FINAL TECHNICAL REPORT
September 1, 2006, through August 31, 2007

Project Title: **ECONOMIC EVALUATION OF ILLINOIS COAL AND WESTERN PRB COAL UNDER DIFFERENT POLLUTION CONTROL SCENARIOS**

ICCI Project Number: 05-1/US-2
Principal Investigator: Shiaoguo (Scott) Chen, Illinois State Geological Survey (ISGS)
Other Investigators: Jonathan P. Loftus, UIUC
Yongqi Lu, ISGS
Robert S. Statnick, Clear Skies Consulting
Project Manager: Francois Botha, ICCI

ABSTRACT

The study focused on identifying policy and Illinois coal free on board (FOB) pricing and transportation cost options to enhance the competitiveness of Illinois coal compared to Powder River Basin coal (PRB). It was concluded that Illinois coal is competitive with the PRB coal for a new mine-mouth electric generating facility. It was also concluded that a blend of 30% Illinois coal - 70% PRB coal is competitive with firing pure PRB coal in the same boiler. The recommendations provided based on the study include: 1) evaluate new mining options to lower FOB mine costs, 2) evaluate the cost to transport Illinois coal from the mine to the end user to determine the cost bottle necks, and 3) develop policy options to reduce the negative impacts of mining and transportation costs on Illinois coal production and sales. Lastly, one feature that makes the Illinois coal and coal blends competitive with PRB coal is their inherent mercury oxidation capacity. It is strongly recommend that the ICCI consider supporting a three to six month evaluation of firing a blend of Illinois and PRB coals to conclusively demonstrate that a coal blend fired in a selective catalytic reducer-dry FGD equipped boiler will remove 90% of the mercury emissions without any operational problems for the boiler owner/operator. Lastly, the Illinois Environmental Protection Agency (EPA) and the ICCI should work together to develop a policy to use the emission credits held by the Illinois EPA to enhance Illinois coal usage and mining employment.

EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency (USEPA) has recently finalized its Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Clean Air Visibility Rule (CAVR) emission regulations. These regulations limit the annual emissions of sulfur dioxide, nitrogen oxides, and mercury. The Illinois EPA has proposed mercury and sulfur dioxide and nitrogen oxide emission regulations that limit the power generator's ability to market excess emission credits.

This study focused on the long-term Illinois environmental regulations, to be complied with by 2015. Due to these regulations, the competitive edge between western PRB coal and Illinois coal may change because more stringent environmental regulations will favor Illinois coal. It is worthwhile to re-evaluate the impacts of current environmental regulations, coal transportation cost and coal FOB mine price on the inter-coal competition. The recent run-up in diesel fuel costs has increased the coal transportation cost from the Powder River Basin to Illinois. To evaluate the impact of environmental compliance costs and delivered coal cost on the cost of electricity, the Illinois State Geological Survey (ISGS) and Clear Skies Consulting (CSC) used the Integrated Environmental Control Model (IECM) developed by Carnegie-Mellon University.

ISGS and CSC interviewed a number of Illinois power generators to determine the preliminary capital cost estimates to be used to develop a cost factor (includes retrofit difficultness, inflation, pricing, labor costs, etc.) for the IECM model. The coal specifications were also determined by discussing with the ICCI and Illinois power generators. Based on the information obtained, the economic performances of a power plant firing either Illinois coal, blends of Illinois and PRB coals, or PRB coal were evaluated using the IECM model. Through a sensitivity study, the best case scenarios for Illinois coal were identified and Illinois environmental policies which would favor these case scenarios were discussed.

The project consisted of four tasks. In the first task, Illinois power plant sites were evaluated based on land availability and discussion with plant personnel on various issues. Second, representative coal specifications were determined from literature surveys and discussions with the Illinois Clean Coal Institute (ICCI) and power generators. For the third task, the IECM model was applied and flue gas desulphurization, selective catalytic reduction and mercury controls were selected. In the fourth task, case scenarios based on tasks 3 and 4 were evaluated using the IECM model, in order to compare the different coal types.

Three major conclusions resulted from the power generator meetings. First, the most probable delivered coal cost of PRB coal to Illinois was $27.50/ton, based on the FOB PRB coal price and transportation price. The team established a range of possible delivered PRB coal costs between $20 and $32/ton. Second, the most probable cost for Illinois coal was $35/ton, with a range of $30 to $40/ton. Third, the capital cost for a SDA/FF system was estimated at $400 MM for a 1200 MW_e plant. A summary of the economic evaluation, in terms of the breakeven delivered Illinois coal cost for the current PRB cost of $27.50/ton, is shown below.

	Breakeven Delivered Illinois Cost ($/ton)		**Current Market Cost ($/ton)**
	650 MW	175 MW	
Coal Type			
PRB-27.5/IL Blend	38.00	33.00	29.75
Mine-mouth	22.50	10.00	17.60
100% Illinois	31.00	19.00	35.00

In the modeling study for a 650 MW_e boiler, 100% Illinois coal costing more than $31.00/ton could not compete with 100% PRB coal at the current PRB price of $27.50/ton. For existing boilers, the economic evaluation showed that 100% Illinois coal could not compete with 100% PRB or a 70/30 PRB/IL blend at any of the three delivered PRB coal prices ($25, $27.50, and $32/ton). However, we did determine that Illinois coal at a new mine-mouth facility, as well as a 70/30 PRB/IL blend, can be competitive with PRB. Illinois coal becomes less competitive with a decrease in boiler size, and for a 175 MW_e boiler even low-cost Illinois coal can not compete with PRB or blend. The best-case scenario for Illinois coal is the 70/30 PRB/IL blend, within a PRB cost range of $27.50 to $32.00 per ton.

Although an investigation of CO_2 emissions was not part of the original study, it was added to show that Illinois coal has an advantage in this area over 100% PRB and PRB/IL blend coals. First there are lower CO_2 emissions for Illinois coal with no CO_2 control system applied. Second, when CO_2 emission controls are applied, there is a lower annual cost when using Illinois coal. A 4% reduction in CO_2 emissions from power plants would favor Illinois coal.

Recommendations for maintaining or increasing Illinois coal use at power generation facilities in Illinois include setting transportation costs that reflect distance traveled for coal delivery, carbon dioxide regulations, long-term demonstration of burning a PRB/Illinois coal blend, use of credits taken for new generation to enhance Illinois coal competitiveness, and determining alternate mining techniques.

OBJECTIVES

The overall objective of this study was to identify policy options which would increase Illinois coal production and coal mining employment. To achieve this objective, the study was divided into two sub-objectives. The first sub-objective was to conduct studies to evaluate the cost to generate one megawatt-hour of electricity from firing Illinois coal, blends of Illinois and Powder River Basin (PRB) coals, and Powder River Basin (PRB) coal while complying with the Illinois mercury, sulfur dioxide (SO_2) and nitrogen oxides (NO_x) annual emission limits for electric generators.

The second sub-objective was to identify factors that influence the electric generator's fuel selection process. This included the delivered price of coal, which included both the free on board (FOB) coal cost and the transportation cost, and the impact of environmental regulations on the fuel selection process.

INTRODUCTION AND BACKGROUND

The U.S. Environmental Protection Agency (USEPA) has recently finalized its Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Clean Air Visibility Rule (CAVR) emission regulations. These regulations limit the annual emissions of sulfur dioxide, nitrogen oxides, and mercury. The CAIR, CAMR, and CAVR regulations envision a cap and trade regime in which power generators are free to over-control at one or more plants and to freely trade the emission credits among power generators. The Illinois EPA has proposed mercury and sulfur dioxide and nitrogen oxide emission regulations that limit the power generator's ability to market excess emission credits. The Illinois EPA has proposed that power generators be able to trade emission credits among plants and boilers within their system. They are not permitted to market emission credits between power generators within or outside of Illinois. The Illinois regulations are summarized in the Table 1 on the following page.

This study focused on the long-term environmental regulations to be complied with by 2013 and 2015. It is important here to note that the mercury emission standard will begin in mid-2009. Since the control technology for one particular pollutant can affect other pollutants as well, Illinois power plants may choose to make decisions before mid-2009 about their multi-pollutant control scheme. Due to all these regulations, the competitive edge between western PRB coal and Illinois coal may change because more stringent environmental regulations will favor Illinois coal. The reason is that under more stringent environmental laws, SO_2 emission control cost will be a lower percentage of the total environmental control cost. It is also expected that a regulation to limit carbon dioxide (CO_2) emissions will considerably favor Illinois coal.

Table 1. Pollutant Emission Limits or Practices[1,2]

	IEPA		USEPA
Pollutant Component	**2013**	**2015**	**New Source Performance Standards (NSPS)**
SO_2	0.33Lb/MMBtu or 44% reduction from base rate of emissions	0.25 Lb/MMBtu or 55% reduction from base rate of emissions	2.0 Lb/MWh_g, or 0.25 Lb/MMBtu
NO_x	0.11 Lb/MMBtu or 80% reduction from base rate of emissions	Same as 2013	1.0 Lb/MWh_g, or 0.126 Lb/MMBtu
Mercury	0.008 Lb/GWh or 90% reduction or injection of halogenated activated carbon*	Same as 2013	$21x10^{-6}$ Lb/MWh_g
PM	0.03 Lb/MMBtu	0.03 Lb/MMBtu	6.4 mg/J, or 0.015 Lb/MMBtu

*For PRB coal, the halogenated activated carbon injection (ACI) rate is 5 Lb/MMacfm, and for bituminous coal the ACI rate is 10 Lb/MMcf.

It is worthwhile to re-evaluate the impacts of current environmental regulations, coal transportation cost and coal FOB mine price on the inter-coal competition. The recent run-up in diesel fuel costs has increased the coal transportation cost from the Powder River Basin to Illinois—we currently estimate the transportation cost to be between $15 and $20+ per ton of coal and the FOB cost of PRB coal is about $7.50 per ton. Combined transportation and FOB price is equivalent to $22.50 to $27.50 per ton of PRB coal delivered. The equivalent delivered cost of Illinois coal is between $30 and $40 per ton.

To evaluate the impact of environmental compliance costs and delivered coal cost on the cost of electricity, the Illinois State Geological Survey (ISGS) and Clear Skies Consulting (CSC) used the Integrated Environmental Control Model (IECM) developed by Carnegie-Mellon University. This model allows for inputting the fuel cost, fuel composition, specification of environmental compliance limits for SO_2, NO_x and mercury, and control technology (e.g. wet or dry flue gas desulphurization; electrostatic precipitator or fabric filter, and combustion modification or selective catalytic reduction).

EXPERIMENTAL PROCEDURES

ISGS and CSC interviewed a number of Illinois power generators to determine the preliminary capital cost estimates to be used to develop a cost factor (includes retrofit difficultness, inflation, pricing, labor costs, etc.) for the IECM model. The coal specifications were also determined by discussing with the ICCI and Illinois power generators. Based on the information obtained, the economic performances of a power plant firing either Illinois coal, blends of Illinois and PRB coals, or PRB coal were evaluated using the IECM model. Through a sensitivity study, the best case scenarios for Illinois coal were identified and Illinois environmental policies which would favor these case scenarios were discussed.

Task 1. Evaluation of Illinois Power Plant Sites

The difficulty of the retrofit (retrofit factor) will strongly impact the retrofit cost for any environmental control technologies. Land availability is the major factor that impacts the retrofit cost. To identify the factors that could influence the level of difficulty in retrofitting sulfur and nitrogen oxide control equipment, the GIS database (satellite images) available at ISGS were used to screen the representative power plants. The images were used to identify open areas at all of the Illinois power plants that could be used to install flue gas desulphurization and other equipment. After the potential power plants were identified, meetings with the power plant personnel were arranged and various issues were discussed.

Task 2: Obtain Illinois Coal Specifications

In obtaining the coal specifications, a review of IECM coal property values and discussions with the ICCI and power generators were conducted. Representative coal specifications were then determined.

Task 3: Application of the IECM Model

The flue gas desulphurization (FGD), selective catalytic reduction (SCR) and mercury controls were selected based on design coal characteristics. The IECM model has a module that uses the coal characteristics to estimate the net and gross plant heat rate. This module calculates the heat rate, Btu/kwh, and includes the delivered coal cost to establish the fuel cost component and total bus-bar electricity cost. The model output includes $/MWh components for environmental controls, fuel, fixed boiler variable cost, and for new units, total fixed and variable costs for the entire plant.

Each coal characteristic could yield a different flue gas flow rate, acfm/ton. The flue gas flow rate is a key parameter in estimating the cost of the flue gas desulphurization and the SCR modules. The IECM model is rather unique in combining boiler parameters and coal characteristics to estimate the capital cost of the environmental control systems. It also estimates the reagent usage, power consumption, and by-product production using the specified coal characteristics. Aside from these unique features, this model has a refined retrofit factor analysis. In the IECM model, there are several cost sub-models that can have different retrofit factors. The IECM cost sub-modules for SO_2 installation are:

Reagent feed, SO_2 removal, Flue gas handling, Solids handling, General support, and Miscellaneous equipment. The sub-modules for SCR installation are: Reactor housing, Ammonia injection, Ducts, Air pre-heater modifications, ID fan differential, Structural support, and Miscellaneous equipment. The sub-modules for mercury control installation are: sorbent injection, sorbent recycle, Duct work, sorbent disposal, Pulse jet fabric filter. Each of the sub-modules can have a different retrofit factor. For example, if a retrofit site has adequate land for a FGD installation but the FGD must be located a large distance from the existing equipment, the IECM model can be adjusted to have a high retrofit factor for flue gas handling, and low to no retrofit factor for the remaining FGD areas. This option makes the IECM very powerful in estimating the cost to retrofit a utility boiler.

In addition to capital cost flexibility, the IECM model allows the user to specify the site-specific reagent, by-product disposal cost or sale price, electricity cost, labor charge, and other O&M costs. The ability to specify the site-specific annual cost components makes the IECM model ideally suited to the type of analysis proposed for the project. Illinois coal-fired power plants are expected to comply with the Illinois regulations by switching to a lower sulfur fuel, installing control technology, or both fuel switching and technology installation. There are a number of IECM configurations available to evaluate the different methods of reducing emissions while complying with Illinois regulations. The control technologies available are listed in Table 2. Additional details of the IECM modeling program can be found by downloading the program from the Internet.[3]

Table 2. Control technology used in the IECM model.

Parameter	Technology
Combustion	
Fuel Type	Coal
NOx	In-Furnace Controls
Post-Combustion	
NOx	Hot-Side SCR
Particulates	Cold-Side ESP, or FF
SO_2	Wet FGD, or SDA
Mercury	ACI, or ACI + Water
CO_2	Amine System, or O_2-CO_2 Recycle

Task 4: Sensitivity Study

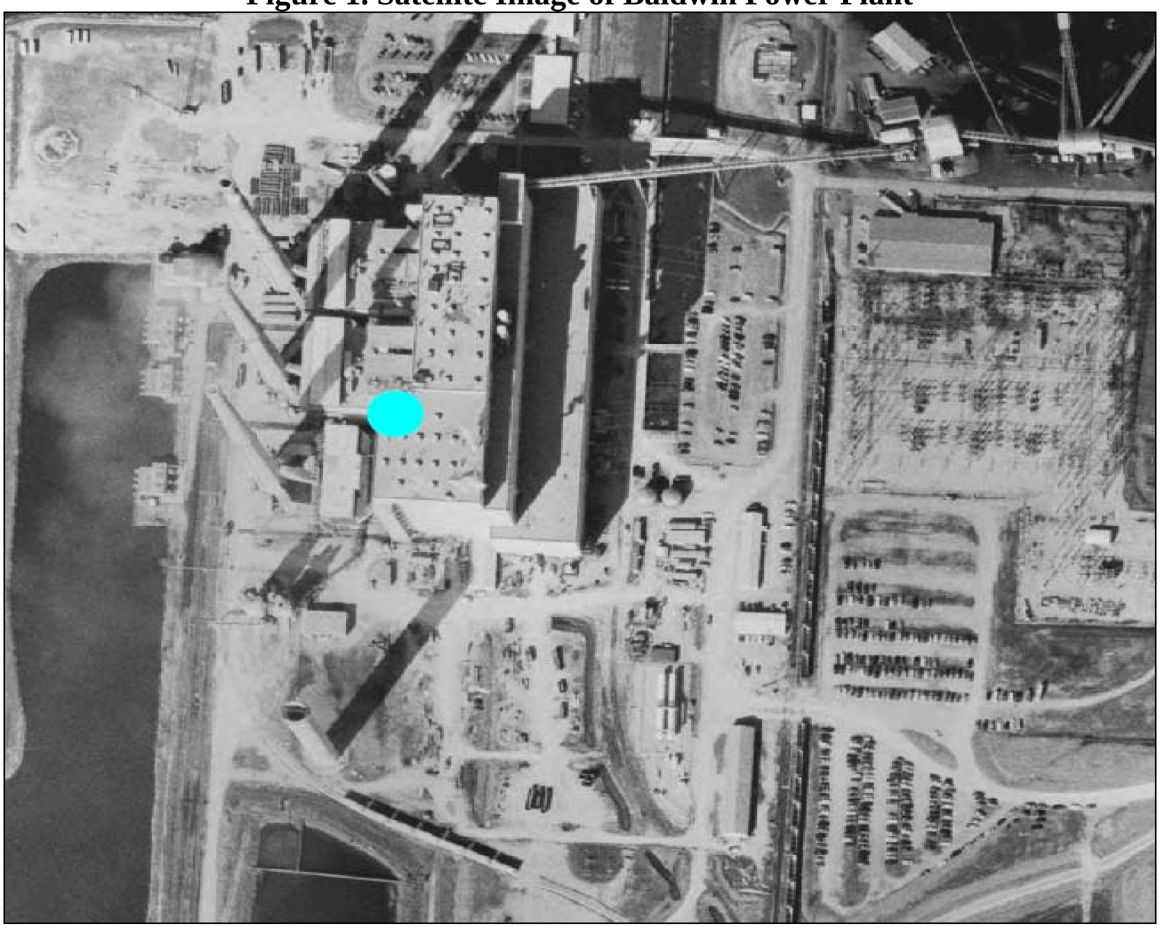
The case scenarios from Task 3 were evaluated using the IECM model, in order to compare the different coal types. The parameters tested were: coal type and cost; control technology for SO_2, NO_X, mercury and particulate matter; boiler type; and boiler size. The breakeven cost of electricity, as well as the capital and O&M costs, were estimated for the scenarios. A preliminary analysis of CO_2 control scenarios for the different coal types was also performed using IECM.

RESULTS AND DISCUSSION

Task 1. Evaluation of Illinois Power Plant Sites

An example of a satellite image from the GIS database at ISGS is presented in Figure 1. After screening all of the coal firing power plants in Illinois, ISGS and CSC identified the potential power plants for the site visiting.

Figure 1. Satellite Image of Baldwin Power Plant



After the plant photos were carefully examined, plants were identified that represented different levels of retrofit difficulty. We identified about eight plants that represented different boiler sizes, land availability, and based on the satellite images degrees of difficulty in retrofitting FGD, mercury, and SCR control equipment. ISGS, CSC, and the

ICCI project manager reviewed the plant options and selected five plants for this study. The plants were: Baldwin, Coffeen, Kincaid, Duck Creek and Edwards. The plant owners were contacted to obtain their concurrence to participate in the study. All of the power plant owners agreed to participate in the study except for one. ISGS and CSC visited each power plant owner that agreed to discuss their environmental control plans. We visited the Kincaid Generating Station, MidWest Generating Corporate, and Dynegy.

After establishing the site visit schedule, a list of questions to ask each power generator was developed. The questions covered electricity generating issues while firing Illinois and PRB coals, discussion of the current delivered price of Illinois and PRB coals, discussion of current environmental issues facing each generator, and what can Illinois do to encourage you to burn Illinois coal. A copy of the questions is attached in Appendix A. After the site visits, the power generator responses were combined to identify common concerns and delivered coal price issues. Based on these common issues, ISGS and CSC developed a matrix of plant size, delivered coal price, environmental regulations, and other assumptions for use in the IECM model to:

- Identify the PRB and Illinois environmental cost factors;
- Identify the delivered Illinois coal price that favors burning a PRB/IL coal blend, Illinois coal, and PRB coal

Results of Power Generator Meetings

At the majority of the power generator meetings, the generator stated that no Illinois coal producer has made a sales call in the past year—in some cases not in recent years. The lack of sales visits may indicate that Illinois coal producers have given up on competing with PRB coal producers to sell Illinois coal to power generators. Illinois coal delivered prices were found to be between $30 and $40 per ton.

Second, Illinois coal could be more competitive if there was an Illinois carbon dioxide regulation. Illinois coal is inherently a lower CO_2 emitter than PRB coal (based on net electrical output). A reduction in CO_2 emissions from power plants would favor Illinois coal. Most of the power generators currently burn PRB coal and are planning on installing spray dryer FGD systems. This all but eliminates Illinois coal from consideration. The power generators should be invited to participate in the CO_2 emission reduction deliberations.

Based on the discussions with power generators, we concluded that the FOB PRB coal price is between $7.25 and $8.00 in 2007 and is estimated to be $9.00 in 2008, and $10.00 in 2009 for an 8800Btu/lb and 0.3 to 0.4% sulfur product. The current estimated PRB coal transportation cost is about $20.00/ton, but the cost is site specific and is dependent on oil prices which have risen significantly since the site visits. The current Illinois coal transportation cost is about $10.00/ton. It is interesting to note that Illinois coal transportation cost is about half the transportation cost of PRB coal but the distance Illinois coal is moved is between 20 to 30% of the distance PRB coal is transported. All of the Illinois power generators have allocated manpower to monitor coal shipments. This adds an additional cost but is not included in the delivered price of PRB coal.

All of the power generators reported no derates associated with switching from Illinois to PRB coal. In most instances, the derates were recovered by installing flue gas conditioning systems (such as SO_3 conditioning) or by upgrading the coal mills and coal delivery systems. In addition, some of the power generators reported downtime while firing Illinois coal because of air heater fouling/ and boiler slagging issues. While firing PRB coal, no cases of air heater fouling were reported.

As of the site visit date, none of the power generators have placed orders for spray dryer FGD systems. All of the power generators are leaning toward selecting the spray dryer technology. The power generators believe that the cost of retrofitting spray dryer FGD systems would be about $300 to $400/KW. This is based on the perceived shortage of boiler makers to construct the units, shortages of basic building materials, and the lack of aggressive pricing by technology vendors.
The power generators also stated that the Illinois EPA took 30% of the NO_x allowances from coal fired generators and set them aside for renewable, clean coal, and other projects. The power generators suggested that some of these allowances could be allocated back to the generators to offset the increased NO_x emissions from using Illinois coal. For some power plants, there is not enough land available to install the FGD systems and have adequate waste storage. The power generators suggested that Illinois could provide assistance in acquiring additional land to accommodate the FGD system and associated waste disposal requirements.

All of the power generators agreed that by adopting more stringent environmental regulations that go beyond CAIR and CAMR regulations, Illinois has placed Illinois power producers at a cost disadvantage in the Pennsylvania-Jersey-Maryland West area. If Kentucky, Indiana, and Wisconsin don’t follow suit, then Illinois power generators will be at a cost disadvantage compared to neighboring states. None of the power generators we met with indicated that they are currently evaluating the addition of new electric generating capacity to their system. They believe that the current Pleasant Prairie Generating Station (located in Kenosha County, Wisconsin) planning should be adequate for the future. One utility suggested that new generation will be limited to:

- Aggressive renewable generation program, and
- Clean Coal Projects such as IGCC

Task 2: Illinois Coal Specifications

The typical coal specifications were based on the IECM model and are listed in Table 3. During the study, it was found that transportation cost within Illinois plays an important role in determining the competitiveness of Illinois coal, blend of Illinois and PRB coals, and PRB coal. In addition to existing power generators, we also developed coal specifications for new mine-mouth coal-fired boilers.

Table 3. Coal properties for the scenarios tested.

	Coal Type			
Property	Illinois #6	Western PRB	70/30 PRB/IL	Mine-mouth
HHV, Btu/lb	10,900	8,340	9,108	9,500
Carbon, wt%	61.353	48.214	52.156	51.998
Hydrogen, wt%	4.211	3.312	3.582	3.568
Oxygen, wt%	6.035	11.878	10.125	5.115
Chlorine, wt%	0.170	0.010	0.058	0.144
Sulfur, wt%	3.000	0.300	1.110	4.000
Nitrogen, wt%	1.163	0.700	0.839	0.986
Ash, wt%	11.028	5.324	7.035	23.144
Moisture, wt%	13.033	30.261	25.093	11.045
Mercury, ppmw	0.090	0.100	0.097	0.090

Task 3: Application of the IECM Model

IECM Model – Case Development

As a result of the site visits, particular IECM performance assumptions were developed. These assumptions were used as inputs in the IECM model to evaluate scenarios with various coal feed and environmental controls. Table 4 shows model parameters and values for the different coal scenarios.

The delivered coal cost for Western PRB and Illinois coals covers a range of delivered costs to Illinois plants. It has been demonstrated for a SCR-SDA/FF system that 93/7 and 86/14 PRB/IL coal ratios remove 50% and 80% mercury, respectively.[4] The coal blend ratio used in this study was 70/30 PRB/IL and is expected to remove a minimum of 90% mercury. Also, it was assumed that the blending of coal would be done on-site and would not add a significant cost to coal handling. Of the boiler types operating at Illinois plants, tangential-fired is the most common. Wall-fired and cyclone boilers were evaluated to cover all possible scenarios.

Table 4. IECM model parameters and values for scenarios.

Model Parameter	Value			
	IL	**PRB**	**70/30 PRB/IL**	**Mine-mouth (new plant)**
Fuel Cost (total as-delivered) $/ton	Low: 30 Mid: 35 High: 40	Low: 20 Mid: 27.5 High: 32	All combinations of PRB costs with IL costs	Low: 17.6 High: 25
Boiler Type*	All	All	All	Tangential
NO_X Emission Limit, Lb/MMBtu or % Removal **	0.11 or 80%	0.11 or 80%	0.11 or 80%	0.11
NO_X Control Technology	Low-NO_X burner + SCR	Low-NO_X burner + SCR	Low-NO_X burner + SCR	Low- NO_X burner + SCR
Particulates Emission Limit, Lb/MMBtu	0.03	0.03	0.03	0.015
Particulate Control Technology	ESP	FF	FF	ESP
SO_2 Emission Limit, Lb/MMBtu	0.25	0.25	0.25	0.25
SO_2 Control Technology	Wet FGD	SDA	SDA	Wet FGD
Mercury Emission Limit, % Removal	90%	ACI	90%	98%
Mercury Control ACI, Lb/MMacfm	N/A	5	N/A	N/A
Boiler Size, MW_e	Small: 175 Large: 650	Small: 175 Large: 650	Small: 175 Large: 650	Small: 175 Large: 650

* Boiler types include: Tangential-fired, Wall-fired, and Cyclone.
** For tangential and wall-fired units, 80% was the operational value; for cyclone units, 0.11 Lb/MMBtu was the operational value.

The retrofit factors for different areas of the plant was determined by first testing a 1200 MW plant with PRB coal, and adjusting the retrofit value until the combined capital cost for the SDA and FF units was $400 MM. This cost corresponds to the value reported by the utility companies interviewed. The resulting retrofit value was 3.0, and this factor was then applied to the ACI, SCR, SDA, FGD, and FF units for all cases. A retrofit value of 1.0 was used in cases where the ESP unit continued operating. The corresponding capital cost was assumed to be sufficient for the additional cost of modifications to the existing ESP. These modifications, which may include an additional field or an increase in size, would be required for improved performance assuming SO_3 conditioning or water vapor addition would not be applied.

Illinois multi-pollutant standards call for the lowest emissions option for NO_X and SO_2. For example, 80% removal of NO_X for an IECM scenario may actually yield less than 0.11 Lb/MMBtu (the alternative emission limit option), and thus the NOx removal efficiency would be set to “80%.” Regulations for mercury and PM removal are a little different. The option implemented for mercury removal when burning PRB coal is set at a fixed ACI rate and requires an ESP or FF system. For Illinois coal, only a SCR-FGD system is required for sufficient mercury removal. When burning a PRB/IL blend coal, current Illinois regulations call for a weighted average of the ACI rates required for bituminous and sub-bituminous coals. However, as stated above, the 70/30 PRB/IL blend is expected to remove over 90% mercury, which would satisfy the alternative compliance option of 90% mercury removal. For PM emissions there is only a Lb/MMBtu limit on PM emissions.

For SO_2 control, wet FGD was used when burning Illinois coal, due to its high-sulfur content. Similarly, wet FGD was used in the mine-mouth case. SDA was used for the PRB coal and PRB/IL coal blend because this technology was selected by the utilities. For controlling particulates, an ESP was used when burning Illinois coal because of its lower cost; however, when burning PRB and blend coal, a fabric filter is used. To control mercury emissions when burning 100% PRB coal, brominated AC was injected at a rate of 5 Lb/MMacfm. This rate achieves the IEPA multi-pollutant standard requirement for mercury removal when burning a sub-bituminous coal. ACI is used only for 100% PRB coal because the coal chlorine content is significantly lower than Illinois coal. The lower amount of chlorine leads to less oxidized mercury and less mercury capture in the SDA/FF system. When burning 100% Illinois coal, the higher chlorine content, along with the inherent SCR oxidation of elemental mercury to oxidized mercury and the inherent oxidized mercury capture by the FGD system, is sufficient for 85-90% mercury removal.[5]

Task 4: Sensitivity Study

IECM Modeling Results

Case scenarios in Table 4 were evaluated using the IECM model. The capital and O&M costs, as well as the breakeven cost of electricity were estimated. Figures 3 and 4 show cost of electricity (COE) values for different scenarios with a tangential-fired boiler. Similar results for wall-fired and cyclone boiler scenarios can be found in Appendix B and C. Capital and O&M cost results for the tangential-fired boiler can be found in Appendix D.

Figure 3A. COE for various delivered coal prices (650 MW_e).

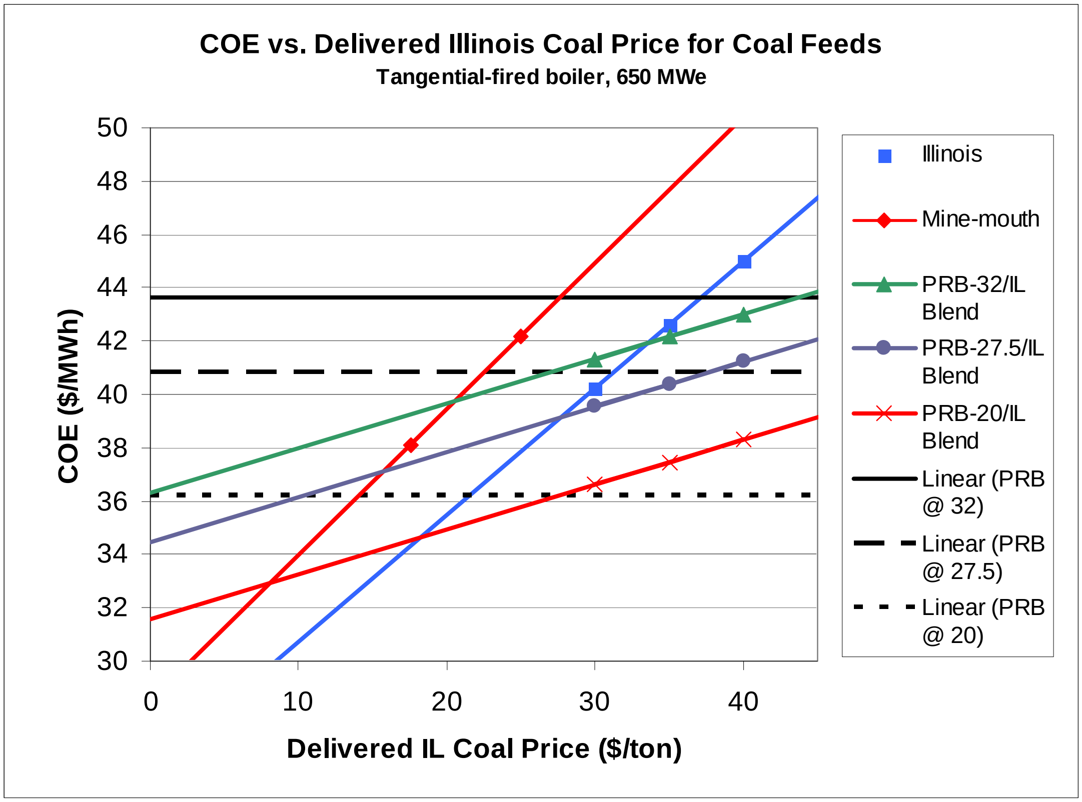
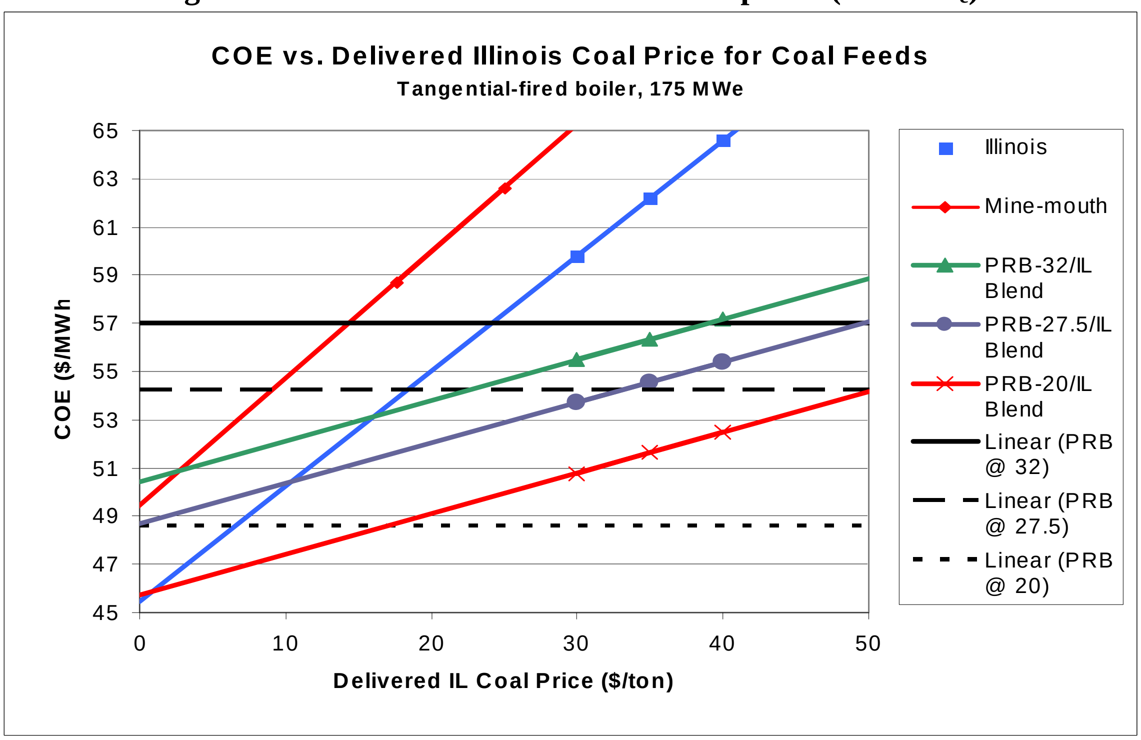


Figure 3B. COE for various delivered coal prices (175 MW_e).



Note: For both graphs, PRB-##/IL indicates the 70/30 PRB/IL blend coal.

Figure 4A. COE for environmental controls and fuel (650 MW_e).

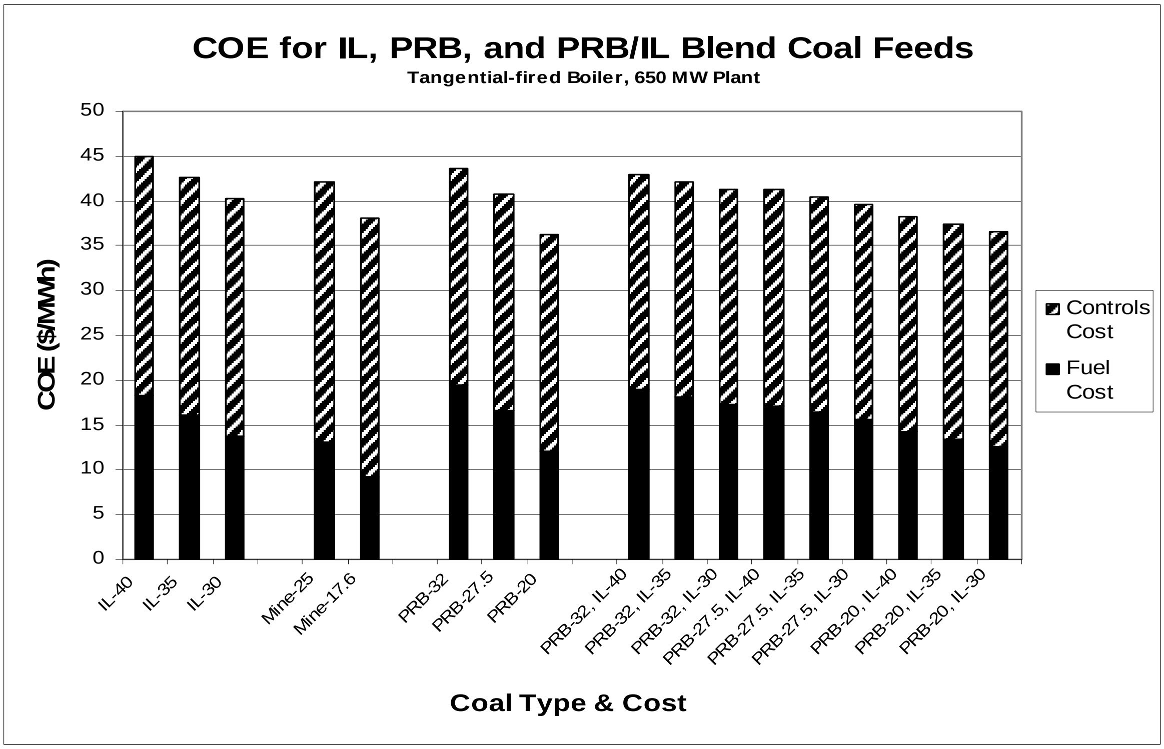


Figure 4B. COE for environmental controls and fuel (175 MW_e).

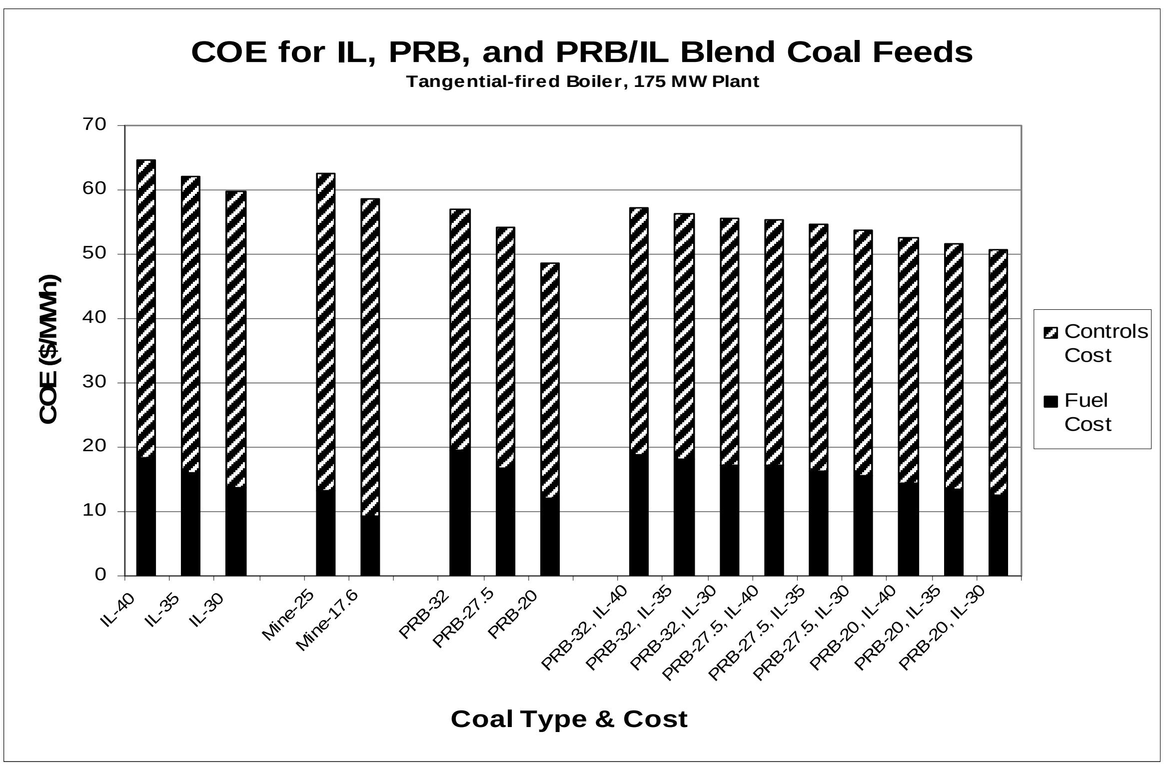


Table 5 shows the breakeven delivered costs of each coal type, for a fixed PRB delivered cost of $27.50/ton. For 100% PRB coal at $27.50/ton, the breakeven costs of 100% Illinois coal are less than the current Illinois coal market cost, showing that Illinois can't compete well with PRB in this case. However, for the 70/30 PRB/IL blend, the breakeven costs of Illinois coal are closer to the current Illinois market costs, making Illinois coal more competitive. As the PRB coal cost increases, the breakeven delivered Illinois, mine-mouth, and blend coal costs increase and those coals become more competitive with PRB coal. For example, at a delivered PRB coal cost of $32/ton at a 650 MW_e plant, the breakeven delivered Illinois coal cost is about $37/ton. For both boiler sizes, the PRB/Illinois blend is the most cost competitive with PRB coal at all of the assumed PRB delivered prices ($20, $27.50, and $32/ton).

Table 5. Breakeven delivered Illinois coal costs against a fixed PRB cost of $27.50/ton.

	Breakeven Delivered Illinois Cost ($/ton)		**Current Market Cost ($/ton)**
	650 MW_e	175 MW_e	
Coal Type			
PRB-27.5/IL Blend	38.00	33.00	29.75
Mine-mouth	22.50	10.00	17.60
100% Illinois	31.00	19.00	35.00

From Figures 3 and 4 there are several important observations. First, the combined fuel and environmental controls costs when burning 100% Illinois coal will be more costly than burning PRB coal or the PRB/IL blend. This shows that burning Illinois coal, without some type of incentive to the generator, can not be competitive with either 100% PRB coal or a coal blend containing PRB. Second, the addition of Illinois coal to PRB coal in a 70/30 PRB/IL blend gives about the same or less COE's compared to 100% PRB coal, for a constant PRB coal cost and the full range of Illinois coal cost (with the exception of market conditions where the delivered PRB coal cost is low at $20/ton). This shows that the PRB/IL coal blend can be competitive with 100% PRB coal, even without incentives. Similar trends can be observed for the 175 MW_e scenario. Third, an Illinois mine-mouth plant can be competitive with the PRB and blend coal, but only at the 650 MW_e size. For this plant size, a low-cost mine coal yields lower COE's than 100% PRB and blend coals, except for some low PRB coal cost cases. At high Illinois mine coal cost, this plant has the same or lower COE than high PRB coal cost and two high blend coal cost cases. Lastly, note the high percentage contribution of "fuel" to the total COE values – an average of 38% for the 650 MW_e case, and 28% for 175 MW_e.

A preliminary analysis of CO_2 control scenarios was also performed. Table 6 shows the annual CO_2 emissions for the various coal feeds.

Table 6. CO_2 emission for coal types, at a 650 MW_e tangential-fired boiler.

	Coal Type			
	Illinois	**PRB**	**PRB/IL Blend**	**Mine-mouth**
Tons CO_2/yr, (x10^6)	5.35	5.58	5.46	5.24

Burning PRB coal results in higher CO_2 emissions than Illinois coal, due to a lower HHV and higher moisture content of the PRB coal. The project team investigated the cost ($/MWh) of controlling CO_2, using an amine-based system, for the flue gas of each coal feed. The cost of 90% CO_2 removal from PRB coal flue gas is over 10% greater than CO_2 removal from Illinois coal. A majority of the higher cost when burning PRB coal results from a higher flue gas volume than Illinois coal, and thus a higher capital cost of control equipment. It was found that a 4% reduction in CO_2 emissions from power plants would favor Illinois coal.

CONCLUSION AND RECOMMENDATIONS

Three major conclusions resulted from the power generator meetings. First, the most probable delivered coal cost of PRB coal to Illinois was $27.50/ton, based on the FOB PRB coal price and transportation price. The team established a range of possible delivered PRB coal costs between $20 and $32/ton. Second, the most probable cost for Illinois coal was $35/ton, with a range of $30 to $40/ton. Third, the capital cost for a SDA/FF system was estimated at $400 MM for a 1200 MW_e plant.

In the modeling study for a 650 MW_e boiler, 100% Illinois coal costing more than $31.00/ton could not compete with 100% PRB coal at the current PRB price of $27.50/ton. For existing boilers, the economic evaluation showed that 100% Illinois coal could not compete with 100% PRB or a 70/30 PRB/IL blend at any of the three delivered PRB coal prices ($25, $27.50, and $32/ton). However, we did determine that Illinois coal at a new mine-mouth facility, as well as a 70/30 PRB/Illinois blend, can be competitive with PRB. Illinois coal becomes less competitive with a decrease in boiler size, and for a 175 MW_e boiler even low-cost Illinois coal can not compete with PRB or blend. The best-case scenario for Illinois coal is the 70/30 PRB/IL blend, within a PRB cost range of $27.50 to $32.00 per ton.

Although an investigation of CO_2 emissions was not part of the original study, it was added to show that Illinois coal has an advantage in this area over 100% PRB and PRB/IL blend coals. First there are lower CO_2 emissions for Illinois coal with no CO_2 control system applied. Second, when CO_2 emission controls are applied, there is a lower annual cost when using Illinois coal. A 4% reduction in CO_2 emissions from power plants would favor Illinois coal.

There are several recommendations for maintaining or increasing Illinois coal use at power generation facilities in Illinois:

- Set transportation costs that reflect distance traveled for coal delivery. For example, if Illinois coal delivery cost could be reduced from $10/ton to $5/ton, then Illinois coal would be more cost competitive. Further research is needed to determine how this reduction in cost can be achieved.
- Determine how to implement alternate mining techniques, e.g. using 800 to 1,000 foot long wall panels to reduce the FOB mine costs, at both existing and mine-mouth plants.
- Consider carbon dioxide regulations that favor Illinois coal and enhance environmental quality.
- Perform a long-term demonstration of burning a PRB/IL coal blend. This would include a 3-6 month study of how ash properties effect boiler operation, mercury reduction, etc. The study would record problems identified during the demonstration, and how they were minimized or otherwise dealt with.
- The Illinois EPA and Illinois Coal Offices should consider how to use the credits taken for new generation to enhance Illinois coal competitiveness and increase mining employment.

REFERENCES

1. “Control of Emissions from Large Combustion Sources.” Illinois Administrative Code, Title 35, Subtitle B, Chapter 1, Subchapter c, Part 225. (2005). Online. http://www.ipcb.state.il.us/documents/dsweb/Get/Document-55740/ June 4, 2007.

2. “Standards of Performance for fossil-fueled steam generators for which construction is commenced after August 17, 1971.” USEPA Code of Federal Regulations, Title 40, Part 60, Subpart D. (2007). Online. http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=22104e17f3384a3e823e978150aed838&rgn=div6&view=text&node=40:6.0.1.1.1.9&idno=40 Aug. 17, 2007.

3. “Integrated Environmental Control Model: A tool for calculating the performance, emissions, and cost of a fossil-fueled power plant.” Carnegie Mellon University. Version 5.21. (2007). Online. www.iecm-online.com. (2007).

4. “Evaluation of Sorbent Injection for Mercury Control.” NETL Meeting. (2005). Online. http://204.154.137.14/publications/proceedings/05/mercury/pdf/Sjostrom-071205-ampdf Aug. 17, 2007.

5. Withum, J.A. 2006. Evaluation of Mercury Emissions from Coal-Fired Facilities with SCR and FGD Systems. Project Final Report, U.S. DOE NETL Cooperative Agreement DE-FC26-02NT41589, CONSOL Energy Inc., South Park, Pennsylvania.

DISCLAIMER STATEMENT

APPENDIX A

Appendix A. Questions for Utilities.

- Fuel Issues
  - Has an Illinois coal producer made a recent sales visit?
  - What is the value of the potential electricity if the derate is eliminated?
  - What is the cause of the derate; e.g. ESP limits boiler load?
  - Has the boiler had any slagging or fouling problems while burning PRB or historically, Illinois coal?
  - If you were to sign a new rail transportation contract in 2007, is $20/ton a fair estimate of the contract cost? If not, higher or lower?
  - If you were to sign a new PRB coal contract, is $8/ton a fair estimate of the FOB coal cost?
  - Do you have any concerns about the delivery schedule of PRB coal? Do you forecast any bottlenecks?
  - In the recent past, there were PRB delivery problems. Did this adversely effect your operation?

- Boiler Issues
  - Does the PRB fired unit operate with any derates?
  - What is the value of the lost production? During the summer? During the winter?
  - When the unit fired Illinois bituminous coal, was there any operating problems? Slagging? Fouling? Mill Issues? Etc.
  - While firing PRB coal, what were the causes of derates? ESP Issues? Coal handling? Etc.

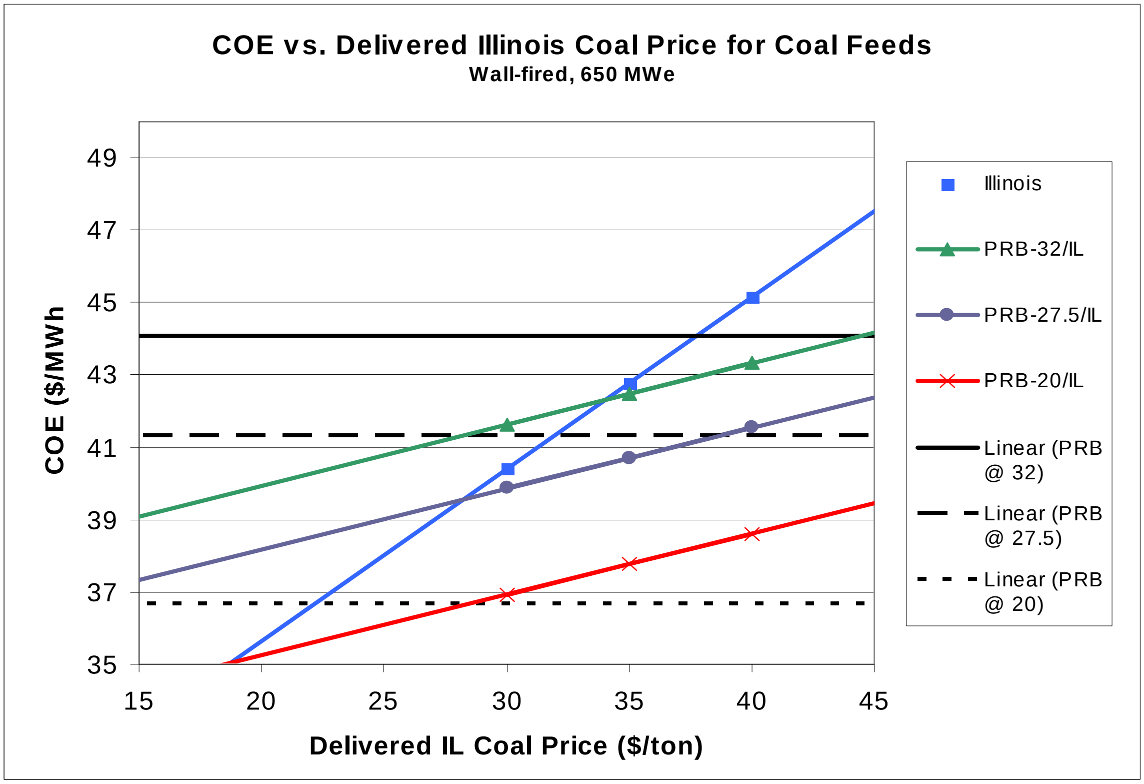
- Environmental Issues
  - Has Illinois EPA provided you with emission allowances for this plant? If yes, how many allowances did you receive?
  - Is there any other agreement between the station and/or utility owner operator and either the federal or state EPA that is more restrictive in limiting SO_2 , NO_x ,or Hg emissions?
  - Have you placed any orders for FGD units? Did you order wet or dry FGD units? What is the start-up schedule for the units ordered?
  - Are you planning to use combined mercury and SO_2 control to comply with the Illinois mercury rule limits?
  - What is the maximum load factor that your utility has hit during the past 3 years? Is there any plan for adding new capacity to the Illinois grid?
  - Are you planning to add additional capacity outside of Illinois to serve Illinois load?

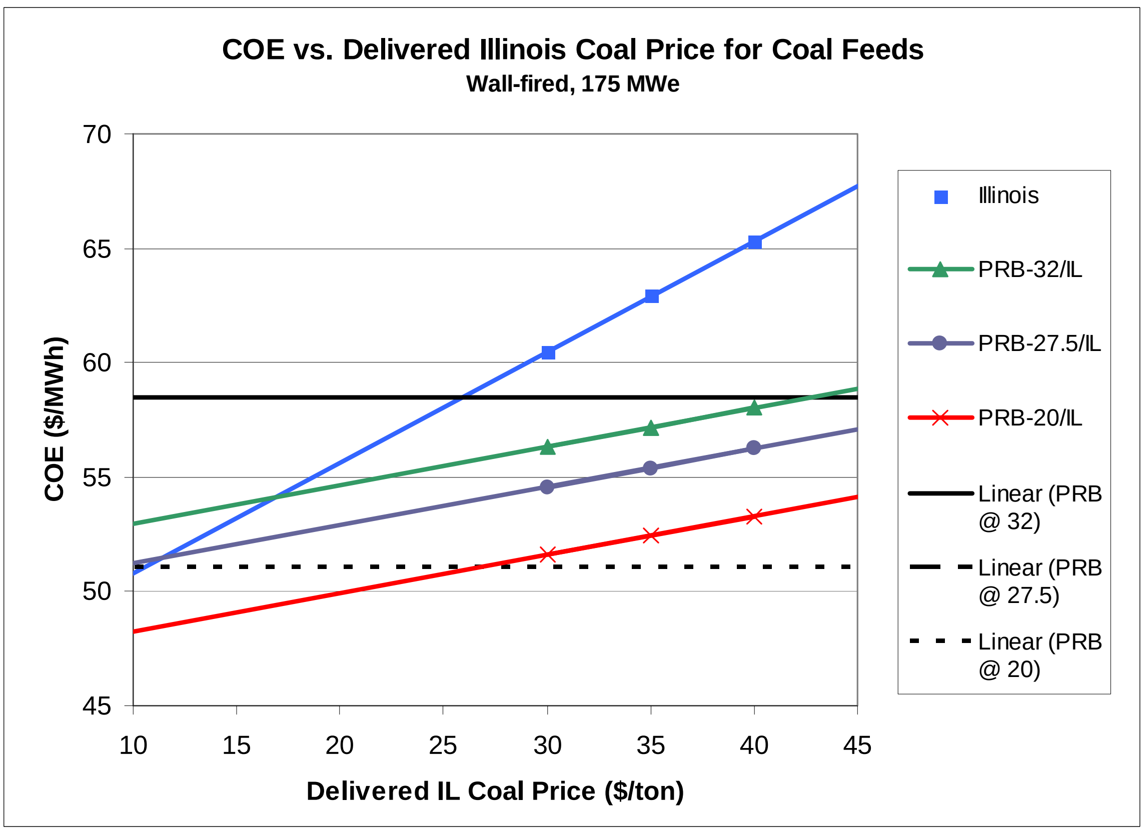
  - If you plan to comply with the CAIR and Mercury Rule regulations by purchasing credits, can you share with us a fair market value you would

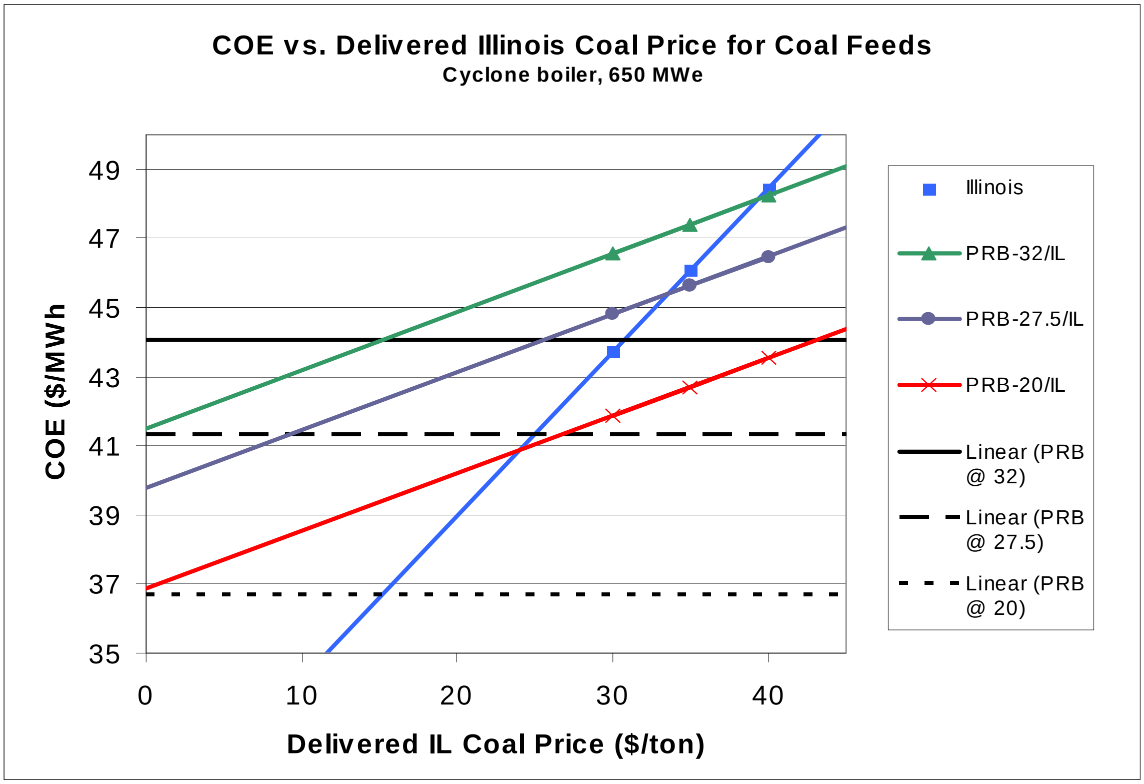
anticipate paying? Is 600 to 700/ton of SO_2 or $18,000 to 25,000 for mercury too high?
    - If you were to install an FGD system, what would be the areas that would increase cost? For example, flue gas handling, waste disposal, or process controls.

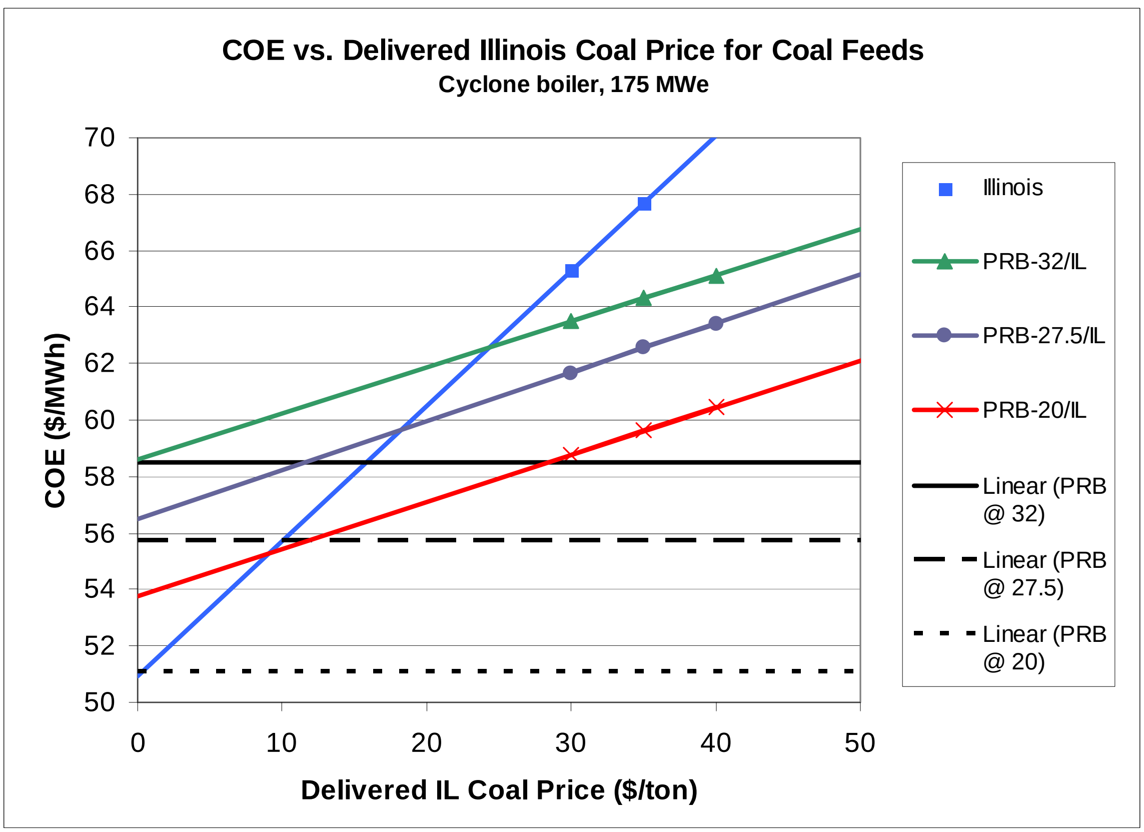
- What can the State of Illinois do to encourage you to install a wet FGD and burn Illinois coal?
    - Discuss with Illinois coal producers options to minimize their FOB mine price.
    - Discuss with the Illinois railroads options to minimize the rail transportation cost.
    - What can the state do to encourage you to switch from PRB to Illinois coal.

Appendix B. COE for various delivered coal prices, wall-fired and cyclone boilers.

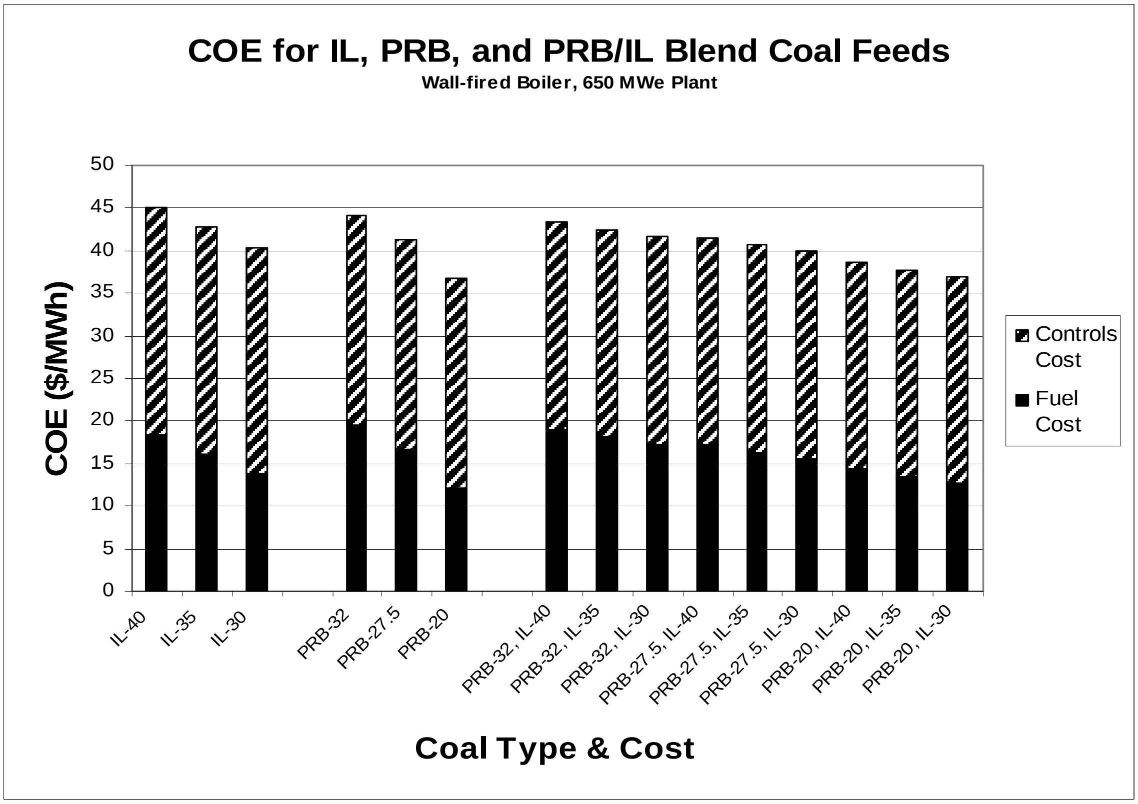


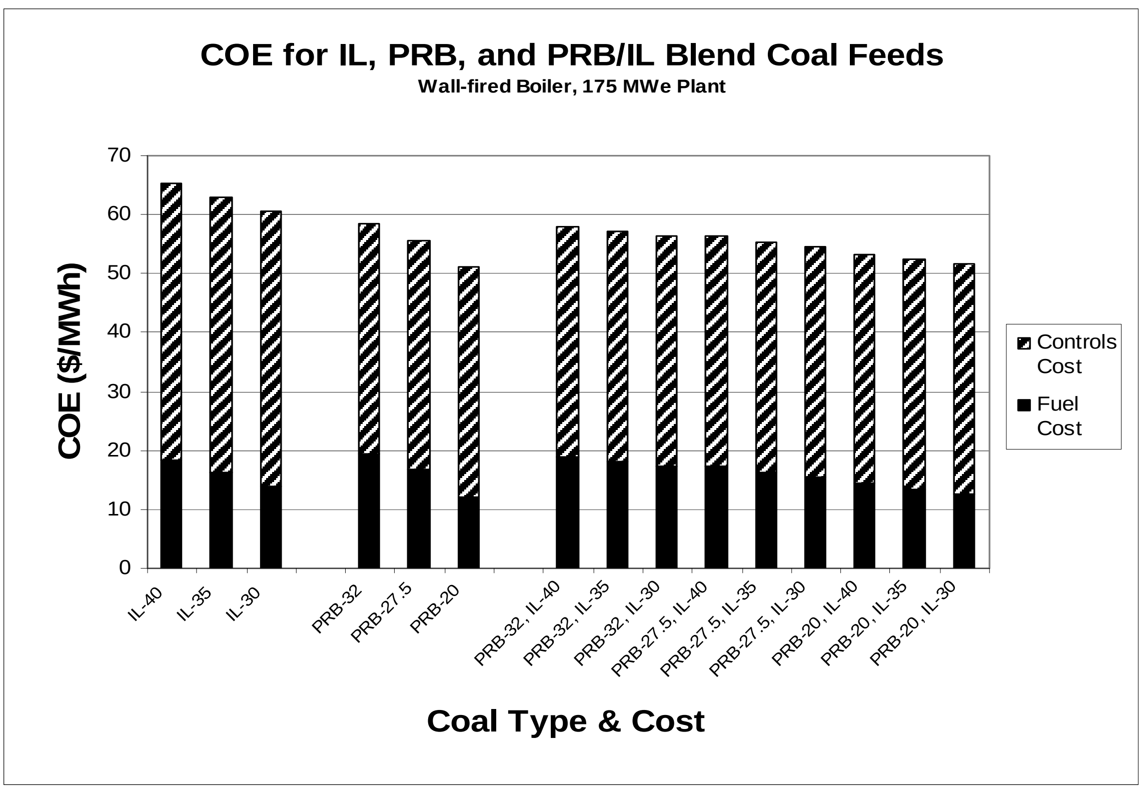


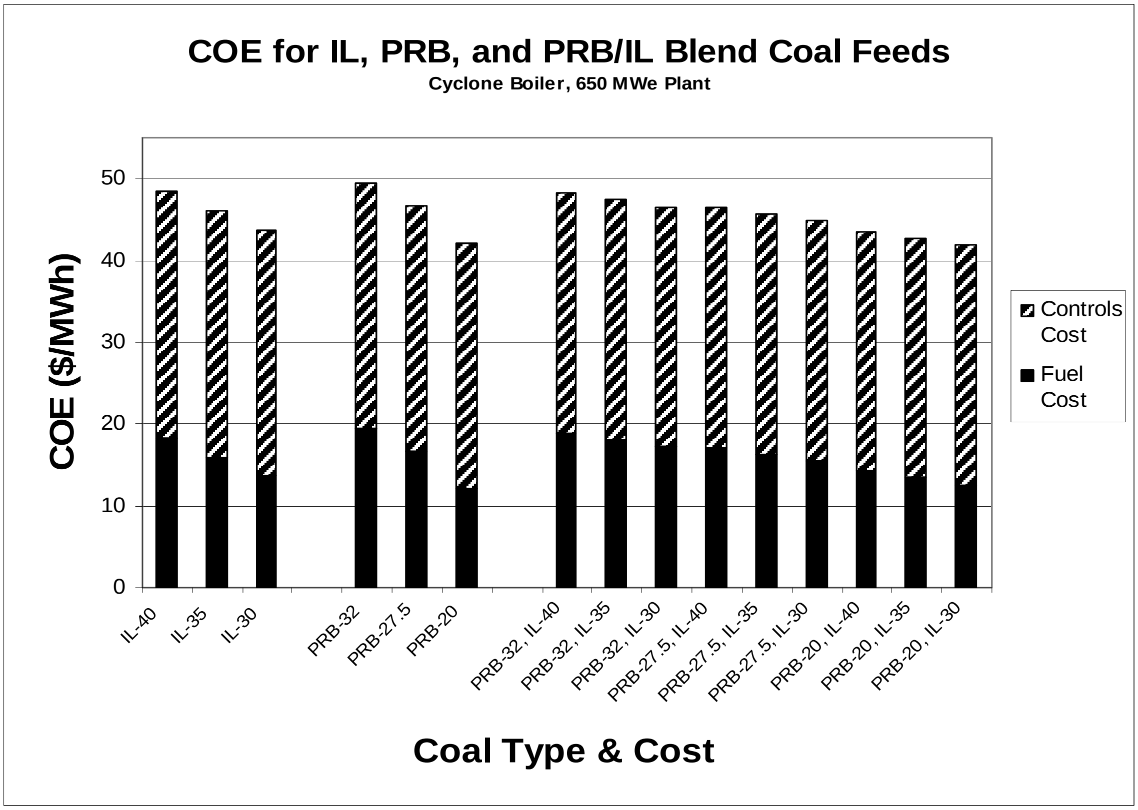

COE vs. Delivered Illinois Coal Price for Coal Feeds
Cyclone boiler, 650 MWe
COE ($/MWh
Delivered IL Coal Price ($/ton)
49
47
45
43
41
39
37
35
0
10
20
30
40
Illinois
PRB-32/IL
PRB-27.5/IL
PRB-20/IL
Linear (PRB @ 32)
Linear (PRB @ 27.5)
Linear (PRB @ 20)

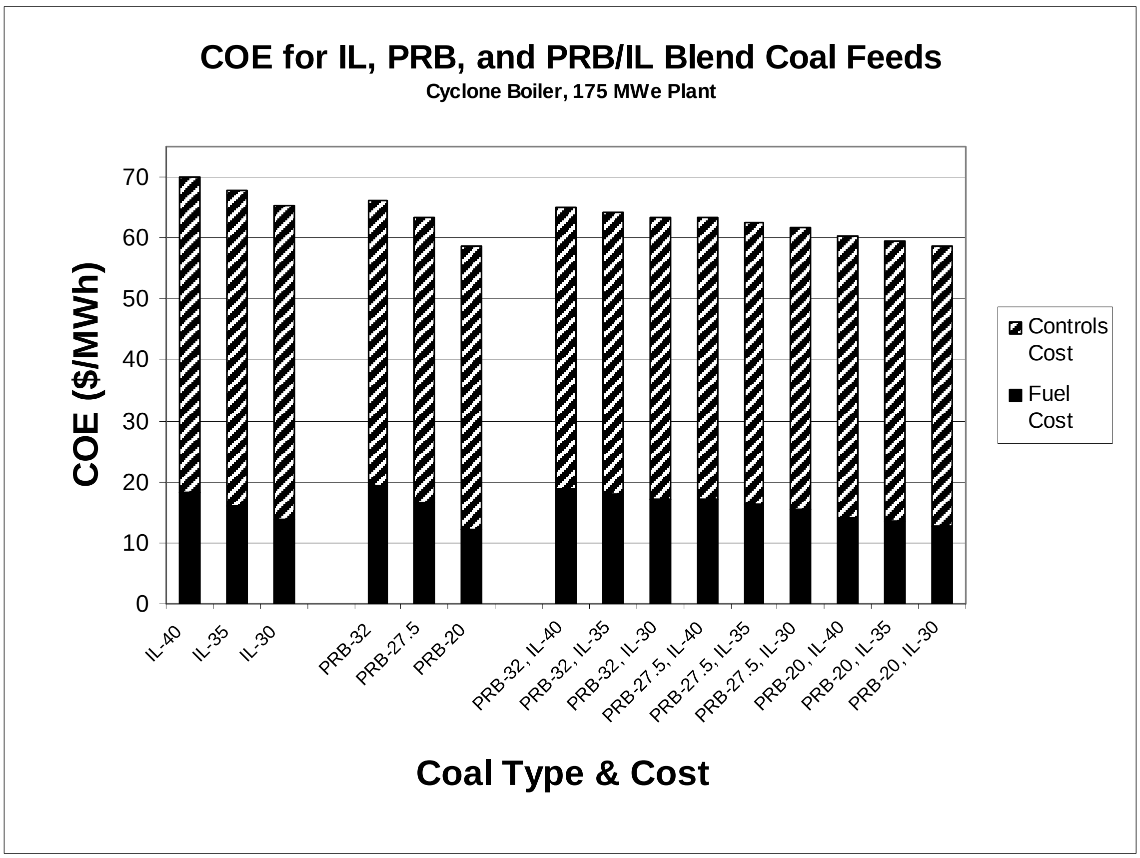

COE vs. Delivered Illinois Coal Price for Coal Feeds
Cyclone boiler, 175 MWe
COE ($/MWh)
Delivered IL Coal Price ($/ton)
70
68
66
64
62
60
58
56
54
52
50
0
10
20
30
40
50
Illinois
PRB-32/IL
PRB-27.5/IL
PRB-20/IL
Linear (PRB @ 32)
Linear (PRB @ 27.5)
Linear (PRB @ 20)

Appendix C. COE for environmental controls and fuel, wall-fired and cyclone boilers.

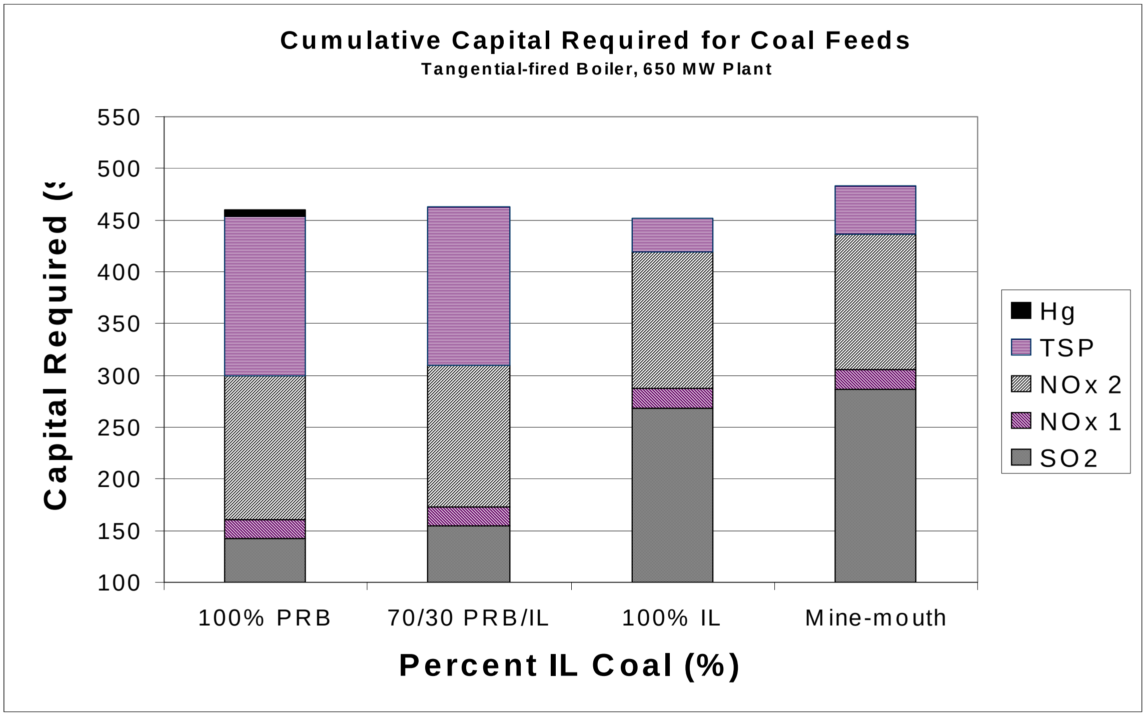


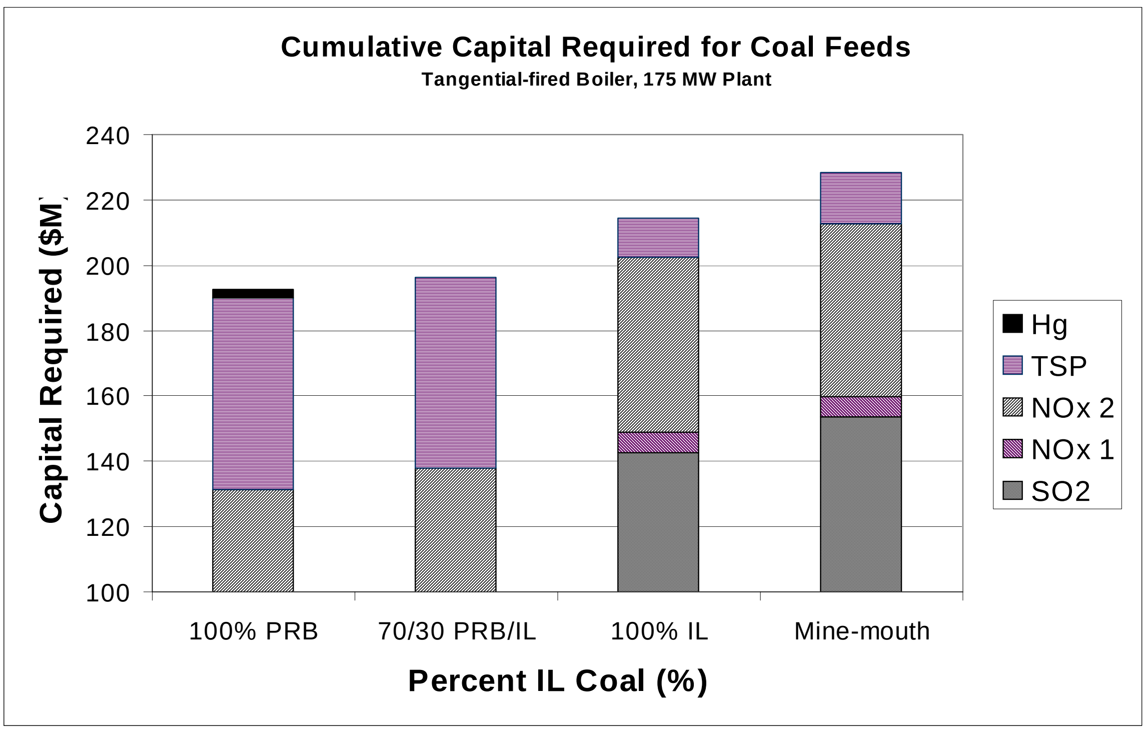



COE for IL, PRB, and PRB/IL Blend Coal Feeds
Cyclone Boiler, 650 MWe Plant
COE ($/MWh)
0
10
20
30
40
50
IL-40
IL-35
IL-30
PRB-32
PRB-27.5
PRB-20
PRB-32, IL-40
PRB-32, IL-35
PRB-32, IL-30
PRB-27.5, IL-40
PRB-27.5, IL-35
PRB-27.5, IL-30
PRB-20, IL-40
PRB-20, IL-35
PRB-20, IL-30
Controls Cost
Fuel Cost
Coal Type & Cost

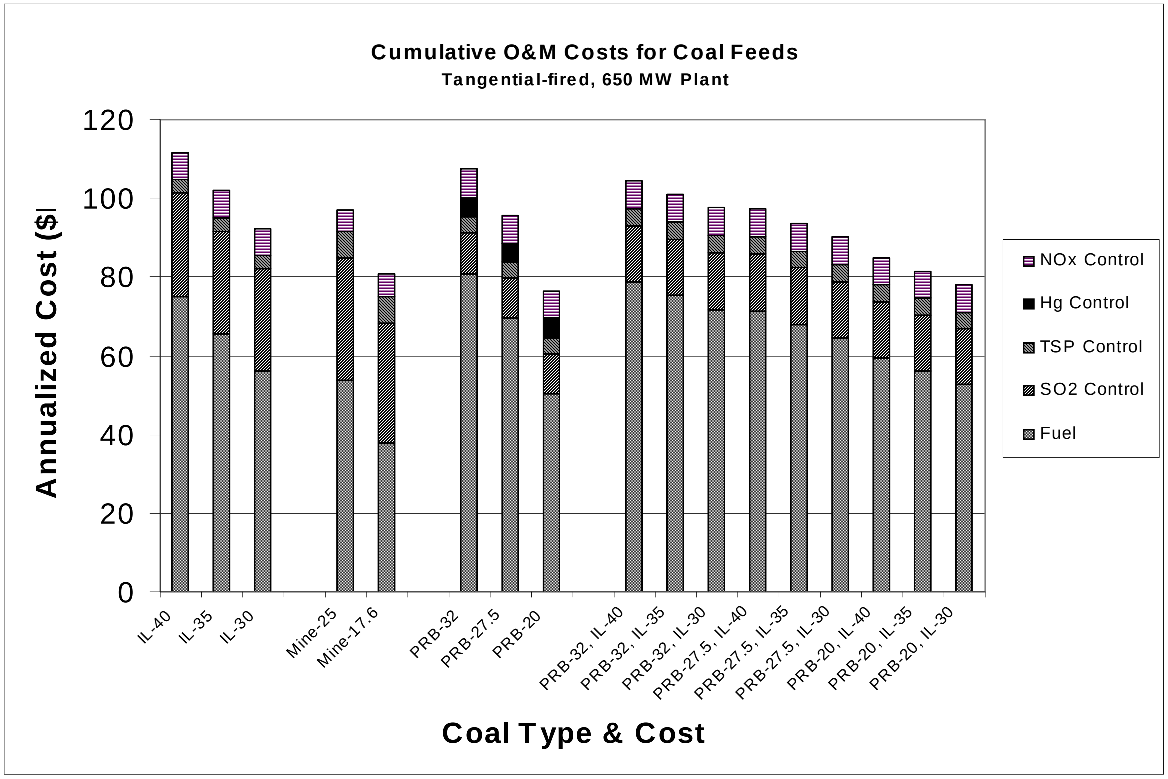

COE for IL, PRB, and PRB/IL Blend Coal Feeds
Cyclone Boiler, 175 MWe Plant
COE ($/MWh)
0
10
20
30
40
50
60
70
IL-40
IL-35
IL-30
PRB-32
PRB-27.5
PRB-20
PRB-32, IL-40
PRB-32, IL-35
PRB-32, IL-30
PRB-27.5, IL-40
PRB-27.5, IL-35
PRB-27.5, IL-30
PRB-20, IL-40
PRB-20, IL-35
PRB-20, IL-30
Controls Cost
Fuel Cost
Coal Type & Cost

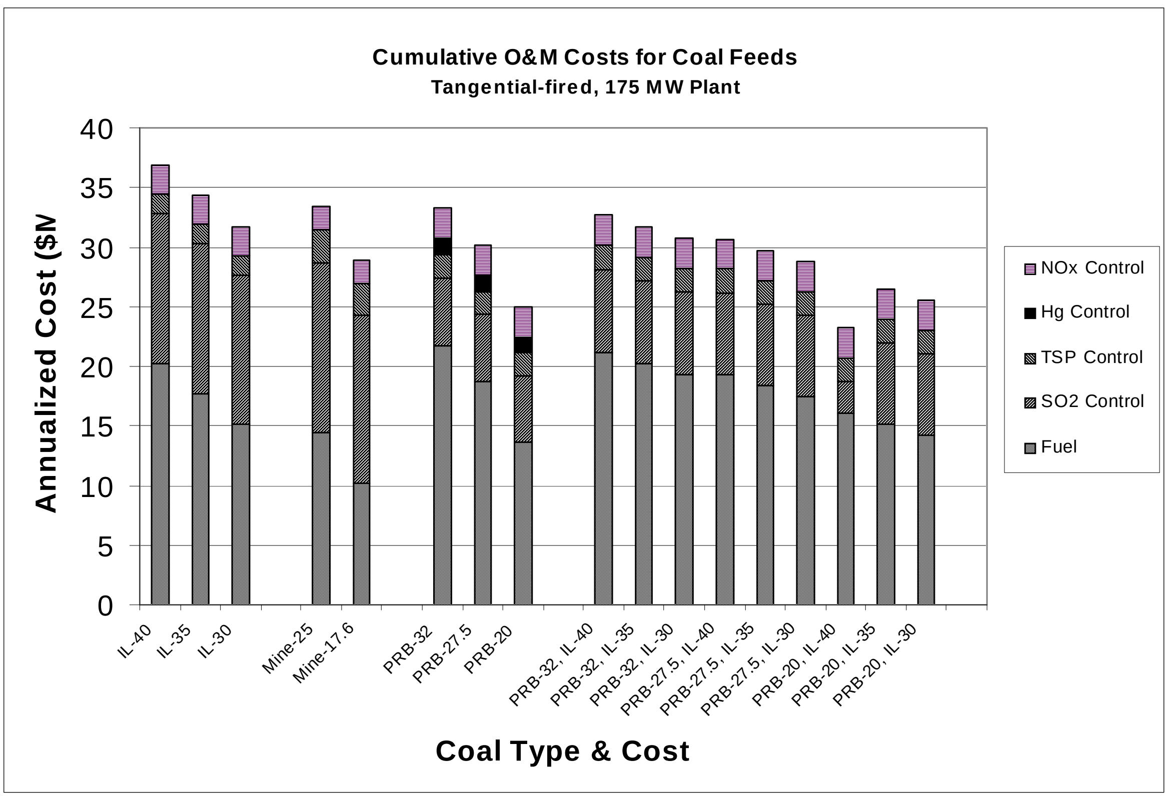
Appendix D. Capital and O&M costs for different coal feeds, tangential-fired boiler.





Note: NOx 1 indicates combustion modification, NOx 2 indicates SCR


Cumulative O&M Costs for Coal Feeds
Tangential-fired, 650 MW Plant
Annualized Cost ($I
120
100
80
60
40
20
0
IL-40
IL-35
IL-30
Mine-25
Mine-17.6
PRB-32
PRB-27.5
PRB-20
PRB-32, IL-40
PRB-32, IL-35
PRB-32, IL-30
PRB-27.5, IL-40
PRB-27.5, IL-35
PRB-27.5, IL-30
PRB-20, IL-40
PRB-20, IL-35
PRB-20, IL-30
Coal Type & Cost
NOx Control
Hg Control
TSP Control
SO2 Control
Fuel


Cumulative O&M Costs for Coal Feeds
Tangential-fired, 175 MW Plant
Annualized Cost ($M
40
35
30
25
20
15
10
5
0
IL-40
IL-35
IL-30
Mine-25
Mine-17.6
PRB-32
PRB-27.5
PRB-20
PRB-32, IL-40
PRB-32, IL-35
PRB-32, IL-30
PRB-27.5, IL-40
PRB-27.5, IL-35
PRB-27.5, IL-30
PRB-20, IL-40
PRB-20, IL-35
PRB-20, IL-30
Coal Type & Cost
NOx Control
Hg Control
TSP Control
SO2 Control
Fuel