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UPDATE ON THE STATUS AND ACTIVITIES OF THE TASK FORCE ON THE ECONOMIC BENEFITS OF IMPROVING MINE SAFETY THROUGH THE EXTRACTION AND USE OF COAL MINE METHANE

CASE STUDY OF THE ECONOMIC IMPACT OF METHANE-RELATED EVENTS AT COAL MINES IN THE UNITED STATES OF AMERICA: CASE STUDY MINE A

Note by secretariat

I. INTRODUCTION

1. This paper is the result of a cooperative effort between the United States Environmental Protection Agency (US EPA) and the UNECE Ad Hoc Group of Experts on Coal Mine Methane. It has been prepared by Mr. Ray Pilcher, Chairman of the Task Force on the Economic Benefits of Improving Mine Safety Through Extraction and Use of Coal Mine Methane, Ms. Charlee Bergamo, Environmental Scientist at Raven Ridge Resources, and Ms. Pamela Franklin, US Environmental Protection Agency. The Ad Hoc Group of Experts established the Task Force to explore the critical link between coal mine safety and economics.

2. As one of its first actions, the Task Force commissioned the development of a template (ECE/ENERGY/GE.4/2007/4) that would act as a guide for experts to use as they develop case studies that examine the relationship between extraction and use of coal mine methane and the overall economic performance of a gassy coal mine. In the United States, the clearest way to

investigate this relationship is through collection and analysis of publicly available financial and economic data and information reported as a result of business conducted by active coal mines. This report was written using the Task Force generated template as a guide. To support the work of the Task Force and the Ad Hoc Group of Experts, the US EPA sponsored the development of two case studies based on the experiences of US coal mines.

3. One mine is located in an eastern USA coal basin, and the other in a western USA coal basin. The criteria used for selecting these two mines include the following:

(a) Mines must be classified as “gassy” and must be large emitters of methane, as determined by US emissions inventories;

(b) All the information used in these case studies must be available from public sources, including published government reports, web-based information resident on government and private websites, corporate annual reports, pricing studies, etc.;

(c) Sufficient financial and economic information must be available to allow general conclusions to be drawn regarding potential improvements if measures to drain and use more gas were taken;

(d) The mines selected should have had one or more methane-related, non-fatal mine accidents in recent years. (The reason for the restriction to non-fatal accident was two-fold. One, fatal accidents would pose extreme challenges in determining the economic impacts of the loss of life. Two, due to increased litigation associated with fatal events, it is often impossible to access accident-related data in these cases.); and

(e) The case studies must present an opportunity to perform an economic analysis for the utilization of gas at the mine.

4. The two mines chosen for this study met all of these criteria. Both mines experienced coal mine methane-caused fires that were in part caused by the need to ventilate the mines with large volumes of air to dilute the gas emitted into mine workings. As a result of these methane-related accidents, each mine suffered large economic losses due to lost coal production and sales caused by the mine’s closure. Additional economic losses were experienced by those workers who were laid off as a result of the idling mines, but this study does not include the economic losses suffered by the workers themselves and the local economy.

5. The Task Force considered including an estimate of the magnitude of economic losses suffered by workers and the local economy in the template. After discussion, however, the Task Force decided that only those losses that could be measured and directly attributable to the overall economic performance of the mine should be required as a part of the economic analysis. Nevertheless, the Task Force and the authors recognize that the impact on the local economy could be substantial.

6. These case studies demonstrate that increasing mine gas drainage and recovery and use systems, while an expensive investment, would produce important economic benefits to the

mine. These benefits include, but are not limited to, the economic benefits of increased mine safety. Increasing drainage would help reduce the need to ventilate portions of the mines' workings. Profitable use of the drained gas (for example, through sales to natural gas pipelines or onsite power generation) offsets the increased operating and capital cost of enhancing the drainage system. Thus, in these two specific cases, by increasing investment in the recovery and use of coal mine methane, mine management can reap multiple benefits. These investments help to ensure continued safe working conditions for miners, allow the mining company and its investors to enjoy the upside of an additional revenue stream arising from the use of the gas, and most importantly, help to avoid the economic and social losses associated with a methane-related accident.

7. The identity of the mines used for this study is omitted for the following reasons:

(a) The identity of the mine being studied does not contribute to the overall understanding of the data and information. Furthermore, knowing the identity and the actual location of the mine may detract from the potential value of the case study as a generally illustrative example of issues that may be shared by many gassy mines situated in various geological and mining conditions.

(b) This study is not intended to be a criticism of the mine management or the actions taken by employees or owners of the mines, nor is it intended that any conclusions drawn from this study or recommendations be construed as actions that should be taken by the subject mine without further review of the full suite of data and information available to mine management. Some of that data and information was not available for analysis and consideration by the authors. Therefore, the authors have withheld the names of the mines to prevent misunderstanding the intent for use of these case studies.

8. Each case study includes the following elements:

(a) The commercial attributes of the mine, such as the magnitude of the annual coal production, basic information regarding the quality of the coal produced, and the use for which the coal is sold;

(b) Volume of gas liberated by mining activities, comprising gas produced from drainage systems, as well as gas emitted to the atmosphere by the mine's ventilation system;

(c) The amount of gas recovered from the mine's drainage system and the amount of gas used;

(d) Major safety issues, serious accidents, and other related incidents that have occurred at the mine in the last ten years;

(e) Costs attributed to the safety issues profiled in the case study including regulatory costs and economic losses associated with loss of production and sale of coal;

(f) Information and data on the existing gas drainage systems, existing gas utilization projects, and a discussion of opportunities and the potential benefits of further developing gas use projects.

II. MINE AND COAL RESOURCE INFORMATION FOR MINE A

9. Tables 1 and 2 below provide mine operations, coal resource, coal production, and methane-generation data for Mine A.

Table 1: Mine information

1 Mine Name			
Mine A			
2 Current Owner			
Intentionally Left Blank			
3 Status			
Active			
4 Location			
4.1 Country		United States	
4.2 Coal Basin/Region		Western Basin	
5 Mine Information Source: Keystone Coal Industry Manual (2005)			
Year of Initial Production	1982	**Number of Employees**	370
Mining Method	Longwall/Continuous	**Depth to Seam (m)**	1,000 - 2,000
Compliance Coal[a]	Yes	**Prep Plant on Site**	Yes
6 Coal Resource Information Source: Keystone Coal Industry Manual (2005)			
Coal Seams Mined	Intentionally Left Blank	**Average Seam Thickness (m)**	3.66
Sulfur Content of Coal Produced (%)	*Minimum*	*Average*	*Maximum*
	0.36	0.49	0.78
Heating Value of Coal (KJ/kg)	*Minimum*	*Average*	*Maximum*
	24,371	27,156	27,852
Type of Coal	Bituminous	**Primary Market**	Steam
Estimated Reserves Remaining (Mil metric tons)	136[b]	**Life Expectancy of the Mine**	2020

[a] Defined as "a coal or a blend of coals that meets sulfur dioxide emission standards for air quality without the need for flue gas desulfurization" by the Energy Information Administration, http://www.eia.gov; and "any coal that emits less than 1.2 lbs (0.54 kg) of sulfur dioxide per million BTU (1.055 million KJ) when burned. Also known as low sulfur coal" by EPA,

[b] Union Pacific Railroad, Customer Profile, http://www.uprr.com/customers/energy/coal/index.shtml

Table 2: Production, ventilation, and drainage data for Mine A

	2000	2001	2002	2003	2004
Coal Production (thousands metric tons/year)[a]	3,040.1	4,556.0	5,947.7	5,888.3	5,890.7
Estimated Total Methane Liberated (thousands m^3/day)[b]	444.6	455.9	560.7	770.2	591.8
Emission from Ventilation Systems: (thousands m^3/day)[b]	334.1	342.6	280.3	385.1	295.9
Estimated Methane Drained (thousands m^3/day)[b]	110.4	113.3	280.3	385.1	295.9
Estimated Specific Emissions (m^3/ton)[b]	48.5	33.1	31.1	43.3	33.3
Methane Recovered (thousands m^3/day)[c]	-	-	-	2.8	NA

[a] MSHA Mine Yearly Reported Production Information, Data Retrieval System

[b] US EPA, 2004. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003, and MSHA ventilation data

[c] US EPA, 2004. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003

III. MAJOR SAFETY ISSUES AT MINE A

10. To document the safety record of Mine A, the authors consulted the Data Retrieval System of the US Mine Safety and Health Administration (MSHA). Mine A’s biggest potential safety issue is methane-related thermal events. The mine has never experienced a fatality or injury due to methane issues; however, the mine has twice been evacuated for extended periods of time due to gas outages. Recently, other safety issues have included accumulation of combustible materials (coal dust, including float coal dust deposited on rock-dusted surfaces, loose coal, and other combustible materials) either in the active workings or on equipment, with over 40 MSHA citations in 2005 and seven in 2006. The mine has been cited for issues surrounding the abatement and maintenance of dusts several times as well. Most accidents reported in 2005 were roof falls, though none resulted in injury. Roof issues have been a problem for this mine before, with adverse roof conditions cited as a reason for lost productivity in years past. Spontaneous combustion is an issue at this mine and other nearby mines with numerous thermal events to date.

IV. SERIOUS ACCIDENTS

11. This mine has had two methane-related fires in the past ten years. One event started in January 2000, the other started in November 2005. To date, no serious injuries have resulted from methane-related accidents.

V. OTHER INCIDENTS

12. Smaller ignitions have occurred due to friction from tools and equipment in late 2000, two in May 2003, and another in mid-2004, though these smaller events did not result in evacuation or lost productivity.[1] The mine also had limited productivity in February 2001 due to the presence of elevated levels of methane. In addition, Mine A has also suffered from other, non-methane related incidents. Roof fall problems in Autumn 2001 had a negative impact on productivity.[2]

VI. REGULATORY COSTS

13. Although penalties were not assessed for particular accidents, fines assessed against the mine for MSHA violations over the past ten years have totalled over $330,000.[1]

VII. ECONOMIC LOSSES ASSOCIATED WITH SUSPENDING PRODUCTION OR CLOSING THE MINE

14. More significant than the cost of penalties has been lost productivity and costs associated with suppression and recovery due to methane outages.

(a) Estimated economic value of lost coal production since first methane fire

15. Lost coal production is estimated by comparing quarterly coal production for the quarter in which idling occurred versus the previous years' respective quarter with full production. This value is then multiplied by the average open market coal price for the respective year to estimate annual losses to due to curtailed coal production. Losses reported in this section are estimates based only on publicly known methane-related incidents and closures, and may not include all production losses due to high methane levels. The comparative basis used for full production against idle is the best estimate; although it is likely conservative as small, unpublicized instances of elevated methane may periodically slow down or halt production at the mine throughout the year. Table 3 summarizes the estimates for lost coal production from publicly known methane-related fires since the first fire in 2000.

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1 MSHA Data Retrieval System

2 Operator Fourth Quarter 2000 Results. Additional citation information withheld to protect identity of mine.

Table 3: Economic value of lost coal production for Mine A

Year	Lost Coal Production (million metric tons)	Average Coal Price (US$ per metric ton)[a]	Lost Coal Production (millions US$)
2000	2.5	16.25	41
2001	0.12	17.52	2
2002	-	18.28	-
2003	-	19.13	-
2004	-	19.35	-
2005	1	19.35[b]	27
2006	1	19.35[b]	18
Total	6.5	-	88

[a] Energy Information Administration, Annual Coal Report, Average Open Market Price of Coal by State and Underground Mining Method

[b] 2004 Price used as estimate

16. Financial reports available from the operator have quantified costs of major methane-related fires and outages. These costs include lost productivity and the cost of suppressing the respective thermal events. Table 4 shows this information as well as any costs recovered by business interruption insurance.

Table 4: Estimated losses due to methane-related fires and accumulations for Mine A

Year	Event or Issue	Loss Before Insurance Recovery (millions US$)	Net Loss After Insurance Recovery (millions US$)
2000	Methane-Related Fire	43	12
2001	Limited Production and Startup Difficulties due to Elevated Methane	11	2
2005	Methane-Related Fire	33	33
2006	Methane-Related Fire Continued	30	10[a]

[a] The operator Coal Second Quarter 2006 Results reported insurance recoveries of $10 million each for first and second quarter

(b) Economic Losses Associated with Mine Closure

17. Both significant methane-related fires at Mine A occurred as the mine was in the process of moving the longwall to a new reserve area; thus there was no significant loss incurred from abandoning remaining coal reserves.

18. The temporary idling of the mine has had other effects, however. During the 2005-2006 thermal event at Mine A, employees not engaged in other tasks were redeployed to the operator's other locations to work. Not only is this costly to the operator, but negatively affects the small town economy dependent upon coal miners. The operator does not indicate how employee issues were handled during the earlier events. In all instances, rail travel was curtailed in the area, affecting the railroad and numerous rail service employees. Also, the 2005-2006 fire is said to be responsible for a $5 increase in average cost of western coal.[3]

(c) Drainage and Ventilation Systems

19. Following the fire in 2000, Mine A encountered further problems with methane accumulation. Mine ventilation systems were inadequate in diluting methane levels as mining progressed into gassier areas. Production had to be curtailed in 2001 to avoid dangerous methane concentrations. To return the mine to full production, Mine A focused on horizontal cross measure boreholes drilled underground and surface drilling of gob vent boreholes. Initial efforts focused on horizontal holes as extreme topography and surface ownership issues were a barrier to surface drilling. When the horizontal cross measure borehole programme provided only slight improvements in productivity, surface gob vent boreholes were pursued. Mine A had to secure US Forest Service permission to access drill sites and construct roads. The first gob vent borehole was drilled in May 2001.[4] Several others followed, and longwall production increased drastically. In 2004, the mine began using gob gas recovered from sealed areas of the mine through in-mine horizontal wells to heat mine ventilation air during winter months.[5]

20. Although the mine implemented a drainage system and was able to maintain full production until the fire in late 2005, methane accumulation is still clearly a hazard. Improvements in the way of pre-drainage ahead of mining operations through surface boreholes as well as further in-mine drainage may be desired.

VIII. OPPORTUNITIES TO DEVELOP CMM USE PROJECTS AT MINE A

21. Mine A currently utilizes approximately 26 m^3/min of the 144 m^3/min collected by horizontal in-mine boreholes during winter months in order to heat mine ventilation air.[5] No utilization of gas from gob vent boreholes occurs, which produces 10 times more methane per hole than the horizontal boreholes.[4] The gassiness of this mine combined with the necessity for drainage as a supplement to ventilation provide ample opportunity to develop a CMM use project, which could potentially offset the cost of additional drainage systems.

IX. UTILIZATION PROJECTS

22. As a result of recent, costly methane-related problems, increased drainage is undoubtedly desired to ease the mine's dependence on ventilation while increasing uninterrupted productivity

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3 Operator's Coal Fourth Quarter 2005 Results. Additional citation information withheld to protect identity of mine.

4 Presentation by Mine Personnel at CMM Conference, 2005.

5 Coalbed Methane Extra, February 2004.

and improving safety conditions. Current drainage at Mine A could substantiate a profitable utilization project, potentially offsetting the cost of the desired improvement in drainage at the mine. Using drainage information, the capital and operating costs for a number of CMM utilization project opportunities were studied, as well as net present value and internal rate of return. Projects include power plants (simple or combined cycle gas turbine or internal combustion engines) as well as pipeline injection. Costs were not differentiated according to the efficiency of the power generation equipment to be installed, and it should be noted that combined cycle and recuperated cycle systems would be more expensive in the way of capital; however, the gain in efficiency obtained with these systems would be more lucrative. Estimates of capital costs as well as operating and maintenance costs were calculated using standardized factors supplied by EPA. These standardized factors for various project options were used to calculate the capital cost for a project of a given size commiserate with the amount of gas available for utilization. Also to be noted is that total capital costs for power projects were estimated for both high installed cost and low installed cost cases, while operation and maintenance costs were assumed to be constant.

23. The estimates below should be taken as order-of-magnitude estimates calculated to get a general indication of the profitability of CMM utilization projects at Mine A and to determine any potential offset in cost of improved drainage. A simple discounted cash flow analysis was done using an assumed discount rate of 10 per cent. Net present value and internal rate of return for prospective project options were based on high and low cost capital costs, operation and maintenance costs, and electricity and gas sales based on available drainage data (see Annex), with 2004 information summarized below in Tables 5 and 6.

24. Based on the electrical efficiencies of these power plant options[6], the amount of electricity to be produced was calculated and current industrial electricity prices[7] were used to calculate electricity sales. These estimates were made with current drainage; however, increased drainage to combat recent methane buildup issues may result in larger plants with applicable higher costs and profits.

25. In addition to power plant utilization, pipeline injection was considered. Again, EPA cost estimates were used to calculate the capital cost of a pipeline project as well as operation and maintenance costs. The last available drainage data was used to determine project size and the amount of gas to be sold. Up-to-date energy price data[7] provided a natural gas price to calculate gas sales. The natural gas price used is the city gate price, not the wellhead price as wellhead prices are not available in real time. The city gate price is slightly higher than what would be received by a gas seller due to additional incorporated pipeline and transportation costs. Table 6 shows the costs associated with installing a pipeline project, the annual operation and maintenance costs, and the projected gas sales based on 2004 drainage.

26. From economic analysis, pipeline sales look to be the most lucrative utilization option with the lowest capital cost and a net present value of $65.7 million and an internal rate of return of 152%; however, a number of factors may inhibit this option at Mine A. The mine lies near a

[6] Gas Turbine, http://en.wikipedia.org/wiki/Gas_turbine and Consumer Energy Council of America, Combustion Turbines, http://www.deforum.org/combustion-turbines.htm
[7] CMOP Documents, Tools, and Resources, Energy Prices, http://epa.gov/coalbed/resources/energyprices.html

remote wilderness area. A pipeline in this area would require permitting by the US Forest Service. The terrain at Mine A also poses extreme difficulty for a pipeline project as areas are rugged and limited in accessibility. In addition, shutdowns and varying supply of gas from the mine may pose a problem as an interrupted source. In the event of lowered supply, shutting down a power plant would be far easier than interrupting the supply chain to pipeline. A pipeline project at Mine A would not likely be feasible.

27. In this instance, a combined cycle gas turbine system would be the most economically desirable and logistically feasible option. The combined cycle gas turbine system gains efficiency as the hot exhaust air from a simple cycle turbine is guided to a heat recovery steam generator to produce steam and drive a steam turbine. This setup will be the most expensive initially, but will be an estimated 20 per cent more efficient than a simple cycle option[8]. This option has a net present value of $108.5 million and an internal rate of return of 73 per cent with a higher estimated capital cost and a net present value of $116.3 million and an internal rate of return of 94 per cent. An increase in electricity prices over time may also increase the value of this system at Mine A.

Table 5: Estimate of power plant costs and profits based on 2004 drainage (Mine A)

	Gas Turbine, Simple Cycle	**Gas Turbine, Combined Cycle**	**Internal Combustion**
Power Plant Size (MW)	52	78	52
Efficiency Assumed[a]	0.4	0.6	0.4
kWh/year (million)	453.61	680.42	453.61
Electricity Sales/Year (million US$)	0.38	36.74	24.50
Installed Cost High Estimate (million US$)	39.35	59.03	52.87
Installed Cost Low Estimate (million US$)	29.52	44.27	47.59
Operation and Maintenance Costs/year (million US$)	4.54	6.80	9.07
Net Present Value High Estimate (million US$)	38.9	108.5	44.0
Net Present Value Low Estimate (million US$)	42.2	116.3	46.8
Internal Rate of Return High Estimate	73%	73%	42%
Internal Rate of Return Low Estimate	94%	94%	47%

[a] Gas Turbine, http://en.wikipedia.org/wiki/Gas_turbine and Consumer Energy Council of America, Combustion Turbines, http://www.deforum.org/combustion-turbines.htm

[8] Gas Turbine, http://en.wikipedia.org/wiki/Gas_turbine

Table 6: Pipeline project costs and sales based on 2004 drainage (Mine A)

Annual Gas Drainage (million m^3)	Capital Gathering Cost (million US$)	O & M Gathering Costs/year (million US$)	Capital Processing Cost (million US$)	O & M Processing Costs/year (million US$)	Capital Compression Cost (million US$)	O & M Compression Costs/year (million US$)
108	5.31	0.78	5.60	0.93	2.90	0.09
Capital Transport Cost (million US$)	**O&M Transport Costs/year (million US$)**	**Capital Injection Into NG Pipe (million US$)**	**Total Capital (million US$)**	**Gas Sales per Year (million US$)**	**Net Present Value (million US$)**	**Internal Rate of Return**
3.00	0.12	0.50	17.31	30.10	65.7	152%

Table 7: Total estimated economic losses due to methane-related issues and safety 2000-2006 (Mine A)

Year	MSHA Penalties Paid (US$)	Lost Coal Production (millions US$)	Total Loss Due to Methane Fires/Gas Outages Before Insurance Recovery (millions US$)	Net Loss Due to Methane Fires/Gas Outages After Insurance (millions US$)
2000	$25,945	41	43	12
2001	$47,732	2	11	2
2002	$28,234	-	-	-
2003	$80,822	-	-	-
2004	$39,818	-	-	-
2005	$42,279	27	33	53
2006	NA	18	30	
Total	$265,000	88	117	67

Note: Losses due to limited coal production may exceed the operator's estimated losses due to an anticipated longwall move accounted for in the operator's calculations.

X. SUMMARY

28. The owners of Mine A have endured substantial financial difficulty due to coal production interruptions and the ensuing aftermath. Fortunately, adept monitoring and awareness prevented the occurrence of injury or death as a direct result of these events. However, failure to improve the situation could lead to further loss in productivity, additional capital requirements, and safety hazards. Lost coal production alone has resulted in an estimated loss of over $88 million since the first fire in 2000. These costs combined with additional costs associated with re-establishing full production following fires, sealing areas, and lost equipment have cost the operator a gross $117 million. Insurance recoveries have minimized the impact of the costs; however, a net loss

of $12.4 million in 2000 and $1.9 million in 2001 were still encountered by the operator after insurance recoveries and a net loss of $53 million for the last incident in 2005-2006.

29. Notably, MSHA penalties have a negligible impact on the operator’s finances compared to the losses methane-related fires have caused. The most significant impacts have come from resulting lost coal production. Penalties over the last six years amount to only $265,000, a cost comparable to one day of lost production at Mine A.

30. Mines A & B (ECE/ENERGY/GE.4/2007/9) were selected for case studies because they clearly illustrate that there can be severe economic losses resulting from methane-related incidents that occur in the course of coal mining. The authors believe that these mines are illustrative of the kinds and magnitudes of accidents and events that occur in other mines in the United States and elsewhere. The difficulty of studying these mines stems from the lack of easily obtainable public data. The data used in these case studies are available from the records of MSHA and other governmental entities. If a coal mine is owned by a publicly owned company (listed on a stock exchange), a much greater level of reporting can be expected than if it is privately owned. The experience that other researchers may have in other countries while collecting and analysing data related to methane-related accidents will be dependent on the amount of data that is publicly available.

XI. RECOMMENDATIONS

31. Increasing the capacity of the methane drainage system at Mine A may be a prudent investment from an overall operations standpoint as well as from a safety perspective. For instance, Mine A implemented drainage systems following the events of 2000 and 2001. Yet Mine A experienced similar losses as a result of a methane-related fire in 2005. A more comprehensive drainage programme could not only improve safety and prevent fires, but bring economic gains. These gains could eventually offset the cost of the additional drainage systems. The capital cost of any of the studied utilization options is less than or close to the net cost of the last methane fire. Should Mine A implement one of these options, this economic analysis suggests that the annual profits from gas or electricity sales will easily cover the cost of a more aggressive drainage programme within a few years.

ANNEX

MINE A: PROJECT ECONOMICS FOR POTENTIAL COAL MINE METHANE PROJECTS

Table A-1: Annual methane drainage and potential CMM power plant size at Mine A (assuming 100 per cent conversion efficiency)

Year	Mm^3/yr	MJ/s (MW)
2000	40.30	48
2001	41.35	50
2002	102.31	123
2003	140.56	168
2004	108.00	129

Table A-2: Summary table of cost and profit for CMM power plant options for Mine A, 2000-2004

Gas Turbine, Simple Cycle (Efficiency 0.4[a])		Installed Costs (US$)		kWh/Year	Operation and Maintenance Costs/Year (US$)	Electricity Sales/Year (US$)
Year	Plant Size (MW)	High Estimate	Low Estimate			
2000	19.32	14,683,200	11,012,400	169,243,200	1,692,432	9,139,133
2001	19.83	15,068,900	11,301,675	173,688,900	1,736,889	9,379,201
2002	49.05	37,279,900	27,959,925	429,699,900	4,296,999	23,203,795
2003	67.39	51,218,300	38,413,725	590,358,300	5,903,583	31,879,348
2004	51.78	39,354,700	29,516,025	453,614,700	4,536,147	24,495,194

[a] Gas Turbine, http://en.wikipedia.org/wiki/Gas_turbine and Consumer Energy Council of America, Combustion Turbines, http://www.deforum.org/combustion-turbines.htm

Table A-3: Summary table of cost and profit for CMM power plant options for Mine A, 2000-2004 (continued)

Gas Turbine, Combined Cycle (Efficiency 0.6[a])		Installed Costs (US$)		kWh/Year	Operation and Maintenance Costs/Year (US$)	Electricity Sales/Year (US$)
Year	Plant Size MW	High Estimate	Low Estimate			
2000	28.98	22,024,800	16,518,600	253,864,800	2,538,648	13,708,699
2001	29.74	22,603,350	16,952,513	260,533,350	2,605,334	14,068,801
2002	73.58	55,919,850	41,939,888	644,549,850	6,445,499	34,805,692
2003	101.09	76,827,450	57,620,588	885,537,450	8,855,375	47,819,022
2004	77.67	59,032,050	44,274,038	680,422,050	6,804,221	36,742,791

[a] Gas Turbine, http://en.wikipedia.org/wiki/Gas_turbine and Consumer Energy Council of America, Combustion Turbines, http://www.deforum.org/combustion-turbines.htm

Table A-4: Summary table of cost and profit for CMM power plant options for Mine A, 2000 2004 (continued)

Internal Combustion (Efficiency 0.4[a])		Installed Costs (US$)		kWh/Year	Operation and Maintenance Costs/Year (US$)	Electricity Sales/Year (US$)
Year	Plant Size MW	High Estimate	Low Estimate			
2000	19.32	19,725,720	17,755,080	169,243,200	3,384,864	9,139,133
2001	19.83	20,243,878	18,221,473	173,688,900	3,473,778	9,379,201
2002	49.05	50,082,603	45,079,248	429,699,900	8,593,998	23,203,795
2003	67.39	68,807,743	61,933,708	590,358,300	11,807,166	31,879,348
2004	51.78	52,869,933	47,588,118	453,614,700	9,072,294	24,495,194

[a] Gas Turbine, http://en.wikipedia.org/wiki/Gas_turbine and Consumer Energy Council of America, Combustion Turbines, http://www.deforum.org/combustion-turbines.htm

Table A-5: Pipeline injection cost and profit summary (Mine A), 2000-2004

Year	Mm^3/d	Capital Gathering Cost (US$)	Gathering O & M Costs (US$)	Capital Processing Cost (US$)	Processing O & M Costs (US$)
2000	0.1104	1,980,298	292,367	2,089,448	346,942
2001	0.1133	2,032,316	300,047	2,144,334	356,055
2002	0.2803	5,027,876	742,304	5,305,003	880,868
2003	0.3851	6,907,724	1,019,841	7,288,464	1,210,211
2004	0.2959	5,307,700	783,617	5,600,251	929,892

Table A-6: Pipeline injection cost and profit summary (Mine A), 2000-2004 (continued)

Year	Capital Compression Cost (US$)	Compression O & M Costs (US$)	Pipeline Length (km)	Capital Transport Cost (US$)	Transport O & M Costs (US$)	Capital Injection Into NG Pipe (US$)
2000	1,083,706	33,915	40	2,999,731	124,989	500,000
2001	1,112,173	34,805	40	2,999,731	124,989	500,000
2002	2,751,475	86,107	40	2,999,731	124,989	500,000
2003	3,780,211	118,302	40	2,999,731	124,989	500,000
2004	2,904,608	90,900	40	2,999,731	124,989	500,000

Table A-7: Pipeline injection cost and profit summary (Mine A), 2000- 2004 (continued)

Year	**Gas Sales (million m^3)**	**Gas Sales (US$)**
2000	40	11,230,499
2001	41	11,525,504
2002	102	28,513,668
2003	141	39,174,505
2004	108	30,100,587
