Appendix A
List of Preparers

List of Preparers

EDAW, Inc.

Larry Keith
Keary Hallack
Chuck Luna
Jennifer Chester
Libby Kaiser
Bliss Lilley

Agapito Associates

Don Haas

WWC Engineering

Doyl Fritz

CH2M Hill

Joe Hammond
Doug Huxley
Randy Schulze
Gary Brown
Bob Pearson
Josh Nall
Brad Ryan
Bob Witherell
Ray Palm
Dan Robinette

Appendix B
Coal Proposal Summary Report

NE Wyoming Generation Project
Evaluation of Coal Supply Proposals

1.0 Introduction

Basin Electric Power Cooperative (BEPC) submitted a Request for Proposal (RFP) for supplying coal for a 250 megawatt proposed power generating facility sited in the Powder River Basin. The RFP requested proposals to provide 1.5 million tons per year of coal as well as potential sites for the power plant. The RFP was directed to seven companies with coal mines along the Eastern Outcrop of the Powder River Basin in Wyoming. All seven companies replied to the RFP, however, none of the replies were fully responsive to the RFP. The seven companies providing responses and their associated mines are:

Company	Mine
Arch Coal, Inc.	Coal Creek Mine
Dry Fork Coal Company (Western Fuels-Wyoming, Inc.)	Dry Fork Mine
Kennecott Energy Company	Cordero Rojo Mine
Peabody Energy Company (Peabody Coal Sales Company)	Caballo Mine
RAG American Coal Holding, Inc.	Eagle Butte Mine
Triton Coal Company, LLC	Buckskin Mine
Wyodak Resources (Black Hills Generation, Inc.)	Clovis Point Mine

The proposals were analyzed by comparing the responses to each other on a comparable basis. However, since none of the proposals were fully responsive to the RFP, not all proposals could be compared on all of the issues. The Dry Fork Coal Company and Peabody Energy Company were the only proposals that submitted definitive pricing. Kennecott Energy Company, Black Hills Generation, and Arch Coal indicated a general price or a price range in response to the RFP. Triton Coal agreed to discuss pricing once a confidentiality agreement was signed between Triton Coal and BEPC. RAG American Coal Holding declined to propose but did provide some information and an idea on how discussions may proceed.

Additionally, the author's experience and knowledge in analyzing coal proposals was utilized to make the comparison as complete as possible by using procedures such as adjusting the prices to make the delivery points comparable. All of the proposals, with the exception of RAG American Coal Holding, stated that they could provide the 1,500,000 tons per year for the first 250 megawatt proposed power generating facility and all of the mining companies have the capability to provide coal for the potential second 250 megawatt power generating facility.

The proposals were ranked utilizing a number of factors including:

- Cost of coal per million Btu
- Reserves controlled by the mine
- Strip ratio (tons of coal per bank cubic yard of overburden)
- Availability of plant site, water, and ash disposal
- Rail access
- Availability of additional reserves
- Impact of contract coal quantities on the coal mine
- Leverage for negotiations with the coal mines
- Other information provided by the companies.

The ranking of the proposal was considered from two separate aspects; 1) individual proposal/mine and 2) mine groupings. Section 2 of this report presents the analysis and ranking of the individual proposals and identifies the factors that determine the ranking of each. Section 3 presents the analysis of the proposals in terms of mine groupings consisting of the Northern and Middle Power River Basin Groups. This analysis discusses the reason for the groupings and the factors that determined the ranking of each group.

The rankings of the individual mines based on the information received in the proposals are:

	Company	**Mine**
1.	Dry Fork Coal Company (Western Fuels-Wyoming, Inc.)	Dry Fork Mine
2.	RAG American Coal Holding, Inc.	Eagle Butte Mine
3.	Kennecott Energy Company	Cordero Rojo Mine
4.	Triton Coal Company, LLC	Buckskin Mine
5.	Wyodak Resources (Black Hills Generation, Inc.)	Clovis Point Mine
6.	Arch Coal, Inc.	Coal Creek Mine
7.	Peabody Energy Company (Peabody Coal Sales Company)	Caballo Mine

The rankings of the proposals by mine groupings are:

	Group Companies	**Mines**
1.	Northern Powder River Basin (Wyoming) Group	
	Dry Fork Coal Company (Western Fuels-Wyoming, Inc.)	Dry Fork Mine
	RAG American Coal Holding, Inc.	Eagle Butte Mine
	Triton Coal Company, LLC	Buckskin Mine
	Wyodak Resources (Black Hills Generation, Inc.)	Clovis Point Mine
2.	Middle Powder River Basin (Wyoming) Group	
	Kennecott Energy Company	Cordero Rojo Mine
	Arch Coal, Inc.	Coal Creek Mine
	Peabody Energy Company (Peabody Coal Sales Company)	Caballo Mine

2.0 Individual Proposals

2.1 General

The advantages and disadvantages of each of the individual proposals will be discussed in this section. None of the proposals were fully responsive to the RFP and, therefore, comparisons of some of the information requested in the RFP cannot be made. All of the proposals are for coal mines with federal coal leases. Based on current federal regulations, all federal coal leases are covered by requirements for Logical Mining Units (LMU) which must be mined within 40 years. Therefore, none of the proposals can guarantee a coal supply for the power plant for the 60-year period stated in the RFP. However, additional federal coal leases may be made available through lease-by-request (LBR) for coal resources adjoining some of the coal mines.

Table 1 compares the various factors from the seven proposals. The first page of the table shows the pricing provided by the respondents along with the development of the price per million Btu. The second page of the table shows the quantity and quality of the reserves along with responses for plant siting on the coal mine land, water availability, ash disposal, and rail access in the area. The potential availability of additional reserves is also presented along with production information. The third page contains miscellaneous comments drawn from information provided in the proposals.

2.2 Dry Fork Coal Company (Western Fuels–Wyoming, Inc.)—Dry Fork Mine

The Dry Fork Mine offered an Opportunity Price of $3.41 per ton delivered at the front-end loader in the pit. To make the pricing comparable to the other proposals, the Opportunity Price was adjusted by $0.60 per ton for the approximate operating cash costs only for coal haulage and crushing. The Opportunity Price is a cost-only price which includes cash and non-cash costs for 950,000 tons per year and cash costs only for 550,000 tons per year. The 550,000 tons per year of production represent mining of the Upper Anderson Seam (referred to as the Anderson Waste) and the Anderson/Canyon (A/C) Parting. Both are currently wasted due to this lower Btu and the higher ash and sulfur contents. The 950,000 tons per year is from the Canyon Seam, which is the same coal that is being shipped to the current customers of the Dry Fork Mine. The utilization of the Upper Anderson and the A/C Parting is based on producing 6 million tons per year at the Dry Fork Mine with the balance of the coal (4.5 million tons per year) from the Canyon Seam shipped to other customers. With a coal quality of 7,803 Btu based on the blend of Upper Anderson and the A/C Parting with the Canyon Seam coal, the cost of coal would be $0.257 per million Btu crushed and ready to be shipped to the power plant. Proper blending of the various qualities of coal from the Upper Anderson, A/C Parting, and the Canyon Seam would be required to provide a consistent quality of feed to the power plant.

The Market Price of the Dry Fork Mine coal was $4.77 per ton after crushing. With a quality of 8,048 Btu, which is the quality of the Canyon Seam only, the cost of this coal would be $0.296 per million Btu ready to be transported to the power plant.

Table 1. Proposal Evaluation Comparison

Bidder	Western Fuels-Wyoming, Inc.	RAG American Coal Holding, Inc.	Kennecott Energy Company	Triton Coal Company, LLC	Black Hills Generation, Inc.	Arch Coal, Inc.	Peabody Coal Sales Company
Mine	Dry Fork Mine	Eagle Butte Mine	Cordero Rojo Mine	Buckskin Mine	Clovis Point Mine	Coal Creek Mine	Caballo Mine
Opportunity Pricing							
Price/ton	$3.41	Not provided		Not provided	$6.50	$7.50 to $8.50	$8.52
Adjustments	$0.60						$0.50
Adjusted Price	$4.01						$9.02
Btu	7,803	8,210		~8,400	8,000	8,300	7,818
Price/MM Btu	$0.257	N/A		N/A	$0.406	$0.452 to $0.512	$0.577
Comments	Cash and non-cash costs for 950,000 tpy and cash costs for 550,000 tpy.			Cost plus pricing.	Cost plus pricing. Coal crushed to 2x0.	Cost plus pricing.	Cost plus pricing. Buyer furnishes all equipment. Buyer responsible for crushing coal.
Adjustment Made	Adjustments for coal haulage and crushing; operating costs only.						Adjustment for crushing; operating and capital costs.
Market-based Pricing							
Price/ton	$4.77		$6.50				Not provided
Btu	8,048 Min.		8,402				7,500
Price/MM Btu	$0.296		$0.387				N/A
Comments	Market price.		Indicated market pricing at this time.				Price based on coal contracts in force for each year.

Table1. Proposal Evaluation Comparison *(continued)*

Bidder	Western Fuels-Wyoming, Inc.	RAG American Coal Holding, Inc.	Kennecott Energy Company	Triton Coal Company, LLC	Black Hills Generation, Inc.	Arch Coal, Inc.	Peabody Coal Sales Company
Mine	Dry Fork Mine	Eagle Butte Mine	Cordero Rojo Mine	Buckskin Mine	Clovis Point Mine	Coal Creek Mine	Caballo Mine
Reserves (Market Coal)							
Quantity (MM tons)	374	120	442	582	190	Not provided	60 years
Quality							
Btu	8,045	8,210	8,402	8,400	8,000 Min	8,300	7,818
Sulfur (%)	0.33	0.41	0.31	0.36 or 0.40	0.7 Max	0.33	0.48
Moisture (%)	32.06	Not stated	29.73	29.90	33.0 Max	30.25	31.0
Ash (%)	4.77	5.17	5.55	5.25	10.0 Max	5.50	7.9
Mercury ppm	0.02 – 0.15	0.08	0.09	0.09	0.15	Not provided	N/A
Sodium (%)	0.87 -2.53	1.5	1.27	1.75	1.0	Not provided	1.7
% Fines	5.995				30		
Strip ratio	1.8 overall	Approx. 2.5	Not provided	Projected 2.8 in 2011	Not provided	Not provided	Not provided
Plant Siting	Yes (5)	Land off coal available.	No	Yes – Rental/ Access Price.	2 - 140 A parcels @ $3,000/A	To be discussed later.	Yes – purchase.
Water Available	Yes	Water rights could be obtained.	Not addressed.	Not addressed.	Yes – share in costs.	To be discussed later.	Not addressed.
Ash Disposal	Yes	Not addressed.	Not addressed.	Yes – BEPC to maintain permits	Yes – fees and costs	To be discussed later.	Not addressed.
Rail Access	BNSF only	BNSF only	BNSF and UP	BNSF only	BNSF only	BNSF and UP	BNSF and UP
Additional Reserves	Minimal – surrounded by other bidders, Rawhide, Eagle Butte, Wyodak/Clovis Point		Additional reserves are available surrounding the Cordero Rojo complex.	Additional reserves are available surrounding Buckskin.	Minimal – limited by Dry Fork, I-90, and City of Gillette	Additional reserves are available surrounding Coal Creek.	Additional reserves are available surrounding Caballo.
Permitted Capacity	15 million tpy	35 million tpy	65 million tpy	27.5 million tpy	12 million tpy	18 million tpy	40 million tpy
2003 Production	4.3 million tpy	25 million tpy	36 million tpy	17.5 million tpy	Would open Clovis Point mine	Not operating 2003	22.7 million tpy
Reserve Life at 2003 Production	87 years	NA-offered to sell portion of reserves	12 years	33 years	NA	NA	60 years

Table1. Proposal Evaluation Comparison *(continued)*

Bidder	Western Fuels-Wyoming, Inc.	RAG American Coal Holding, Inc.	Kennecott Energy Company	Triton Coal Company, LLC	Black Hills Generation, Inc.	Arch Coal, Inc.	Peabody Coal Sales Company
Mine	Dry Fork Mine	Eagle Butte Mine	Cordero Rojo Mine	Buckskin Mine	Clovis Point Mine	Coal Creek Mine	Caballo Mine
One unit as %age of Production	35%	NA-offered to sell portion of reserves	4%	9%	NA	NA	7%

Table 1. Proposal Evaluation Comparison *(continued)*

Bidder	Western Fuels-Wyoming, Inc.	RAG American Coal Holding, Inc.	Kennecott Energy Company	Triton Coal Company, LLC	Black Hills Generation, Inc.	Arch Coal, Inc.	Peabody Coal Sales Company
Mine	Dry Fork Mine	Eagle Butte Mine	Cordero Rojo Mine	Buckskin Mine	Clovis Point Mine	Coal Creek Mine	Caballo Mine
Miscellaneous Comments							
	Water for power plant – 500 gpm available with existing wells/rights. Additional water sources available.	Offered to open mine in NE, sell reserves to BEPC, and leave equipment for mine (1 shovel, 3-4 trucks).	Potential for jointly acquiring lower Btu coal.	Cost information released upon signed confidentiality agreement.		Weighted average of MPC and CPRPC.	Annual payments to hold reserves from 2005 to 2011.
	Multiple ash disposal options. Multiple coal delivery options		Coal for electricity power swap potential.	Proposal stressed high efficiency and safe operation.		MPC – Market Price Component – market based on Platts "Coal Trader"	Caballo LMU ends in 2024.
	Cost sharing options listed. Environmental assistance offered.		Kennecott as investor in power plant potential.	Capital investment planned to reduce operating costs.		CPRPC – Cost Plus Return Price Component – predetermined rate of return 12% after tax – 25% tax rate.	
	Quality variability: 1 Std. Dev. Btu – 1.01%, S – 18.2%, Moisture – 1.7%, Ash – 13.46%.		"Hard to carve out 1.5 mm tpy for power plant" – page 6 of proposal.	Quality variability: 1 Std. Dev. Btu – 1.45%, S – 25%, Moisture – 3.8%, Ash – 22.67%.			
	Minimum or maximum quality for Opportunity Pricing (below)	Mine area already permitted.	Potential lower Btu coal available.	In-pit crusher and overland conveyor offered.		Minimum or maximum quality for Opportunity Pricing (below)	Minimum or maximum quality for Opportunity Pricing (below)
	7,800 Btu min					8,100 / 8,000 Btu	7,500 Btu min
	0.67% S max					1.20% S / 1.20% S	0.60% S max
	34% H_2O max					31% H_2O/ NA	33% H_2O max
	9.5% Ash max					6.5% Ash / NA	10% Ash max
	1% Na max						

The reserves of 374 million tons at the Dry Fork Mine would provide the 60 years of coal for the power plant, but the mine is a Logical Mining Unit and the reserves must be mined in 40 years based on current federal regulations. Additional federal leases from the adjoining area are doubtful because the mine lease is surrounded by other leases except to the southwest which is very close to the town of Gillette, which makes a new federal coal lease doubtful. The stripping ratio of 1.8 is the lowest ratio of the mines submitting the information which would indicate a lower cost of mining throughout the reserve life. The permitted production capacity of 15 million tons per year provides sufficient capacity for additional power units at the mine. With the power plant demand of 1.5 million tons per year, the power plant would be a significant portion (35% of the 2003 production of 4.3 million tons) of the production from the mine and BEPC would therefore have significant leverage in negotiations with the mine. The mine is serviced by the Burlington Northern Santa Fe Railroad only with a rail loop at the loadout.

The positive factors (advantages) for the Dry Fork Mine are the low cost per million Btu for both Opportunity Pricing and for Market Pricing, the sufficient reserves for the life of the power plant, a low strip ratio, the permitted production capacity for additional power units, and negotiating leverage with a significant portion of the mine production for the power plant. The negative factors (disadvantages) are the lack of new federal coal leases available adjoining the property and the lack of competition in rail transportation. Based on the overall positive and negative factors, the Dry Fork Mine is ranked number 1.

2.3 RAG American Coal Holding, Inc.—Eagle Butte Mine

RAG American Coal Holding, Inc. submitted a letter in response to the RFP stating that RAG Coal International was in the final stages of the sale of its subsidiary, RAG American Coal Holding, Inc., to Blackstone Group/First Reserve Corporation and the sale is expected to close on or about July 31, 2004. Due to the pending sale, RAG American Coal Holding, Inc. was unable to submit a proposal at this time.

Although RAG American Coal Holding, Inc. was unable to provide a proposal at this time, they stated that they would be interested in discussing a proposal following the closing of their sale to Blackstone Group/First Reserve Corporation. Also, RAG American Coal Holding, Inc. did provide information about the Eagle Butte Mine. They stated that they envisioned a scenario in which Eagle Butte would mine out a portion in the northeast corner of the coal lease adjoining the Dry Fork Mine which would provide a developed mining face. RAG American Coal

Holding, Inc. would leave a 295B Bucyrus reconditioned shovel and three or four 240 ton haul trucks for the removal of the overburden and the mining of the coal. The remaining reserves on this coal lease area would contain approximately 120 million tons of coal for the power plant at a 2.5 strip ratio. The reserve area is surrounded by other coal leases and the opportunity to expand the reserve area is doubtful. Rail access is provided to the reserve area by the Burlington Northern Santa Fe Railroad only.

The positive factors for the Eagle Butte Mine are the proximity to the Dry Fork Mine and the 120 million tons of coal reserves solely for the power plant. The negative factors are the inability to negotiate with BEPC at this time, the lack of new federal coal leases available adjoining the property, and the lack of competition in rail transportation. Based on the positive and negative factors, the Eagle Butte Mine is ranked number 2 solely on the ability to combine the reserves with the Dry Fork Mine.

2.4 Kennecott Energy Company—Cordero Rojo Mine

The Cordero Rojo Mine did not offer an Opportunity Price but did state that today's market indicates a price of $6.50 per ton crushed and ready to be transported to the power plant. With a coal quality of 8,402 Btu, the cost of the coal would be $0.387 per million Btu crushed and ready to be transported to the power plant.

The Cordero Rojo Mine produced 36 million tons of coal in 2003, and has a remaining reserve of 442 million tons and, at that production rate, would have 12 years of mine life before depletion of the current reserves. Additional federal coal leases could be made available through lease-by-request from the federal coal around the Cordero Rojo Mine. The permitted production capacity of the Cordero Rojo Mine is 65 million tons per year. The stripping ratio of the reserves was not provided in the proposal. The mine has sufficient production capacity and permitted capacity to provide the power plant with coal. However, as stated in the proposal, "The annual production at this mine (36m to 46m tons over the last five years) makes it harder to carve out 1.0m to 1.5m tons for a mine-mouth power plant." With the power plant demand of 1.5 million tons per year, the power plant would be a very small portion (4% of the 2003 production) of the production from the mine and BEPC would therefore have very little leverage in negotiations with the mine, especially in a high demand market in which the profitability of the mines increases and the profit per ton increases significantly compared to the profit per ton for coal supplied to the power plant.

The mine is serviced by both the Burlington Northern Santa Fe and the Union Pacific Railroads. The Cordero Rojo Mine did not offer a power plant site. Kennecott did state that they would be interested in jointly acquiring a lower Btu coal reserve, and would be interested in a coal for electric power swap. Kennecott would also be interested in being an investor in the power plant. Cordero Rojo did not address the power plant needs for ash disposal and water.

The positive factors for the Cordero Rojo Mine are the second lowest cost per million Btu for Market Pricing, the production capacity to fulfill the power plant requirements, being serviced by both the Burlington Northern Santa Fe and the Union Pacific Railroads, and the interest in discussing other potential opportunities with BEPC. The negative factors are the high production rate in comparison to the needs of the power plant (which provides very little leverage for negotiations and contract discussions), the 12 years of mine life at the current production rate, the lack of offering of a power plant site, and the lack of addressing the water consumption needs or ash disposal requirements. Based on positive and negative factors stated above, the Cordero Rojo Mine is ranked number 3.

2.5 Triton Coal Company, LLC—Buckskin Mine

The Buckskin Mine did not provide any pricing information in the proposal, but stated that cost plus pricing would be of interest and that they would allow BEPC to review their cost information following the signing of a confidentiality agreement. The average coal quality is approximately 8,400 Btu for the reserve area to be mined at the time of the startup of the power plant. No Opportunity Pricing was offered.

The Buckskin Mine has 435 million tons of coal reserves currently and a lease-by-application is pending for an additional 147 million tons, which would bring the total coal reserves to 582 million tons. At the 2003 production rate of 17.5 million tons per year, the coal reserves would be depleted in 33 years. Additional federal coal leases through a lease-by-request could be made available from the federal coal around the Buckskin Mine. The current strip ratio is approximately 1.5 but the strip ratio will increase to approximately 2.8 starting in 2011, which is the planned start date for the power plant. With the power plant demand of 1.5 million tons per year, the power plant would be a small portion (9% of the 2003 production) of the production from the mine and BEPC would therefore have modest leverage in negotiations with the mine.

The mine is serviced by the Burlington Northern Santa Fe Railroad, with a rail loop at the loadout. No other rail roads service this facility. The Buckskin Mine did offer a plant site and ash disposal at the mine. However, the water requirements of the power plant were not addressed. The Buckskin Mine proposal stressed the high efficiency and safety of the operation which would be important in cost plus pricing. The Buckskin Proposal also stated that they planned some capital investment in the future which would reduce the operating costs of the mine.

The positive factors for the Buckskin Mine are the highest Btu coal offered in the Northern Powder River Basin, the high efficiency of the operation, the capital investment planned to reduce operating costs, and the modest leverage available in negotiations with the mine. The negative aspects for the Buckskin Mine are the lack of a current price estimate, the increased stripping ratio starting in 2011, and the lack of response on the water needs of the power plant. Based on the positive and negative factors, the Buckskin Mine is ranked number 4. However, the ranking of the Buckskin Mine could change based on the cost information developed after the confidentiality agreement is signed.

2.6 Wyodak Resources (Black Hills Generation, Inc.)—Clovis Point Mine

The Clovis Point Mine offered an estimated Opportunity Price of $6.50 per ton at the Clovis Point Mine processing facility with the coal crushed and ready for transport to the power plant based on a cost plus contract. With a coal quality of 8,000 Btu, the cost of coal would be $0.406 per million Btu ready for transport to the power plant.

The reserves of the Clovis Point Mine, which is currently inactive, are 190 million tons of coal. With a production rate of 1.5 million tons per year required for the power plant, the reserve life would be 127 years. The mine is contained as a Logical Mining Unit and the reserves must be mined in 40 years based on current federal regulations. Additional federal leases from adjoining acres are unlikely because the mine lease is surrounded by other existing leases, with the exception of the area to the west. However, this area is very close to the town of Gillette which makes a new federal coal lease doubtful. The stripping ratio for the reserves was not provided. The Clovis Point Mine has a permitted mining capacity of 12 million tons per year. With the Clovis Point Mine opened for the BEPC power plant, the power plant may have significant leverage in negotiations with the mine, but Wyodak Resources may also have leverage by being able to utilize the mine production and/or the equipment at the Wyodak Mine for their own power plants.

The mine is serviced by the Burlington Northern Santa Fe Railroad only, with a rail loop at the loadout. The Clovis Point Mine has offered a plant site, the availability of water, and the availability of ash disposal.

> The positive factors for the Clovis Point Mine are that the mine could be dedicated to the power plant, the coal reserves are sufficient for the power plant plus an additional power plant if needed, and the mine has sufficient permitted capacity. The Clovis Point Mine has also offered a plant site, the availability of water, and the availability of ash disposal. The coal price per million Btu is neutral in that the coal price is in the middle of the prices provided in the proposals. The negative factors are the Burlington Northern Santa Fe is the only railroad access and the lack of incentive to keep operating costs down since the mine would be dedicated to the power plant, unless a portion of the coal is being sold on a market basis. Based on the positive and negative factors, the Clovis Point Mine is ranked number 5.

2.7 Arch Coal, Inc.—Coal Creek Mine

The Coal Creek Mine offered a cost plus Opportunity Price range of $7.50 per ton to $8.50 per ton crushed and ready to be transported to the power plant. With a coal quality of 8,300 Btu, the cost of coal would be from $0.452 to $0.512 per million Btu at the mine ready for transport to the power plant. The Coal Creek Mine offered a pricing based on a weighted average between a Market Price Component (MPC) and a Cost Plus Return Price Component (CPRPC) with the weighting determined by BEPC. The MPC would be determined from the market price for coal in Platts “Coal Trader” or similar publication. The CPRPC would be determined by the operating costs plus a 12% return on net invested capital after tax with a set tax rate of 25%.

The Coal Creek Mine did not provide any reserve information or any strip ratio for the reserves. The Coal Creek Mine did provide minimum and maximum quality for the suspension and rejection of any coal shipped from the mine. The Coal Creek Mine stated that the plant siting, water availability, and the ash disposal would be discussed later. Additional federal coal leases could be made available through lease-by-request from the federal coal around the Coal Creek Mine. The Coal Creek Mine is currently inactive but has a permitted production of 18 million tons per year. The Clovis Point Mine would be opened for the power plant and, therefore, the power plant may have significant leverage in negotiations with the mine. The mine is serviced by both the Burlington Northern Santa Fe and the Union Pacific Railroads.

The positive factors for the Coal Creek Mine are the mine may be dedicated to the power plant, the Coal Creek Mine has the necessary permitted capacity, and the mine is serviced by both the Burlington Northern Santa Fe and the Union Pacific Railroads. The negative factors are the high price of the coal in cost per million Btu and the lack of incentive to keep operating costs down since the mine may be dedicated to the power plant, unless a portion of the coal is being sold on a market basis. Based on the positive and negative factors, the Coal Creek Mine is ranked number 6.

2.8 Peabody Energy Company (Peabody Coal Sales Company)—Caballo Mine

The Caballo Mine did not provide reserve information but did state that they would dedicate 90 million tons for 60-year life of the power plant and the reserves would be held by certain holding costs paid by BEPC. However, the logical mining unit in which the Caballo Mine is currently operating expires in 2024. Additional federal coal leases may be made available through lease-by-request from the federal coal around the Caballo Mine. The strip ratio for the reserves was not provided. The Caballo Mine had a 2003 coal production of 22.7 million tons and has a permitted mining capacity of 40 million tons per year. With the power plant demand of 1.5 million tons per year, the power plant would be a very small portion (7% of the 2003 production) of the production from the mine and BEPC would therefore have very little leverage in negotiations with the mine.

The mine is serviced by both the Burlington Northern Santa Fe and the Union Pacific Railroads. The Caballo Mine did offer to sell BEPC a power plant site. They did not address the availability of water or the disposal of ash. The Caballo Mine would require $2,000,000 on January 1, 2005 and $1,000,000 per year thereafter until production starts to hold the reserves for BEPC.

The positive factors are that the Caballo Mine has sufficient reserves and sufficient production capacity to provide the coal to the power plant and is serviced by both the Burlington Northern Santa Fe and Union Pacific Railroads. The negative factors are the highest price of all of the proposals, the high production rate in comparison to the needs of the power plant, which provides very little leverage for negotiations and contract discussions, the annual payments to hold the reserves and the logical mining unit that ends in 2024. Based on the positive and negative factors, the Caballo Mine is rated number 7.

3.0 Mine Groupings

3.1 General

The discussions presented in this section address the advantages and disadvantages of each mine group. Grouping the mines provides an assessment of the flexibility and negotiating leverage that is available from considering several mines in close proximity to each other. The mines are grouped into the Northern Powder River Basin and the Middle Powder River Basin mine groups.

3.2 Northern Powder River Basin of Wyoming Group

The Northern Powder River Basin of Wyoming Group includes the following mines:

Company	Mine
Dry Fork Coal Company (Western Fuels-Wyoming, Inc.)	Dry Fork Mine
RAG American Coal Holding, Inc.	Eagle Butte Mine
Triton Coal Company, LLC	Buckskin Mine
Wyodak Resources (Black Hills Generation, Inc.)	Clovis Point Mine

The relative position of these mines is illustrated in Figure 1, which shows the coal lease areas for each of the mines. Also shown on Figure 1 are the coal leases for Peabody's Rawhide Mine and Black Hills' Wyodak Mine. The town of Gillette is shown along with Interstate 90 and the rail lines in the area.

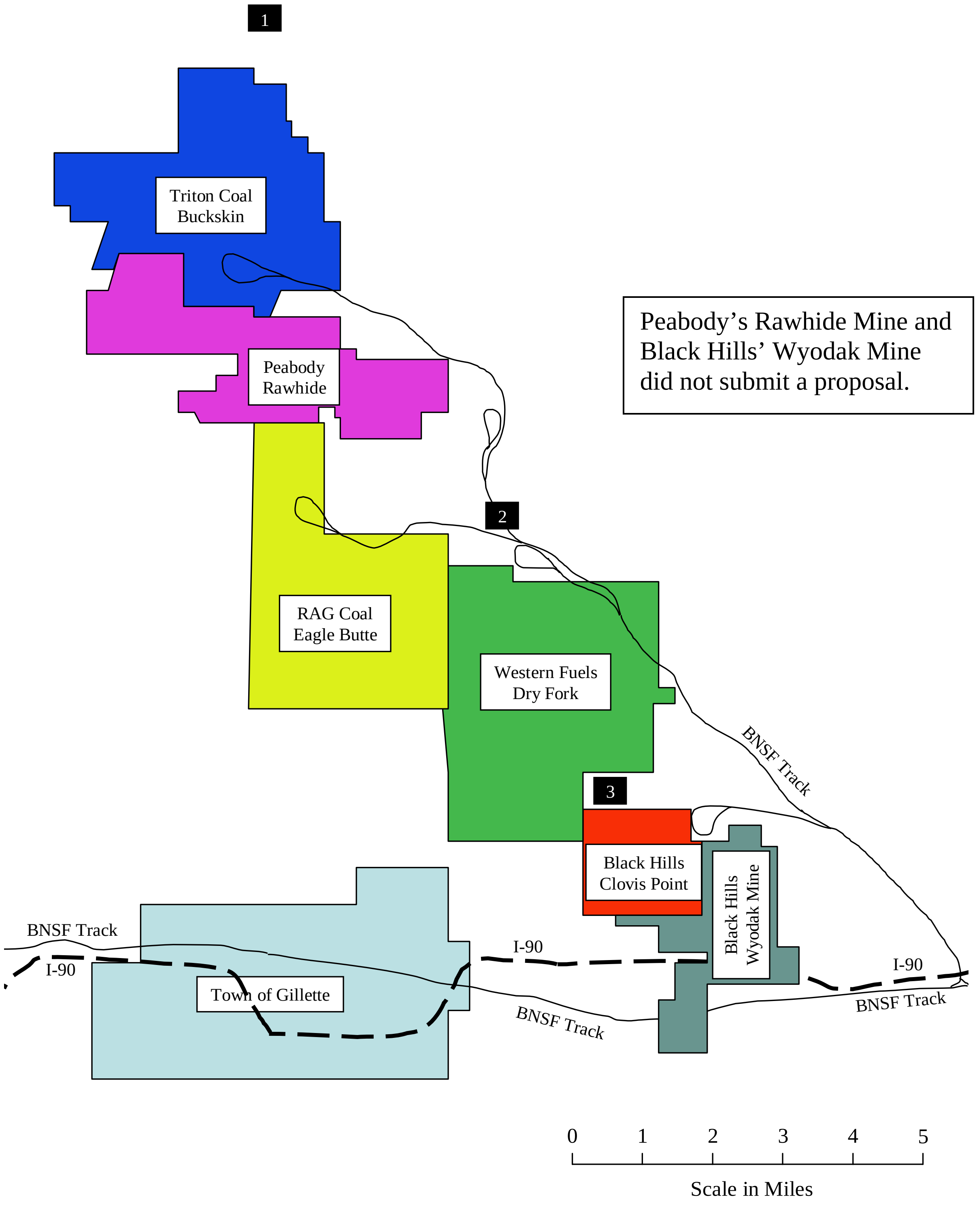


Figure 1. Northern Powder River Basin Mines of Wyoming

Each of the mines in this group was discussed individually in Section 2.0. On Figure 1, three black squares are shown for the general location of the potential power plant sites as identified in the proposals with Numbers 1, 2, and 3. Other potential power plant sites are potentially available. The Number 1 site is located on Section 16 north of the Buckskin Mine and is near a high voltage transmission line and along the path of the progression of the Buckskin Mine. The Number 2 site is located immediately north of the Dry Fork Mine and is central to all of the mines in the Northern Powder River Basin Group. The Number 3 site is located between the Dry Fork Mine and the Clovis Point Mine.

The Northern Powder River Basin Group has an advantage in that all of the mines are in close proximity to each other. This provides a distinct advantage in negotiating with the mines for coal supply and lowers the transportation cost regardless of which mine or mines are utilized as the source of the coal. All of the mines are lower production rate mines with the exception of the Buckskin Mine, which provides additional leverage in any negotiations.

The disadvantages of the Northern Powder River Basin of Wyoming Group are that the mines are serviced by only the Burlington Northern Santa Fe Railroad, which provides a transportation cost disadvantage. Another disadvantage is that only the Buckskin Mine has the potential to expand their reserves through additional federal leases.

Based on the advantages and disadvantages, the Northern Powder River Basin of Wyoming Group is ranked number 1.

3.3 Middle Powder River Basin of Wyoming Group

The Middle Powder River Basin of Wyoming Group includes the following mines:

Company	**Mine**
Kennecott Energy Company	Cordero Rojo Mine
Arch Coal, Inc.	Coal Creek Mine
Peabody Energy Company (Peabody Coal Sales Company)	Caballo Mine

The relative position of these mines is illustrated in Figure 2, which shows the coal lease areas for each of the mines. Also shown in Figure 2 are the coal leases for RAG American Coal Holding’s Belle Ayr Mine.

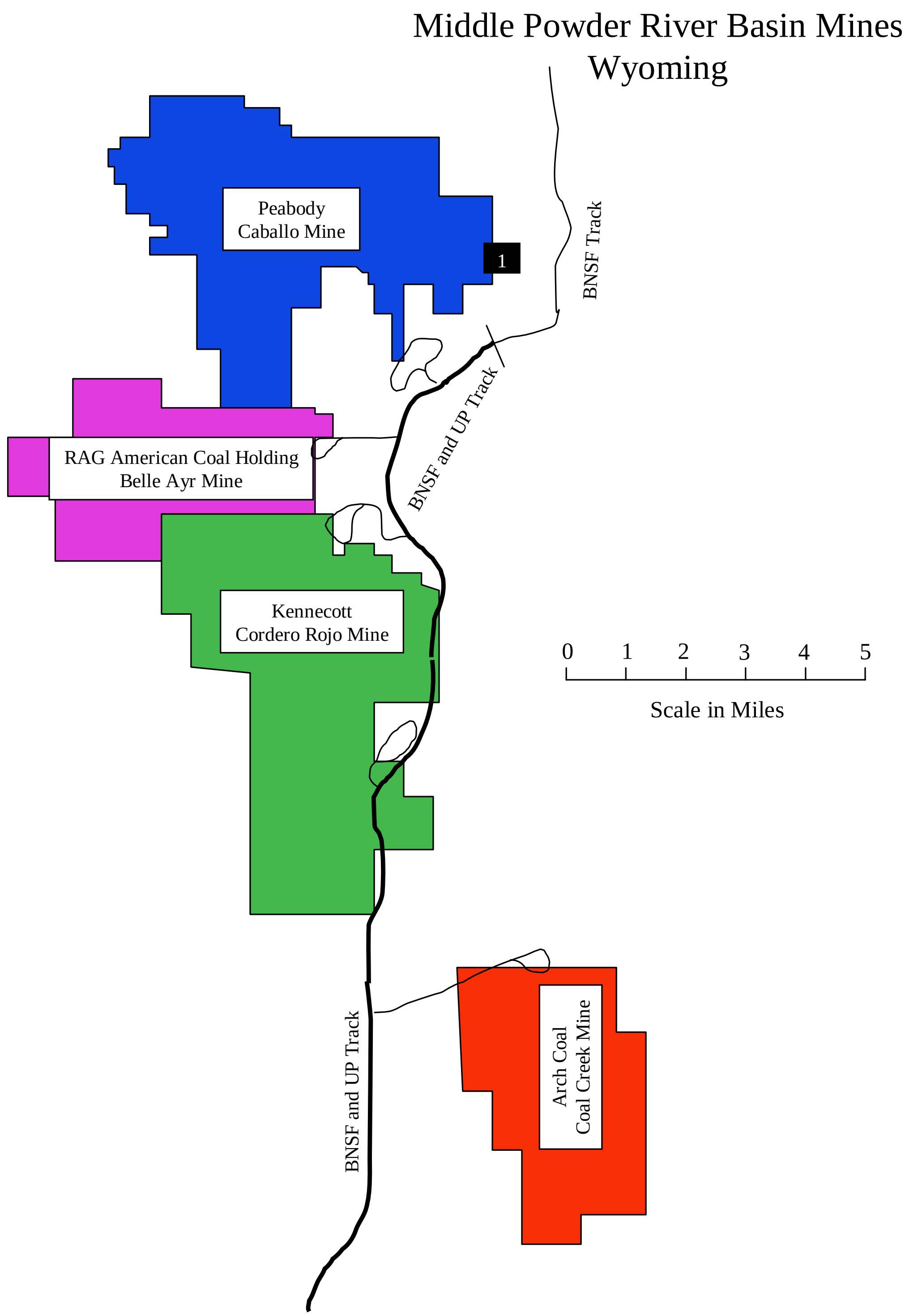


Figure 2. Middle Powder River Basin Mines of Wyoming

Each of the mines in this group was discussed individually in Section 2.0 above. One black square is shown on Figure 2, which is the potential power plant site offered by the Caballo Mine. Other potential power plant sites are available but the other mines did not provide a location in their proposals. The site that was offered is located on the east side of the Caballo Mine coal leases.

The Middle Powder River Basin Group has the advantages that all mines have high production outputs and significant production capacities. These high production mines have the advantage of economies of scale. All of the mines are accessed by both the Burlington Northern Santa Fe and the Union Pacific Railroads.

One disadvantage of the Middle Powder River Basin of Wyoming Group is that the mines are high production mines which offer very little leverage in negotiations because the sales to the power plant are very small compared to the overall production from these mines. Another disadvantage is the potential contractual problems in a high demand market in which the profitability of the mines increase and the profit per ton increases significantly compared to the profit per ton for coal supplied to the power plant.

Based on the advantages and disadvantages, the Middle Powder River Basin Group is ranked number 2.

Appendix C
Air and Water Resources – Supplemental Information

NE Wyoming Generation Project
Air and Water Review for Fatal Flaw Analysis

PREPARED FOR: Larry Keith, EDAW

PREPARED BY: Joseph J. Hammond

COPIES: Keary Hallack, EDAW
Tom Neer, EDAW
Randy Schulze, EDAW

DATE: June 7, 2004

I have reviewed the potential air and water issues related to the initial siting study area for the NE Wyoming Generation Project.

Air Issues

There are no major air issues that appear to differentiate the various site locations. We feel we could successfully negotiate an air permit for any of the potential sites in the study area.

Non-Attainment Areas

The study area is in Campbell County, Wyoming. Campbell County is in attainment with all National Ambient Air Quality Standards (NAAQS). Sheridan County in the northern part of the state is the only non-attainment area in Wyoming. It is a moderate non-attainment area for PM_{10}. As a reference, non-attainment maps are attached.

Class 1 Areas

As part of the air permitting analysis, we will have to conduct CALPUFF long range (greater than 50 kM) visibility modeling for the power plant stack emissions and compare to FLAG visibility threshold guidance standards set by the Federal Land Manager (or National Park Service in this case). Maps of the National Park Service, Forest Service, Fish and Wildlife Class1 areas are attached. At a later date, we will develop a diagram of the proximity of Class 1 areas to the proposed site location in the Gillette, Wyoming area. An example of what we did for the Intermountain Power Project in Utah is attached. The closest Class 1 areas are Badlands National Park (~230 kM) and Wind Cave National Park (~180 kM).

Other

It is expected that the primary air quality permitting issue will be with the near field impacts at fenceline related to PM_{10} from material handling operations. Demonstration of compliance with other criteria pollutant NAAQS should be relatively straight forward. There is some advantage to sites that are further from Gillette from a public relations perspective in the air quality permitting process.

Water Issues

The following is a broad overview of water supply relative to sites in the study area. This is very preliminary - based on reports reviewed to date.

Potential Surface Water Supplies

I understand that EDAW will map potential surface water supplies from current data.

Potential Ground Water Supplies

If a dry cooling option is selected, the installation of a 500 gpm well field appears to be feasible at all potential site locations in the study area. However, if a wet cooling option is desired (~ 4,000 gpm for a 250 MW unit), reports from WWC Engineering indicate that certain sites have advantages over others. The northeast sites in the study area appear to have some advantages relative to their placement in the Lance/Fox Hills aquifer. Further investigation and follow-up with WWC Engineering will be needed to evaluate potential water supply for each of the preferred sites.

Potential Re-Use Water Supplies

The potential use of water from coal bed methane production is more likely for potential sites that are on the western side of the study area. Thus, this would favor mine mouth sites versus sites like Rozet or those east of the Hughes Substation.

Summary of PM_{10} Control Program in Powder River Basin Wyoming

TO: Jim K. Miller, BEPC
Deborah Levchak, BEPC
Clyde Bush, BEPC
Joe Hammond, CH2M HILL
Randy Schulze, CH2M HILL
Larry Keith, EDAW
Keary Hallack, EDAW

FROM: Robert Pearson and Josh Nall, CH2M HILL

DATE: July 1, 2004

This summary of the PM_{10} program in Wyoming is taken from conversations by Josh Nall with Ken Rairigh of the Wyoming DEQ, a conversation Bob Pearson had with Larry Volmert and Ed Harris of the law firm Holland and Hart and a conversation Bob Pearson had with Fred Carl, Environmental Manager for Black Hills Power regarding the Wygen facility.

The control of PM_{10} in the Powder River Basin (PRB) has a long history. Several years ago Wyoming set the PM minor source baseline date for all of Wyoming but given the projected coal development in the PRB, established a separate air quality control region for the PRB and did not trigger the PM minor source baseline in the PRB. Then whenever a new stationary source (not a coal mine) came in for an air permit, a smaller air quality control region was carved out for the plant and its immediate surroundings, typically smaller than a section. In this new air quality control region the minor source baseline was triggered, leaving the rest of the PRB alone. EPA agreed with this approach for the first six permits. The last two re-designation requests (for Encoal and Two Elk) were submitted in 2001 and are still sitting on EPA's desk awaiting action. Since these re-designation requests are still pending, and since the permits were issued in 2001 for Encoal and Two Elk, the PM_{10} minor source baseline has now been triggered in the PRB.

Since the 2001 minor source baseline date, coal bed methane (CBM) development has flourished in the PRB, particularly north of Gillette. Now even mobile sources (pickup trucks running up and down dirt roads) are consuming increment to the extent the traffic count has increased in the last three years. WDEQ is trying to calculate increment consumption for stationary sources (including pumping and compressor stations, fairly easy given each has filed notice with WDEQ) but also the other sources (pickup trucks)—not so easy. Given this, WDEQ is trying to get their arms around this issue. The source categories are bring treated as follows.

<u>Coal Mine Modeling</u>: Ken said that projects involving the coal mines in the Gillette area usually are not PSD, and therefore do not conduct the typical cumulative increment/ NAAQS analyses. If WDEQ requests a cumulative analysis, they ask that the mine owner model other nearby mine sources only. WDEQ's policy is that the near-field models such as

ISC are not "robust" enough to adequately estimate short-term (24-hour) impacts from fugitive sources, so 24-hour analyses are conducted for point sources only. Fugitive sources are modeled with the ISCLT (long-term version of the model) model to look at annual impacts only. Ken said that a recent mine analysis yielded 49+ $\mu g/m^3$ for annual PM_{10} impacts (vs. NAAQS of 50). Josh asked if he could get files and/or reports for that analysis, and Ken said that he would check with WDEQ's Sheridan office. He said that in lieu of 24-hour modeling, the mines are required to monitor PM-10 "upwind and downwind". Ken also said that the northern area (N of Gillette) has a lot of coal bed methane (CBM) development, and although no cumulative analysis has been conducted, it could become an issue in the future. Not as much CBM development in the area south of Gillette. Farther to the south, Ken said that PM_{10} monitors are exceeding that NAAQS near that particular cluster of mines (North Rochelle, Black Thunder, Antelope).

Power Plant Modeling: Josh asked Ken if the same policy on 24-hour modeling would apply to fugitive sources from a coal-fired power plant, and he said it would. He said that WDEQ would demand that fugitive sources be well controlled. This would include closed conveyors, paved roads (or very well controlled), limited open storage. For the Two Elk Project, the applicant did submit 24-hour modeling that included fugitives, but Ken said WDEQ "did not look at that modeling". That project eventually went to covered coal storage to satisfy WDEQ. Fred Carl said that for the Wygen project, they modeled short term PM_{10} impacts and went to considerable lengths reducing fugitive emissions to get below the Class II increment at the plant fence. They did not need to cover the coal pile to demonstrate compliance. Ken mentioned that the WYGEN long range CALPUFF modeling showed problems with Class I increments at the Northern Cheyenne reservation. This was to be expected, because of two old boilers at Colstrip that "bust the NAAQS by themselves". WDEQ recognized that WYGEN did not contribute significantly to the problem and they issued the permit which has been appealed by the Park Service due to concerns on visibility impacts at Wind Cave and Badlands National Parks from the SO_2 and NO_x emissions primarily.

EIS Modeling: Ken said that there have been a few EIS-type modeling efforts over the years, but they dealt mostly with NO_x, and possible CO and formaldehyde. He said that Darla Potter (307.777.7346) at WDEQ specializes in those analyses. Ken cautioned that EIS-type modeling might not be as rigorous as NSR modeling in terms of the protocol and approaches.

Monitoring Data: Ken said that the area has existing SO_2 that could be used as background. They expect to have a full year of NO_x data soon. For meteorology, Josh asked if he would require on-site monitoring, and he mentioned the Basin 100-m tower that we were already aware of. He thought that it could be used for ISC or AERMOD. He said that it had wind data at 10, 50, and 100-meters. He said that he wasn't sure if the Basin data was in the "public domain", however.

Follow-Up Issues

Ed Harris and Larry Volmert of Holland & Hart recommended that the project team meet with Dan Olsen, Bernie Dailey and staff at the WDEQ, Air Quality Division as soon as possible to discuss the project siting and potential PM_{10} issues in the Powder River Basin.

On June 30, Bob Hammer and Miriam Hacker with Tetra Tech forwarded a CD containing model input files and met data that were developed in the May 2001 preliminary siting study performed by Tetra Tech for Basin Electric. Josh Nall will review the data and recommend any further analysis needed at this time.

State, County, Pollutant, * Part County NAA, NAA Area Name, Classification Standard

WASHINGTON

Spokane Co

Carbon Monoxide	*	Spokane, WA - Serious
PM-10	*	Spokane Co, WA - Moderate

Walla Walla Co

PM-10	*	Wallula, WA - Serious

Yakima Co

Carbon Monoxide	*	Yakima, WA - Not Classified
PM-10	*	Yakima Co, WA - Moderate

* Only a portion of the county is designated nonattainment (NAA). See the Code of Federal Regulations (40 CFR Part 81) and pertinent Federal Register notices for legal lists and boundaries.

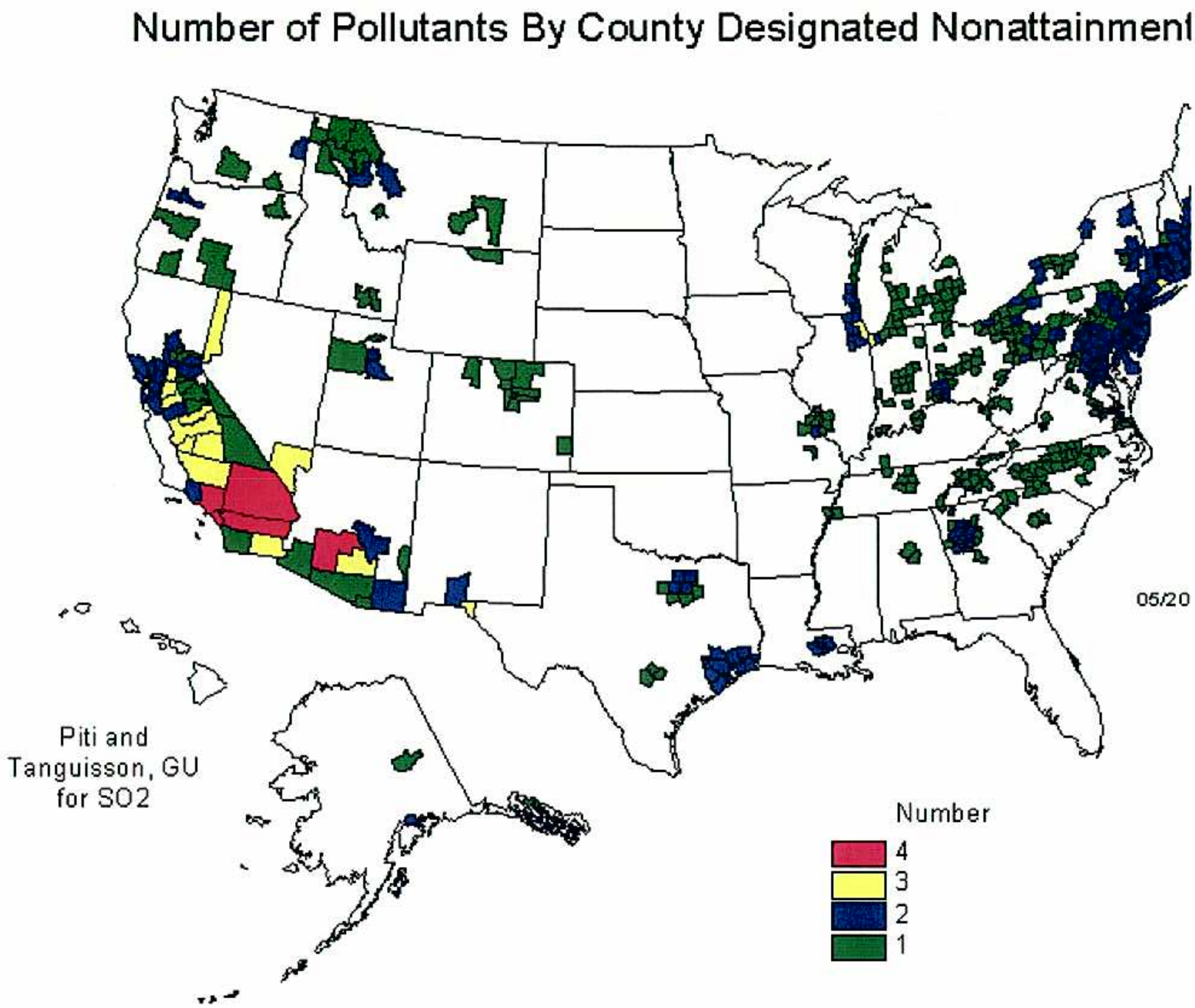
State, County, Pollutant, * Part County NAA, NAA Area Name, Classification Standard

WYOMING

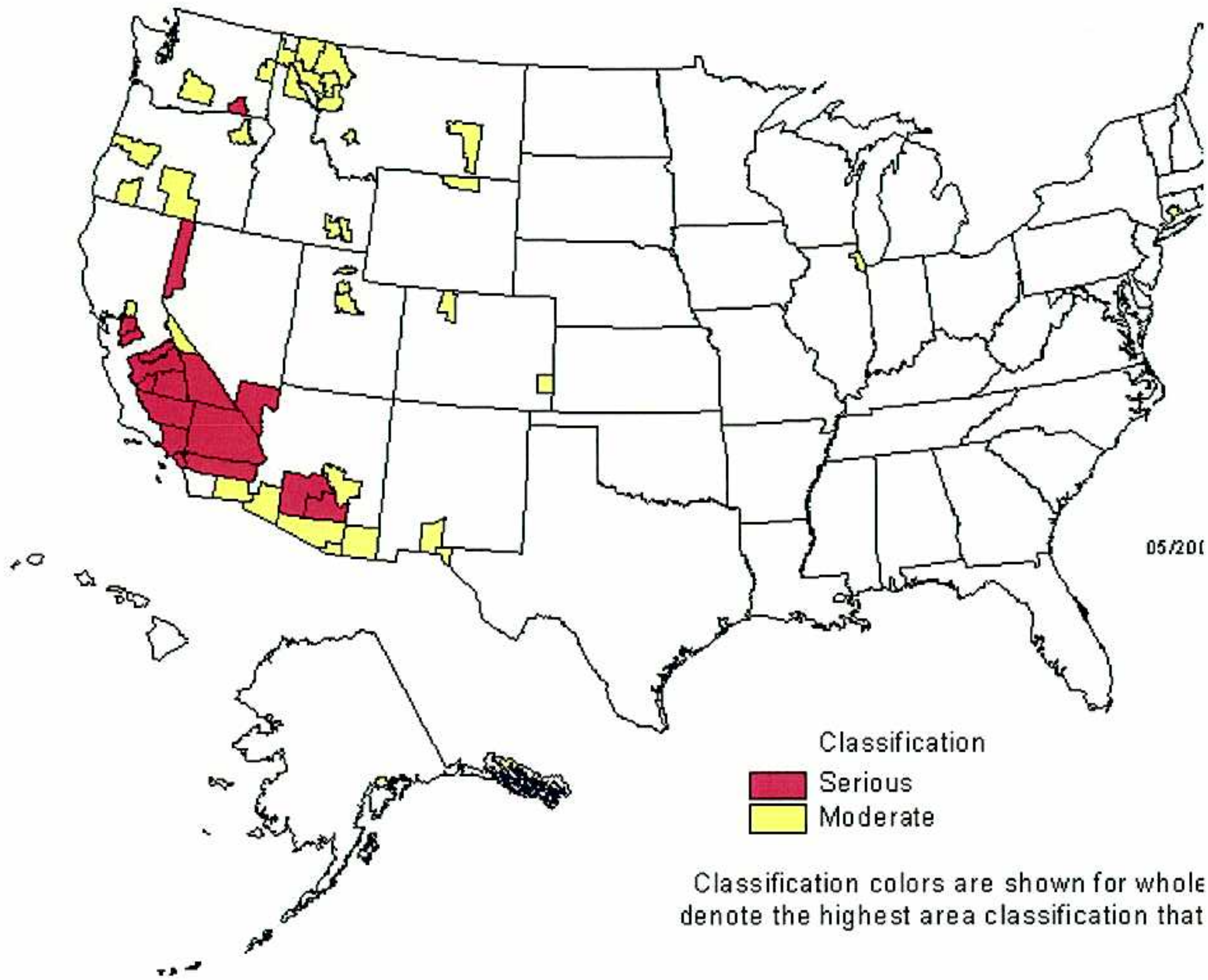
Sheridan Co

PM-10	*	Sheridan, WY - Moderate

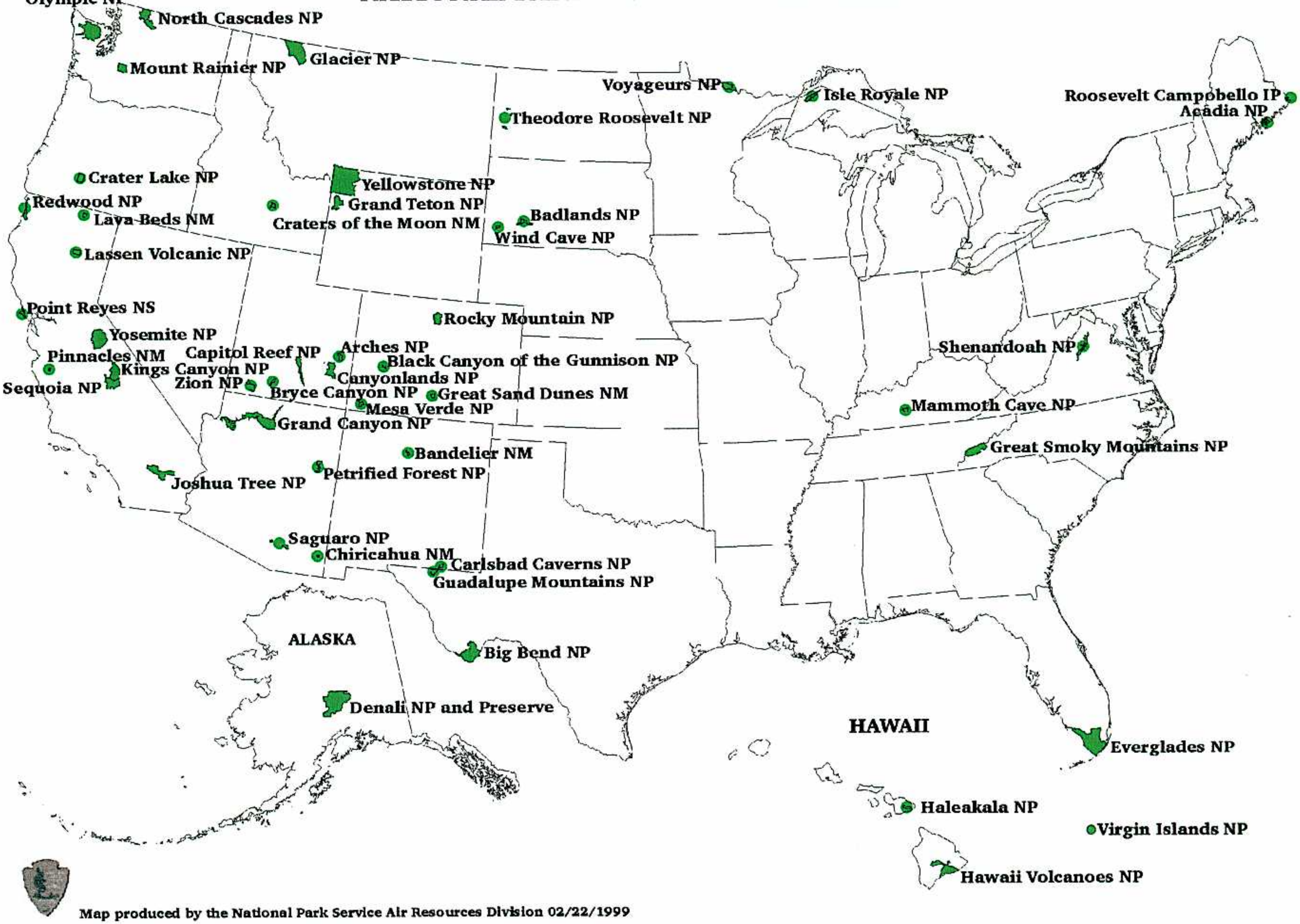
* Only a portion of the county is designated nonattainment (NAA). See the Code of Federal Regulations (40 CFR Part 81) and pertinent Federal Register notices for legal lists and boundaries.


Number of Pollutants By County Designated Nonattainment
05/20
Piti and
Tanguisson, GU
for SO2
Number
4
3
2
1

Counties Designated Nonattainment for PM-10

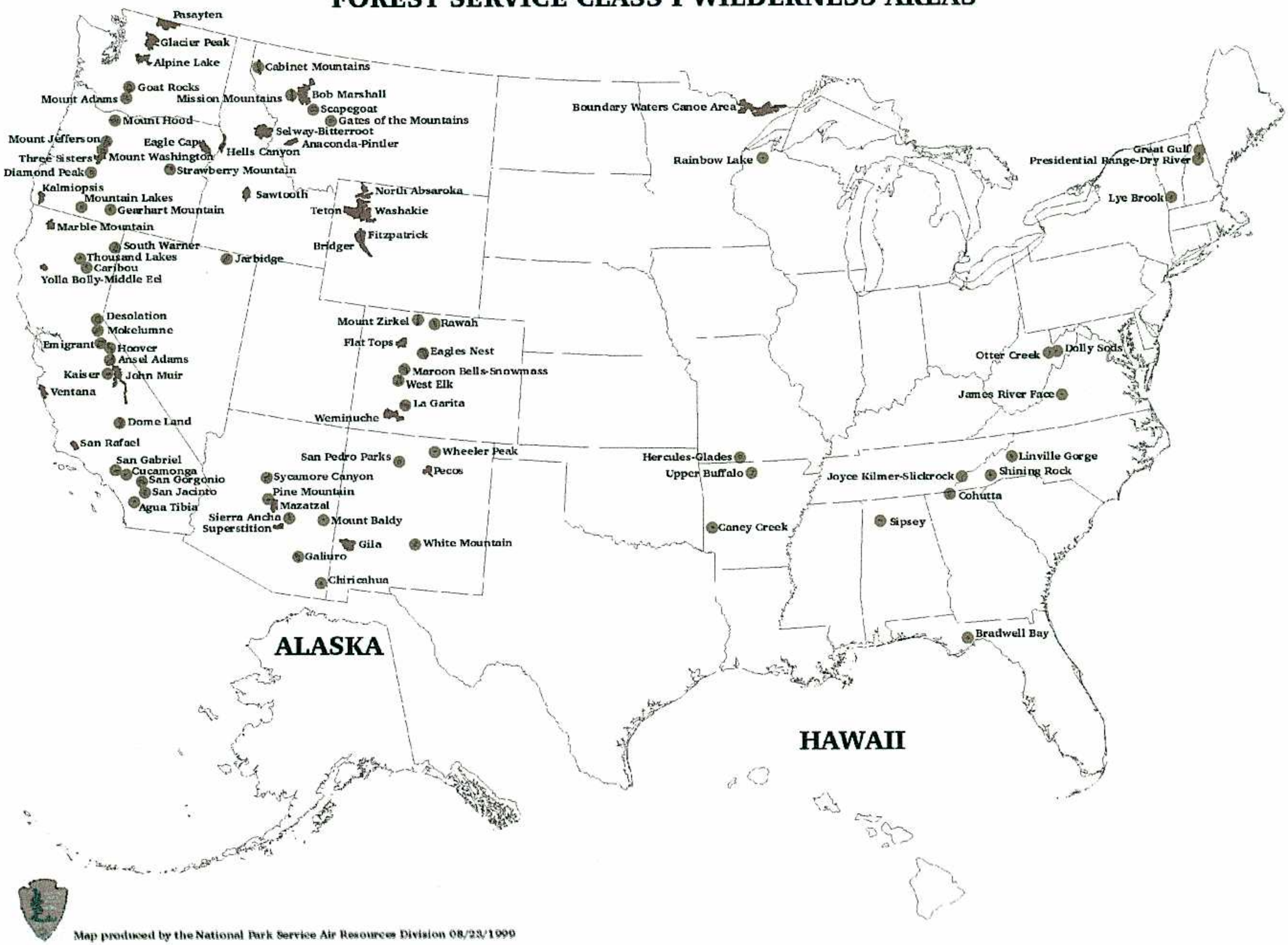


NATIONAL PARK SERVICE CLASS I AREAS



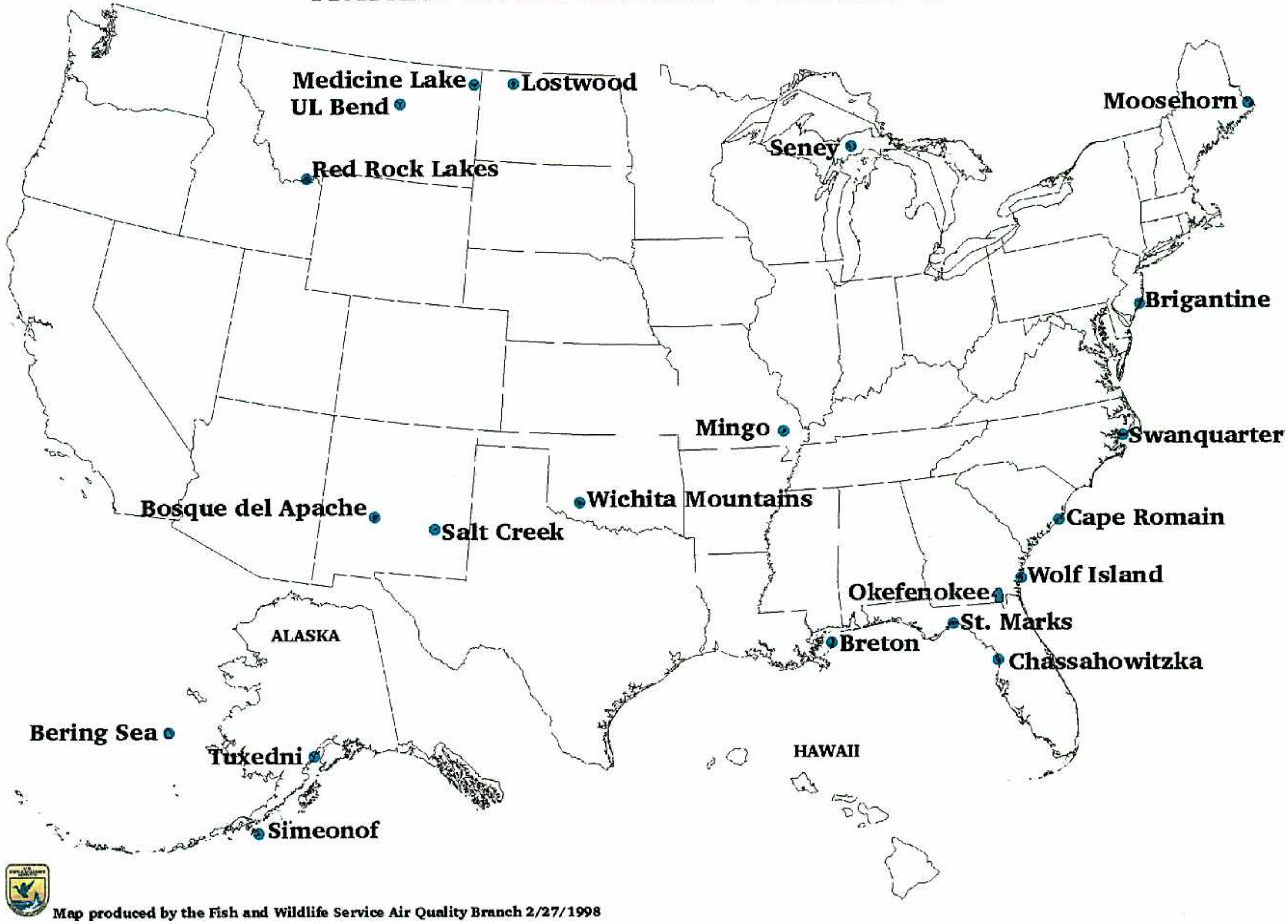
Map produced by the National Park Service Air Resources Division 02/22/1999

FOREST SERVICE CLASS I WILDERNESS AREAS

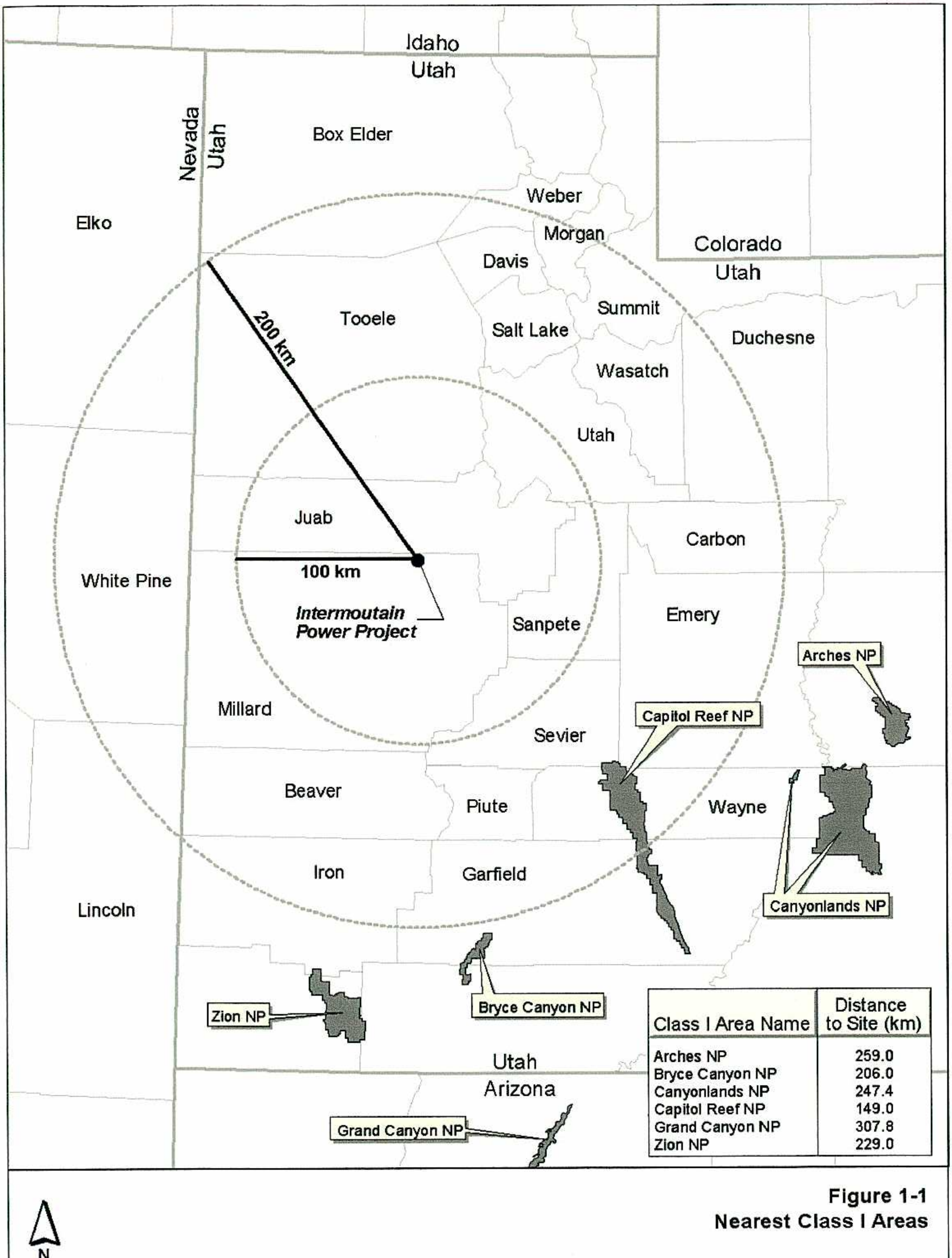


Map produced by the National Park Service Air Resources Division 08/23/1999

FISH AND WILDLIFE SERVICE CLASS I AREAS



Map produced by the Fish and Wildlife Service Air Quality Branch 2/27/1998



Class I Area Name	Distance to Site (km)
Arches NP	259.0
Bryce Canyon NP	206.0
Canyonlands NP	247.4
Capitol Reef NP	149.0
Grand Canyon NP	307.8
Zion NP	229.0

Figure 1-1
Nearest Class I Areas

List of 156 Mandatory Class I Federal Areas

Area Name	Acreage	Federal Land Manager	Public Law
81.401 Alabama			
Sipsey Wilderness Area	12,646	USDA-FS	93-622
81.402 Alaska			
Bering Sea Wilderness Area	41,113	USDI-FWS	91-622
Denali NP (formerly Mt. McKinley NP)	1,949,493	USDI-FWS	64-353
Simeonof Wilderness Area	25,141	USDI-FWS	94-557
Tuxedni Wilderness Area	6,402	USDI-FWS	91-504
81.403 Arizona			
Chiricahua National Monument Wilderness Area.	9,440	USDI-NPS	94-567
Chiricahua Wilderness Area	18,000	USDA-FS	88-577
Galiuro Wilderness Area	52,717	USDA-FS	88-577
Grand Canyon NP	1,176,913	USDI-NPS	65-277
Mazatzal Wilderness Area	205,137	USDA-FS	88-577
Mount Baldy Wilderness Area	6,975	USDA-FS	91-504
Petrified Forest NP	93,493	USDI-NPS	85-358
Pine Mountain Wilderness Area	20,061	USDA-FS	92-230
Saguaro Wilderness Area	71,400	USDI-FS	94-567
Sierra Ancha Wilderness Area	20,850	USDA-FS	88-577
Superstition Wilderness Area	124,117	USDA-FS	88-577
Sycamore Canyon Wilderness Area	47,757	USDA-FS	92-241
81.404 Arkansas			
Caney Creek Wilderness Area	4,344	USDA-FS	93-622
Upper Buffalo Wilderness Area	9,912	USDA-FS	93-622
81.405 California			
Agua Tibia Wilderness Area	15,934	USDA-FS	93-632
Caribou Wilderness Area	19,080	USDA-FS	88-577

Cucamonga Wilderness Area	9,022	USDA-FS	88-577
Desolation Wilderness Area	63,469	USDA-FS	91-82
Dome Land Wilderness Area	62,206	USDA-FS	88-577
Emigrant Wilderness Area	104,311	USDA-FS	93-632
Hoover Wilderness Area	47,916	USDA-FS	88-577
John Muir Wilderness Area	484,673	USDA-FS	8-577
Joshua Tree Wilderness Area	429,690	USDI-NPS	94-567
Kaiser Wilderness Area	22,500	USDA-FS	94-577
Kings Canyon NP	459,994	USDI-NPS	76-424
Lassen Volcanic NP	105,800	USDI-NPS	64-184
Lava Beds Wilderness Area	28,640	USDI-NPS	92-493
Marble Mountain Wilderness Area	213,743	USDA-FS	88-577
Minarets Wilderness Area	109,484	USDA-FS	88-577
Mokelumme Wilderness Area	50,400	USDA-FS	88-577
Pinnacles Wilderness Area	12,952	USDI-NPS	94-567
Point Reyes Wilderness Area	25,370	USDI-NPS	94-544
Redwood NP	27,792	USDI-NPS	90-545
San Gabriel Wilderness Area	36,137	USDA-FS	90-318
San Gorgonio Wilderness Area	34,644	USDA-FS	88-577
San Jacinto Wilderness Area	20,564	USDA-FS	88-577
San Rafael Wilderness Area	142,722	USDA-FS	90-271
Sequoia NP	386,642	USDI-NS	({1})
South Warner Wilderness Area	68,507	USDA-FS	88-577
Thousand Lakes Wilderness Area	15,695	USDA-FS	88-577
Ventana Wilderness Area	95,152	USDA-FS	91-58
Yolla-Bolly-Middle-Eel Wilderness Area	109,091	USDA-FS	88-577
Yosemite NP	759,172	USDI-NPS	58-49
81.406 Colorado			
Black Canyon of the Gunnison Wilderness Area	11,180	USDI-NPS	94-567
Eagles Nest Wilderness Area	133,910	USDA-FS	94-352
Flat Tops Wilderness Area	235,230	USDA-FS	94-146
Great Sand Dunes Wilderness Area	33,450	USDI-NPS	94-567
La Garita Wilderness Area	48,486	USDA-FS	88-577
Maroon Bells-Snowmass Wilderness Area	71,060	USDA-FS	88-577
Mesa Verde NP	51,488	USDI-NPS	59-353

Rawah Wilderness Area	26,674	USDA-FS	88-577
Rocky Mountain NP	263,138	USDI-NPS	63-238
Weminuche Wilderness Area	400,907	USDA-FS	93-632
West Elk Wilderness Area	61,412	USDA-FS	88-577
81.407 Florida			
Chassahowitzka Wilderness Area	23,360	USDI-FWS	94-557
Everglades NP	1,397,429	USDI-NPS	73-267
St. Marks Wilderness Area	17,745	USDI-FWS	93-632
81.408 Georgia			
Cohotta Wilderness Area	33,776	USDA-FS	93-622
Okefenokee Wilderness Area	343,850	USDI-FWS	93-429
Wolf Island Wilderness Area	5,126	USDI-FWS	93-632
81.409 Hawaii			
Haleakala NP	27,208		
Hawaii Volcanoes NP	217,029		
81.41 Idaho			
Craters of the Moon Wilderness Area	43,243	USDI-NPS	91-504
Hells Canyon Wilderness Area{1}	83,800	USDA-FS	94-199
Sawtooth Wilderness Area	216,383	USDA-FS	92-400
Selway-Bitterroot Wilderness Area{2}	988,770	USDA-FS	88-577
Yellowstone NP{3}	31,488	USDI-NPS	({4})
{1} Hells Canyon Wilderness, 192,700 acres overall, of which 108,900 acres are in Oregon and 83,800 acres are in Idaho. {2} Selway Bitterroot Wilderness, 1,240,700 acres overall, of which 988,700 acres are in Idaho and 251,930 acres are in Montana. {3} Yellowstone National Park, 2,219,737 acres overall, of which 2,020,625 acres are in Wyoming, 167,624 acres are in Montana, and 31,488 acres are in Idaho {4} 17 Stat. 32 (42nd Cong.).			
81.411 Kentucky			
Mammoth Cave NP	51,303	USDI-NPS	69-283
81.412 Louisiana			
Breton Wilderness Area	5,000+	USDI-FWS	93-632
81.413 Maine			
Acadia National Park	37,503	USDI-NPS	65-278
Moosehorn Wilderness Area	7,501	USDI-FWS	
(EDMUNDS UNIT)	(2,782)		91-504
(Baring Unit)	(4,719)		93-632

81.414 Michigan			
Isle Royale NP	542,428	USDI-NPS	71-835
Seney Wilderness Area	25,150	USDI-FWS	91-504
81.415 Minnesota			
Boundary Waters Canoe Area Wilderness Area	747,840	USDA-FS	99-577
Voyageurs NP	114,964	USDI-NPS	99-261
81.416 Missouri			
Hercules-Glades Wilderness Area	12,315	USDA-FS	94-557
Mingo Wilderness Area	8,000	USDI-FWS	95-557
81.417 Montana			
Anaconda-Pintlar Wilderness Area	157,803	USDA-FS	88-577
Bob Marshall Wilderness Area	950,000	USDA-FS	88-577
Cabinet Mountains Wilderness Area	94,272	USDA-FS	88-577
Gates of the Mtn Wilderness Area	28,562	USDA-FS	88-577
Glacier NP	1,012,599	USDI-NPS	61-171
Medicine Lake Wilderness Area	11,366	USDI-FWS	94-557
Mission Mountain Wilderness Area	73,877	USDA-FS	93-632
Red Rock Lakes Wilderness Area	32,350	USDI-FWS	94-557
Scapegoat Wilderness Area	239,295	USDA-FS	92-395
Selway-Bitterroot Wilderness Area{1}	251,930	USDA-FS	88-577
U. L. Bend Wilderness Area	20,890	USDI-FWS	94-557
Yellowstone NP{2}	167,624	USDI-NPS	({3})
{1} Selway-Bitterroot Wilderness, 1,240,700 acres overall, of which 988,770 acres are in Idaho and 251,930 acres are in Montana. {2} Yellowstone National Park, 2,219,737 acres overall, of which 2,020,625 acres are in Wyoming, 167,624 acres are in Montana, and 31,488 acres are in Idaho. {3} 17 Stat. 32 (42nd Cong.) [44 FR 69124, Nov. 30, 1979; 45 FR 6103, Jan. 25, 1980]			
81.418 Nevada			
Jarbidge Wilderness Area	64,667	USDA-FS	88-577
81.418 New Hampshire			
Great Gulf Wilderness Area	5,552	USDA-FS	88-577
Presidential Range-Dry River Wilderness Area	20,000	USDA-FS	93-622
81.42 New Jersey			
Brigantine Wilderness Area	6,603	USDI-FWS	93-632
81.421 New Mexico			
Bandelier Wilderness Area	23,267	USDI-NPS	94-567

Bosque del Apache Wilderness Area	80,850	USDI-FWS	93-632
Carlsbad Caverns NP	46,435	USDI-NPS	71-216
Gila Wilderness Area	433,690	USDA-FS	88-577
Pecos Wilderness Area	167,416	USDA-FS	88-577
Salt Creek Wilderness Area	8,500	USDI-FWS	91-504
San Pedro Parks Wilderness Area	41,132	USDA-FS	88-577
Wheeler Peak Wilderness Area	6,027	USDA-FS	88-577
White Mountain Wilderness Area	31,171	USDA-FS	88-577
81.422 North Carolina			
Great Smoky Mountains NP{1}	273,551	USDI-NPS	69-268
Joyce Kilmer-Slickrock Wilderness Area{2}	10,201	USDA-FS	93-622
Linville Gorge Wilderness Area	7,575	USDA-FS	88-577
Shining Rock Wilderness Area	13,350	USDA-FS	88-577
Swanquarter Wilderness Area	9,000	USDI-FWS	94-557
{1}Great Smoky Mountains National Park, 514,758 acres overall, of which 273,551 acres are in North Carolina, and 241,207 acres are in Tennessee. **{2}**Joyce Kilmer-Slickrock Wilderness, 14,033 acres overall, of which 10,201 acres are in North Carolina, and 3,832 acres are in Tennessee.			
81.423 North Dakota			
Lostwood Wilderness	5,557	USDI-FWS	93-632
Theodore Roosevelt NP	69,675	USDI-NPS	80-38
81.424 Oklahoma			
Wichita Mountains Wilderness	8,900	USDI-FWS	91-504
81.425 Oregon			
Crater Lake NP	160,290	USDA-NPS	57-121
Diamond Peak Wilderness	36,637	USDA-FS	88-577
Eagle Cap Wilderness	293,476	USDA-FS	88-577
Gearhart Mountain Wilderness	18,709	USDA-FS	88-577
Hells Canyon Wilderness{1}	108,900	USDA-FS	94-199
Kalmiopsis Wilderness	76,900	USDA-FS	88-577
Mountain Lakes Wilderness	23,071	USDA-FS	88-577
Mount Hood Wilderness	14,160	USDA-FS	88-577
Mount Jefferson Wilderness	100,208	USDA-FS	90-548
Mount Washington Wilderness	46,116	USDA-FS	88-577
Strawberry Mountain Wilderness	33,003	USDA-FS	88-577
Three Sisters Wilderness	199,902	USDA-FS	88-577

{10} Hells Canyon Wilderness, 192,700 acres overall, of which 108,900 acres are in Oregon, and 83,800 acres are in Idaho.

81.426 South Carolina			
Cape Romain Wilderness	28,000	USDI-FWS	93-632
81.427 South Dakota			
Badlands Wilderness	64,250	USDI-NPS	94-567
Wind Cave NP	28,060	USDI-NPS	57-16
81.428 Tennessee			
Great Smoky Mountains NP{1}	241,207	USDI-NPS	69-268
Joyce Kilmer-Slickrock Wilderness{2}	3,832	USDA-FS	93-622

{1} Great Smoky Mountains National Park, 514,758 acres overall, of which 273,551 acres are in North Carolina, and 241,207 acres are in Tennessee.
{2} Joyce Kilmer Slickrock Wilderness, 14,033 acres overall, of which 10,201 acres are in North Carolina, and 3,832 acres are in Tennessee.

[44 FR 69124, Nov. 30, 1979; 45 FR 6103, Jan. 25, 1980]

81.429 Texas			
Big Bend NP	708,118	USDI-NPS	74-157
Guadalupe Mountains NP	76,292	USDI-NPS	89-667
81.43 Utah			
Arches NP	65,098	USDI-NPS	92-155
Bryce Canyon NP	35,832	USDI-NPS	68-277
Canyonlands NP	337,570	USDI-NPS	88-590
Capitol Reef NP	221,896	USDI-NPS	92-507
Capitol Reef NP	221,896	USDI-NPS	92-507
Zion NP	142,462	USDI-NPS	68-83
81.431 Vermont			
Lye Brook Wilderness	12,430	USDA-FS	93-622
81.432 Virgin Islands			
Virgin Islands NP	12,295	USDI-NPS	84-925
81.433 Virginia			
James River Face Wilderness	8,703	USDA-FS	93-622
Shenandoah NP	190,535	USDI-NPS	69-268
81.434 Washington			
Alpine Lakes Wilderness	303,508	USDA-FS	94-357
Glacier Peak Wilderness	464,258	USDA-FS	88-577
Goat Rocks Wilderness	82,680	USDA-FS	88-577

Mount Adams Wilderness	32,356	USDA-FS	88-577
Mount Rainer NP	235,239	USDI-NPS	({1})
North Cascades NP	503,277	USDI-NPS	90-554
Olympic NP	892,578	USDI-NPS	75-778
Pasayten Wilderness	505,524	USDA-FS	90-544
{1} 30 Stat. 993 (55th Cong.).			
81.435 West Virginia			
Dolly Sods Wilderness	10,215	USDA-FS	93-622
Otter Creek Wilderness	20,000	USDA-FS	93-622
81.436 Wyoming			
Bridger Wilderness	392,160	USDA-FS	88-577
Fitzpatrick Wilderness	191,103	USDA-FS	94-567
Grand Teton NP	305,504	USDI-NPS	81-787
North Absaroka Wilderness	351,104	USDA-FS	88-577
Teton Wilderness	557,311	USDA-FS	88-577
Washakie Wilderness	686,584	USDA-FS	92-476
Yellowstone NP{1}	2,020,625	USDI-NPS	({2})
{1} Yellowstone National Park, 2,219,737 acres overall, of which 2,020,625 acres are in Wyoming, 167,624 acres are in Montana, and 31,488 acres are in Idaho. **{2}** 17 Stat. 32 (42nd Cong.).			
81.437 New Brunswick, Canada			
Roosevelt Campobello International Park	2,721	({1})	88-363
{1} Chairman, RCIP Commission.			
*All references are to Part 51 of the Code of Federal Regulations **Abbreviations:** USDI-NPS: U.S. Department of Interior, National Park Service USDA-FS: U.S. Department of Agriculture, U.S. Forest Service USDI-FWS: U.S. Department of Interior, Fish and Wildlife Service			

Last updated on Friday, March 29th, 2002
URL: http://www.epa.gov/oar/vis/class1.html

Appendix D
Siting Rational for Elimination of Candidate Sites

Northeast Wyoming Generation Project

Siting Rational for Elimination of Candidate Sites

During August 16 - 18, 2004, a site reconnaissance team comprised of Basin Electric, CH2M HILL, and EDAW representatives evaluated 36 potential power plant sites, including the 33 sites that were identified prior to site reconnaissance and three additional sites that were identified after meeting with mine operations personnel. The site reconnaissance team evaluated sites from a helicopter and on the ground by driving to the sites where access was available. The site reconnaissance team based the site evaluation process on a number of criteria in order to ground truth the mapped data that was previously acquired. Ground truthing the resource information consisted of focusing on the following criteria:

- Area in floodplain
- Surface water or drainage precluding a larger area of use
- Existing ecological sensitivities
- Potential for hazardous contamination
- Visual sensitivity based on elevation, topography, and/or viewpoints
- Current and adjacent land use compatibility, including structures within ½ mile
- Overall feasibility of transmission line, conveyor supply, solid waste disposal (primarily fly ash), road access, and rail access
- Site that can accommodate plant facilities without unreasonable civil work

The site reconnaissance team categorized the sites into three levels of consideration. These levels of consideration included Tier 1, Tier 2, and those sites eliminated from further consideration.

Tier 1 consists of sites that present the best opportunities for a power plant site. The boundaries of many of these sites were reconfigured from the initial site identification process; the general location of the power plant site remained the same, however. The Tier 1 sites included sites a new Dry Fork Site (near Silo), a new Dry Fork Site (close to Garner Lake Road), a new Ft. Union Site, as well as sites 6, 11, 12, 13 and 14 and are shown on **Figure 16 Preferred Candidate Sites**. The preferred candidate sites, some of which were previously labeled with numbers, were renamed with the letters A through H. The following information identifies the Tier 1 sites and the rational associated with their preferred status.

Tier 1 Level of Consideration

Site A (newly identified Dry Fork – Near Silo Site)

Site A was identified during site reconnaissance and discussions with Dry Fork Mine operations personnel. The terrain of Site A is flat and ash could be disposed of at the mine. A limited length of conveyor, if any, would be required. The site contains very small acreage and the existing rail loop and mine allow for a smaller area to be needed for the power plant. A separate rail loop would likely have to be developed and the Dry Fork access road would need to be relocated. The area east of the “BLM burn line”, which is a line delineating the minable coal deposits, was the westerly boundary of the site. According to the BLM and the research they have conducted regarding the coal seam boundary, the geology west of the BLM burn line will likely have the most opportunity for coal and therefore, the area east of the BLM burn line is of higher opportunity since it will not likely be mined.

Site B (newly identified Dry Fork – Garner Road Site)

Site B was added during site reconnaissance. The terrain of the Site B is flat to the south and a bit hilly south of the Dry Fork access road and west of Garner Lake Road. Ash could be placed at the mine and a limited length of conveyor, if any, would be required. The Dry Fork Burn line limits the site on the west, and the existing rail loop and mine allow for a smaller area to be needed for the power plant. The proximity of Site B to Garner Lake Road may result in air permitting issues. The area east of the “BLM burn line”, which is a line delineating the minable coal deposits, was the westerly boundary of the site. According to the BLM and the research they have conducted regarding the coal seam boundary, the geology west of the BLM burn line will likely have the most opportunity for coal and therefore, the area east of the BLM burn line is of higher opportunity since it will not likely be mined.

Site C (formerly Site 5)

Agricultural land use covers Site C and there are only a few residences in the area. The size of the site would accommodate the Project, however a dry lake bed associated with Garner Lake and ridges onsite would constrain the development footprint of the Project to the east side of the site. Because of the dry lakebed, there were concerns that the recharge in this area could potentially be higher in this area. Due to the power plant operations and ash land filling, recharge areas should be avoided. For this reason, the site was constrained on the north by the dry lakebed. Railroad access would enter the site from the south, between the ridges. Storage of oil processing equipment adjacent to the site would require further research.

Site D (newly identified Ft. Union Site)

Site D was added during site reconnaissance. The terrain of Site D is generally flat, and ash disposal could potentially be placed at the adjacent Fort Union Mine. A railroad is adjacent to the site on the south and west. A 69kV line crossing the site would need to be relocated.

Site E (formerly Sites 13 and 14)

Site E combines Sites 13 and 14 to result in sufficient acreage for the Project. A dry pond area located in a floodplain would require mitigation.

Site G (formerly Sites 11 and 12)

Site G combines Sites 11 and 12, because Site 11 was too small by itself and expanding the site boundary to include Site 12 would provide sufficient acreage for the power plant. The relatively flat terrain of the site would accommodate road access, rail, and conveyor. There are oil wells onsite and a 69kV line crossing the site may need to be relocated. Pock holes onsite would require additional research to determine the geologic conditions.

Site H (formerly Site 6)

Site H had initially been eliminated from consideration during Phase 2 because the parcel was too small to accommodate ash disposal. After further evaluation, it was determined that Site H had adequate space for the power plant site if ash were disposed off-site at the Dry Fork mine. For this reason, the site was included for further analysis in Phase 3.

Tier 2 Level of Consideration

Tier 2 level of consideration consists of two sites that have the potential to be feasible locations, yet they are less desirable than Tier 1 sites. The Tier 2 sites, Sites 17 and 28, would present alternatives to Tier 1 sites if air permitting issues arise at Tier 1 sites. However, construction on Tier 2 sites would be costly due to distance to the mine, resulting in increased length of conveyor (e.g., Site 17) and/or civil work that would be required to make the sites feasible for construction.

Site 17

- Numerous nearby residences
- Site is too small
- Ridge on south may present air issues
- Conveyor would not be economically feasible due to distance to coal source

Site 28

- Undesirable topography
- Site is too small - constrained by railroad and terrain

Sites Eliminated From Further Consideration

The remaining 26 sites were eliminated from consideration due to the distance to the north mines, which had the lowest cost and terrain.

Site 1

- Partly covered by Hay Creek floodplain
- Undesirable topography
- Ecological sensitivities include riparian vegetation and prairie dogs
- Site is too small– constrained by topography and floodplain
- Rail would have to be located in floodplain to avoid rough terrain
- Conveyor would not be feasible due to distance from coal source

Site 2

- Undesirable topography
- Conveyor would not be feasible due to distance from coal source
- Vehicular and rail access would be difficult

Site 3

- Partly covered by Little Powder River floodplain
- Undesirable topography
- Conveyor would not be feasible due to distance from coal source
- Vehicular and rail access would be difficult

Site 4

- Partly covered by Little Powder River floodplain
- Site is too small – constrained by floodplain

Site 6

- Partly covered by Dry Fork floodplain
- Ecological sensitivities include riparian areas
- Couldn’t accommodate ash disposal with existing size of parcel; would have to use with Site 7
- Air permitting may not be feasible due to terrain

Site 7

- Ecological sensitivities include reclaimed mine area
- Conveyor loop and rail access not feasible due to the size of the site

Site 8

- KFx equipment on site would require removal; also Phase 1 environmental assessment
- Existing rail spur
- May present landowner acquisition or fuel source contract issues
- Topography is flat
- Ash could potentially be placed at Ft. Union Mine
- Site being used by KFx

Site 9

- Site is too small – constrained by topography
- Undesirable topography (small plateau in center)

Site 10

- Located in a floodplain
- Numerous nearby residences
- Undesirable topography

Site 15

- Numerous nearby residences to the south and west
- Site is too small
- Site is too close to Gillette

Site 16

- Numerous nearby residences
- Site is too small
- Site is too close to Gillette

Site 18

- Numerous nearby residences
- Collectively, the multiple land uses (fire department, cemetery, residences) make the site incompatible
- Site is too small – constrained by residences
- Active oil field

Site 19

- Numerous nearby residences
- Active oil field
- Rail and conveyor on wrong side of Interstate 90 for economical construction of conveyor
- Hughes and Rozet substations; many transmission lines onsite would need to be relocated

Site 20

- Numerous nearby residences
- Active oil field
- Rail and conveyor on wrong side of Interstate 90 for economical construction of conveyor

Site 21

- Partly covered by floodplains of several creeks
- Ecological sensitivities include riparian areas
- Numerous nearby residences
- Site too small – constrained by floodplains and residences
- Conveyor would not be economically feasible due to distance to coal source

Site 22

- Did not evaluate due to location in Specific Minor Source Baseline Area

Site 23

- Did not evaluate due to location in Specific Minor Source Baseline Area

Site 24

- Did not evaluate due to location in Specific Minor Source Baseline Area

Site 25

- Undesirable topography
- Site is too small – constrained by topography
-

Site 26

- Partly covered by Tisdale Creek floodplain

- Ecological sensitivities include riparian areas
- Undesirable topography
- Site is too small – constrained by floodplain, topography, and railroad through center of property

Site 27

- Partly covered by Caballo Creek floodplain
- Ecological sensitivities include riparian areas
- Undesirable topography
- Site is too small – constrained by railroad and floodplain

Site 29

- Did not evaluate due to location in Specific Minor Source Baseline Area

Site 30

- Partly covered by Bella Fouche River floodplain
- Ecological sensitivities include riparian areas
- Active oil field
- Numerous residences onsite
- Site is too small – constrained by floodplain, oil wells and residences

Site 31

- Partly covered by a floodplain/drainage
- Ecological sensitivities include riparian areas
- Site is too small to accommodate rail access
- Residences (Ranch with old airstrip) on site
- Active oil field

Site 32

- Creek runs through site; also active oil field on site
- Ecological sensitivities include riparian areas
- Site is too small

Site 33

- Conveyor would not be economically feasible due to distance to coal source
- Air issues may be present due to terrain and proximity to mine

Appendix E
Pulverized Coal and Circulating Fluidized Bed Coal Pro Forma

PC and CFB Pro Forma Summary for Basin Electric NE Wyoming Power Project

PREPARED FOR: Basin Electric Power Cooperative

PREPARED BY: CH2M HILL

DATE: December 9, 2004

General Plant Data

The annual average net power output of a PC or CFB unit is 273 MW. The average annual net plant heat rate, which includes a 5% margin over the calculated heat rate from the Gates Cycle thermal balance, is 9,613 Btu/kW-Hr. An annual average plant capacity factor of 85 percent was used for the evaluation. The pro formas were based on the Dry Fork Mine commercial quality coal (8,045 btu/lb, 0.32% Sulfur, 4.77% ash).

Capital Costs

The base plant cost estimate for the PC unit is $531.8 Million. The base plant cost estimate for the CFB unit is $547.7 Million. The total capital cost of the PC unit ranged from $645.3 to $679.6 Million for the eleven site options. The total capital cost of the CFB unit ranged from $663.8 to $698.1 Million for the eleven site options. The largest site-specific capital cost differences encountered during our evaluation of the eleven sites that were under consideration was from the conveyor length to the Dry Fork Mine and the site work differentials. The difference between the PC and CFB Unit costs for each site was from the $15.9 Million higher base plant cost for CFB and the corresponding $2.6 Million higher Interest During Construction (IDC).

Life Cycle and Busbar Costs

The Net Present Value (NPV) for each plant site was calculated based on a 6.0 percent discount rate and annual cash flows for a plant economic life of 42 years.

The NPV for the PC plant ranged from $1,171.8 to $1,206.1 Million for the eleven site options. The NPV for the CFB plant ranged from $1,154.3 to $1,188.6 Million for the eleven site options.

The largest life cycle cost driver was the debt service for the capital cost of the plant at approximately 66% of the total NPV. The annual debt service cost was calculated based on financing 100 percent of the plant capital cost for 30 years at a 6.0 percent annual interest rate.

The next largest life cycle cost component was the non-fuel operating & maintenance (O&M) cost component at approximately 23% of the total NPV. The PRB coal fuel cost was the smallest life cycle cost component at approximately 11% of the total NPV.

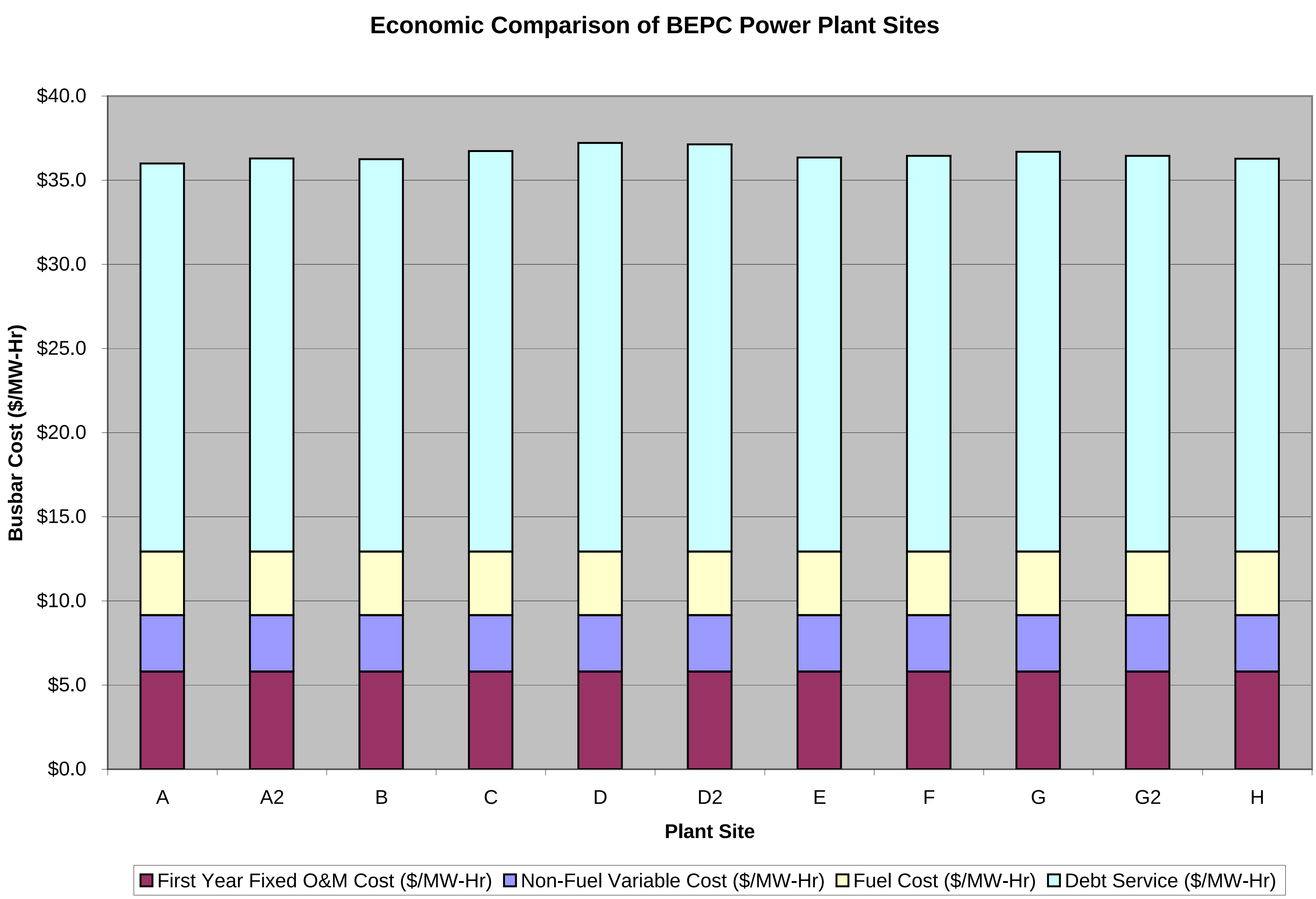
The average busbar cost of $36.3/MW-Hr for the CFB Unit was slightly less than the average PC Unit cost of $36.5/MW-Hr at the eleven sites. The higher CFB Unit annual debt service is offset to a greater degree by the lower annual non-fuel operating and maintenance cost compared to a PC Unit.

NE Wyoming Generation Project Economic Comparison - Rev 4 12-09-04

Basin Electric Power Cooperative, Gillette, WY

Base Case: PC Unit w/Dry Fork Mine Coal ($2011)

Site ---->	A	A2	B	C	D	D2	E	F	G	G2	H
Total Capital Cost ($ Million)	**$645.3**	**$653.6**	**$652.4**	**$666.1**	**$679.6**	**$677.1**	**$655.2**	**$657.9**	**$664.8**	**$658.1**	**$653.4**
First Year Fixed O&M Cost ($/MW-Hr)	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8
Non-Fuel Variable Cost ($/MW-Hr)	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3
Fuel Cost ($/MW-Hr)	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8
Total O&M Cost ($/MW-Hr)	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**
Debt Service ($/MW-Hr)	**$23.1**	**$23.4**	**$23.3**	**$23.8**	**$24.3**	**$24.2**	**$23.4**	**$23.5**	**$23.8**	**$23.5**	**$23.4**
Total First Year Busbar Cost ($/MW-Hr)	**$36.0**	**$36.3**	**$36.2**	**$36.7**	**$37.2**	**$37.1**	**$36.3**	**$36.4**	**$36.7**	**$36.5**	**$36.3**
42 Year NPV ($ Million)	**$1,171.8**	**$1,180.1**	**$1,178.8**	**$1,192.6**	**$1,206.1**	**$1,203.6**	**$1,181.7**	**$1,184.4**	**$1,191.3**	**$1,184.6**	**$1,179.9**



Economic Comparison of BEPC Power Plant Sites
Busbar Cost ($/MW-Hr)
$40.0
$35.0
$30.0
$25.0
$20.0
$15.0
$10.0
$5.0
$0.0
A
A2
B
C
D
D2
E
F
G
G2
H
Plant Site
First Year Fixed O&M Cost ($/MW-Hr)
Non-Fuel Variable Cost ($/MW-Hr)
Fuel Cost ($/MW-Hr)
Debt Service ($/MW-Hr)

NE Wyoming Generation Project Economic Comparison

Basin Electric Power Cooperative, Gillette, WY

Parameter	Input	Comments
Plant Output and Heat Rate		
Full Load - Net Power Output @ Annual Average (kW)	273,000	Annual Average from Heat Balances
Full Load - Net Plant Heat Rate @ Annual Average (Btu/kW-Hr)	9,613	Annual Average from Heat Balances w/5% Margin
General Plant Data		
Annual Plant Capacity Factor	0.85	Assumed
Economic Factors		
Interest Rate (%)	6.0%	From BEPC
Discount Rate (%)	6.0%	From BEPC
Equity Amoritization Period (Years)	30	From BEPC
Plant Economic Life (Years)	42	From BEPC
SO2 Allowance Cost ($/Ton)	500	Argus Air Daily
Annual SO2 Allowance Escalation Rate (%)	2.0%	Assumed
Capital Costs in $2011		
Total Capital Cost ($)	$653,384,548	Proforma Input Spreadsheet
($/kW, Net)	$2,393	Calculated
Base Case Operating and Maintenance (O&M) Costs		
Fixed O&M Costs ($/kW-Yr)	$38.33	From BEPC
($)	$10,464,090	Calculated
Non-Fuel Variable O&M Costs ($/kW-Hr)	$0.0027	From BEPC
($)	$5,529,102	Calculated
Annual Non-Fuel O&M Cost Escalation Rate (%)	2.0%	From BEPC
Makeup Water Cost		
Makeup Water Requirement (Gpm)	521	Air Cooled Condenser
Makeup Water Cost ($/1000 Gallons)	$0.50	Assumed
Annual Water Cost Escalation Rate (%)	2.0%	From BEPC
Powder River Basin (PRB) Fuel Cost		
Dry Fork Coal Mine		
Coal HHV (Btu/Lb)	8,045	Dry Fork Mine Target
Coal Sulfur Content (Wt.%)	0.32%	From BEPC
Coal Ash Content (Wt.%)	4.77%	Dry Fork Mine Target
Mine Mouth Coal Cost ($/Ton)	$5.63	Calculated
($/MMBtu)	$0.35	From BEPC
Annual SO2 Emissions (Tons)	780	Calculated from FGD Mass Balance
Clovis Point Coal Mine		
Coal HHV (Btu/Lb)	8,000	Minimum Specification
Coal Sulfur Content (Wt.%)	0.54%	From BEPC
Coal Ash Content (Wt.%)	5.00%	Assumed
Mine Mouth Coal Cost ($/Ton)	$6.40	Calculated
($/MMBtu)	$0.40	From BEPC
Annual SO2 Emissions (Tons)	1,322	Calculated from FGD Mass Balance
Ash/FGD Solids Waste Disposal		
Ash/FGD Solids Waste Disposal Tipping Fee ($/Ton)	$0.00	Dry Fork Mine (From BEPC)
Annual Coal & Waste Diposal Cost Escalation Rate (%)	2.0%	From BEPC

CAPITAL COST AMORTIZATION SCHEDULE

Total EPC Contract Cost ($) = $653,384,548

Interest Rate = 6.0%

Year		Debt Beginning Amount	Payment	Interest	Principle Repayment	Remaining Balance
1	2004	$653,384,548	($47,467,676)	($39,203,073)	($8,264,603)	$645,119,945
2	2005	$645,119,945	($47,467,676)	($38,707,197)	($8,760,480)	$636,359,465
3	2006	$636,359,465	($47,467,676)	($38,181,568)	($9,286,108)	$627,073,357
4	2007	$627,073,357	($47,467,676)	($37,624,401)	($9,843,275)	$617,230,082
5	2008	$617,230,082	($47,467,676)	($37,033,805)	($10,433,871)	$606,796,211
6	2009	$606,796,211	($47,467,676)	($36,407,773)	($11,059,904)	$595,736,307
7	2010	$595,736,307	($47,467,676)	($35,744,178)	($11,723,498)	$584,012,810
8	2011	$584,012,810	($47,467,676)	($35,040,769)	($12,426,908)	$571,585,902
9	2012	$571,585,902	($47,467,676)	($34,295,154)	($13,172,522)	$558,413,380
10	2013	$558,413,380	($47,467,676)	($33,504,803)	($13,962,873)	$544,450,506
11	2014	$544,450,506	($47,467,676)	($32,667,030)	($14,800,646)	$529,649,861
12	2015	$529,649,861	($47,467,676)	($31,778,992)	($15,688,685)	$513,961,176
13	2016	$513,961,176	($47,467,676)	($30,837,671)	($16,630,006)	$497,331,170
14	2017	$497,331,170	($47,467,676)	($29,839,870)	($17,627,806)	$479,703,364
15	2018	$479,703,364	($47,467,676)	($28,782,202)	($18,685,474)	$461,017,890
16	2019	$461,017,890	($47,467,676)	($27,661,073)	($19,806,603)	$441,211,287
17	2020	$441,211,287	($47,467,676)	($26,472,677)	($20,994,999)	$420,216,288
18	2021	$420,216,288	($47,467,676)	($25,212,977)	($22,254,699)	$397,961,589
19	2022	$397,961,589	($47,467,676)	($23,877,695)	($23,589,981)	$374,371,609
20	2023	$374,371,609	($47,467,676)	($22,462,297)	($25,005,380)	$349,366,229
21	2024	$349,366,229	($47,467,676)	($20,961,974)	($26,505,702)	$322,860,526
22	2025	$322,860,526	($47,467,676)	($19,371,632)	($28,096,045)	$294,764,482
23	2026	$294,764,482	($47,467,676)	($17,685,869)	($29,781,807)	$264,982,675
24	2027	$264,982,675	($47,467,676)	($15,898,960)	($31,568,716)	$233,413,959
25	2028	$233,413,959	($47,467,676)	($14,004,838)	($33,462,839)	$199,951,120
26	2029	$199,951,120	($47,467,676)	($11,997,067)	($35,470,609)	$164,480,511
27	2030	$164,480,511	($47,467,676)	($9,868,831)	($37,598,846)	$126,881,666
28	2031	$126,881,666	($47,467,676)	($7,612,900)	($39,854,776)	$87,026,889
29	2032	$87,026,889	($47,467,676)	($5,221,613)	($42,246,063)	$44,780,827
30	2033	$44,780,827	($47,467,676)	($2,686,850)	($44,780,827)	$0
31	2034					
32	2035					
33	2036					
34	2037					
35	2038					
36	2039					
37	2040					
38	2041					
39	2042					
40	2043					
41	2044					
42	2045					

Power Generation Cost - Dry Fork Mine Coal

Year -->	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
From Plant Startup	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
From Present	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
PLANT OPERATION																							
Annual PRB Coal Usage (Tons)			1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475
Annual Ash/FGD Solids Production (Tons)			117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058
Annual Export Power (kW-Hr)	-	-	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000
OPERATING EXPENSES																							
Annual Fixed O&M Cost ($)			11,784,265	12,019,950	12,260,349	12,505,556	12,755,667	13,010,781	13,270,996	13,536,416	13,807,145	14,083,287	14,364,953	14,652,252	14,945,297	15,244,203	15,549,087	15,860,069	16,177,270	16,500,816	16,830,832	17,167,449	17,510,798
Annual Non-Fuel Variable Cost ($)			6,226,667	6,351,200	6,478,224	6,607,788	6,739,944	6,874,743	7,012,238	7,152,483	7,295,532	7,441,443	7,590,272	7,742,077	7,896,919	8,054,857	8,215,954	8,380,273	8,547,879	8,718,836	8,893,213	9,071,077	9,252,499
Makeup Water Cost ($)			131,064	133,685	136,359	139,086	141,868	144,705	147,599	150,551	153,562	156,633	159,766	162,961	166,221	169,545	172,936	176,395	179,923	183,521	187,192	190,935	194,754
Annual Ash/FGD Solids Tipping Fee ($)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchase of SO2 Allowances ($)			439,028	447,808	456,764	465,900	475,218	484,722	494,416	504,305	514,391	524,679	535,172	545,876	556,793	567,929	579,288	590,873	602,691	614,745	627,040	639,580	652,372
Annual Delivered Coal Cost ($)	-	-	7,702,181	7,856,224	8,013,349	8,173,616	8,337,088	8,503,830	8,673,906	8,847,384	9,024,332	9,204,819	9,388,915	9,576,693	9,768,227	9,963,592	10,162,864	10,366,121	10,573,443	10,784,912	11,000,611	11,220,623	11,445,035
Total Operating Expenses			26,283,204	26,808,868	27,345,045	27,891,946	28,449,785	29,018,781	29,599,156	30,191,139	30,794,962	31,410,861	32,039,079	32,679,860	33,333,457	34,000,127	34,680,129	35,373,732	36,081,206	36,802,830	37,538,887	38,289,665	39,055,458
Capital Charges																							
Debt Service	-	-	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676
Total Annual Power Generation Cost			73,750,880	74,276,544	74,812,721	75,359,622	75,917,461	76,486,457	77,066,832	77,658,816	78,262,638	78,878,538	79,506,755	80,147,536	80,801,134	81,467,803	82,147,805	82,841,408	83,548,882	84,270,507	85,006,563	85,757,341	86,523,134
POWER GENERATION COST ($/kW-Hr)																							
Fixed O&M Cost			$0.0058	$0.0059	$0.0060	$0.0062	$0.0063	$0.0064	$0.0065	$0.0067	$0.0068	$0.0069	$0.0071	$0.0072	$0.0074	$0.0075	$0.0076	$0.0078	$0.0080	$0.0081	$0.0083	$0.0084	$0.0086
Non-Fuel Variable Cost			$0.0033	$0.0034	$0.0035	$0.0035	$0.0036	$0.0037	$0.0038	$0.0038	$0.0039	$0.0040	$0.0041	$0.0042	$0.0042	$0.0043	$0.0044	$0.0045	$0.0046	$0.0047	$0.0048	$0.0049	$0.0050
Fuel Cost			$0.0038	$0.0039	$0.0039	$0.0040	$0.0041	$0.0042	$0.0043	$0.0044	$0.0044	$0.0045	$0.0046	$0.0047	$0.0048	$0.0049	$0.0050	$0.0051	$0.0052	$0.0053	$0.0054	$0.0055	$0.0056
Debt Service			$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234
Busbar Cost ($/kW-Hr)	-	-	$0.0363	$0.0365	$0.0368	$0.0371	$0.0373	$0.0376	$0.0379	$0.0382	$0.0385	$0.0388	$0.0391	$0.0394	$0.0397	$0.0401	$0.0404	$0.0408	$0.0411	$0.0415	$0.0418	$0.0422	$0.0426

FINANCIAL SUMMARY: **Net Present Value (NPV) =** **$1,179,853,811**

Power Generation Cost - Clovis Point Mine Coal

Year -->	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
From Plant Startup	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
From Present	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
PLANT OPERATION																							
Annual PRB Coal Usage (Tons)			1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306
Annual Ash/FGD Solids Production (Tons)			145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215
Annual Export Power (kW-Hr)	-	-	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000
OPERATING EXPENSES																							
Annual Fixed O&M Cost ($)			11,784,265	12,019,950	12,260,349	12,505,556	12,755,667	13,010,781	13,270,996	13,536,416	13,807,145	14,083,287	14,364,953	14,652,252	14,945,297	15,244,203	15,549,087	15,860,069	16,177,270	16,500,816	16,830,832	17,167,449	17,510,798
Annual Non-Fuel Variable Cost ($)			6,226,667	6,351,200	6,478,224	6,607,788	6,739,944	6,874,743	7,012,238	7,152,483	7,295,532	7,441,443	7,590,272	7,742,077	7,896,919	8,054,857	8,215,954	8,380,273	8,547,879	8,718,836	8,893,213	9,071,077	9,252,499
Annual Makeup Water Cost ($)			131,064	133,685	136,359	139,086	141,868	144,705	147,599	150,551	153,562	156,633	159,766	162,961	166,221	169,545	172,936	176,395	179,923	183,521	187,192	190,935	194,754
Annual Ash/FGD Solids Tipping Fee ($)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchase of SO2 Allowances ($)			744,625	759,518	774,708	790,202	806,006	822,127	838,569	855,340	872,447	889,896	907,694	925,848	944,365	963,252	982,517	1,002,168	1,022,211	1,042,655	1,063,508	1,084,779	1,106,474
Annual Delivered Coal Cost ($)	-	-	8,802,492	8,978,542	9,158,113	9,341,275	9,528,101	9,718,663	9,913,036	10,111,296	10,313,522	10,519,793	10,730,189	10,944,793	11,163,688	11,386,962	11,614,701	11,846,995	12,083,935	12,325,614	12,572,126	12,823,569	13,080,040
Total Operating Expenses			27,689,113	28,242,895	28,807,753	29,383,908	29,971,586	30,571,018	31,182,438	31,806,087	32,442,209	33,091,053	33,752,874	34,427,932	35,116,490	35,818,820	36,535,196	37,265,900	38,011,218	38,771,443	39,546,872	40,337,809	41,144,565
Capital Charges																							
Debt Service	-	-	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676
Total Annual Power Generation Cost			75,156,789	75,710,571	76,275,429	76,851,584	77,439,262	78,038,694	78,650,115	79,273,763	79,909,885	80,558,729	81,220,550	81,895,608	82,584,166	83,286,496	84,002,873	84,733,576	85,478,894	86,239,119	87,014,548	87,805,485	88,612,241
POWER GENERATION COST ($/kW-Hr)																							
Fixed O&M Cost			$0.0058	$0.0059	$0.0060	$0.0062	$0.0063	$0.0064	$0.0065	$0.0067	$0.0068	$0.0069	$0.0071	$0.0072	$0.0074	$0.0075	$0.0076	$0.0078	$0.0080	$0.0081	$0.0083	$0.0084	$0.0086
Non-Fuel Variable Cost			$0.0035	$0.0036	$0.0036	$0.0037	$0.0038	$0.0039	$0.0039	$0.0040	$0.0041	$0.0042	$0.0043	$0.0043	$0.0044	$0.0045	$0.0046	$0.0047	$0.0048	$0.0049	$0.0050	$0.0051	$0.0052
Fuel Cost			$0.0043	$0.0044	$0.0045	$0.0046	$0.0047	$0.0048	$0.0049	$0.0050	$0.0051	$0.0052	$0.0053	$0.0054	$0.0055	$0.0056	$0.0057	$0.0058	$0.0059	$0.0061	$0.0062	$0.0063	$0.0064
Debt Service			$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234
Busbar Cost ($/kW-Hr)	-	-	$0.0370	$0.0372	$0.0375	$0.0378	$0.0381	$0.0384	$0.0387	$0.0390	$0.0393	$0.0396	$0.0400	$0.0403	$0.0406	$0.0410	$0.0413	$0.0417	$0.0421	$0.0424	$0.0428	$0.0432	$0.0436

FINANCIAL SUMMARY: **Net Present Value (NPV) =** **$1,208,015,066**

Power Generation Cost - Dry Fork Mine Coal

Year -->	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2046	2047	2048	2049	2050	
From Plant Startup	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	
From Present	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
PLANT OPERATION																						
Annual PRB Coal Usage (Tons)	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	
Annual Ash/FGD Solids Production (Tons)	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	
Annual Export Power (kW-Hr)	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	
OPERATING EXPENSES																						**NPV**
Annual Fixed O&M Cost ($)	17,861,014	18,218,234	18,582,599	18,954,251	19,333,336	19,720,002	20,114,402	20,516,690	20,927,024	21,345,565	21,772,476	22,207,926	22,652,084	23,105,126	23,567,228	24,038,573	24,519,344	25,009,731	25,509,926	26,020,124	26,540,527	$236,046,311
Annual Non-Fuel Variable Cost ($)	9,437,549	9,626,300	9,818,826	10,015,203	10,215,507	10,419,817	10,628,213	10,840,777	11,057,593	11,278,745	11,504,320	11,734,406	11,969,094	12,208,476	12,452,646	12,701,698	12,955,732	13,214,847	13,479,144	13,748,727	14,023,701	$124,724,087
Makeup Water Cost ($)	198,649	202,622	206,675	210,808	215,024	219,325	223,711	228,185	232,749	237,404	242,152	246,995	251,935	256,974	262,113	267,356	272,703	278,157	283,720	289,394	295,182	$2,625,293
Annual Ash/FGD Solids Tipping Fee ($)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Purchase of SO2 Allowances ($)	665,419	678,728	692,302	706,148	720,271	734,677	749,370	764,358	779,645	795,238	811,143	827,365	843,913	860,791	878,007	895,567	913,478	931,748	950,383	969,390	988,778	$8,794,003
Annual Delivered Coal Cost ($)	11,673,936	11,907,415	12,145,563	12,388,474	12,636,244	12,888,968	13,146,748	13,409,683	13,677,876	13,951,434	14,230,463	14,515,072	14,805,373	15,101,481	15,403,510	15,711,581	16,025,812	16,346,329	16,673,255	17,006,720	17,346,855	$154,279,569
Total Operating Expenses	39,836,567	40,633,299	41,445,964	42,274,884	43,120,381	43,982,789	44,862,445	45,759,694	46,674,888	47,608,385	48,560,553	49,531,764	50,522,399	51,532,847	52,563,504	53,614,774	54,687,070	55,780,811	56,896,428	58,034,356	59,195,043	526,469,263
Capital Charges																						
Debt Service	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	0	0	0	0	0	0	0	0	0	0	0	0	$653,384,548
Total Annual Power Generation Cost	87,304,243	88,100,975	88,913,641	89,742,560	90,588,058	91,450,465	92,330,121	93,227,370	94,142,564	47,608,385	48,560,553	49,531,764	50,522,399	51,532,847	52,563,504	53,614,774	54,687,070	55,780,811	56,896,428	58,034,356	59,195,043	1,179,853,811
POWER GENERATION COST ($/kW-Hr)																						
Fixed O&M Cost	$0.0088	$0.0090	$0.0091	$0.0093	$0.0095	$0.0097	$0.0099	$0.0101	$0.0103	$0.0105	$0.0107	$0.0109	$0.0111	$0.0114	$0.0116	$0.0118	$0.0121	$0.0123	$0.0125	$0.0128	$0.0131	
Non-Fuel Variable Cost	$0.0051	$0.0052	$0.0053	$0.0054	$0.0055	$0.0056	$0.0057	$0.0058	$0.0059	$0.0061	$0.0062	$0.0063	$0.0064	$0.0066	$0.0067	$0.0068	$0.0070	$0.0071	$0.0072	$0.0074	$0.0075	
Fuel Cost	$0.0057	$0.0059	$0.0060	$0.0061	$0.0062	$0.0063	$0.0065	$0.0066	$0.0067	$0.0069	$0.0070	$0.0071	$0.0073	$0.0074	$0.0076	$0.0077	$0.0079	$0.0080	$0.0082	$0.0084	$0.0085	
Debt Service	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Busbar Cost ($/kW-Hr)	$0.0429	$0.0433	$0.0437	$0.0441	$0.0446	$0.0450	$0.0454	$0.0459	$0.0463	$0.0234	$0.0239	$0.0244	$0.0249	$0.0254	$0.0259	$0.0264	$0.0269	$0.0274	$0.0280	$0.0285	$0.0291	

FINANCIAL SUMMARY:

Power Generation Cost - Clovis Point Mine Coal

Year -->	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2046	2047	2048	2049	2050	
From Plant Startup	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	
From Present	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
PLANT OPERATION																						
Annual PRB Coal Usage (Tons)	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	
Annual Ash/FGD Solids Production (Tons)	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	
Annual Export Power (kW-Hr)	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	
OPERATING EXPENSES																						**NPV**
Annual Fixed O&M Cost ($)	17,861,014	18,218,234	18,582,599	18,954,251	19,333,336	19,720,002	20,114,402	20,516,690	20,927,024	21,345,565	21,772,476	22,207,926	22,652,084	23,105,126	23,567,228	24,038,573	24,519,344	25,009,731	25,509,926	26,020,124	26,540,527	$236,046,311
Annual Non-Fuel Variable Cost ($)	9,437,549	9,626,300	9,818,826	10,015,203	10,215,507	10,419,817	10,628,213	10,840,777	11,057,593	11,278,745	11,504,320	11,734,406	11,969,094	12,208,476	12,452,646	12,701,698	12,955,732	13,214,847	13,479,144	13,748,727	14,023,701	$124,724,087
Annual Makeup Water Cost ($)	198,649	202,622	206,675	210,808	215,024	219,325	223,711	228,185	232,749	237,404	242,152	246,995	251,935	256,974	262,113	267,356	272,703	278,157	283,720	289,394	295,182	$2,625,293
Annual Ash/FGD Solids Tipping Fee ($)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Purchase of SO2 Allowances ($)	1,128,604	1,151,176	1,174,199	1,197,683	1,221,637	1,246,070	1,270,991	1,296,411	1,322,339	1,348,786	1,375,761	1,403,277	1,431,342	1,459,969	1,489,168	1,518,952	1,549,331	1,580,317	1,611,924	1,644,162	1,677,046	$14,915,319
Annual Delivered Coal Cost ($)	13,341,641	13,608,474	13,880,643	14,158,256	14,441,421	14,730,250	15,024,855	15,325,352	15,631,859	15,944,496	16,263,386	16,588,654	16,920,427	17,258,835	17,604,012	17,956,092	18,315,214	18,681,518	19,055,149	19,436,252	19,824,977	$176,319,508
Total Operating Expenses	41,967,456	42,806,806	43,662,942	44,536,200	45,426,925	46,335,463	47,262,172	48,207,416	49,171,564	50,154,995	51,158,095	52,181,257	53,224,882	54,289,380	55,375,167	56,482,671	57,612,324	58,764,571	59,939,862	61,138,659	62,361,433	554,630,518
Capital Charges																						
Debt Service	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	47,467,676	0	0	0	0	0	0	0	0	0	0	0	0	$653,384,548
Total Annual Power Generation Cost	89,435,133	90,274,482	91,130,618	92,003,877	92,894,601	93,803,139	94,729,848	95,675,092	96,639,240	50,154,995	51,158,095	52,181,257	53,224,882	54,289,380	55,375,167	56,482,671	57,612,324	58,764,571	59,939,862	61,138,659	62,361,433	1,208,015,066
POWER GENERATION COST ($/kW-Hr)																						
Fixed O&M Cost	$0.0088	$0.0090	$0.0091	$0.0093	$0.0095	$0.0097	$0.0099	$0.0101	$0.0103	$0.0105	$0.0107	$0.0109	$0.0111	$0.0114	$0.0116	$0.0118	$0.0121	$0.0123	$0.0125	$0.0128	$0.0131	
Non-Fuel Variable Cost	$0.0053	$0.0054	$0.0055	$0.0056	$0.0057	$0.0058	$0.0060	$0.0061	$0.0062	$0.0063	$0.0065	$0.0066	$0.0067	$0.0069	$0.0070	$0.0071	$0.0073	$0.0074	$0.0076	$0.0077	$0.0079	
Fuel Cost	$0.0066	$0.0067	$0.0068	$0.0070	$0.0071	$0.0072	$0.0074	$0.0075	$0.0077	$0.0078	$0.0080	$0.0082	$0.0083	$0.0085	$0.0087	$0.0088	$0.0090	$0.0092	$0.0094	$0.0096	$0.0098	
Debt Service	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0234	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Busbar Cost ($/kW-Hr)	$0.0440	$0.0444	$0.0448	$0.0453	$0.0457	$0.0461	$0.0466	$0.0471	$0.0475	$0.0247	$0.0252	$0.0257	$0.0262	$0.0267	$0.0272	$0.0278	$0.0283	$0.0289	$0.0295	$0.0301	$0.0307	

FINANCIAL SUMMARY:

Basin Electric Power Cooperative - NE Wyoming Generation Project - PC Unit Pro Forma Cost Comparison - Rev 4 12-09-04														
Sites	**A**	**A2**	**B**	**C**	**D**	**D2**	**E**	**F**	**G**	**G2**	**H**	**Unit Quantities / Prices**	**Units**	**Comments / Assumptions**
Total Area of Site (Acres)	205	205	330	1780	1393	1393	555	717	1207	1207	353			
Plant Type	Pulverized Coal	Pulverized Coal	Pulverized Coal	Pulverized Coal	Pulverized Coal	Pulverized Coal	Pulverized Coal	Pulverized Coal	Pulverized Coal	Pulverized Coal	Pulverized Coal			
Net MW of Facility	273	273	273	273	273	273	273	273	273	273	273			
Water Source	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater			
Discharge Water	ZLD	ZLD	ZLD	ZLD	ZLD	ZLD	ZLD	ZLD	ZLD	ZLD	ZLD			
Cooling Technology	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser			
Air Emission Controls	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu			
Coal Cost Dry Fork Mine ($/MMBtu)	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	($/MMBtu)	Commercial Coal From BEPC
Coal Cost Clovis Mine ($/MMBtu)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	($/MMBtu)	Commercial Coal From BEPC
New Coal Delivery Rail Spur Length (Miles)	NA	NA	1.59	2.82	2.95	2.12	2.35	3.70	2.64	NA	NA			
Cost of Coal Delivery Rail ($ Million)	NA	NA	1.75	3.10	3.25	2.33	2.59	4.07	2.90	NA	NA	1.10	($ Million/Mile)	
New Construction Rail Spur Length (Miles)	0.33	0.33	0.57	0.41	0.75	0.67	0.69	0.73	0.58	0.89	0.75			
Cost of Construction Rail ($ Million)	0.36	0.36	0.63	0.45	0.83	0.74	0.76	0.80	0.64	0.98	0.83	1.10	($ Million/Mile)	
Conveyor Length to Dry Fork Mine (Miles)	0.98	0.98	1.69	2.78	3.43	4.33	NA	NA	NA	NA	1.86			
Cost of Dry Fork Conveyor ($ Million)	3.33	3.33	5.75	9.45	11.66	14.72	NA	NA	NA	NA	6.32	3.40	($ Million/Mile)	
Conveyor Length to Future Dry Fork Mining Area (Miles)	NA	NA	NA	NA	NA	NA	1.78	2.38	3.65	3.44	NA			
Cost of Dry Fork Conveyor to Future Mining Area ($ Million)	NA	NA	NA	NA	NA	NA	6.05	8.09	12.41	11.70	NA	3.40	($ Million/Mile)	
Conveyor Length to Clovis Mine (Miles)	4.57	4.57	3.85	4.12	3.29	1.81	1.51	1.30	0.65	0.83	NA			
Cost of Clovis Conveyor ($ Million)	15.54	15.54	13.09	14.01	11.19	6.15	5.13	4.42	2.21	2.82	NA	3.40	($ Million/Mile)	
Transmission Length to Carr Draw (Miles)	25.58	25.58	25.49	26.10	26.54	27.22	27.83	27.83	27.80	27.80	22.77			
Carr Draw Transmission Line Cost, including ROW ($ Million)	8.44	8.44	8.41	8.61	8.76	8.98	9.18	9.18	9.17	9.17	7.51	0.33	($ Million/Mile)	
Estimated Land Cost for Generation Site ($ Million)	0.62	0.62	0.99	5.34	4.18	4.18	1.67	2.15	3.62	3.62	1.06	3,000	($/Acre)	
Sitework Cost ($ Million)	(2.38)	5.77	0.15	4.05	15.96	11.09	0.25	(1.16)	1.20	(2.23)	1.57			
Ash/FGD Solids Produced per year, Dry Fork Coal (Tons)	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	(Tons/Year)	
Ash/FGD Solids Produced per year, Clovis Coal (Tons)	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	(Tons/Year)	
Flyash Disposal - On-Site, Dry Fork, Clovis or Fort Union	Dry Fork	Dry Fork	Dry Fork	Fort Union	Fort Union	Fort Union	On-Site **Dry Fork** Clovis	On-Site **Dry Fork** Clovis	On-Site **Clovis**	**Clovis**	**Dry Fork**			
Flyash Transportation Length to Dry Fork Mine (Miles)	0.66	0.63	0.76	NA	NA	NA	3.03	3.03	4.67	4.79	2.11			
Flyash Transportation Length to Clovis Mine (Miles)	NA	NA	NA	NA	NA	NA	1.61	1.62	1.68	1.71	1.71			

Sites	A	A2	B	C	D	D2	E	F	G	G2	H	Unit Quantities / Prices	Units	Comments / Assumptions
Flyash Transportation Length to Fort Union Mine (Miles)	NA	NA	NA	0.84	0.35	0.59	NA	NA	NA	NA	NA			
Cost of On-Site Landfill ($ Million)	20.90	20.90	20.90	20.90	20.90	20.90	20.90	20.90	20.90	20.90	20.90	20.90	($ Million)	From Consol Energy Landfill Cost Model for Disposal of CCPs
Cost of Dry ForkLandfill ($ Million)	0.00	0.00	0.00	NA	NA	NA	0.00	0.00	NA	NA	0.00	0.00	($ Million)	
Cost of Clovis Landfill ($ Million)	NA	NA	NA	NA	NA	NA	NA	NA	0.00	0.00	NA	0.00	($ Million)	
Cost of Fort Union Landfill ($ Million)	NA	NA	NA	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00	($ Million)	
Transportation Cost of Ash Disposal ($ Million)	0.04	0.04	0.04	0.05	0.02	0.03	0.18	0.18	0.10	0.10	0.12	0.50	$/Ton-Mile)	
Natural Gas Pipeline Connection Length (Miles)	2.65	2.48	2.07	2.26	1.53	1.13	1.93	1.93	1.28	1.26	5.02			
Natural Gas Pipeline Cost ($ Million)	1.12	1.05	0.87	0.95	0.65	0.48	0.82	0.82	0.54	0.53	2.12	0.42	($ Million/Mile)	
Access Road to Plant Site Length (Miles)	0.00	0.70	0.00	1.18	1.69	2.57	0.41	0.40	1.83	1.87	0.54			
Access Road Cost ($ Million)	0.00	0.21	0.00	0.35	0.51	0.77	0.12	0.12	0.55	0.56	0.16	0.30	($ Million/Mile)	

TOTAL CAPITAL COST ($ Million - 2011)

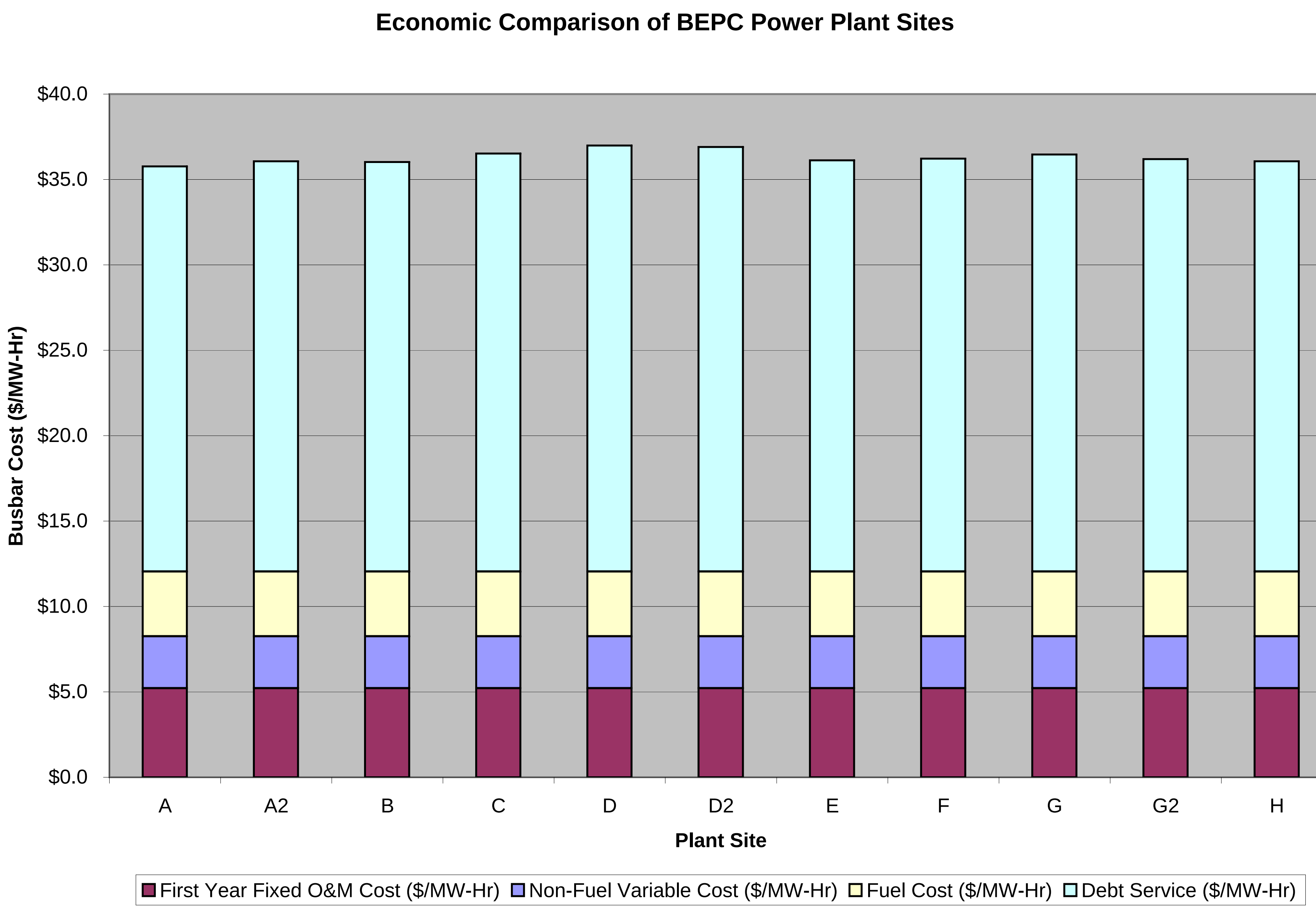
	A	A2	B	C	D	D2	E	F	G	G2	H
BASE PLANT COST	$531.8	$531.8	$531.8	$531.8	$531.8	$531.8	$531.8	$531.8	$531.8	$531.8	$531.8
SITE SPECIFIC ADJUSTMENT COSTS											
Coal Delivery Rail Spur	NA	NA	$1.7	$3.1	$3.2	$2.3	$2.6	$4.1	$2.9	NA	NA
Construction Rail Spur	$0.4	$0.4	$0.6	$0.5	$0.8	$0.7	$0.8	$0.8	$0.6	$1.0	$0.8
Conveyor to Dry Fork	$3.3	$3.3	$5.7	$9.5	$11.7	$14.7	NA	NA	NA	NA	$6.3
Conveyor to Dry Fork Future Mining Area	NA	NA	NA	NA	NA	NA	$6.1	$8.1	$12.4	$11.7	NA
Conveyor to Clovis	$15.5	$15.5	$13.1	$14.0	$11.2	$6.2	$5.1	$4.4	$2.2	$2.8	NA
Transmission to Carr Draw	$8.4	$8.4	$8.4	$8.6	$8.8	$9.0	$9.2	$9.2	$9.2	$9.2	$7.5
Land for Plant Site	$0.6	$0.6	$1.0	$5.3	$4.2	$4.2	$1.7	$2.2	$3.6	$3.6	$1.1
Site Work	($2.4)	$5.8	$0.2	$4.1	$16.0	$11.1	$0.3	($1.2)	$1.2	($2.2)	$1.6
On-Site Landfill	$20.9	$20.9	$20.9	$20.9	$20.9	$20.9	$20.9	$20.9	$20.9	$20.9	$20.9
Dry Fork Landfill	$0.0	$0.0	$0.0	NA	NA	NA	$0.0	$0.0	NA	NA	$0.0
Clovis Landfill	NA	NA	NA	NA	NA	NA	NA	NA	$0.0	$0.0	NA
Fort Union Landfill	NA	NA	NA	$0.0	$0.0	$0.0	NA	NA	NA	NA	NA
Natural Gas Pipeline	$1.1	$1.0	$0.9	$1.0	$0.6	$0.5	$0.8	$0.8	$0.5	$0.5	$2.1
Offsite Access Road to Plant	$0.0	$0.2	$0.0	$0.4	$0.5	$0.8	$0.1	$0.1	$0.5	$0.6	$0.2
NON-SITE SPECIFIC COSTS											
IDC	$76.6	$76.6	$76.6	$76.6	$76.6	$76.6	$76.6	$76.6	$76.6	$76.6	$76.6
Current PS & I Work Order/Direct Staff Costs	$10.3	$10.3	$10.3	$10.3	$10.3	$10.3	$10.3	$10.3	$10.3	$10.3	$10.3
Operating Spares	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5
Rolling Stock/O&M Equipment Costs	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0
Coal Mine Capital Improvements	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5
Offsite Communications System	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Start-up & Commissioning Fuel Costs (Coal/Gas)	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5
Revenue from Power Sales During Start-up & Commissioning	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)
Impact Alleviation	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5
Water Supply Wellfield/Pipeline	$2.8	$2.8	$2.8	$2.8	$2.8	$2.8	$2.8	$2.8	$2.8	$2.8	$2.8

Base Case Economic Comparison - PC Unit w/Dry Fork Mine Coal ($ Million - 2011)

	A	A2	B	C	D	D2	E	F	G	G2	H
Total Capital Cost ($)	**$645.3**	**$653.6**	**$652.4**	**$666.1**	**$679.6**	**$677.1**	**$655.2**	**$657.9**	**$664.8**	**$658.1**	**$653.4**
First Year Fixed O&M Cost ($/MW-Hr)	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8	$5.8
Non-Fuel Variable Cost ($/MW-Hr)	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3	$3.3
Fuel Cost ($/MW-Hr)	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8
Total O&M Cost ($/MW-Hr)	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**	**$12.9**
Debt Service ($/MW-Hr)	**$23.1**	**$23.4**	**$23.3**	**$23.8**	**$24.3**	**$24.2**	**$23.4**	**$23.5**	**$23.8**	**$23.5**	**$23.4**
Total First Year Busbar Cost ($/MW-Hr)	**$36.0**	**$36.3**	**$36.2**	**$36.7**	**$37.2**	**$37.1**	**$36.3**	**$36.4**	**$36.7**	**$36.5**	**$36.3**
42 Year NPV ($ Million)	**$1,171.8**	**$1,180.1**	**$1,178.8**	**$1,192.6**	**$1,206.1**	**$1,203.6**	**$1,181.7**	**$1,184.4**	**$1,191.3**	**$1,184.6**	**$1,179.9**

NE Wyoming Generation Project Economic Comparison - Rev 2 12-09-04
Basin Electric Power Cooperative, Gillette, WY
Alternate Case: CFB Unit w/Dry Fork Mine Coal ($2011)

Site ---->	A	A2	B	C	D	D2	E	F	G	G2	H
Total Capital Cost ($ Million)	**$663.8**	**$672.1**	**$670.9**	**$684.6**	**$698.1**	**$695.6**	**$673.7**	**$676.4**	**$683.3**	**$675.7**	**$671.9**
First Year Fixed O&M Cost ($/MW-Hr)	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2
Non-Fuel Variable Cost ($/MW-Hr)	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0
Fuel Cost ($/MW-Hr)	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8
Total O&M Cost ($/MW-Hr)	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**
Debt Service ($/MW-Hr)	**$23.7**	**$24.0**	**$24.0**	**$24.5**	**$24.9**	**$24.9**	**$24.1**	**$24.2**	**$24.4**	**$24.1**	**$24.0**
Total First Year Busbar Cost ($/MW-Hr)	**$35.8**	**$36.1**	**$36.0**	**$36.5**	**$37.0**	**$36.9**	**$36.1**	**$36.2**	**$36.5**	**$36.2**	**$36.1**
42 Year NPV ($ Million)	**$1,154.3**	**$1,162.6**	**$1,161.4**	**$1,175.1**	**$1,188.6**	**$1,186.1**	**$1,164.2**	**$1,166.9**	**$1,173.8**	**$1,166.2**	**$1,162.4**



Economic Comparison of BEPC Power Plant Sites
Busbar Cost ($/MW-Hr)
$40.0
$35.0
$30.0
$25.0
$20.0
$15.0
$10.0
$5.0
$0.0
A
A2
B
C
D
D2
E
F
G
G2
H
Plant Site
First Year Fixed O&M Cost ($/MW-Hr)
Non-Fuel Variable Cost ($/MW-Hr)
Fuel Cost ($/MW-Hr)
Debt Service ($/MW-Hr)

NE Wyoming Generation Project Economic Comparison

Basin Electric Power Cooperative, Gillette, WY

Parameter	Input	Comments
Plant Output and Heat Rate		
Full Load - Net Power Output @ Annual Average (kW)	**273,000**	Annual Average from Heat Balances
Full Load - Net Plant Heat Rate @ Annual Average (Btu/kW-Hr)	**9,613**	Annual Average from Heat Balances w/5% Margin
General Plant Data		
Annual Plant Capacity Factor	**0.85**	Assumed
Economic Factors		
Interest Rate (%)	**6.0%**	From BEPC
Discount Rate (%)	**6.0%**	From BEPC
Equity Amoritization Period (Years)	**30**	From BEPC
Plant Economic Life (Years)	**42**	From BEPC
SO2 Allowance Cost ($/Ton)	**500**	Argus Air Daily
Annual SO2 Allowance Escalation Rate (%)	**2.0%**	Assumed
Capital Costs in $2011		
Total Capital Cost ($)	**$671,884,548**	Proforma Input Spreadsheet
($/kW, Net)	**$2,461**	Calculated
Base Case Operating and Maintenance (O&M) Costs		
Fixed O&M Costs ($/kW-Yr)	**$34.50**	From BEPC
($)	**$9,418,500**	Calculated
Non-Fuel Variable O&M Costs ($/kW-Hr)	**$0.0025**	From BEPC
($)	**$4,980,257**	Calculated
Annual Non-Fuel O&M Cost Escalation Rate (%)	**2.0%**	From BEPC
Makeup Water Cost		
Makeup Water Requirement (Gpm)	**521**	Air Cooled Condenser
Makeup Water Cost ($/1000 Gallons)	**$0.50**	Assumed
Annual Water Cost Escalation Rate (%)	**2.0%**	From BEPC
Powder River Basin (PRB) Fuel Cost		
Dry Fork Coal Mine		
Coal HHV (Btu/Lb)	**8,045**	Dry Fork Mine Target
Coal Sulfur Content (Wt.%)	**0.32%**	From BEPC
Coal Ash Content (Wt.%)	**4.77%**	Dry Fork Mine Target
Mine Mouth Coal Cost ($/Ton)	**$5.63**	Calculated
($/MMBtu)	**$0.35**	From BEPC
Annual SO2 Emissions (Tons)	**780**	Calculated from FGD Mass Balance
Clovis Point Coal Mine		
Coal HHV (Btu/Lb)	**8,000**	Minimum Specification
Coal Sulfur Content (Wt.%)	**0.54%**	From BEPC
Coal Ash Content (Wt.%)	**5.00%**	Assumed
Mine Mouth Coal Cost ($/Ton)	**$6.40**	Calculated
($/MMBtu)	**$0.40**	From BEPC
Annual SO2 Emissions (Tons)	**1,322**	Calculated from FGD Mass Balance
Ash/FGD Solids Waste Disposal		
Ash/FGD Solids Waste Disposal Tipping Fee ($/Ton)	**$0.00**	Dry Fork Mine (From BEPC)
Annual Coal & Waste Diposal Cost Escalation Rate (%)	**2.0%**	From BEPC

CAPITAL COST AMORTIZATION SCHEDULE

Total EPC Contract Cost ($) = $671,884,548

Interest Rate = 6.0%

Year		Debt Beginning Amount	Payment	Interest	Principle Repayment	Remaining Balance
1	2004	$671,884,548	($48,811,681)	($40,313,073)	($8,498,608)	$663,385,940
2	2005	$663,385,940	($48,811,681)	($39,803,156)	($9,008,525)	$654,377,415
3	2006	$654,377,415	($48,811,681)	($39,262,645)	($9,549,036)	$644,828,379
4	2007	$644,828,379	($48,811,681)	($38,689,703)	($10,121,978)	$634,706,401
5	2008	$634,706,401	($48,811,681)	($38,082,384)	($10,729,297)	$623,977,104
6	2009	$623,977,104	($48,811,681)	($37,438,626)	($11,373,055)	$612,604,049
7	2010	$612,604,049	($48,811,681)	($36,756,243)	($12,055,438)	$600,548,611
8	2011	$600,548,611	($48,811,681)	($36,032,917)	($12,778,764)	$587,769,846
9	2012	$587,769,846	($48,811,681)	($35,266,191)	($13,545,490)	$574,224,356
10	2013	$574,224,356	($48,811,681)	($34,453,461)	($14,358,220)	$559,866,136
11	2014	$559,866,136	($48,811,681)	($33,591,968)	($15,219,713)	$544,646,423
12	2015	$544,646,423	($48,811,681)	($32,678,785)	($16,132,896)	$528,513,528
13	2016	$528,513,528	($48,811,681)	($31,710,812)	($17,100,869)	$511,412,658
14	2017	$511,412,658	($48,811,681)	($30,684,760)	($18,126,922)	$493,285,737
15	2018	$493,285,737	($48,811,681)	($29,597,144)	($19,214,537)	$474,071,200
16	2019	$474,071,200	($48,811,681)	($28,444,272)	($20,367,409)	$453,703,791
17	2020	$453,703,791	($48,811,681)	($27,222,227)	($21,589,454)	$432,114,337
18	2021	$432,114,337	($48,811,681)	($25,926,860)	($22,884,821)	$409,229,516
19	2022	$409,229,516	($48,811,681)	($24,553,771)	($24,257,910)	$384,971,606
20	2023	$384,971,606	($48,811,681)	($23,098,296)	($25,713,385)	$359,258,222
21	2024	$359,258,222	($48,811,681)	($21,555,493)	($27,256,188)	$332,002,034
22	2025	$332,002,034	($48,811,681)	($19,920,122)	($28,891,559)	$303,110,475
23	2026	$303,110,475	($48,811,681)	($18,186,628)	($30,625,053)	$272,485,422
24	2027	$272,485,422	($48,811,681)	($16,349,125)	($32,462,556)	$240,022,867
25	2028	$240,022,867	($48,811,681)	($14,401,372)	($34,410,309)	$205,612,558
26	2029	$205,612,558	($48,811,681)	($12,336,753)	($36,474,928)	$169,137,630
27	2030	$169,137,630	($48,811,681)	($10,148,258)	($38,663,423)	$130,474,207
28	2031	$130,474,207	($48,811,681)	($7,828,452)	($40,983,229)	$89,490,978
29	2032	$89,490,978	($48,811,681)	($5,369,459)	($43,442,222)	$46,048,756
30	2033	$46,048,756	($48,811,681)	($2,762,925)	($46,048,756)	$0
31	2034					
32	2035					
33	2036					
34	2037					
35	2038					
36	2039					
37	2040					
38	2041					
39	2042					
40	2043					
41	2044					
42	2045					

Power Generation Cost - Dry Fork Mine Coal

Year -->	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
From Plant Startup	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
From Present	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
PLANT OPERATION																							
Annual PRB Coal Usage (Tons)			1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475
Annual Ash/FGD Solids Production (Tons)			117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058
Annual Export Power (kW-Hr)	-	-	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000
OPERATING EXPENSES																							
Annual Fixed O&M Cost ($)			10,606,761	10,818,896	11,035,274	11,255,979	11,481,099	11,710,721	11,944,935	12,183,834	12,427,511	12,676,061	12,929,582	13,188,174	13,451,937	13,720,976	13,995,396	14,275,303	14,560,810	14,852,026	15,149,066	15,452,048	15,761,089
Annual Non-Fuel Variable Cost ($)			5,608,578	5,720,750	5,835,165	5,951,868	6,070,906	6,192,324	6,316,170	6,442,494	6,571,343	6,702,770	6,836,826	6,973,562	7,113,034	7,255,294	7,400,400	7,548,408	7,699,376	7,853,364	8,010,431	8,170,640	8,334,052
Makeup Water Cost ($)			131,064	133,685	136,359	139,086	141,868	144,705	147,599	150,551	153,562	156,633	159,766	162,961	166,221	169,545	172,936	176,395	179,923	183,521	187,192	190,935	194,754
Annual Ash/FGD Solids Tipping Fee ($)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchase of SO2 Allowances ($)			439,028	447,808	456,764	465,900	475,218	484,722	494,416	504,305	514,391	524,679	535,172	545,876	556,793	567,929	579,288	590,873	602,691	614,745	627,040	639,580	652,372
Annual Delivered Coal Cost ($)	-	-	7,702,181	7,856,224	8,013,349	8,173,616	8,337,088	8,503,830	8,673,906	8,847,384	9,024,332	9,204,819	9,388,915	9,576,693	9,768,227	9,963,592	10,162,864	10,366,121	10,573,443	10,784,912	11,000,611	11,220,623	11,445,035
Total Operating Expenses			24,487,611	24,977,363	25,476,911	25,986,449	26,506,178	27,036,301	27,577,028	28,128,568	28,691,139	29,264,962	29,850,261	30,447,267	31,056,212	31,677,336	32,310,883	32,957,101	33,616,243	34,288,568	34,974,339	35,673,826	36,387,302
Capital Charges																							
Debt Service	-	-	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681
Total Annual Power Generation Cost			73,299,292	73,789,045	74,288,592	74,798,130	75,317,859	75,847,983	76,388,709	76,940,249	77,502,820	78,076,643	78,661,943	79,258,948	79,867,893	80,489,017	81,122,564	81,768,782	82,427,924	83,100,249	83,786,020	84,485,507	85,198,983
POWER GENERATION COST ($/kW-Hr)																							
Fixed O&M Cost			$0.0052	$0.0053	$0.0054	$0.0055	$0.0056	$0.0058	$0.0059	$0.0060	$0.0061	$0.0062	$0.0064	$0.0065	$0.0066	$0.0067	$0.0069	$0.0070	$0.0072	$0.0073	$0.0075	$0.0076	$0.0078
Non-Fuel Variable Cost			$0.0030	$0.0031	$0.0032	$0.0032	$0.0033	$0.0034	$0.0034	$0.0035	$0.0036	$0.0036	$0.0037	$0.0038	$0.0039	$0.0039	$0.0040	$0.0041	$0.0042	$0.0043	$0.0043	$0.0044	$0.0045
Fuel Cost			$0.0038	$0.0039	$0.0039	$0.0040	$0.0041	$0.0042	$0.0043	$0.0044	$0.0044	$0.0045	$0.0046	$0.0047	$0.0048	$0.0049	$0.0050	$0.0051	$0.0052	$0.0053	$0.0054	$0.0055	$0.0056
Debt Service			$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240
Busbar Cost ($/kW-Hr)	-	-	$0.0361	$0.0363	$0.0365	$0.0368	$0.0371	$0.0373	$0.0376	$0.0379	$0.0381	$0.0384	$0.0387	$0.0390	$0.0393	$0.0396	$0.0399	$0.0402	$0.0405	$0.0409	$0.0412	$0.0416	$0.0419

FINANCIAL SUMMARY: **Net Present Value (NPV) = $1,162,386,955**

Power Generation Cost - Clovis Point Mine Coal

Year -->	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
From Plant Startup	-1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
From Present	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
PLANT OPERATION																							
Annual PRB Coal Usage (Tons)			1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306
Annual Ash/FGD Solids Production (Tons)			145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215
Annual Export Power (kW-Hr)	-	-	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000
OPERATING EXPENSES																							
Annual Fixed O&M Cost ($)			10,606,761	10,818,896	11,035,274	11,255,979	11,481,099	11,710,721	11,944,935	12,183,834	12,427,511	12,676,061	12,929,582	13,188,174	13,451,937	13,720,976	13,995,396	14,275,303	14,560,810	14,852,026	15,149,066	15,452,048	15,761,089
Annual Non-Fuel Variable Cost ($)			5,608,578	5,720,750	5,835,165	5,951,868	6,070,906	6,192,324	6,316,170	6,442,494	6,571,343	6,702,770	6,836,826	6,973,562	7,113,034	7,255,294	7,400,400	7,548,408	7,699,376	7,853,364	8,010,431	8,170,640	8,334,052
Annual Makeup Water Cost ($)			131,064	133,685	136,359	139,086	141,868	144,705	147,599	150,551	153,562	156,633	159,766	162,961	166,221	169,545	172,936	176,395	179,923	183,521	187,192	190,935	194,754
Annual Ash/FGD Solids Tipping Fee ($)			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchase of SO2 Allowances ($)			744,625	759,518	774,708	790,202	806,006	822,127	838,569	855,340	872,447	889,896	907,694	925,848	944,365	963,252	982,517	1,002,168	1,022,211	1,042,655	1,063,508	1,084,779	1,106,474
Annual Delivered Coal Cost ($)	-	-	8,802,492	8,978,542	9,158,113	9,341,275	9,528,101	9,718,663	9,913,036	10,111,296	10,313,522	10,519,793	10,730,189	10,944,793	11,163,688	11,386,962	11,614,701	11,846,995	12,083,935	12,325,614	12,572,126	12,823,569	13,080,040
Total Operating Expenses			25,893,520	26,411,391	26,939,619	27,478,411	28,027,979	28,588,539	29,160,310	29,743,516	30,338,386	30,945,154	31,564,057	32,195,338	32,839,245	33,496,030	34,165,950	34,849,269	35,546,255	36,257,180	36,982,323	37,721,970	38,476,409
Capital Charges																							
Debt Service	-	-	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681
Total Annual Power Generation Cost			74,705,202	75,223,072	75,751,300	76,290,092	76,839,660	77,400,220	77,971,991	78,555,197	79,150,067	79,756,835	80,375,738	81,007,019	81,650,926	82,307,711	82,977,631	83,660,950	84,357,936	85,068,861	85,794,004	86,533,651	87,288,090
POWER GENERATION COST ($/kW-Hr)																							
Fixed O&M Cost			$0.0052	$0.0053	$0.0054	$0.0055	$0.0056	$0.0058	$0.0059	$0.0060	$0.0061	$0.0062	$0.0064	$0.0065	$0.0066	$0.0067	$0.0069	$0.0070	$0.0072	$0.0073	$0.0075	$0.0076	$0.0078
Non-Fuel Variable Cost			$0.0032	$0.0033	$0.0033	$0.0034	$0.0035	$0.0035	$0.0036	$0.0037	$0.0037	$0.0038	$0.0039	$0.0040	$0.0040	$0.0041	$0.0042	$0.0043	$0.0044	$0.0045	$0.0046	$0.0046	$0.0047
Fuel Cost			$0.0043	$0.0044	$0.0045	$0.0046	$0.0047	$0.0048	$0.0049	$0.0050	$0.0051	$0.0052	$0.0053	$0.0054	$0.0055	$0.0056	$0.0057	$0.0058	$0.0059	$0.0061	$0.0062	$0.0063	$0.0064
Debt Service			$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240
Busbar Cost ($/kW-Hr)	-	-	$0.0368	$0.0370	$0.0373	$0.0375	$0.0378	$0.0381	$0.0384	$0.0386	$0.0389	$0.0392	$0.0395	$0.0399	$0.0402	$0.0405	$0.0408	$0.0412	$0.0415	$0.0418	$0.0422	$0.0426	$0.0429

FINANCIAL SUMMARY: **Net Present Value (NPV) = $1,190,548,209**

Power Generation Cost - Dry Fork Mine Coal

Year -->	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2046	2047	2048	2049	2050	
From Plant Startup	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	
From Present	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
PLANT OPERATION																						
Annual PRB Coal Usage (Tons)	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	1,214,475	
Annual Ash/FGD Solids Production (Tons)	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	
Annual Export Power (kW-Hr)	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	
OPERATING EXPENSES																						**NPV**
Annual Fixed O&M Cost ($)	16,076,310	16,397,836	16,725,793	17,060,309	17,401,515	17,749,546	18,104,536	18,466,627	18,835,960	19,212,679	19,596,933	19,988,871	20,388,649	20,796,422	21,212,350	21,636,597	22,069,329	22,510,716	22,960,930	23,420,148	23,888,551	$212,460,155
Annual Non-Fuel Variable Cost ($)	8,500,733	8,670,748	8,844,163	9,021,046	9,201,467	9,385,497	9,573,207	9,764,671	9,959,964	10,159,163	10,362,347	10,569,594	10,780,986	10,996,605	11,216,537	11,440,868	11,669,685	11,903,079	12,141,141	12,383,964	12,631,643	$112,343,387
Makeup Water Cost ($)	198,649	202,622	206,675	210,808	215,024	219,325	223,711	228,185	232,749	237,404	242,152	246,995	251,935	256,974	262,113	267,356	272,703	278,157	283,720	289,394	295,182	$2,625,293
Annual Ash/FGD Solids Tipping Fee ($)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Purchase of SO2 Allowances ($)	665,419	678,728	692,302	706,148	720,271	734,677	749,370	764,358	779,645	795,238	811,143	827,365	843,913	860,791	878,007	895,567	913,478	931,748	950,383	969,390	988,778	$8,794,003
Annual Delivered Coal Cost ($)	11,673,936	11,907,415	12,145,563	12,388,474	12,636,244	12,888,968	13,146,748	13,409,683	13,677,876	13,951,434	14,230,463	14,515,072	14,805,373	15,101,481	15,403,510	15,711,581	16,025,812	16,346,329	16,673,255	17,006,720	17,346,855	$154,279,569
Total Operating Expenses	37,115,048	37,857,349	38,614,496	39,386,786	40,174,522	40,978,012	41,797,572	42,633,524	43,486,194	44,355,918	45,243,037	46,147,897	47,070,855	48,012,272	48,972,518	49,951,968	50,951,008	51,970,028	53,009,428	54,069,617	55,151,009	490,502,407
Capital Charges																						
Debt Service	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	0	0	0	0	0	0	0	0	0	0	0	0	$671,884,548
Total Annual Power Generation Cost	85,926,729	86,669,030	87,426,177	88,198,467	88,986,203	89,789,693	90,609,254	91,445,205	92,297,875	44,355,918	45,243,037	46,147,897	47,070,855	48,012,272	48,972,518	49,951,968	50,951,008	51,970,028	53,009,428	54,069,617	55,151,009	1,162,386,955
POWER GENERATION COST ($/kW-Hr)																						
Fixed O&M Cost	$0.0079	$0.0081	$0.0082	$0.0084	$0.0086	$0.0087	$0.0089	$0.0091	$0.0093	$0.0095	$0.0096	$0.0098	$0.0100	$0.0102	$0.0104	$0.0106	$0.0109	$0.0111	$0.0113	$0.0115	$0.0118	
Non-Fuel Variable Cost	$0.0046	$0.0047	$0.0048	$0.0049	$0.0050	$0.0051	$0.0052	$0.0053	$0.0054	$0.0055	$0.0056	$0.0057	$0.0058	$0.0060	$0.0061	$0.0062	$0.0063	$0.0065	$0.0066	$0.0067	$0.0068	
Fuel Cost	$0.0057	$0.0059	$0.0060	$0.0061	$0.0062	$0.0063	$0.0065	$0.0066	$0.0067	$0.0069	$0.0070	$0.0071	$0.0073	$0.0074	$0.0076	$0.0077	$0.0079	$0.0080	$0.0082	$0.0084	$0.0085	
Debt Service	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Busbar Cost ($/kW-Hr)	$0.0423	$0.0426	$0.0430	$0.0434	$0.0438	$0.0442	$0.0446	$0.0450	$0.0454	$0.0218	$0.0223	$0.0227	$0.0232	$0.0236	$0.0241	$0.0246	$0.0251	$0.0256	$0.0261	$0.0266	$0.0271	

FINANCIAL SUMMARY:

Power Generation Cost - Clovis Point Mine Coal

Year -->	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2046	2047	2048	2049	2050	
From Plant Startup	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	
From Present	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
PLANT OPERATION																						
Annual PRB Coal Usage (Tons)	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	1,221,306	
Annual Ash/FGD Solids Production (Tons)	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	
Annual Export Power (kW-Hr)	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	2,032,758,000	
OPERATING EXPENSES																						**NPV**
Annual Fixed O&M Cost ($)	16,076,310	16,397,836	16,725,793	17,060,309	17,401,515	17,749,546	18,104,536	18,466,627	18,835,960	19,212,679	19,596,933	19,988,871	20,388,649	20,796,422	21,212,350	21,636,597	22,069,329	22,510,716	22,960,930	23,420,148	23,888,551	$212,460,155
Annual Non-Fuel Variable Cost ($)	8,500,733	8,670,748	8,844,163	9,021,046	9,201,467	9,385,497	9,573,207	9,764,671	9,959,964	10,159,163	10,362,347	10,569,594	10,780,986	10,996,605	11,216,537	11,440,868	11,669,685	11,903,079	12,141,141	12,383,964	12,631,643	$112,343,387
Annual Makeup Water Cost ($)	198,649	202,622	206,675	210,808	215,024	219,325	223,711	228,185	232,749	237,404	242,152	246,995	251,935	256,974	262,113	267,356	272,703	278,157	283,720	289,394	295,182	$2,625,293
Annual Ash/FGD Solids Tipping Fee ($)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	$0
Purchase of SO2 Allowances ($)	1,128,604	1,151,176	1,174,199	1,197,683	1,221,637	1,246,070	1,270,991	1,296,411	1,322,339	1,348,786	1,375,761	1,403,277	1,431,342	1,459,969	1,489,168	1,518,952	1,549,331	1,580,317	1,611,924	1,644,162	1,677,046	$14,915,319
Annual Delivered Coal Cost ($)	13,341,641	13,608,474	13,880,643	14,158,256	14,441,421	14,730,250	15,024,855	15,325,352	15,631,859	15,944,496	16,263,386	16,588,654	16,920,427	17,258,835	17,604,012	17,956,092	18,315,214	18,681,518	19,055,149	19,436,252	19,824,977	$176,319,508
Total Operating Expenses	39,245,937	40,030,856	40,831,473	41,648,103	42,481,065	43,330,686	44,197,300	45,081,246	45,982,871	46,902,528	47,840,579	48,797,390	49,773,338	50,768,805	51,784,181	52,819,865	53,876,262	54,953,787	56,052,863	57,173,920	58,317,399	518,663,661
Capital Charges																						
Debt Service	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	48,811,681	0	0	0	0	0	0	0	0	0	0	0	0	$671,884,548
Total Annual Power Generation Cost	88,057,619	88,842,537	89,643,154	90,459,784	91,292,746	92,142,367	93,008,981	93,892,927	94,794,552	46,902,528	47,840,579	48,797,390	49,773,338	50,768,805	51,784,181	52,819,865	53,876,262	54,953,787	56,052,863	57,173,920	58,317,399	1,190,548,209
POWER GENERATION COST ($/kW-Hr)																						
Fixed O&M Cost	$0.0079	$0.0081	$0.0082	$0.0084	$0.0086	$0.0087	$0.0089	$0.0091	$0.0093	$0.0095	$0.0096	$0.0098	$0.0100	$0.0102	$0.0104	$0.0106	$0.0109	$0.0111	$0.0113	$0.0115	$0.0118	
Non-Fuel Variable Cost	$0.0048	$0.0049	$0.0050	$0.0051	$0.0052	$0.0053	$0.0054	$0.0056	$0.0057	$0.0058	$0.0059	$0.0060	$0.0061	$0.0063	$0.0064	$0.0065	$0.0066	$0.0068	$0.0069	$0.0070	$0.0072	
Fuel Cost	$0.0066	$0.0067	$0.0068	$0.0070	$0.0071	$0.0072	$0.0074	$0.0075	$0.0077	$0.0078	$0.0080	$0.0082	$0.0083	$0.0085	$0.0087	$0.0088	$0.0090	$0.0092	$0.0094	$0.0096	$0.0098	
Debt Service	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0240	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Busbar Cost ($/kW-Hr)	$0.0433	$0.0437	$0.0441	$0.0445	$0.0449	$0.0453	$0.0458	$0.0462	$0.0466	$0.0231	$0.0235	$0.0240	$0.0245	$0.0250	$0.0255	$0.0260	$0.0265	$0.0270	$0.0276	$0.0281	$0.0287	

FINANCIAL SUMMARY:

Basin Electric Power Cooperative - NE Wyoming Generation Project - CFB Unit Pro Forma Cost Comparison - Rev 2 12-09-04

Sites	A	A2	B	C	D	D2	E	F	G	G2	H	Unit Quantities / Prices	Units	Comments / Assumptions
Total Area of Site (Acres)	205	205	330	1780	1393	1393	555	717	1207	1207	353			
Plant Type	Circulating Fluid Bed	Circulating Fluid Bed	Circulating Fluid Bed	Circulating Fluid Bed	Circulating Fluid Bed	Circulating Fluid Bed	Circulating Fluid Bed	Circulating Fluid Bed	Circulating Fluid Bed	Circulating Fluid Bed	Circulating Fluid Bed			
Net MW of Facility	273	273	273	273	273	273	273	273	273	273	273			
Water Source	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater	Groundwater			
Discharge Water	ZLD	ZLD	ZLD	ZLD	ZLD	ZLD	ZLD	ZLD	ZLD	ZLD	ZLD			
Cooling Technology	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser			
Air Emission Controls	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SNCR 0.07 lbs/mmbtu SO_2 - CFB Unit 0.10 lbs/mmbtu	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu	PM10 - Baghouse 0.012 lbs/mmbtu NOx - SNCR 0.07 lbs/mmbtu SO2 - CFB Unit 0.10 lbs/mmbtu	PM10 - Baghouse 0.012 lbs/mmbtu NOx - SNCR 0.07 lbs/mmbtu SO2 - CFB Unit 0.10 lbs/mmbtu	PM10 - Baghouse 0.012 lbs/mmbtu NOx - SNCR 0.07 lbs/mmbtu SO2 - CFB Unit 0.10 lbs/mmbtu	PM10 - Baghouse 0.012 lbs/mmbtu NOx - SNCR 0.07 lbs/mmbtu SO2 - CFB Unit 0.10 lbs/mmbtu	PM10 - Baghouse 0.012 lbs/mmbtu NOx - SNCR 0.07 lbs/mmbtu SO2 - CFB Unit 0.10 lbs/mmbtu	PM10 - Baghouse 0.012 lbs/mmbtu NOx - SNCR 0.07 lbs/mmbtu SO2 - CFB Unit 0.10 lbs/mmbtu	PM10 - Baghouse 0.012 lbs/mmbtu NOx - SNCR 0.07 lbs/mmbtu SO2 - CFB Unit 0.10 lbs/mmbtu	PM10 - Baghouse 0.012 lbs/mmbtu NOx - SNCR 0.07 lbs/mmbtu SO2 - CFB Unit 0.10 lbs/mmbtu	PM_{10} - Baghouse 0.012 lbs/mmbtu NO_x - SCR 0.07 lbs/mmbtu SO_2 - Spray Dryer 0.10 lbs/mmbtu			
Coal Cost Dry Fork Mine ($/MMBtu)	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	($/MMBtu)	Commercial Coal From BEPC
Coal Cost Clovis Mine ($/MMBtu)	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	($/MMBtu)	Commercial Coal From BEPC
New Coal Delivery Rail Spur Length (Miles)	NA	NA	1.59	2.82	2.95	2.12	2.35	3.70	2.64	NA	NA			
Cost of Coal Delivery Rail ($ Million)	NA	NA	1.75	3.10	3.25	2.33	2.59	4.07	2.90	NA	NA	1.10	($ Million/Mile)	
New Construction Rail Spur Length (Miles)	0.33	0.33	0.57	0.41	0.75	0.67	0.69	0.73	0.58	0.89	0.75			
Cost of Construction Rail ($ Million)	0.36	0.36	0.63	0.45	0.83	0.74	0.76	0.80	0.64	NA	0.83	1.10	($ Million/Mile)	
Conveyor Length to Dry Fork Mine (Miles)	0.98	0.98	1.69	2.78	3.43	4.33	NA	NA	NA	NA	1.86			
Cost of Dry Fork Conveyor ($ Million)	3.33	3.33	5.75	9.45	11.66	14.72	NA	NA	NA	NA	6.32	3.40	($ Million/Mile)	
Conveyor Length to Future Dry Fork Mining Area (Miles)	NA	NA	NA	NA	NA	NA	1.78	2.38	3.65	3.44	NA			
Cost of Dry Fork Conveyor to Future Mining Area ($ Million)	NA	NA	NA	NA	NA	NA	6.05	8.09	12.41	11.70	NA	3.40	($ Million/Mile)	
Conveyor Length to Clovis Mine (Miles)	4.57	4.57	3.85	4.12	3.29	1.81	1.51	1.30	0.65	0.83	NA			
Cost of Clovis Conveyor ($ Million)	15.54	15.54	#NAME?	14.01	11.19	6.15	5.13	4.42	2.21	2.82	NA	3.40	($ Million/Mile)	
Transmission Length to Carr Draw (Miles)	25.58	25.58	25.49	26.10	26.54	27.22	27.83	27.83	27.80	27.80	22.77			
Carr Draw Transmission Line Cost, including ROW ($ Million)	8.44	8.44	#VALUE!	8.61	8.76	8.98	9.18	9.18	9.17	9.17	7.51	0.33	($ Million/Mile)	
Estimated Land Cost for Generation Site ($ Million)	0.62	0.62	0.99	5.34	4.18	4.18	1.67	2.15	3.62	3.62	1.06	3,000	($/Acre)	
Sitework Cost ($ Million)	(2.38)	5.77	0.15	4.05	15.96	11.09	0.25	(1.16)	1.20	(2.23)	1.57			
Ash/FGD Solids Produced per year, Dry Fork Coal (Tons)	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	117,058	(Tons/Year)	
Ash/FGD Solids Produced per year, Clovis Coal (Tons)	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	145,215	(Tons/Year)	
Flyash Disposal - On-Site, Dry Fork, Clovis or Fort Union	Dry Fork	Dry Fork	Dry Fork	Fort Union	Fort Union	Fort Union	On-Site **Dry Fork** Clovis	On-Site **Dry Fork** Clovis	On-Site **Clovis**	**Clovis**	**Dry Fork**			
Flyash Transportation Length to Dry Fork Mine (Miles)	0.66	0.63	0.76	NA	NA	NA	3.03	3.03	4.67	4.79	2.11			
Flyash Transportation Length to Clovis Mine (Miles)	NA	NA	NA	NA	NA	NA	1.61	1.62	1.68	1.71	1.71			

Sites	A	A2	B	C	D	D2	E	F	G	G2	H	Unit Quantities / Prices	Units	Comments / Assumptions
Flyash Transportation Length to Fort Union Mine (Miles)	NA	NA	NA	0.84	0.35	0.59	NA	NA	NA	NA	NA			
Cost of On-Site Landfill ($ Million)	20.90	20.90	20.90	20.90	20.90	20.90	20.90	20.90	20.90	20.90	20.90	20.90	($ Million)	l Energy Landfill Cost Model for Dispo
Cost of Dry ForkLandfill ($ Million)	0.00	0.00	0.00	NA	NA	NA	0.00	0.00	NA	NA	NA	0.00	($ Million)	
Cost of Clovis Landfill ($ Million)	NA	NA	NA	NA	NA	NA	NA	NA	0.00	0.00	0.00	0.00	($ Million)	
Cost of Fort Union Landfill ($ Million)	NA	NA	NA	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00	($ Million)	
Transportation Cost of Ash Disposal ($ Million)	0.04	0.04	#VALUE!	0.05	0.02	0.03	0.18	0.18	0.10	0.10	0.12	0.50	$/Ton-Mile)	
Natural Gas Pipeline Connection Length (Miles)	2.65	2.48	2.07	2.26	1.53	1.13	1.93	1.93	1.28	1.26	5.02			
Natural Gas Pipeline Cost ($ Million)	1.12	1.05	0.87	0.95	0.65	0.48	0.82	0.82	0.54	0.53	2.12	0.42	($ Million/Mile)	
Access Road to Plant Site Length (Miles)	0.00	0.70	0.00	1.18	1.69	2.57	0.41	0.40	1.83	1.87	0.54			
Access Road Cost ($ Million)	0.00	0.21	0.00	0.35	0.51	0.77	0.12	0.12	0.55	0.56	0.16	0.30	($ Million/Mile)	

TOTAL CAPITAL COST ($ Million - 2011)

BASE PLANT COST	$547.7	$547.7	$547.7	$547.7	$547.7	$547.7	$547.7	$547.7	$547.7	$547.7	$547.7
SITE SPECIFIC ADJUSTMENT COSTS											
Coal Delivery Rail Spur	NA	NA	$1.7	$3.1	$3.2	$2.3	$2.6	$4.1	$2.9	NA	NA
Construction Rail Spur	$0.4	$0.4	$0.6	$0.5	$0.8	$0.7	$0.8	$0.8	$0.6	NA	$0.8
Conveyor to Dry Fork	$3.3	$3.3	$5.7	$9.5	$11.7	$14.7	NA	NA	NA	NA	$6.3
Conveyor to Dry Fork Future Mining Area	NA	NA	NA	NA	NA	NA	$6.1	$8.1	$12.4	$11.7	NA
Conveyor to Clovis	$15.5	$15.5	$0.0	$14.0	$11.2	$6.2	$5.1	$4.4	$2.2	$2.8	NA
Transmission to Carr Draw	$8.4	$8.4	$1,780.0	$8.6	$8.8	$9.0	$9.2	$9.2	$9.2	$9.2	$7.5
Land for Plant Site	$0.6	$0.6	Circulating Fluid Bed	$5.3	$4.2	$4.2	$1.7	$2.2	$3.6	$3.6	$1.1
Site Work	($2.4)	$5.8	$273.0	$4.1	$16.0	$11.1	$0.3	($1.2)	$1.2	($2.2)	$1.6
On-Site Landfill	$20.9	$20.9	$20.9	$20.9	$20.9	$20.9	$20.9	$20.9	$20.9	$20.9	$20.9
Dry Fork Landfill	$0.0	$0.0	$0.0	NA	NA	NA	$0.0	$0.0	NA	NA	NA
Clovis Landfill	NA	NA	NA	NA	NA	NA	NA	NA	$0.0	$0.0	$0.0
Fort Union Landfill	NA	NA	NA	$0.0	$0.0	$0.0	NA	NA	NA	NA	NA
Natural Gas Pipeline	$1.1	$1.0	$0.9	$1.0	$0.6	$0.5	$0.8	$0.8	$0.5	$0.5	$2.1
Offsite Access Road to Plant	$0.0	$0.2	$0.0	$0.4	$0.5	$0.8	$0.1	$0.1	$0.5	$0.6	$0.2
NON-SITE SPECIFIC COSTS											
IDC	$79.2	$79.2	$79.2	$79.2	$79.2	$79.2	$79.2	$79.2	$79.2	$79.2	$79.2
Current PS & I Work Order/Direct Staff Costs	$10.3	$10.3	$10.3	$10.3	$10.3	$10.3	$10.3	$10.3	$10.3	$10.3	$10.3
Operating Spares	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5
Rolling Stock/O&M Equipment Costs	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0
Coal Mine Capital Improvements	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5
Offsite Communications System	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Start-up & Commissioning Fuel Costs (Coal/Gas)	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5
Revenue from Power Sales During Start-up & Commissioning	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)	($2.7)
Impact Alleviation	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5	$2.5
Water Supply Wellfield/Pipeline	$2.8	$2.8	$2.8	$2.8	$2.8	$2.8	$2.8	$2.8	$2.8	$2.8	$2.8

Base Case Economic Comparison - CFB Unit w/Dry Fork Mine Coal ($ Million - 2011)

Total Capital Cost ($)	**$663.8**	**$672.1**	**$2,714.3**	**$684.6**	**$698.1**	**$695.6**	**$673.7**	**$676.4**	**$683.3**	**$675.7**	**$671.9**
First Year Fixed O&M Cost ($/MW-Hr)	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2
Non-Fuel Variable Cost ($/MW-Hr)	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0
Fuel Cost ($/MW-Hr)	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8
Total O&M Cost ($/MW-Hr)	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**	**$12.0**
Debt Service ($/MW-Hr)	**$23.7**	**$24.0**	**$24.0**	**$24.5**	**$24.9**	**$24.9**	**$24.1**	**$24.2**	**$24.4**	**$24.1**	**$24.0**
Total First Year Busbar Cost ($/MW-Hr)	**$35.8**	**$36.1**	**$36.0**	**$36.5**	**$37.0**	**$36.9**	**$36.1**	**$36.2**	**$36.5**	**$36.2**	**$36.1**
42 Year NPV ($ Million)	**$1,154.3**	**$1,162.6**	**$1,161.4**	**$1,175.1**	**$1,188.6**	**$1,186.1**	**$1,164.2**	**$1,166.9**	**$1,173.8**	**$1,166.2**	**$1,162.4**