subtotal	$0	$0	0
2. Indirect Business Taxes[e]	$0	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	$0	$0	0
Total	$0	$0	0
Solar			
1. Direct Solar Electricity Generation Replacement[d]	$0	$0	0
Electricity Demand Multiplier	1.429	1.765	4.065
Subtotal	$0	$0	0
2. Indirect Business Taxes[e]	$0	c	c
Government Expenditure Multiplier	1.928	c	c
Subtotal	$0	$0	0
Total	$0	$0	0
Replacement Grand Total	$4,875	$1,434	19,971

Notes:

a. Value computed by multiplying average price of coal-fired generation in surrounding region in 2015 (from EPA, 2005b) by projection of coal-fired generation in 2015 (from EPA, 2005a).

b. Includes taxes paid by all coal-fired electricity generation, by coal mining for electricity generation, and by railroad transportation of coal (to the electricity generation sector).

c. Total impacts determined by special calculation (see text).

d. Value computed by multiplying average price of the corresponding electricity generation in surrounding region in 2015 (from EIA, 2005b) by projection of the corresponding electricity generation in 2015 (from EPA, 2005a and EIA, 2005c).

e. Includes taxes paid by all corresponding electricity generation, by mining or processing (where applicable), and by transportation or distribution (where applicable).

Economic Impacts Tables of High Price Scenario

CA Table 4A. Economic Impacts of 100% Coal-Fired Electricity Displacement, 2015

(in millions of 2005 dollars, and in person-years)

Impact Components	Output	Personal Income	Employment
1. Coal Displacement Grand Total	-$8,440	-$2,670	-38,475
2. Price Differential Effect	-$66,495	-$25,589	-399,689
Net Grand Total	-$74,935	-$28,259	-438,164

CA Table 4B. Economic Impacts of 66% Coal-Fired Electricity Replacement, 2015

(in millions of 2005 dollars, and in person-years)

Impact Components	Output	Personal Income	Employment
1. Coal Displacement Grand Total	-$5,570	-$1,763	-25,394
2. Coal Replacement Grand Total	$9,751	$2,867	39,942
3. Price Differential Effect	-$37,995	-$14,621	-228,384
Net Grand Total	-$33,815	-$13,517	-213,835

CA Table 4C. Economic Impacts of 33% Coal-Fired Electricity Replacement, 2015
(in millions of 2005 dollars, and in person-years)

Impact Components	Output	Personal Income	Employment
1. Coal Displacement Grand Total	-$2,785	-$881	-12,697
2. Coal Replacement Grand Total	$4,875	$1,434	19,971
3. Price Differential Effect	-$17,525	-$6,744	-105,339
Net Grand Total	-$15,435	-$6,192	-98,065

Economic Impacts Tables of Low Price Scenario

CA Table 4D. Economic Impacts of 100% Coal-Fired Electricity Displacement, 2015
(in millions of 2005 dollars, and in person-years)

Impact Components	Output	Personal Income	Employment
1. Coal Displacement Grand Total	-$8,440	-$2,670	-38,475
2. Price Differential Effect	-$33,443	-$12,869	-201,017
Net Grand Total	-$41,882	-$15,540	-239,492

CA Table 4E. Economic Impacts of 66% Coal-Fired Electricity Replacement, 2015
(in millions of 2005 dollars, and in person-years)

Impact Components	Output	Personal Income	Employment
1. Coal Displacement Grand Total	-$5,570	-$1,763	-25,394
2. Coal Replacement Grand Total	$9,751	$2,867	39,942
3. Price Differential Effect	-$16,181	-$6,227	-97,260
Net Grand Total	-$12,000	-$5,122	-82,712

CA Table 4F. Economic Impacts of 33% Coal-Fired Electricity Replacement, 2015

(in millions of 2005 dollars, and in person-years)

Impact Components	Output	Personal Income	Employment
1. Coal Displacement Grand Total	-$2,785	-$881	-12,697
2. Coal Replacement Grand Total	$4,875	$1,434	19,971
3. Price Differential Effect	-$6,618	-$2,547	-39,777
Net Grand Total	-$4,527	-$1,994	-32,503

Price Differential Impacts Analysis of CA - High Price Scenario (2015) (in 2005 dollars)

Level 1: 100% displacement coal-fired generation case

	Basic fuel price			
1	Price of coal ($/million BTU)		1.24	1
2	Price of gas ($/thousand cubic feet)		12.00	2
3	Price of gas ($/million BTU)		11.70	3
	Fuel cost differential			
4	Total amount of coal consumed in electric power sector (million BTU)	[Calculated by the authors][a]	640,000,000.00	4
5	Total amount of electricity coal displaced by gas (million BTU)	[Calculated by the authors][b]	449,259,673.16	5
6	Total cost of coal displaced by gas (million $)	[Row 5 X Row 1]	558.94	6
7	Total physical amount when gas is used (million BTU)	[Row 5 X 0.70 (Conversion Factor)]	314,481,771.21	7
8	Total cost of gas (million $)	[Row 7 X Row 3]	3,678.15	8
9	Cost differential of coal and gas (million $)	[Row 8 - Row 6]	3,119.21	9
	Electricity price differential			
10	Displaced coal-fired electricity (excluding the part displaced by gas) (million kwh)	[From "APPENDIX A" Table 1]	20,465.23	10
11	Price of coal-fired electricity (2005cents/kwh)	[From "APPENDIX A" Table 4]	5.68	11
12	Total value of displaced coal-fired electricity (excluding the part displaced by gas) (million $)	[Row 10 X Row 11]	1,162.29	12
13	Displacement generation by renewables (million kwh)	[From "APPENDIX A" Table 1]	0.00	13
14	Weighted average price of renewable electricity (2005cents/kwh)	[25% higher than the price from "APPENDIX A" Table 4]	9.88	14
15	Total value of displacement renewable electricity (million $)	[Row 13 X Row 14]	0.00	15
16	Displacement generation by nuclear (million kwh)	[From "APPENDIX A" Table 1]	20,465.23	16
17	Price of nuclear electricity (2005cents/kwh)	[25% higher than the price from "APPENDIX A" Table 4]	12.75	17
18	Total value of displacement nuclear electricity (million $)	[Row 16 X Row 17]	2,609.82	18
19	Total value of the displacement renewable and nuclear electricity (million $)	[Row 15 + Row 18]	2,609.82	19
20	Total value differential of electricity with displacement (million $)	[Row 19 - Row 12 + Row 9]	4,566.74	20
21	Total electricity generation (million kwh)	[From "APPENDIX A" Table 1]	289,331.31	21
22	Average mix price of electricity after displacement (2005cents/kwh)	[From "APPENDIX A" Table 4]	9.78	22
23	Total value of electricity generation (million $)	[Row 21 X Row 22]	28,282.14	23
24	Price differential averaged over all electricity in the state (%)	[(Row 20 / Row 21) X 100]	16.15	24
	Impact Differential			
25	Elasticity of regional economic activity	[From Text]	**-0.10**	25
26	Impact differential factor (%)	[Row 24 X Row 25]	-1.61	26
	Impact Results			
	Output			
27	Total base gross output (million $)	[Calculated by the Authors]	4,118,076.03	27
28	Gross output change induced by price differential (million $)	[Row 26 X Row 27]	-66,494.95	28
	Income			
29	Total base income generated (million $)	[Calculated by the Authors]	1,584,726.83	29
30	Income change (million $)	[Row 26 X Row 29]	-25,588.73	30
	Employment			
31	Total employment	[Calculated by the Authors]	24,753,029.91	31
32	Employment change (person years)	[Row 26 X Row 31]	-399,689.46	32

notes: a. This is calculated by multiplying the EIA regional projection of electricity coal consumption in 2015 by the EPA projected ratio of state coal-fired electricity to regional coal-fired electricity in 2015.
b. This is calculated by multiplying the number in Row 4 by the percentage of gas-fired electricity in total displacement electricity.

Level 2: 66% replacement of coal-fired generation

	Basic fuel price			
1	Price of coal ($/million BTU)		1.24	1
2	Price of gas ($/thousand cubic feet)		10.00	2
3	Price of gas ($/million BTU)		9.75	3
	Fuel cost differential			
4	Total amount of coal consumed in electric power sector (million BTU)	[Calculated by the authors][a]	640,000,000.00	4
5	Total amount of electricity coal replaced by gas (million BTU)	[Calculated by the authors][b]	296,511,384.29	5
6	Total cost of coal replaced by gas (million $)	[Row 5 X Row 1]	368.90	6
7	Total physical amount when gas is used (million BTU)	[Row 5 X 0.70 (Conversion Factor)]	207,557,969.00	7
8	Total cost of gas (million $)	[Row 7 X Row 3]	2,022.98	8
9	Cost differential of coal and gas (million $)	[Row 8 - Row 6]	1,654.08	9
	Electricity price differential			
10	Replaced coal-fired electricity (excluding the part replaced by gas) (million kwh)	[From "APPENDIX A" Table 1]	13,507.06	10
11	Price of coal-fired electricity (2005cents/kwh)	[From "APPENDIX A" Table 4]	5.68	11
12	Total value of replaced coal-fired electricity (excluding the part replaced by gas) (million $)	[Row 10 X Row 11]	767.11	12
13	Replacement generation by renewables (million kwh)	[From "APPENDIX A" Table 1]	0.00	13
14	Weighted average price of renewable electricity (2005cents/kwh)	[25% higher than the price from "APPENDIX A" Table 4]	9.88	14
15	Total value of replacement renewable electricity (million $)	[Row 13 X Row 14]	0.00	15
16	Replacement generation by nuclear (million kwh)	[From "APPENDIX A" Table 1]	13,507.06	16
17	Price of nuclear electricity (2005cents/kwh)	[25% higher than the price from "APPENDIX A" Table 4]	12.75	17
18	Total value of replacement nuclear electricity (million $)	[Row 16 X Row 17]	1,722.48	18
19	Total value of the replacement renewable and nuclear electricity (million $)	[Row 15 + Row 18]	1,722.48	19
20	Total value differential of electricity with replacement (million $)	[Row 19 - Row 12 + Row 9]	2,609.45	20
21	Total electricity generation (million kwh)	[From "APPENDIX A" Table 1]	289,331.31	21
22	Average mix price of electricity after replacement (2005cents/kwh)	[From "APPENDIX A" Table 4]	9.78	22
23	Total value of electricity generation (million $)	[Row 21 X Row 22]	28,282.14	23
24	Price differential averaged over all electricity in the state (%)	[(Row 20 / Row 21) X 100]	9.23	24
	Impact Differential			
25	Elasticity of regional economic activity	[From Text]	**-0.10**	25
26	Impact differential factor (%)	[Row 24 X Row 25]	-0.9227	26
	Impact Results			
	Output			
27	Total base gross output (million $)	[Calculated by the Authors]	4,118,076	27
28	Gross output change induced by price differential (million $)	[Row 26 X Row 27]	-37,995	28
	Income			
29	Total base income generated (million $)	[Calculated by the Authors]	1,584,727	29
30	Income change (million $)	[Row 26 X Row 29]	-14,621	30
	Employment			
31	Total employment	[Calculated by the Authors]	24,753,030	31
32	Employment change (person years)	[Row 26 X Row 31]	-228,384	32

notes: a. This is calculated by multiplying the EIA regional projection of electricity coal consumption in 2015 by the EPA projected ratio of state coal-fired electricity to regional coal-fired electricity in 2015.
b. This is calculated by multiplying the number in Row 4 by 66% and by the percentage of gas-fired electricity in total replacement electricity.

Level 3: 33% replacement of coal-fired generation

	Basic fuel price			
1	Price of coal ($/million BTU)		1.24	1
2	Price of gas ($/thousand cubic feet)		9.00	2
3	Price of gas ($/million BTU)		8.77	3
	Fuel cost differential			
4	Total amount of coal consumed in electric power sector (million BTU)	[Calculated by the authors][a]	640,000,000.00	4
5	Total amount of electricity coal replaced by gas (million BTU)	[Calculated by the authors][b]	148,255,692.14	5
6	Total cost of coal replaced by gas (million $)	[Row 5 X Row 1]	184.45	6
7	Total physical amount when gas is used (million BTU)	[Row 5 X 0.70 (Conversion Factor)]	103,778,984.50	7
8	Total cost of gas (million $)	[Row 7 X Row 3]	910.34	8
9	Cost differential of coal and gas (million $)	[Row 8 - Row 6]	725.89	9
	Electricity price differential			
10	Replaced coal-fired electricity (excluding the part replaced by gas) (million kwh)	[From "APPENDIX A" Table 1]	6,753.53	10
11	Price of coal-fired electricity (2005cents/kwh)	[From "APPENDIX A" Table 4]	5.68	11
12	Total value of replaced coal-fired electricity (excluding the part replaced by gas) (million $)	[Row 10 X Row 11]	383.55	12
13	Replacement generation by renewables (million kwh)	[From "APPENDIX A" Table 1]	0.00	13
14	Weighted average price of renewable electricity (2005cents/kwh)	[25% higher than the price from "APPENDIX A" Table 4]	9.88	14
15	Total value of replacement renewable electricity (million $)	[Row 13 X Row 14]	0.00	15
16	Replacement generation by nuclear (million kwh)	[From "APPENDIX A" Table 1]	6,753.53	16
17	Price of nuclear electricity (2005cents/kwh)	[25% higher than the price from "APPENDIX A" Table 4]	12.75	17
18	Total value of replacement nuclear electricity (million $)	[Row 16 X Row 17]	861.24	18
19	Total value of the replacement renewable and nuclear electricity (million $)	[Row 15 + Row 18]	861.24	19
20	Total value differential of electricity with replacement (million $)	[Row 19 - Row 12 + Row 9]	1,203.58	20
21	Total electricity generation (million kwh)	[From "APPENDIX A" Table 1]	289,331.31	21
22	Average mix price of electricity after replacement (2005cents/kwh)	[From "APPENDIX A" Table 4]	9.78	22
23	Total value of electricity generation (million $)	[Row 21 X Row 22]	28,282.14	23
24	Price differential averaged over all electricity in the state (%)	[(Row 20 / Row 21) X 100]	4.26	24
	Impact Differential			
25	Elasticity of regional economic activity	[From Text]	**-0.10**	25
26	Impact differential factor (%)	[Row 24 X Row 25]	-0.4256	26
	Impact Results			
	Output			
27	Total base gross output (million $)	[Calculated by the Authors]	4,118,076	27
28	Gross output change induced by price differential (million $)	[Row 26 X Row 27]	-17,525	28
	Income			
29	Total base income generated (million $)	[Calculated by the Authors]	1,584,727	29
30	Income change (million $)	[Row 26 X Row 29]	-6,744	30
	Employment			
31	Total employment	[Calculated by the Authors]	24,753,030	31
32	Employment change (person years)	[Row 26 X Row 31]	-105,339	32

notes: a. This is calculated by multiplying the EIA regional projection of electricity coal consumption in 2015 by the EPA projected ratio of state coal-fired electricity to regional coal-fired electricity in 2015.
b. This is calculated by multiplying the number in Row 4 by 33% and by the percentage of gas-fired electricity in total replacement electricity.

Price Differential Impacts Analysis of CA - Low Price Scenario (2015) (in 2005 dollars)

Level 1: 100% displacement coal-fired generation case

	Basic fuel price			
1	Price of coal ($/million BTU)		1.24	1
2	Price of gas ($/thousand cubic feet)		8.00	2
3	Price of gas ($/million BTU)		7.80	3
	Fuel cost differential			
4	Total amount of coal consumed in electric power sector (million BTU)	[Calculated by the authors][a]	640,000,000.00	4
5	Total amount of electricity coal displaced by gas (million BTU)	[Calculated by the authors][b]	449,259,673.16	5
6	Total cost of coal displaced by gas (million $)	[Row 5 X Row 1]	558.94	6
7	Total physical amount when gas is used (million BTU)	[Row 5 X 0.70 (Conversion Factor)]	314,481,771.21	7
8	Total cost of gas (million $)	[Row 7 X Row 3]	2,452.10	8
9	Cost differential of coal and gas (million $)	[Row 8 - Row 6]	1,893.16	9
	Electricity price differential			
10	Displaced coal-fired electricity (excluding the part displaced by gas) (million kwh)	[From "APPENDIX A" Table 1]	20,465.23	10
11	Price of coal-fired electricity (2005cents/kwh)	[From "APPENDIX A" Table 4]	5.68	11
12	Total value of displaced coal-fired electricity (excluding the part displaced by gas) (million $)	[Row 10 X Row 11]	1,162.29	12
13	Displacement generation by renewables (million kwh)	[From "APPENDIX A" Table 1]	0.00	13
14	Weighted average price of renewable electricity (2005cents/kwh)	[25% lower than the price from "APPENDIX A" Table 4]	5.93	14
15	Total value of displacement renewable electricity (million $)	[Row 13 X Row 14]	0.00	15
16	Displacement generation by nuclear (million kwh)	[From "APPENDIX A" Table 1]	20,465.23	16
17	Price of nuclear electricity (2005cents/kwh)	[25% lower than the price from "APPENDIX A" Table 4]	7.65	17
18	Total value of displacement nuclear electricity (million $)	[Row 16 X Row 17]	1,565.89	18
19	Total value of the displacement renewable and nuclear electricity (million $)	[Row 15 + Row 18]	1,565.89	19
20	Total value differential of electricity with displacement (million $)	[Row 19 - Row 12 + Row 9]	2,296.77	20
21	Total electricity generation (million kwh)	[From "APPENDIX A" Table 1]	289,331.31	21
22	Average mix price of electricity after displacement (2005cents/kwh)	[From "APPENDIX A" Table 4]	9.78	22
23	Total value of electricity generation (million $)	[Row 21 X Row 22]	28,282.14	23
24	Price differential averaged over all electricity in the state (%)	[(Row 20 / Row 21) X 100]	8.12	24
	Impact Differential			
25	Elasticity of regional economic activity	[From Text]	**-0.10**	25
26	Impact differential factor (%)	[Row 24 X Row 25]	-0.81	26
	Impact Results			
	Output			
27	Total base gross output (million $)	[Calculated by the Authors]	4,118,076.03	27
28	Gross output change induced by price differential (million $)	[Row 26 X Row 27]	-33,442.52	28
	Income			
29	Total base income generated (million $)	[Calculated by the Authors]	1,584,726.83	29
30	Income change (million $)	[Row 26 X Row 29]	-12,869.42	30
	Employment			
31	Total employment	[Calculated by the Authors]	24,753,029.91	31
32	Employment change (person years)	[Row 26 X Row 31]	-201,017.08	32

notes: a. This is calculated by multiplying the EIA regional projection of electricity coal consumption in 2015 by the EPA projected ratio of state coal-fired electricity to regional coal-fired electricity in 2015.
b. This is calculated by multiplying the number in Row 4 by the percentage of gas-fired electricity in total displacement electricity.

Level 2: 66% replacement of coal-fired generation

	Basic fuel price			
1	Price of coal ($/million BTU)		1.24	1
2	Price of gas ($/thousand cubic feet)		6.00	2
3	Price of gas ($/million BTU)		5.85	3
	Fuel cost differential			
4	Total amount of coal consumed in electric power sector (million BTU)	[Calculated by the authors][a]	640,000,000.00	4
5	Total amount of electricity coal replaced by gas (million BTU)	[Calculated by the authors][b]	296,511,384.29	5
6	Total cost of coal replaced by gas (million $)	[Row 5 X Row 1]	368.90	6
7	Total physical amount when gas is used (million BTU)	[Row 5 X 0.70 (Conversion Factor)]	207,557,969.00	7
8	Total cost of gas (million $)	[Row 7 X Row 3]	1,213.79	8
9	Cost differential of coal and gas (million $)	[Row 8 - Row 6]	844.89	9
	Electricity price differential			
10	Replaced coal-fired electricity (excluding the part replaced by gas) (million kwh)	[From "APPENDIX A" Table 1]	13,507.06	10
11	Price of coal-fired electricity (2005cents/kwh)	[From "APPENDIX A" Table 4]	5.68	11
12	Total value of replaced coal-fired electricity (excluding the part replaced by gas) (million $)	[Row 10 X Row 11]	767.11	12
13	Replacement generation by renewables (million kwh)	[From "APPENDIX A" Table 1]	0.00	13
14	Weighted average price of renewable electricity (2005cents/kwh)	[25% lower than the price from "APPENDIX A" Table 4]	5.93	14
15	Total value of replacement renewable electricity (million $)	[Row 13 X Row 14]	0.00	15
16	Replacement generation by nuclear (million kwh)	[From "APPENDIX A" Table 1]	13,507.06	16
17	Price of nuclear electricity (2005cents/kwh)	[25% lower than the price from "APPENDIX A" Table 4]	7.65	17
18	Total value of replacement nuclear electricity (million $)	[Row 16 X Row 17]	1,033.49	18
19	Total value of the replacement renewable and nuclear electricity (million $)	[Row 15 + Row 18]	1,033.49	19
20	Total value differential of electricity with replacement (million $)	[Row 19 - Row 12 + Row 9]	1,111.27	20
21	Total electricity generation (million kwh)	[From "APPENDIX A" Table 1]	289,331.31	21
22	Average mix price of electricity after replacement (2005cents/kwh)	[From "APPENDIX A" Table 4]	9.78	22
23	Total value of electricity generation (million $)	[Row 21 X Row 22]	28,282.14	23
24	Price differential averaged over all electricity in the state (%)	[(Row 20 / Row 21) X 100]	3.93	24
	Impact Differential			
25	Elasticity of regional economic activity	[From Text]	**-0.10**	25
26	Impact differential factor (%)	[Row 24 X Row 25]	-0.3929	26
	Impact Results			
	Output			
27	Total base gross output (million $)	[Calculated by the Authors]	4,118,076	27
28	Gross output change induced by price differential (million $)	[Row 26 X Row 27]	-16,181	28
	Income			
29	Total base income generated (million $)	[Calculated by the Authors]	1,584,727	29
30	Income change (million $)	[Row 26 X Row 29]	-6,227	30
	Employment			
31	Total employment	[Calculated by the Authors]	24,753,030	31
32	Employment change (person years)	[Row 26 X Row 31]	-97,260	32

notes: a. This is calculated by multiplying the EIA regional projection of electricity coal consumption in 2015 by the EPA projected ratio of state coal-fired electricity to regional coal-fired electricity in 2015.
b. This is calculated by multiplying the number in Row 4 by 66% and by the percentage of gas-fired electricity in total replacement electricity.

Level 3: 33% replacement of coal-fired generation

	Basic fuel price			
1	Price of coal ($/million BTU)		1.24	1
2	Price of gas ($/thousand cubic feet)		5.00	2
3	Price of gas ($/million BTU)		4.87	3
	Fuel cost differential			
4	Total amount of coal consumed in electric power sector (million BTU)	[Calculated by the authors][a]	640,000,000.00	4
5	Total amount of electricity coal replaced by gas (million BTU)	[Calculated by the authors][b]	148,255,692.14	5
6	Total cost of coal replaced by gas (million $)	[Row 5 X Row 1]	184.45	6
7	Total physical amount when gas is used (million BTU)	[Row 5 X 0.70 (Conversion Factor)]	103,778,984.50	7
8	Total cost of gas (million $)	[Row 7 X Row 3]	505.75	8
9	Cost differential of coal and gas (million $)	[Row 8 - Row 6]	321.30	9
	Electricity price differential			
10	Replaced coal-fired electricity (excluding the part replaced by gas) (million kwh)	[From "APPENDIX A" Table 1]	6,753.53	10
11	Price of coal-fired electricity (2005cents/kwh)	[From "APPENDIX A" Table 4]	5.68	11
12	Total value of replaced coal-fired electricity (excluding the part replaced by gas) (million $)	[Row 10 X Row 11]	383.55	12
13	Replacement generation by renewables (million kwh)	[From "APPENDIX A" Table 1]	0.00	13
14	Weighted average price of renewable electricity (2005cents/kwh)	[25% lower than the price from "APPENDIX A" Table 4]	5.93	14
15	Total value of replacement renewable electricity (million $)	[Row 13 X Row 14]	0.00	15
16	Replacement generation by nuclear (million kwh)	[From "APPENDIX A" Table 1]	6,753.53	16
17	Price of nuclear electricity (2005cents/kwh)	[25% lower than the price from "APPENDIX A" Table 4]	7.65	17
18	Total value of replacement nuclear electricity (million $)	[Row 16 X Row 17]	516.74	18
19	Total value of the replacement renewable and nuclear electricity (million $)	[Row 15 + Row 18]	516.74	19
20	Total value differential of electricity with replacement (million $)	[Row 19 - Row 12 + Row 9]	454.49	20
21	Total electricity generation (million kwh)	[From "APPENDIX A" Table 1]	289,331.31	21
22	Average mix price of electricity after replacement (2005cents/kwh)	[From "APPENDIX A" Table 4]	9.78	22
23	Total value of electricity generation (million $)	[Row 21 X Row 22]	28,282.14	23
24	Price differential averaged over all electricity in the state (%)	[(Row 20 / Row 21) X 100]	1.61	24
	Impact Differential			
25	Elasticity of regional economic activity	[From Text]	**-0.10**	25
26	Impact differential factor (%)	[Row 24 X Row 25]	-0.1607	26
	Impact Results			
	Output			
27	Total base gross output (million $)	[Calculated by the Authors]	4,118,076	27
28	Gross output change induced by price differential (million $)	[Row 26 X Row 27]	-6,618	28
	Income			
29	Total base income generated (million $)	[Calculated by the Authors]	1,584,727	29
30	Income change (million $)	[Row 26 X Row 29]	-2,547	30
	Employment			
31	Total employment	[Calculated by the Authors]	24,753,030	31
32	Employment change (person years)	[Row 26 X Row 31]	-39,777	32

notes: a. This is calculated by multiplying the EIA regional projection of electricity coal consumption in 2015 by the EPA projected ratio of state coal-fired electricity to regional coal-fired electricity in 2015.
b. This is calculated by multiplying the number in Row 4 by 33% and by the percentage of gas-fired electricity in total replacement electricity.

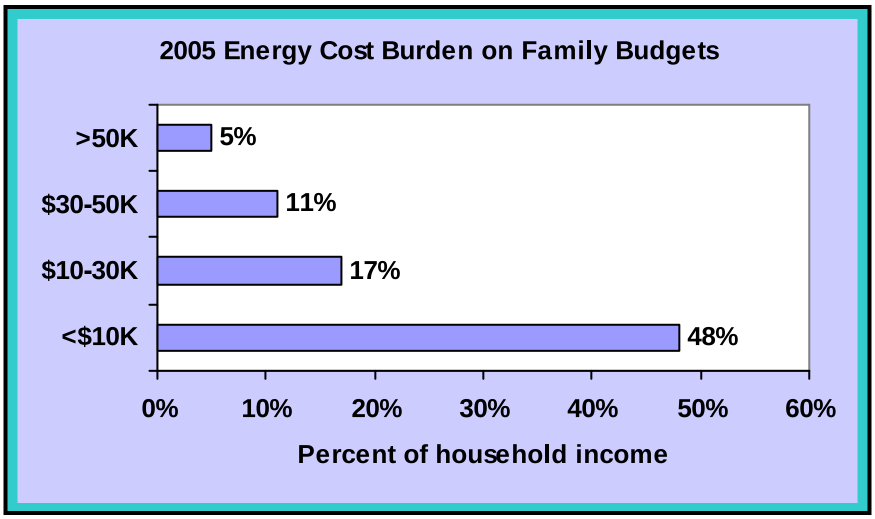
Attachment 7

to
CEED COMMENTS

Balanced Energy Report

Energy Cost Burdens on American Families

AMERICANS ARE FEELING THE PINCH OF SKYROCKETING ENERGY PRICES



> "Overall, the 56 percent of American households with annual incomes of $50,000 or less, totaling 63 million families, will spend 20 percent of their pre-tax income on energy in 2005."

By: Eugene M. Trisko
Attorney at Law

October 2005

Energy Cost Burdens on American Families

This paper analyzes the effects of 2005 prices for residential and transportation energy based on data from the U.S. Department of Energy's Energy Information Administration (EIA)[1], the U.S. Bureau of the Census,[2] and the U.S. Department of Transportation (DOT).[3]

Key findings of this report include:

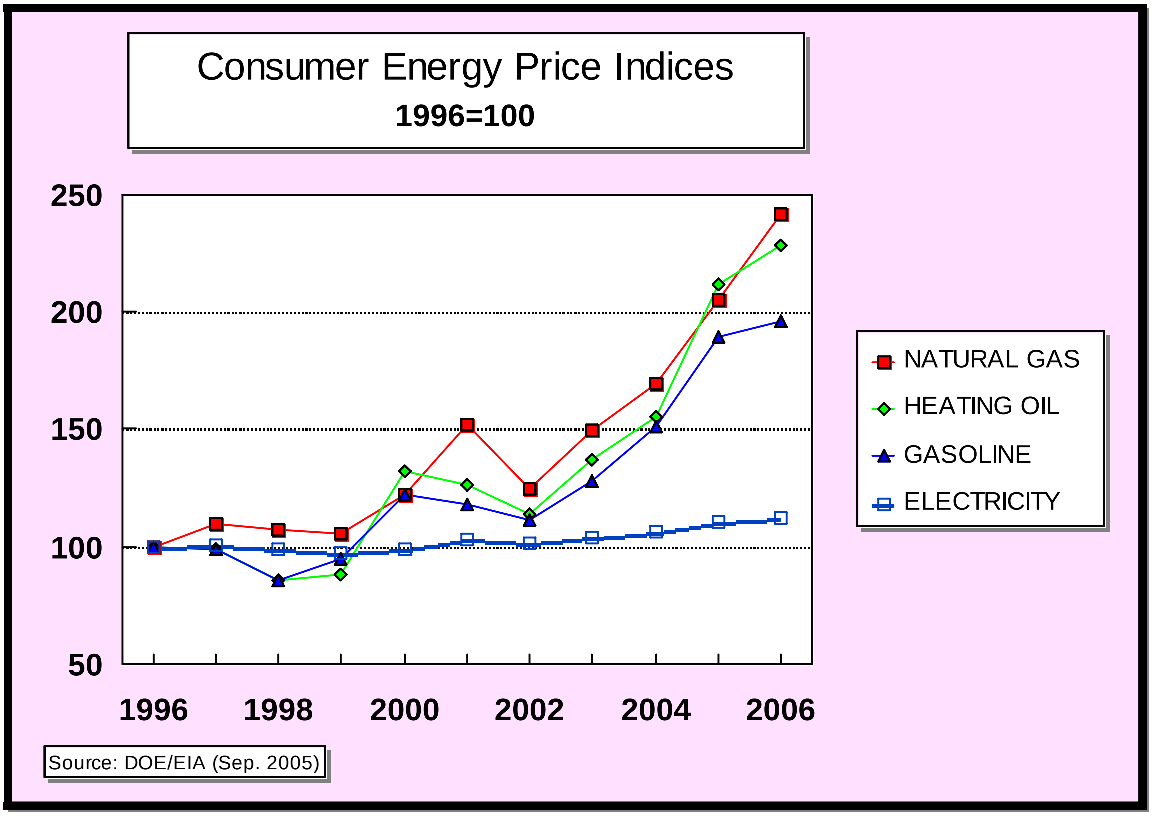
- In 2005, energy costs will consume 48 percent of the budgets of U.S. families with incomes of less than $10,000.
- The 29 million U.S. households with incomes of $10,000 to $30,000 (averaging $19,700) will spend 17 percent of their pre-tax income on energy products and services in 2005.
- Overall, the 56 percent of American families with incomes of $50,000 or less (totaling 63 million families) will spend 20 percent of their pre-tax income on energy in 2005.
- Households with family incomes greater than $50,000 will spend five percent of their gross incomes for residential and transportation energy.

<u>Among consumer energy purchases, only residential electric services have maintained a low rate of price increase over the past decade. Compared to gasoline, home heating oil, natural gas, and other petroleum-based products, residential electricity prices have remained stable.</u>

Relative Fuel Price Increases

Chart 1 summarizes consumer energy price trends for the period 1996 to 2005, including EIA's projections for 2006, indexed to the year 1996. Prices for residential natural gas and home heating oil will more than triple by 2006, while gasoline prices will nearly double. Residential electricity is projected to increase by 10 percent from 1996 to 2005, and by 12 percent from 1996 to 2006.

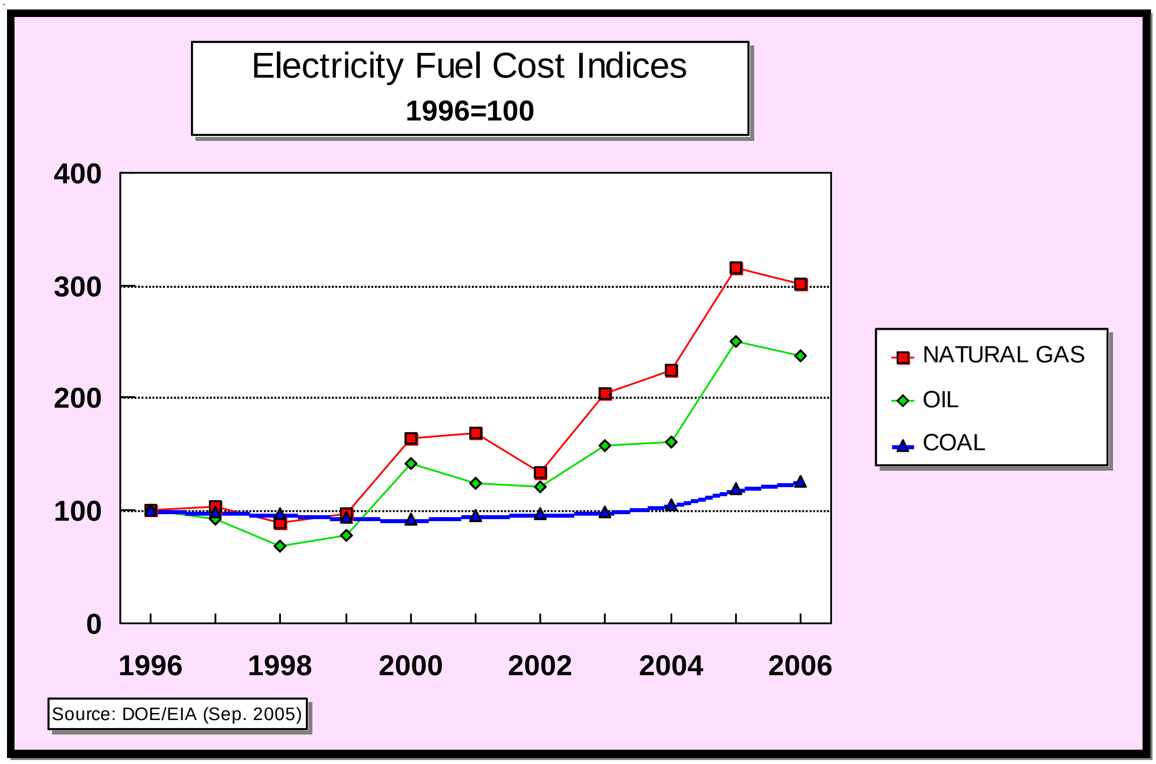
Chart 1



The modest rate of price increase for residential electric services reflects, in part, the electric utility industry's historic reliance on low-cost coal for more than 50 percent of its energy inputs. The price trends of fuels used for electric generation are shown in Chart 2, also indexed to 1996.

The price of natural gas for electric generation has tripled since 1996, similar to the trend for residential natural gas. Oil used for electric generation will cost 150 percent more in 2005 than in 1996. <u>EIA projects that coal prices in 2005 will be only 20 percent above their 1996 level</u>.

Chart 2



Total Energy Expenditures

The distribution of American households by income category in 2003 provides the basis for estimating the effect of current energy prices on consumers. Census data indicate that average household incomes have fallen slightly in recent years, except for gains among the highest-earning families. The 2003 Census data are representative of the current distribution of incomes among low- and middle-income families.

EIA's 2001 Survey of Residential Energy Consumption (updated to 2005 with EIA's September 2005 forecast of residential energy prices) is the source for estimating energy expenditures for residential heating, cooling, electricity, and other energy services.

The Department of Transportation's 2001 National Household Travel Survey provides information for estimating transportation energy costs. These transportation costs have been updated using EIA's 2005 projected national average retail gasoline price of $2.37 per gallon.

Household Incomes

Median family incomes peaked in 1999 and have declined slightly since that time. Mean, or average family incomes, peaked in 2000. The fraction of high-income families with incomes greater than $100,000 annually has grown recently, while the share of families in relatively low ($15-25K) incomes has remained stable.

U.S. income trends, 1997-2003

Year	Average income	Median income	Pct. $15-$25K	Pct. >$100K
2003	$59,067	$43,318	13.1%	15.1%
2002	$59,177	$43,381	12.9%	14.7%
2001	$60,488	$43,883	12.9%	14.9%
2000	$61,031	$44,853	12.5%	15.2%
1999	$60,420	$44,922	13.0%	15.0%
1998	$58,433	$43,825	13.1%	13.9%
1997	$58,795	$42,294	13.4%	12.9%

In 2003, more than one-third of American families had incomes of $30,000 or less, while 44 percent of families enjoyed incomes greater than $50,000 annually. Overall, U.S. families had an average income of $59,067 in 2003. Median family income was $43,318, meaning that one-half of families had incomes below this amount, and one-half had incomes of more than $43,318.

Distribution of U.S. households by income, 2003

Annual income	<$10K	$10-$30K	$30-$50K	>$50K	Total
No. of households (millions)	10.1	29.1	23.4	49.3	111.9
Pct. Of households	9%	26%	21%	44%	100%
Average income	$5,700	$19,700	$39,200	$107,700	$59,067

Residential Energy Expenses

The principal residential energy expenses are for electricity and natural gas, followed by home heating oil. Propane gas and kerosene are used by a relatively small number of households.

Since 2001, total residential energy expenditures have increased from $160 billion to more than $200 billion annually. The largest share of household income spent for residential energy falls disproportionately on poor and lower-income families. While some very low-income consumers may qualify for energy assistance through state or federal programs, these government programs will struggle to keep pace with the rapid escalation of energy prices. It is primarily the poor, fixed income, and other relatively low-income families who will bear the greatest burden of recent energy price increases. Only a massive increase in the amount of funds available to energy assistance programs - made possible by tax increases or by a redistribution of government spending - would soften the blow of rising costs for residential heating and cooling.

The following table shows the changing pattern of residential energy costs from 2001 to 2005, reflecting major increases in fuel oil and natural gas prices. Electricity prices have remained relatively stable, reducing the overall increase of residential energy prices.

Household energy expenses by fuel, 2001 and 2005

	2001	2005	Pct. Change
Electricity	$938	$1,050	12%
Natural gas	$702	$950	35%
Fuel oil	$737	$1,232	67%
Propane gas	$605	$979	62%
Total*	$1,493	$1,834	23%

**Columns do not add to totals because some households use more than one type of fuel. Costs by fuel are averages for households using that type of fuel.*

The effect of higher residential energy prices on low- and middle-income families is illustrated in the table below. Residential energy costs represent 23 percent of the household earnings of the lowest income families, less than $10,000, and eight percent of the pre-tax incomes of families with incomes of $10,000 to $30,000. These calculations do not include the effects of Federal and state income taxes, or contributions to Social Security and other programs that reduce “take-home” pay.

Residential energy costs by income category, 2005

2005 income:	<$10K	$10-30K	$30-$50K	>$50K	Total
Electricity	$703	$864	$1,032	$1,311	$1,050
Natural gas	$751	$858	$916	$1,089	$950
Fuel oil	$966	$1,083	$1,159	$1,433	$1,232
Propane gas	$683	$972	$984	$1,071	$979
Total*	$1,285	$1,554	$1,791	$2,247	$1,834
Pct. of average h/h income	23%	8%	5%	2%	3%

**Columns do not add to totals because some households use more than one type of fuel. Costs by fuel are averages for households using that type of fuel*.

Transportation Costs

Gasoline prices account for the largest single increase in consumer energy costs since 2001. Pump prices currently exceed $2.75 per gallon in most areas, and are $3.00 or more in major markets such as New York and California. EIA projects 2005 average retail gasoline costs at $2.37 per gallon, a 61 percent increase from the $1.47 per gallon price prevailing in 2001.

The rapid increase in gas prices follows a decade-long trend of increased use of motor vehicles, measured in millions of vehicle miles driven annually, increased market shares of pickup trucks and SUVs, and an increase in the average number of vehicles owned per household.[4]

EIA estimates that 181 million American vehicles – cars, vans, SUVs, pickup trucks, and motorcycles – consumed 107 billion gallons of gasoline and traveled 2.2 trillion miles in 2001. The total bill for these fuel purchases was $142 billion in 2001. In 2005, gasoline costs will exceed $250 billion.

Adjusting the most recent EIA fuel consumption data by projected increases in gasoline costs indicates that American families will spend more than $2,200 per family on gasoline in 2005. Based on DOT and EIA surveys of fuel use, low- and middle-income families will bear the greatest burden of these price increases.

Projected 2005 energy costs for personal vehicles

Household income:	$0-10K	$10K-$30K	$30K-$50K	>$50K	Total
Fuel costs per h/h	$1,433	$1,891	$2,447	$3,019	$2,264
Avg. h/h income	$5,700	$19,700	$39,200	$107,700	$59,067
Pct. of avg. income	25%	10%	6%	3%	4%

Total Household Energy Costs

Soaring residential energy costs (for natural gas, heating oil, and other fuels) and gasoline prices approaching $3 per gallon are imposing severe strains on low- and middle-income family budgets. Heating, cooling, and transportation are necessities of life, and the rapid increase in consumer energy costs is diverting low- and middle-income family budgets from other necessary goods and services such as improved health care, housing, and nutrition.

In 2005, the average American family will spend $4,100 on energy. This is seven percent of average pre-tax household income, and nine percent of the $43,318 median household income. The 63 million households earning less than $50,000, representing 56 percent of the population, will devote 20 percent of their pre-tax income to energy.

Total consumer energy expenditures, 2005

2005 income:	<$10K	$10-30K	$30-$50K	>$50K	Total
Residential energy	$1,285	$1,554	$1,791	$2,247	$1,834
Transportation	$1,433	$1,891	$2,447	$3,019	$2,264
Total energy	$2,718	$3,445	$4,238	$5,266	$4,098
Avg. h/h income	$5,700	$19,700	$39,200	$107,700	$59,067
Pct. of average h/h income	48%	17%	11%	5%	7%

Disproportionate Impacts on Minorities

The costs of residential and transportation energy represent even larger fractions of household expenditures for minority citizens. The Bureau of the Census finds that the median incomes of Hispanic and African American families in 2001 were $33,575 and $29,470, respectively, or 27 percent to 36 percent below the $46,305 median income of non-Hispanic Caucasian families.[5]

The U.S. Government does not publish data on household energy consumption by ethnic background, so it is impossible to estimate with precision the potentially greater burdens that energy costs are imposing on minority families. However, the lower median family incomes of these groups make it apparent that they may be disproportionately represented among the income categories with the highest energy cost burdens as a percentage of household income.

Conclusion

International market conditions (such as increased oil demand by China and other developing nations) affect all of the fuel price trends for petroleum: gasoline, home heating oil, natural gas, and propane. These fuels have experienced the fastest rate of price increase in this decade because they are subject to both international market demand pressures and supply uncertainties.

The prices of petroleum-based fuels have increased significantly above the rate of inflation in the past five years, while the residential cost of electricity has barely kept pace with inflation. The moderating influence of coal-based electric generation on overall energy price trends should be a key consideration for state and federal policymakers in decisions affecting the electric utility industry for the foreseeable future.

The rapid escalation of U.S. consumer energy prices, together with sluggish growth of income among lower- and middle-income households, underscores the need to find ways to slow these surging costs. Expanding the use of our abundant domestic coal resources - a primary source of low-cost electric energy generation, and a potential source of ultra-clean fuel products for industry and consumer uses - is an immediate, common sense policy response available to the United States Government.

Gene Trisko is an environmental attorney and energy economist who represents labor and industry clients. Mr. Trisko concentrates on issues surrounding the Clean Air Act and the continued use of coal as part of America's fuel mix.

End Notes

[1] Data on residential energy consumption patterns are from U.S. Department of Energy, Energy Information Administration, 2001 Survey of Residential Energy Consumption (RECS), http://www.eia.doe.gov/emeu/recs/contents.html. Data for 2001 energy consumption by fuel type were updated to estimated 2005 values based on consumer energy cost projections in EIA's Short Term Energy Outlook (September 2005, Hurricane Katrina "middle recovery" case), http://www.eia.doe.gov/emeu/steo/pub/contents.html.

[2] The most recent data on U.S. household income by income categories (2003) are from U.S. Bureau of the Census, "Income, Poverty, and Health Insurance Coverage in the United States, 2003," http://www.census.gov/hhes/www/income/income.html. Total and average household incomes by income category and race are from the distribution of household income in U.S. Bureau of the Census, "Money Income in the United States, 2001," (September 2002), http://www.census.gov/prod/2002pubs/p60-218.pdf.

[3] Data on consumer transportation expenditures were obtained from the U.S. Department of Transportation's 2001 National Household Travel Survey, http://www.fhwa.dot.gov/policy/ohpi/nhts/, with supplemental data by DOE/EIA in "Appendix K. Documentation On Estimation Methodologies For Fuel Economy And Fuel Cost," http://www.eia.doe.gov/emeu/rtecs/nhts_survey/2001/. Fuel costs for 2001 were updated to 2005 based on EIA's 2005 gasoline price projection in the Short-Term Energy Outlook (September 2005), n. 1, *supra*. The distribution of fuel costs by household income category was estimated from 1997 and 1994 DOT survey data.

[4] U.S. DOT, 2001 National Household Travel Survey, "Summary of Travel Trends," (December 2004).

[5] U.S. Bureau of the Census, "Money Income in the United States, 2001," (September 2002), http://www.census.gov/prod/2002pubs/p60-218.pdf.

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