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Feasibility Study of CMM Utilization for Guizhou Nengfa Power Fuel Development Co., Ltd. Linhua Mine

Located in Guizhou Province, People's Republic of China

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Feasibility Study of CMM Utilization for Guizhou Nengfa Power Fuel Development Co., Ltd. Linhua Mine Located in Guizhou Province, People's Republic of China

Conducted by Raven Ridge Resources, Incorporated
For U.S. EPA
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Acronyms and Abbreviations

°C	Degrees Celsius
CAPEX	Capital Expenditures
CBM	Coalbed Methane
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CMM	Coal Mine Methane
CO_2e	Carbon Dioxide (CO_2) Equivalent
IRR	Internal Rate of Return
km	Kilometers
kWh	Kilowatt Hour
l/s	Liters per second
LNG	Liquefied Natural Gas
LWD	Logging while drilling
m	Meters
m^3	Cubic meters
mm	Millimeters
mmbtu	Million British Thermal Units
mmkWh	Million kilowatt hours
MPa	Megapascal
MW	Megawatt
MWD	Measurement while drilling
MWh	Megawatt hours
N/A	Not applicable
NDRC	China National Development and Reform Commission
NPV	Net present value
OPEX	Operating expenditures
p10	Indicates there is a 10% chance that the forecast will be less than or equal to the p10 amount
p50	Indicates there is a 50% chance that the forecast will be less than or equal to the p50 amount

p90	Indicates there is a 90% chance that the forecast will be less than or equal to the p90 amount
RMB	Renminbi, Chinese currency
¥	Yuan, Unit of Chinese currency (RMB)
t	Metric tons
TWH	TeraWatt Hour(s)
USD	United States Dollars
VAM	Ventilation Air Methane
VAT	Value Added Tax
VER	Voluntary Emission Reduction

1.0 Executive Summary

Under contract number EP-W-05-063 TO 19, USEPA awarded a task order for a prefeasibility and feasibility study of the potential to develop a methane emissions reduction project utilizing coal mine methane (CMM) drained and recovered from a mine located in Guizhou Province, of the People's Republic of China. Raven Ridge Resources (RRR) met with the Guizhou Mine Safety Bureau (GMSB) to discuss potential candidate mines for this feasibility study. The selection process was based on a list of potential mining areas developed by the GMSB. Guizhou Linhua Mines Co., Ltd (Linhua Mine), founded in November of 2003 and currently owned by Guizhou Nengfa Fuel and Power Development Co., Ltd (Nengfa), was chosen as the feasibility study partner. Aside from being a very gassy mine, the Linhua Mine was chosen because it was nearing the production stage of development, its managers were willing to participate as the partner mine, and the potential for replication of a successfully implemented coal mine methane (CMM) recovery and utilization project is high.

Nengfa is owned by the fifth largest power producer in China, China Power Investment Corporation. Annual coal consumption for the utility's Guizhou operations is 60 million tonnes per annum (Mtpa), and they target producing 20 Mtpa of their Guizhou fuel needs through Nengfa. Nengfa is operating one mine and developing five others. Currently, the Bei Le Mine is producing 300 thousand tonnes per annum (Ktpa) and expected to produce up to 600 Ktpa in the future. The Linhua Mine, separated geographically into two mining districts (Linhua 1 Mine and Linhua 2 Mine), had a goal to begin production in September of 2009 with a designed production capacity of 1.5 Mtpa; however, because of the extensive gas outburst problems they have encountered during development, the mine still has not reached design capacity. The remaining four mines are still under construction. Total production from the six mines when built to design capacity will be 5+ Mtpa.

Original development operations began in the Linhua 2 Mine, the focus of this investigation, in 2001 and it was designed as a 1.5 Mtpa mine with 51 years of reserves. Total coal reserves in the mining area are estimated at 174.5 million metric tons. The rank of the coal occurring in the Linhua Mining area is anthracite; however, coal quality in the mining area varies relative to depth. During the development period, from 2001 through 2006, there were more than 20 gas and rock outbursts in the mine, one of which claimed the lives of eight mine workers. The mine was idled in 2006, until it was sold to Nengfa, and development operations resumed in 2009.

All six mines under the control of Nengfa are gassy, and three, including Linhua, are highly prone to gas outbursts. The Linhua Mine will have annual emissions of more than 40 million cubic meters of methane per year. Consequently, Nengfa engineers and management are keen to pursue new methods of recovery and utilization. The biggest challenges facing gas utilization in Guizhou is determining the appropriate drilling technology for the local conditions and using it to recover high-concentration-produced gas for utilization.

The Linhua Mine property is located in Jinsha County in Guizhou Province (**Figure I**), on the Northern margin of the Guizhou Plateau. Coal has been mined in the area for decades, but more recent geologic exploration programs have been conducted to determine the extent of the coal resource and to collect sufficient geologic data for designing a modern, efficient coal mine.

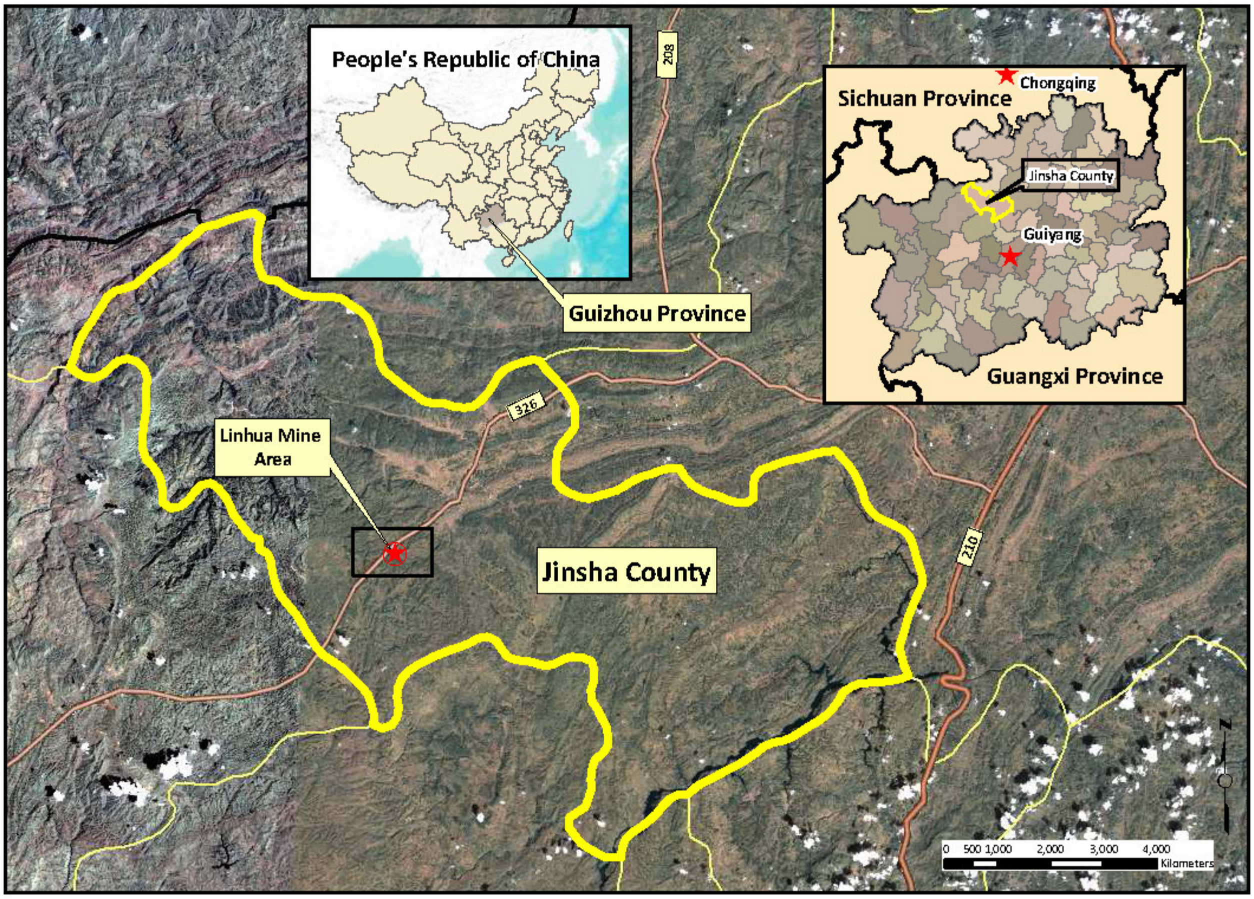

Figure I: Overview area map.

Geologic Setting

Situated on the Guizhou Plateau, the Linhua Mining area is found within steep terrain dominated by erosional features such as narrow ridges, deep and narrow canyons, as well as karstic sinkhole features. The limestones and shales of the lower Triassic Yelang and Maocaopu formations are exposed at the surface. The Upper Permian Longtan Formation is coal bearing and the focus of coal mined in this area.

The region surrounding the Linhua Coal Mine has undergone a complex geologic history. A number of tectonic episodes resulted in geologic structures that complicate mining. The impact of the orientation of the geologic structures present in the Linhua Mining area is significant. Numerous studies have shown that outbursts typically occur at loci typified by geologic structures that occur as a result of compressional stress regimes, i.e. strike-slip, reverse and re-activated normal faults (Shepherd, 1995). Further, Cao et al (2001) noted that outbursts were most dangerous if mining approaches from the downthrown side of a fault.

The Linhua Mine is rated as a high outburst mine, and has experienced several outbursts associated with crossing the downthrown side of faults. Cao et al (2001) also noted that outbursts in mines in China often occur in relatively narrow zones. These zones are often localized along intensely faulted and folded zones. A zone such as Cao describes may exist at the Linhua Mine. This zone is defined by the belt of reverse faults crossing the mining block in a north-northeasterly direction. At present the mine plan calls for retreat of the longwall to occur in a northwesterly direction, parallel to the compressive axis. Mining in this direction will result in continued exposure to dangerous outbursts as mining approaches some of the faults from the downthrown side. The present borehole drainage pattern is effective because it crosses the fractures parallel to the principal axis of extension – from a northeast or southwest direction.

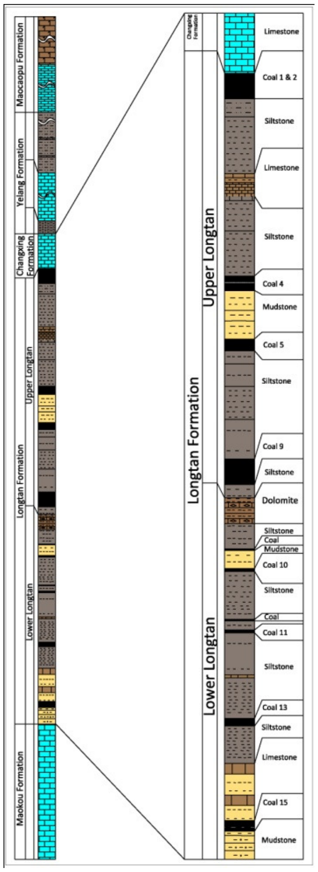

Figure II: Simplified - Stratigraphic Column -

The object of the proposed drilling program is to pre-drain the exploitable coal seams: the 9 (2.5 m thick), and the overlying 5 and 4 coal seams (each 1.5 m thick). The inseam cross panel drilling that has been conducted in the 9 coal seam has been relatively successful in draining gas; however this approach is limited by the diameter of the boreholes that can be drilled, the spacing that can be achieved, and the length of time that the boreholes can be allowed to drain the coal. The proposed program envisions drilling across several planned longwall panels using directionally drilled boreholes comprised of "trunk" wells and directionally drilled branching extensions, or “sidetracks”. The sidetracks will be drilled at approximately 60 m spacing (or less) along the trunk. These sidetracks provide borehole penetration into the coal lying between the main trunk wells. The proposed plan incorporates eight clusters of wells comprising the trunks and sidetracks. These clusters of wells, or directionally drilled well array (DDWA), will be drilled for each of the three exploitable coal seams. Below is a block diagram depicting the proposed layout showing trunk wells and sidetracks. In order to conserve costs associated with construction of drilling pads and extensive road building, pads will be constructed in such a way to offset the wellheads by constructing the pads progressively outward away from the toe of the wells, sequentially drilling the 4 seam, then the 5 seam, and finally the 9 seam.

The Guizhou Provincial Geologic Bureau owns and operates a modern and well equipped directional drilling rig. This rig is currently being used in a program at another mine in the region that requires drilling boreholes similar to the ones proposed in this feasibility study.

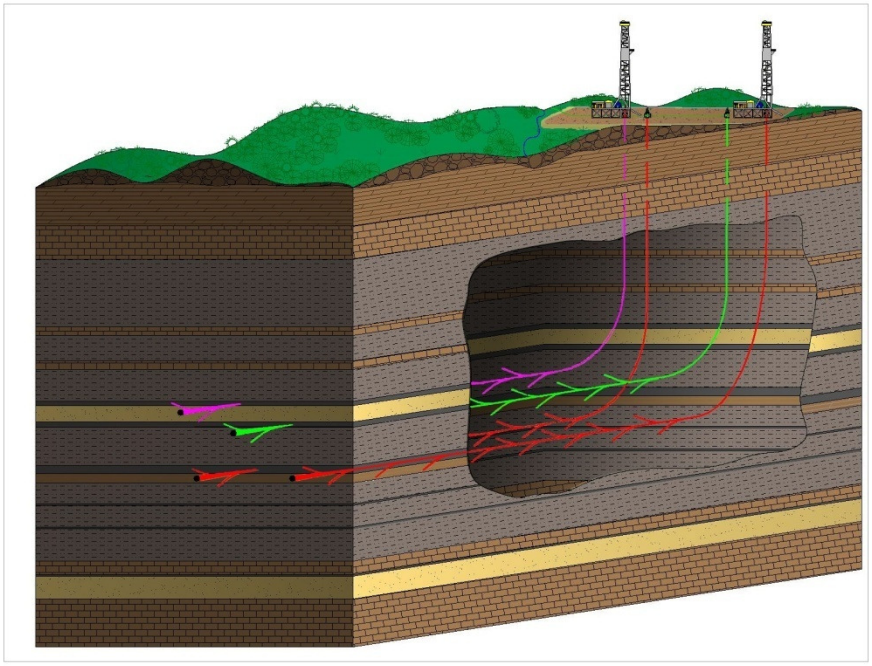

Figure III: Block Diagram Showing Conceptual Layout of Boreholes

Coal Market

The Linhua Coal Mine, situated seven km southwest of the Jinsha County seat, is designed to supply the Qianbei (4 x 300 MW units) and Jinsha (4 x 135 MW units) power plants owned by the Guizhou Jinyuan Group Subsidiary of China Power Investment Company (Linhua's parent company), which are located adjacent to each other on the outskirts of the county seat. A portion of the output of these plants is sold into the Guizhou Provincial grid, and a portion is transmitted through China Southern Power Grid 500 kilovolt transmissions lines for sale into coastal Guangdong Province under the "West to East" electricity program sponsored by the central government.

The Guangdong market is in effect an insurance policy for Qianbei and other Guizhou "West to East" electricity plants in the event of future unforeseen shocks to the Guizhou local market. As noted in the Electricity section of this report, the Chinese Southern Grid authorities increased the allotment of electricity from "West to East" plants such as Qianbei to Guangdong Province when the local Guizhou market contracted in the second-half of 2008.

The Jinyuan Group has announced its intention to close the 135 MW units at the Jinsha plant, which will be replaced by two higher-efficiency 600 MW generating units. This move will have no negative impact on the power plant's demand for coal. The Linhua Mine is designed to provide higher quality, more reliable supply; Linhua's entire output up to its 1.5 million ton design capacity will immediately and permanently replace coal from the power plants' current suppliers; thus, there is no realistic risk of a downturn in demand for the coal output of the Linhua Mine.

Gas Market

The Chinese central government's decision at the turn of the twenty-first century to develop long-distance pipelines to transmit gas from rich fields in remote areas of Northwest and North-Central China to the eastern heartland and to introduce imported liquefied natural gas (LNG) into the southern coastal areas has sparked an historic boom in China's natural gas consumption which was unaffected by the economic turbulence of 2008-2009 and appears poised to continue for the foreseeable future. Natural gas usage increased at an average rate of almost 16 percent between 2000 and 2009, to approximately 88 billion cubic meters annually (CESY 2008 Table 5-12, NBSC 2010 Table 2, China Daily July 5 2010).

Even this impressive growth only brought the natural gas proportion of China's primary energy supply to 4-5 percent, compared to 23-24 percent in Europe and the USA. According to the China National Development and Reform Commission's (NDRC) Energy Research Institute, demand for natural gas could rise by 20 billion cubic meters annually to a total of 300 billion by 2020 (People's Daily March 2010).

Demand for natural gas is currently driven primarily by:

- <u>Residential and commercial use:</u> as a clear burning substitute for coal gasa, lpg and coal briquettes.
- <u>Industrial use:</u> Where available, natural gas fuel is being systematically substituted for liquid hydrocarbons or coal gas in petrochemical factories, glass plants, steel mills, etc.

Secondary end-use sectors include:

- <u>Electric power generation</u>: At central government direction, dozens of state-of-the-art combined cycle power plants were constructed between 2000 and 2010 to provide guaranteed offtakers for the new long-distance pipelines and LNG terminals.

- Automotive: The low price of natural gas relative to gasoline in China has stimulated the development of a compressed natural gas (CNG) distribution infrastructure in a number of Chinese cities.

The central government has recognized since the turn of the century that imports would be a necessary component of the natural gas supply when it committed to building massive LNG import terminals along the southern coast. In addition to importing LNG, the Chinese government, CNPC, is introducing imported pipeline natural gas through the following transactions:

- A long-term contract to purchase 30 billion m^3 of gas per year from Turkmenistan, and
- Agreements with the government of Burma and a Daewoo offshore gas production consortium for CNPC to purchase 12 billion cubic meters per year.

As of early 2010, Guizhou is a virtually untapped gas market. The province has no known conventional oil or natural gas deposits. CMM is a major potential source of non-traditional natural gas for Guizhou. But at present, the vast majority of liberated CMM is lost as VAM. Of the 684 million m^3 recovered in 2009 province-wide, all but 84 million were reported to be vented to the atmosphere (Xinhuanet Economic News 2010). No CMM is known to have been used outside of the immediate mining areas.

The provincially owned Guizhou Gas Group is the predominant distribution company both for coal gas and for the limited volumes of pipeline natural gas currently distributed in the major cities of Guizhou, such as Guiyang and Zunyi County. The prices it can charge its customers for both coal gas and natural gas are fixed by the Guizhou Provincial Price Bureau. Guizhou Gas Group will be partially responsible for the development of these markets. The CNPC itself, however, appears to be taking direct responsibility for the marketing of some of its Burmese gas in Guizhou.

Reports indicate that the CNPC plans to:

- Set up a network of 12 major CNG production sites and 120 to 150 CNG automotive filling stations throughout the province;
- Construct four combined cycle power generation stations to be used for peaking power;
- Develop residential distribution networks in a number of localities;
- Create natural gas industrial parks, and sell directly to existing major industrial energy users such as the Guizhou Aluminum Factory and the Maotai Spirits Factory (Huaxia, 2010).

In sum, the size of the market in Guizhou is likely to exceed initial expectations once natural gas is actually present and the convenience and environmental benefits of natural gas are experienced for the first time. The speed at which this transformation occurs, however, is hard to predict, and there remains some possibility that the supply of new pipeline gas may temporarily exceed in-province demand.

The planned in-province pipeline network that will be constructed to distribute Burmese gas does not extend to the area of the Linhua Mine. The Guizhou Gas Company has contemplated a pipeline network that would extend to Renhuai County, approximately 30 km east of Linhua, but has not indicated how quickly this network will be constructed.

Prior to the anticipated arrival of gas from Burma in 2013, Guizhou should be able to absorb LNG produced by Linhua. Even if supply temporarily outstrips demand for the first few years after the arrival of pipeline gas, local distribution companies under the Guizhou Gas Group – and possibly even those under the CNPC - will have an interest to retain a reliable local supplier like Linhua in order to:

- Hedge against the risks of supply interruption from Burma
- Supply the parts of the province that are not initially covered by the new pipeline network

The estimated city-gate Guizhou price of 2.8 to 3.0 yuan per cubic meter for Burmese gas will establish the baseline for the ex-LNG plant price that Linhua would be able to charge a distribution company. Given the reported 0.1 yuan per 100 km tanker truck transport cost for LNG produced by other coalbed methane (CBM) producers in China and the approximately 300 km distance from Linhua to Guiyang, 2.5 yuan per cubic meter is represents a reasonable estimate for the price that Linhua could expect to receive.

Electricity Market

During the sustained boom fueled by exports and domestic capital investment between 2000 and 2007 (Figure 12), China's electricity consumption grew by an average of 13.5 percent, a full 30 percent higher than overall economic growth. Patterns of growth changed abruptly under the impact of the global economic slowdown in the second half of 2008, carrying through into the first half of 2009. Year-on-year economic growth decelerated to a low of 6.1 percent in the first quarter of 2009. As new investment spending and factory orders for steel and the other electricity intensive commodities dried up, electricity consumption declined in absolute terms during both fourth quarter 2008 and first quarter 2009. The government's four trillion yuan (approximately 600 million USD) infrastructure investment stimulus program gradually revived both the economy as a whole and electricity consumption starting from the second half of 2009. Just as electricity consumption had fallen more drastically than the economy as a whole during the downturn, it rose more rapidly after the stimulus kicked in as orders for steel and other energy-intensive products rebounded.

The Guizhou power grid is one of five interconnected provincial grids which are controlled by the state-owned China Southern Power Grid Company (CSPGC). While the Guizhou Power Grid Company (GPGC) under CSPGC manages the distribution of electricity within the province, the CSPGC controls the substantial electricity transfers between the provinces. Demand for power from generating plants in Guizhou should therefore be considered in a regional context.

Electricity consumption within Guizhou has likewise followed the national/regional pattern, with strong double digit growth 2005-2007, giving way to a temporary decline in the second half of 2008 and first half of 2009 under the impact of the global economic slowdown, followed by a rebound carrying through into 2010.

With this, it is reasonable to assume that Guizhou's economy and its electricity consumption will grow within the projected eight to ten percent range for the country as a whole in the medium term. At the lower end of the range, electric load would increase from an order of magnitude of 12,000 MW in 2010 to 20,500 in 2016, and electricity consumption from approximately 77,440 TWH to 132,800 TWH.

Approximately 60 percent of the generating capacity burns coal from Guizhou's mines, with the remainder hydro, including about 2000 MW of small-scale (under 50 MW) run of river hydro-plants. Because of fluctuations in river water levels, however, hydro only accounts for an estimated 31-32 percent of actual power generation. With the exception of the economic slowdown from the second-half 2008 through first- half 2009, the major coal-fired plants in Guizhou have operated in a range of 6000-7000 hours a year, a high utilization rate by Chinese standards that reflects strong demand both inside and outside the province.

Coal mine methane is among the more promising source of new, lower carbon energy in Guizhou Province. Most of the 138 million metric tons of coal mined in Guizhou during 2009 came from mines with high methane concentration that poses considerable safety risk. Under the relatively conservative assumption that 15 cubic meters of methane were liberated per ton of coal mined, Guizhou Province emitted approximately 2 billion m^3 of CMM in 2009 (pure methane), enough to supply over 1,300 MW of power capacity operating at 6000 hours per year at 40 percent energy conversion efficiency.

Approximately 52 MW of CMM-fired power generation capacity were in operation in Guizhou in 2010. Panjiang, the largest coal mining company and the largest CMM emitter in the province, reports that it is building additional facilities at eight separate locations that will increase the company's total CMM power capacity to 31 MW (Guizhou Daily 2009).

The April 2007 "Opinions Regarding Use of Coalbed Methane and Coalmine Methane" put forth by the NDRC, called for public grid companies such as GPGC to:

- Purchase all power generated in excess of the mining companies' own needs by CMM generation plants, and to pay the purchase price in a "timely manner."

- Pay the CMM power generators the same prices as for power from biomass generation plants, - equivalent to the regulated wholesale purchase prices for power from new coal-fired plants, plus a 0.25 yuan per kwh surcharge.

The Guizhou regulatory authorities, however, have not yet taken concrete measures to enforce these requirements.

CMM End-use Options and Analysis

Through consultation with Nengfa and Linhua Mine management, the study team determined that there were three principal options for using methane gas drained from SCEC mines. These options are:

- *Power Generation and Electricity Sales Option*- This option entails installing a CMM-fueled internal combustion power generation facility in close proximity to the mine's surface facilities, which would be designed to supply power to the mine as well as sell any unused electricity to the grid.
- *LNG Option*- Under this scenario, all coal mine methane produced, with the exception of the volume of gas required to operate the existing Shengli engines will be converted to LNG for sale on the market. The LNG facility will be built in close proximity to where the mine's surface facilities are located in the northern end of the property. Construction will begin in 2011 and will be completed in 2012, sized to fit the CMM production rates forecasted during peak production reached in 2015.
- *Natural Gas Sales Option*- Under this scenario, all coal mine methane produced, other than the gas required to operate the Shengli engines, will be sold to Guizhou Gas (Group) Company LTD (Guizhou Gas). The sales price is structured in our analysis, with the assumption that the transaction will take place at the central gathering location at the mine; any additional transportation costs will be borne by Guizhou Gas.

Table I displays the comparison of each end-use option examined by the study team for this feasibility study.

Table I: Comparison of End-use Options

Comparison of Economic Performance for Three End-Use Options (Base Case)			
End-Use Option	**Power Generation**	**LNG Sales**	**Natural Gas Sales**
Gas Forecast - P50 (million m^3)	51.5		
Total CAPEX (million USD)	200.1	189.3	175.9
Tons of CO_2e (million)	3.88	3.10	3.48
CAPEX/Tons CO_2e	51.57	61.06	50.56
NPV/Tons CO_2e	-4.30	-1.11	1.61
NPV (Million USD)	-16.67	-4.32	6.26
IRR (%)	N/A	N/A	34.55

The Raven Ridge team performed a sensitivity analysis on all three options using the p50 CMM production forecast utilizing Microsoft Excel's What-If Analysis tool. Under the base case scenario, 80 percent of the CAPEX was financed at an interest rate of five percent, and revenue from the sale of carbon emission reductions was included in the analysis. Four other scenarios were also evaluated; one scenario where only fifty percent of the CAPEX was financed, a second scenario where the revenues from the sale of VERs and CERs were not included in the analysis; a third scenario where the interest rate for the money borrowed (80% of CAPEX) is 7.5 percent; and a fourth scenario where the interest rate is 10 percent. Only in the case of natural gas sales was the NPV positive (34.6 million USD),. The two other options resulted in negative NPV values, and in all three options, the base case scenario exhibited the most favorable economic outcome.

The economic performance of an investment in a CMM end-use project can be measured by commonly used indicators such as return on investment, net present value, and internal rate of return. Economic and sensitivity analysis performed by the study team indicates that the end-use options being contemplated all have strengths and weaknesses; however, the Raven Ridge team has concluded that the best economic performance would result from natural gas sales, as all economic indicators strongly support this option. This project option requires the least amount of CAPEX, very little gas is lost to processing, and the option exhibits strong gas sales for the life of the project. However, from a market perspective, the market for LNG is already established in the region, and a CMM to LNG project is underway just to the north in Songzao, which supports this option's viability. Both current economic and market conditions should be evaluated when the decision is made to select an end-use option.

Conclusions, Recommendations, and Next Steps

In summary, we recommend Linhua Mine should implement a drilling program which consists of a series of long boreholes drilled from the surface to pre-drain the coals in advance of mining. When designing the program, consideration should be given to the following aspects of a drilling program:

- The instability of the coals and determining the ideal azimuth of the wells.
- The mechanical directional portion of the drilling design needs higher level engineering.
- The expertise and know-how to design and manage such a project may not be readily available in China; thus, prior to commencing with the commercial drilling program, a pilot program should be carried out for training and capacity building, to insure success once the commercial drilling operations begin. Drilling the recommended first DDWA could comprise the pilot project.
- Adjunct to determination of availability of expertise, engineering design must take into account successful practices and avoid problems that have occurred in similar geologic settings.

In conclusion, two viable options for gas sales exist: 1) conversion of CMM to LNG and transporting the -product to markets which are experiencing an under-supply of natural gas; or 2) injecting produced CMM into a pipeline that connects with the Burma-China Pipeline. It is important to determine as early as practicable which of the two market approaches is the best use for Linhua's gas, as both options will require extensive infrastructural upgrades and each will need to be implemented and completed before any gas can be sold.

2.0 Background

Under contract number EP-W-05-063 TO 19, USEPA awarded a task order for a prefeasibility and feasibility study of the potential to develop a methane emissions reduction project utilizing coal mine methane (CMM) drained and recovered from a mine located in Guizhou Province, of the People's Republic of China. The Raven Ridge team met with the Guizhou Mine Safety Bureau (GMSB) to discuss potential candidate mines for this feasibility study. The selection process was based on a list of potential mining areas developed by the GMSB. Guizhou Linhua Mines Co., Ltd (Linhua Mine), founded in November of 2003 and currently owned by Guizhou Nengfa Fuel and Power Development Co., Ltd (Nengfa) (holding company) and Lindong Mining Bureau (shareholder) was chosen as the feasibility study partner. Aside from being a very gassy mine, the Linhua Mine was chosen because it was nearing the production stage of development, its managers were willing to participate as the partner mine, and the potential for replication of a successfully implemented coal mine methane (CMM) recovery and utilization project is high.

Nengfa is owned by the fifth largest power producer in China, China Power Investment Corporation. Annual coal consumption for the utility's Guizhou operations is 60 million tonnes per annum (Mtpa), and they target producing 20 Mtpa of their Guizhou needs through Nengfa. Nengfa is operating one mine and developing five others. Currently, the Bei Le Mine is producing 300 thousand tonnes per annum (Ktpa) and expected to produce up to 600 Ktpa in the future. The Linhua Mine, separated geographically into two mining districts (Linhua 1 Mine and Linhua 2 Mine), had a goal to begin production in September of 2009 with a designed production capacity of 1.5 Mtpa; however, because of the extensive gas outburst problems they have encountered during development, the mine still has not reached design capacity. The remaining four mines are also still under construction. Total production from the six mines when built to design capacity will be 5+ Mtpa.

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All six mines under the control of Nengfa are gassy, and three, including Linhua, are highly prone to gas outbursts. The Linhua Mine will have annual emissions of more than 40 million m^3 of methane per year. Consequently, Nengfa engineers and management are keen to pursue new methods of recovery and utilization. The biggest challenge facing gas utilization in Guizhou is determining the appropriate drilling technology for the local conditions and using it to recover high concentration produced gas for utilization.

3.0 Introduction

This document reports the findings of a comprehensive coal mine methane (CMM) recovery and utilization feasibility study that was conducted as a part of a larger initiative funded by the U.S. EPA. This initiative supports U.S. EPA's efforts under the Global Methane Initiative (GMI), formerly the Methane to Markets Partnership (M2M).

This work was conducted with the cooperation of the Guizhou Nengfa Power Fuel Development Co., Ltd., in Guizhou Province in southern China. The findings of this work will serve as a bankable CMM feasibility study.

The study is the result of investigations that entailed:

- Field visits to the mines, ventilation shafts, and gas pumping and storage facilities;
- Extensive research on national and local gas and electricity markets;
- Translation and review of technical documents;
- Kinematic analysis of geologic structures;
- Forecast of production based on statistical analysis of coal mine methane drainage (CMM) and ventilation air methane(VAM); and
- Economic analysis based quotes from vendors and gas sales prices based on current markets.

3.1 Objective

Nengfa is owned by the fifth largest power producer in China, China Power Investment Corporation. Annual coal consumption for the utility's Guizhou operations is 60 Mtpa, and they target producing 20 Mtpa of their Guizhou needs through Nengfa. Nengfa will acquire mines and expand production rapidly. The purpose of the feasibility study undertaken at the Linhua Mine is to help mine managers to develop a gas drainage and utilization program that can be implemented at the Linhua Mine, and eventually be used as a model for other Nengfa owned coal mines; and perhaps even some of those in which it has a non-controlling interest.

3.2 Location

The Linhua Mine area is located in the mountains on the Guizhou Plateau (**Figure 1**). The highest point on the plateau is Mt. Dapo with an elevation of 1,617 m, and the lowest elevation is the Maluo River to the east at 1,170 m. Two major rivers, the Youjia River and the Toudao River, flow through the mine area from south to north (**Map 1**). The Youjia, which flows year round, is 8.2 km and is located south of the mine area. The Toudao River flows year round from southwest to northeast for 6.5 km; however, during the dry season the river water is supplied from water pumped from the mine and from numerous local springs.

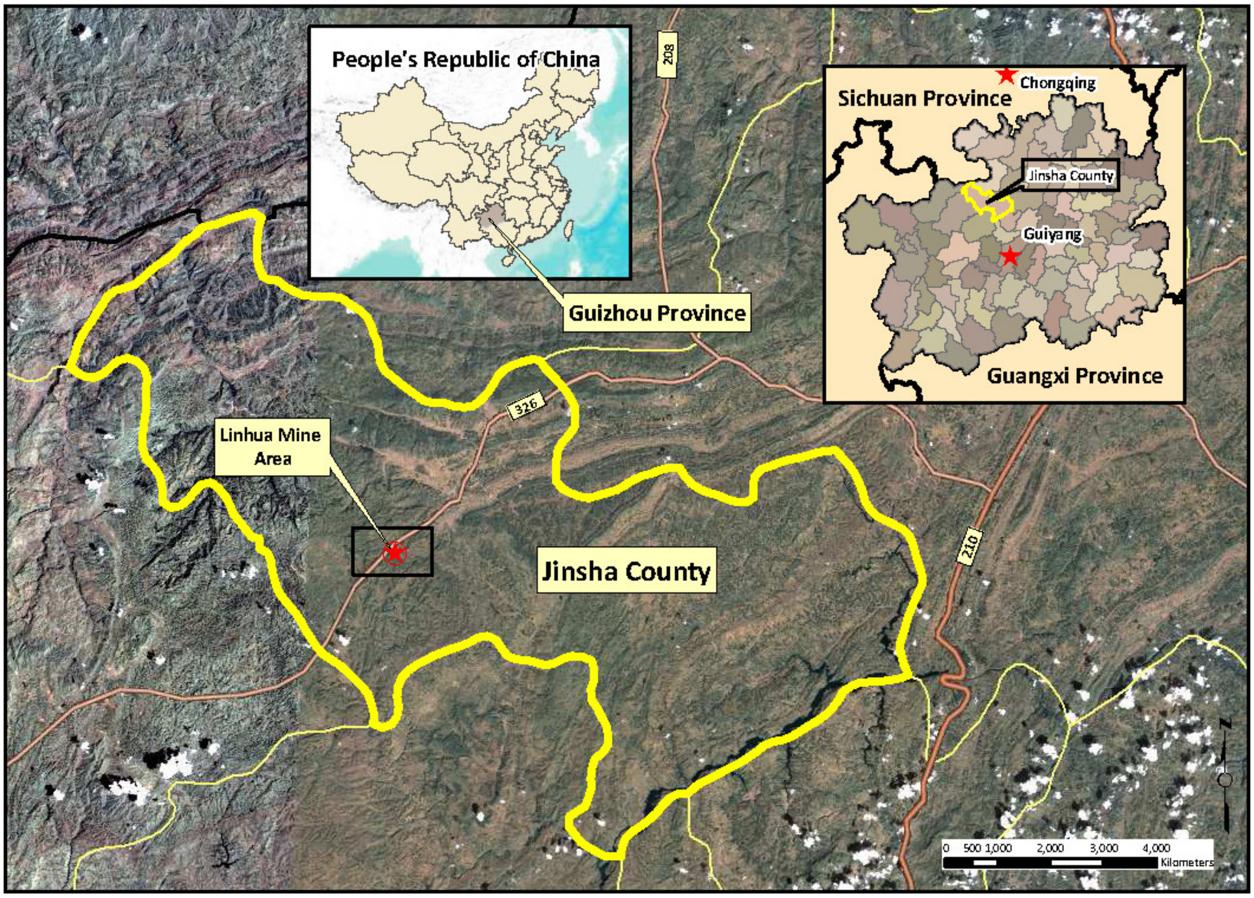

Figure 1: Overview area map

The climate within the mining area is warm and humid with mild winter and summer temperatures. From 1990 to 2001 the annual maximum temperature was 37° C with an annual minimum temperature of -4.9° C, and an average temperature of 15° C. During the winter, there were 5 to 10 days each year of freezing temperatures.

The rainy season lasts from April through September. From 1990 to 2001 the annual maximum precipitation was 1,179 mm and the annual minimum precipitation was 774.7 mm. The annual average rainfall is 1,057 mm, and the daily maximum was 115.3 mm.

4.0 Geology, Coal, and Gas Resources of Nengfa Coal Mining Properties

The Linhua Mine property is located in Jinsha County in Guizhou Province, on the Northern margin of the Guizhou Plateau. Coal has been mined in the area for decades, but more recent geologic exploration programs have been conducted to determine the extent of the coal resource and to collect sufficient geologic data for designing a coal mine.

4.1 Geologic Setting

Situated on the Guizhou Plateau, the Linhua Mining area is found within steep terrain dominated by erosional features such as narrow ridges, deep and narrow canyons, as well as karstic sinkhole features. The limestones and shales of the lower Triassic Yelang and Maocaopu formations are exposed at the surface (**Map 1)**. The Upper Permian Longtan Formation is coal bearing and the focus of coal mined in this area.

4.1.1 Geologic Structures

Work performed by the Guizhou Geology Prospecting Bureau of the Institute of Coal Geology in this area was published in 2002. The Linhua Mine management provided the entire text of the report and other portions of the report that they had in their possession including four cross sections, coal thickness and geologic structure maps (**Exhibit 1**). Backup data that was included in the original publication as appendices was not available. The information provided was sufficient for analysis and allowed the Raven Ridge team to determine that several episodes of geologic deformation had affected the region.

The region surrounding the Linhua Coal Mine has undergone a complex geologic history, the detail of which is beyond the scope of this study. A number of tectonic episodes resulted in geologic structures that complicate mining. The episodic tectonic events that can be identified as the cause of these geologic structures are:

- Extensive large scale folding that extends for many kilometers in a northeasterly direction as a result of intense compression caused by the movement of the Philippine crustal plate toward the eastern margin of the Eurasian continental plate;
- Northerly trending low angle thrusts and high angle reverse faults which also formed as a result of the Philippine-Eurasian plate interaction;
- A few northerly trending normal faults that were caused by uplift and extension following the prior compressional events.

The extensional episode is an event that may have indirectly resulted from the northward movement of the India plate into the southern margin of the Eurasian plate. The movement of the Philippine plate juxtaposing the movement of the India plate is causing rotation and shearing of large crustal blocks in Sichuan and Guizhou provinces. It is also known that tectonism continues as demonstrated by measurements of the velocity of crustal movement being tracked by an elaborate GPS network established on the Tibetan plateau and its margins (Zhang et al, 2004). Mapping resulting from Zhang's study shows extensional movement of the Eurasian crustal block containing the Linhua Mine off to the east. These strong extensional forces oppose the existing compressional forces and have resulted in relaxation in the coal bearing strata. All of the recognized events have occurred post the Triassic period. Researchers in Sichuan province to the north conclude that three discrete episodes of tectonism occurred in the Triassic, Cretaceous and Tertiary periods (Cao et al, 2001). It is reasonable to assume that these episodes were manifest in Guizhou province as well.

The following sections provide more detail regarding the impact that the mappable geologic structures have on the mining conditions at the Linhua Mine.

4.1.2 Folding

The Linhua Mining area is located along the western limb of a large scale northeast-southwest trending asymmetrical synclinal structure. This geologic structure is a synclinorium that comprises a number of smaller scale synclines. The Jinsha-Qianxi synclinorium is approximately 20 km wide and 20 km long and plunges to the north, with the dip of the beds along the structure ranging from 28 degrees on the northwest limb to 10 degrees along the southeast limb. This structure can be easily seen on the satellite imagery used in **Map 4.**

One of the smaller scale secondary folds that comprise the Jinsha-Qianxi synclinorium is the Xinhua syncline. The Xinhua syncline lies along the northwest limb of the Jinsha-Qianxi synclinorium extending 11 km in a north northeast–south southwest direction. This structure is also identifiable on **Map 4**. The Xinhua syncline plunges to the northeast bisecting the Linhua Mining area. The dip of the seams mined along the southeast limb of the structure range from seven to 11 degrees.

4.1.3 Faulting

According to the 2002 coal exploration report there were 15 faults mapped in the area. Among these, six were identified by surface geologic mapping. Since the Institute of Coal Geology published its report on the Linhua Mining area, at least 17 additional faults have been discovered within the mine area. These were found in the subsurface within the mine while driving the entryways, and outside the mine workings by exploration drilling. Of these 33 faults:

- Three faults are more than 1000 m long, displacing the coal bearing strata in a range from 20 to -30 m along fault planes that dip from 30 to 47 degrees;
- Four faults are greater than 500 m long but less than 1000 m long, displacing the strata from 7 to 15 m along fault planes that dip from 37 to 60 degrees;
- Eight faults that are greater than 150 m and less than 500 m long, displacing the coal bearing strata in range from 2 to 6 m; and
- The remaining 20 mapped faults are small-scale, displacing strata in a range from 0.4 to 2 m along a strike length of less than 50 m along fault planes that dip 25 to 85 degrees.

Thus far, most of the larger scale faults have been mapped at the periphery of the mining reserve block, with only a few mapped inside the area planned for mining. Exploration boreholes are relatively wide-spaced on the eastern side of the reserve block, with as much as 1000 m separating adjacent boreholes. Borehole spacing on this magnitude significantly lowers the probability that all but the largest scale faults would be discovered. All of the smallest scale faults were discovered while driving entryways.

4.1.4 Kinematic Analysis

The Raven Ridge team utilized mine-supplied data from mapping the faults and folds that occur within the mining area and satellite imagery to perform kinematic analysis. Kinematic analysis was first used to unravel complex structural geology and reported in a ground-breaking paper published in the Journal of Structural Geology (Marrett and Allmendinger, 1990). Kinematic analysis provides mechanical bases for the description of the relative movement of geologic structures. This form of analysis is performed without regard to the cause of the motion. The analysis of the Linhua Mine area was facilitated by the use of GEOrient software (Holcombe, 2010). Three dimensional lattitudinal data for each of the geologic structures is input and results are output as various forms of stereographic plots and statistical data. Input data included: bedding attitude data (strike and dip direction and magnitude) which captured the spatial information regarding folding; and data representing the spatial orientation and magnitude of the faults. Based on the analysis, the Raven Ridge team concluded that earlier compressional events manifest as northeasterly folding and more northerly reverse faulting were followed by a separate extensional event, manifest as normal faults.

Although kinematic analysis is done without regard to cause, it is clear that the compressional and extensional events resulting from the episodic interplay of the large-scale tectonic events are described above. Change from a largely compressional stress regime to a largely extensional regime is a reflection of the changing tectonic dynamics. The compressional forces which have acted to shorten the earth's crust and close fractures are oriented in a northwesterly direction, whereas the extensional forces that serve to open fractures and lengthen the crust are oriented in a northeasterly direction (**Map 4**).

4.1.5 Impact of the Orientation of Geologic Structures on Mining at the Linhua Mine -

The impact of the orientation of the geologic structures present in the Linhua Mining area is significant. Numerous studies have shown that outbursts typically occur at loci typified by geologic structures that occur as a result of compressional stress regimes, i.e. strike-slip, reverse and re-activated normal faults (Shepherd, 1995). Further, Cao et al (2001) noted that outbursts were most dangerous if mining approaches from the downthrown side of a fault. In a reverse fault, the footwall is downthrown and overridden by the hanging wall (**Figure 2**), resulting in additional stress or loading being placed on the footwall. If the strata are gas-charged, additional compressional stress increases the gas pressure in the pores. Although there is still some conjecture involved in describing the mechanism responsible for outbursts, it is clear that a sudden reduction in the loading pressure on the coal can result in the instantaneous desorption and release of gas, which in turn ruptures the pores and destroys the internal structural integrity of the coal. The sudden release of gas and comminution of the coal often results in outbursts of gas and coal.

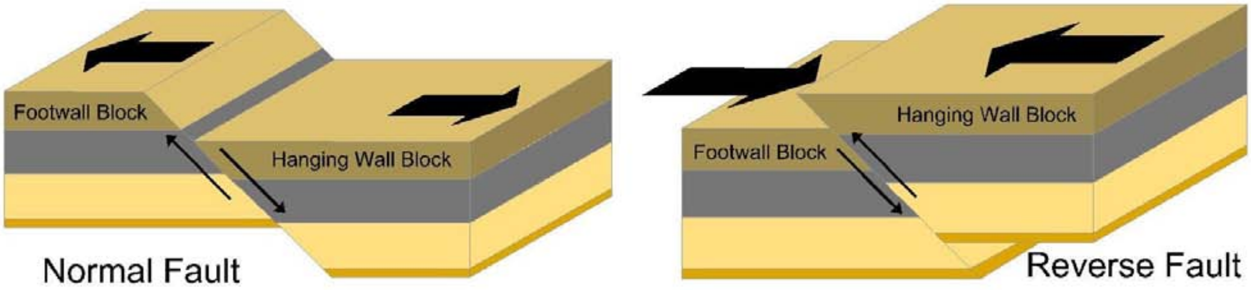

Figure 2: Normal and reverse fault diagram, showing hanging wall and footwall blocks.

The Linhua Mine is rated as a high outburst mine, and has experienced several outbursts associated with crossing the downthrown side of faults. Cao et al (2001) also noted that outbursts in mines in China often occur in relatively narrow zones. These zones are often localized along intensely faulted and folded zones. A zone such as Cao describes may exist at the Linhua Mine. This zone is defined by the belt of reverse faults crossing the mining block in a north-northeasterly direction. At present the mine plan calls for retreat of the longwall to occur in a northwesterly direction, parallel to the compressive axis. Mining in this direction will result in continued exposure to dangerous outbursts as mining approaches some of the faults from the downthrown side. The present borehole drainage pattern is effective because it crosses the fractures parallel to the principal axis of extension – from a northeast or southwest direction. To minimize exposure to dangerous outburst the direction of retreat could be changed to avoid the downthrown side of reverse faults by crossing the faults obliquely. Re-orientation of mining will also provide additional options for designing effective drainage programs.

4.2 Stratigraphy

The following short summary highlights the characteristic attributes of each the major stratigraphic units (**Figure 3** and **Exhibit 5**) that occur within the Linhua Mining block.

4.2.1 Lower Triassic

The lower Triassic Yelang and Maocaopu formations are exposed at the surface within the mine area and are shown in **Map 1**. Both of these formations contain limestones which are aquifers with caverns, sinkholes and springs, and are interbedded with dolomite and impermeable siltstones.

Maocaopu Formation

The Maocaopu Formation is exposed in the eastern part of the mining area. The upper facies consists of 240 m of dolomite. The lower facies of the Maocaopu is limestone, averaging 236 m thick with thin interbeds of dolomite. It is karstic and contains an aquifer that has produced water at greater than 100 liters per second (l/s).

Yelang Formation

The Yelang Formation consists of three lithologic units; the Jiujitan Section, the upper facies, is composed predominately of siltstone with an average thickness of 164 m; the middle facies, the Yulong Mountain Section, is an oolitic limestone averaging 217 m thick, and the underlying limestone, the Shabaowan Section, is an impermeable bed of siltstone averaging 15 m thick. The oolitic limestone is an aquifer with significant water flows reported.

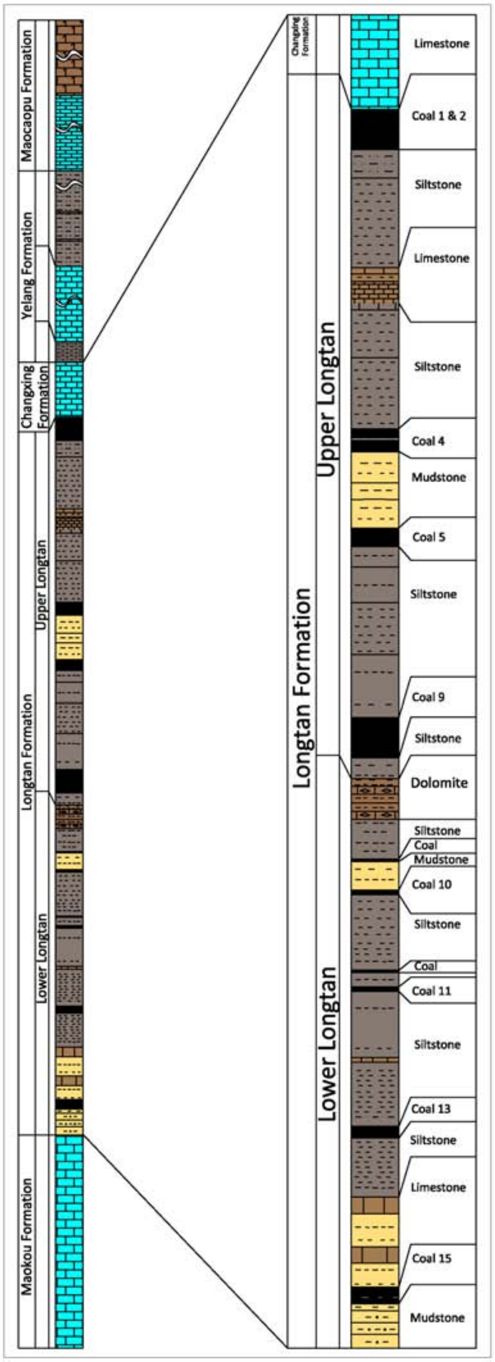

Figure 3: Simplified Stratigraphic - Column, showing rock formations with - limestone acquifers in blue. -

4.2.2 Permian Sediments -

The underlying Permian sediments are separated into an upper and lower facies. The Upper Permian in the mine area averages 133 m thick and comprises the Changxing Formation limestone and the coal bearing Longtan Formation. The Changxing limestone is an aquifer and the Longtan Formation is divided into the Upper and Lower Longtan. It is predominately a suite of rocks that were deposited in a fresh water environment consisting of siltstones and mudstones with interbedded coal seams; coal seams 1 through 9 in the Upper Longtan and seams 10 through 15 in the Lower Longtan. Some of the rocks in this rock package were deposited in marine and near marine environments.

Changxing Formation

The Upper Permian Changxing Formation is predominantly limestone with an average thickness of 39 m. This limestone is an aquifer producing as much as 20 l/s of water measured from springs and is capable of producing water through fractures into the underlying number 4 and 5 coal seams and into vertical mine shafts and vents. Lost circulation of drilling fluids and an increase in water production has been reported while drilling this formation.

Longtan Formation

The Upper Permian Longtan Formation is exposed on the northern and western periphery of the mining area, and ranges from 92 to 127 m in thickness with an average thickness of 106 m. The Longtan Formation consists of marine and non-marine sediments that include fine-grained sandstones, siltstones, mudstones, marlstones, limestones and coal (seams 1 through 15). It is the only coal bearing formation in the area.

Upper Longtan

The Upper Longtan averages approximately 58 m thick and is predominately siltstone interbedded with mudstones, thin limestones and coal seams 1 through 9. Coal seams 4, 5 and 9 are generally of mineable thickness and quality. The 4 coal seam averages 1.65 m and the 5 seam is 1.45 m thick, but are only locally thick enough to mine, (**Table 1**). The 9 seam is the thickest of the three seams, averaging 2.98 m with mineable quality and thickness throughout the mining area.

Table 1: Coal Seam Thickness Rank and Distribution -

COAL SEAM No.	AVERAGE THICKNESS(m)	AVERAGE MINED THICKNESS(m)	Vitrinite Reflectance	DISTRIBUTION
4	1.65	1.21	3.280	70% of mine area, 1.5m north and south in mine area
5	1.45	1.17	3.444	Presnt in middle of mining area
9	2.98	2.77	3.460	100% of mine area, thickest 3-5m through middle of mine area
13	1.02	1.14	na	Thicknest 0.8 - 2.0m in the northern half of mine area
15	1.26	1.14	3.254	Thickest is in the north and southwest of mine area

Source: GGPBICG (2002)

Due to the close proximity of the overlying Changxing Formation limestone aquifer, averaging only 29 m above the 4 seam, subsidence from mining activity can produce fractures up into the Changxing Formation, creating a conduit for water to flow into the coal mine.

Lower Longtan

The Lower Longtan averages 48 m thick and consists of mudstones, siltstones interbedded with fine sandstones, coal seams and some argillaceous limestone beds in the lower facies. Coal seams 10 through 15 are found in this interval.

Maokou Formation

Underlying the Lower Longtan Formation is the Lower Permian Maokou limestone, with microcrystalline to fine crystalline texture. Some karstic features occur where exposed to the north and northwest of the mining area. This formation is at least 83 m thick, as most coal exploration boreholes do not penetrate the entire thickness of the Maokou. The Maokou is a low-yield aquifer with measured flow ranging from 0.13 - 1.75 l/s.

4.3 Coal Resources

The number of coal seams found within the Longtan Formation range from nine to twenty-one across the mine property, varying in quality, thickness and distribution. Prevalent coal seams found within the mining area are the 1, 2, 4, 5, 9, 10, 11, 13, and 15 seams. Longwall mining is the method used to mine coal in this region.

4.3.1 Thickness and Distribution

Of the coal seams found within the mining area, the 4, 5, 9, 13 and 15 coal seams are considered to be of mineable thickness. The cumulative thickness ranges from 3.01 to 12.13 m, and averages 6.39 m. The primary seam targeted for mining at the Linhua Mine is the 9 coal seam, because it is the thickest and most consistently found in the mining area.

Coal Seam 4

Seam 4 is located in the Upper Longtan Formation approximately 20.1 to 44.6 m below the Changxing limestone, with an average thickness of 1.65 m (**Figure 4**). Total coal reserves in the mining area for seam 4 are estimated to be 34.58 million metric tons.

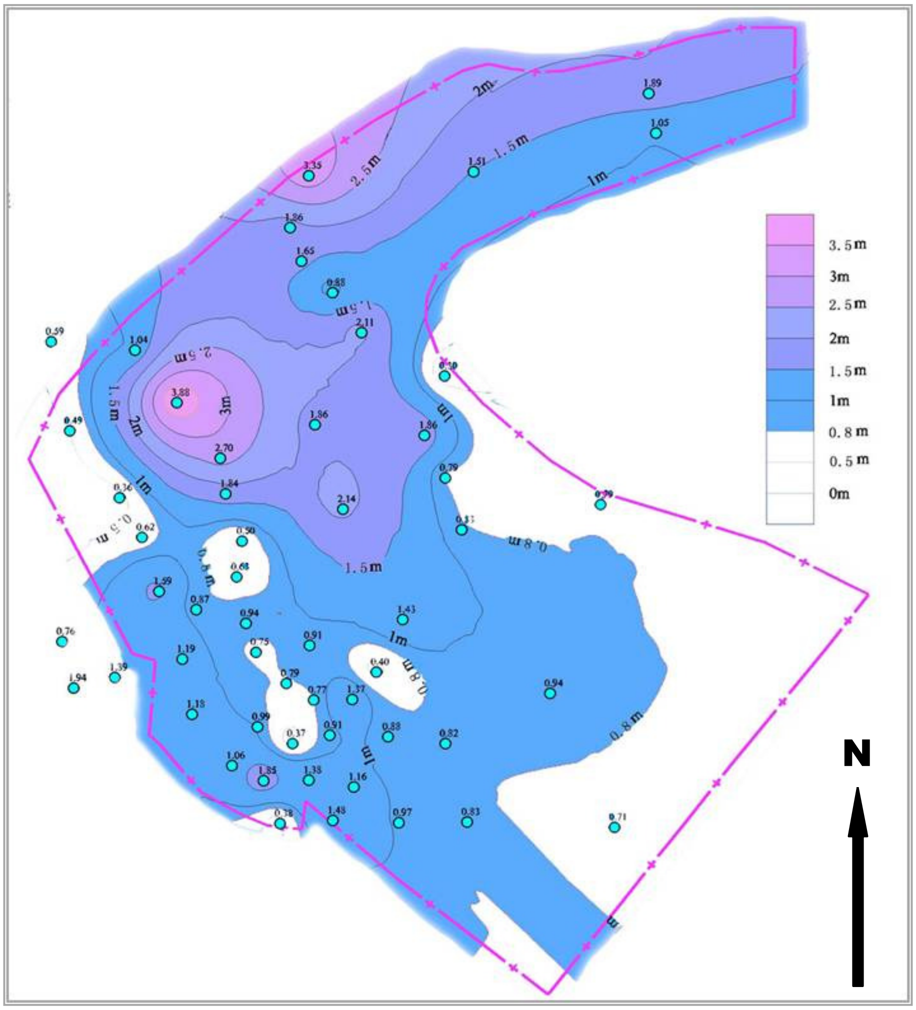

Figure 4 : Coal Seam 4 Thickness Map. Source: GGPBICG (2002)

Coal Seam 5

Coal seam 5 is also found within the Upper Longtan Formation and is between 6.0 and 7.0 m below the 4 seam, varying in thickness from 0.58 m near the center of the mine area to 2.02 m in the north. The average thickness is 1.45 m (**Figure 5**). Total coal reserves in the mining area for seam 5 are estimated to be 28.56 million metric tons.

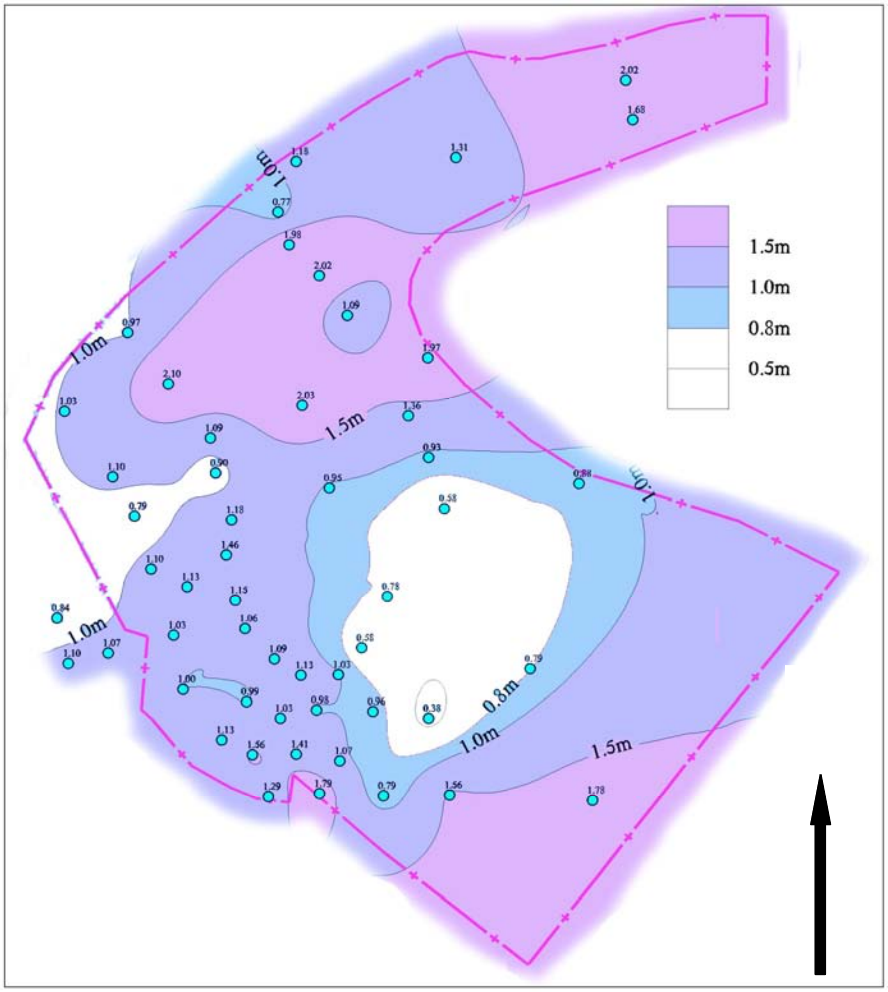

Figure 5: Coal Seam 5 Thickness Map. Source: GGPBICG (2002)

Coal Seam 9

Seam 9 occurs in the lowermost Upper Longtan Formation and ranges in thickness from 0.7 to 5.8 m, averaging 2.98 m. The 9 seam is the thickest, most widely distributed, highest quality coal seam in the mining area, and thus, the most easily extracted of all the mineable coal seams in the reserve block (**Figure 6**). Total coal reserves in the mining area for seam 9 are estimated to be 85.09 million metric tons.

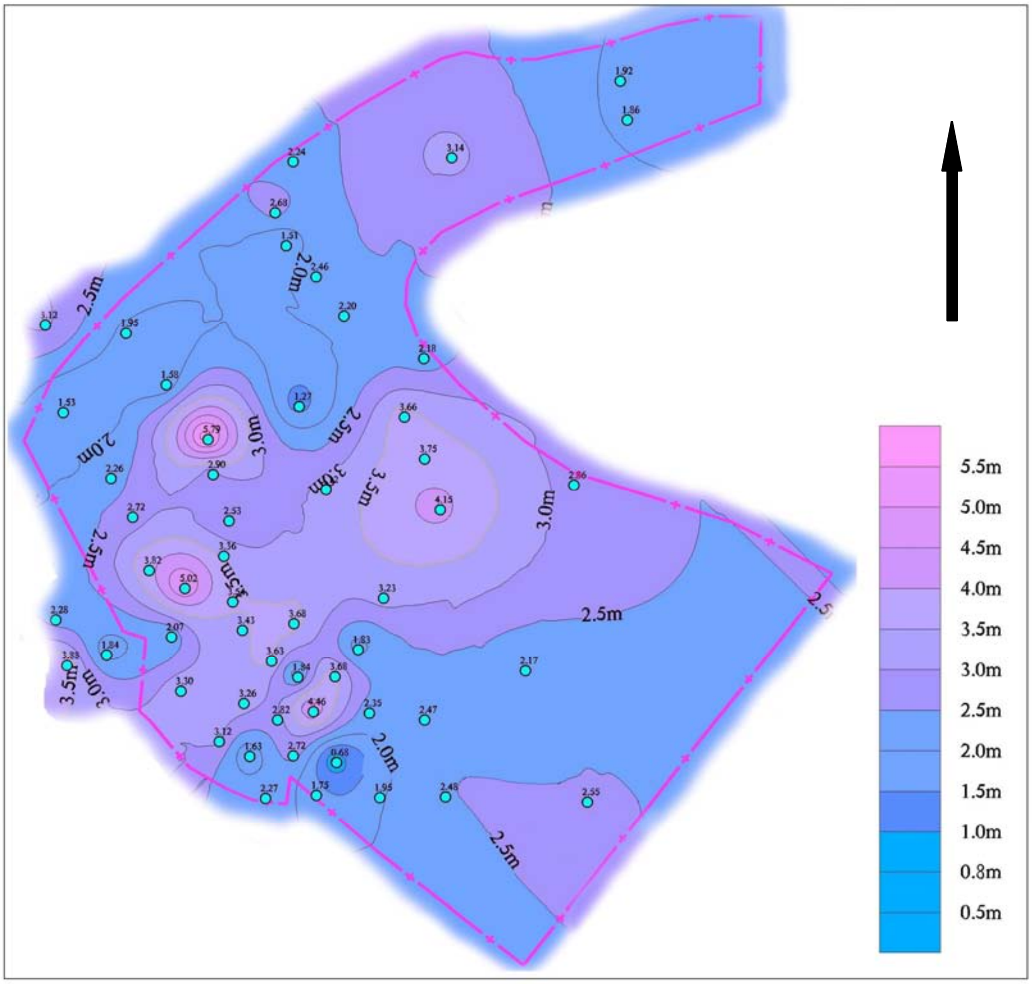

Figure 6: Coal Seam 9 Thickness Map. Source: GGPBICG (2002)

Coal Seam 13

Coal seam 13 is found in the lower facies of the Lower Longtan Formation, with an average thickness of 1.02 m, ranging from 0.28 m in south to 2.56 m in the northern part of the mining area (**Figure 7**). Total coal reserves in the mining area for seam 13 are estimated to be 14.19 million metric tons.

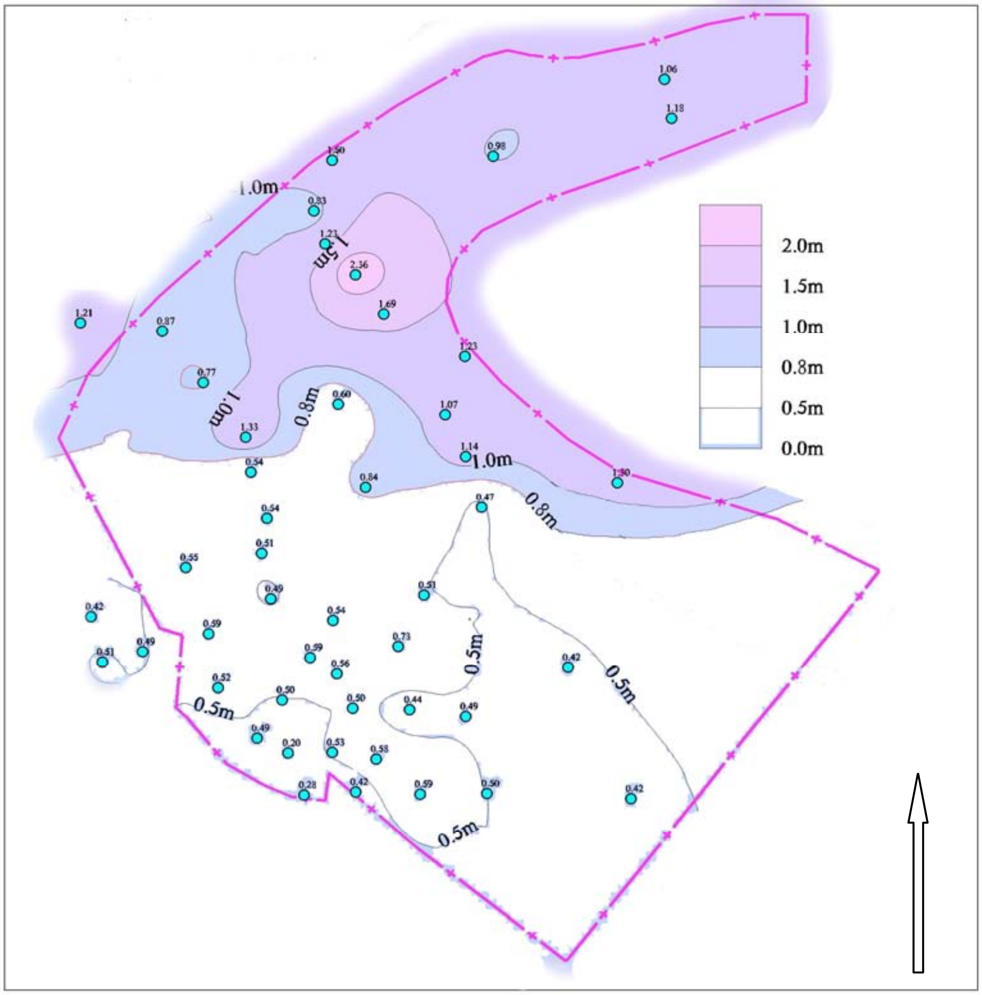

Figure 7: Coal Seam 13 Thickness Map. Source: GGPBICG (2002)

Coal Seam 15

Coal seam 15 is also found in the lower portion of the Lower Longtan Formation, below the 13 seam and from 3.0 to 4.0 m from the top of the Maokou Formation. With an average thickness of 1.26 m, it ranges in thickness from 2.69 m in the north to where it is absent in the center of the mining property (**Figure 8**). Total coal reserves in the mining area for seam 15 are estimated to be 12.05 million metric tons.

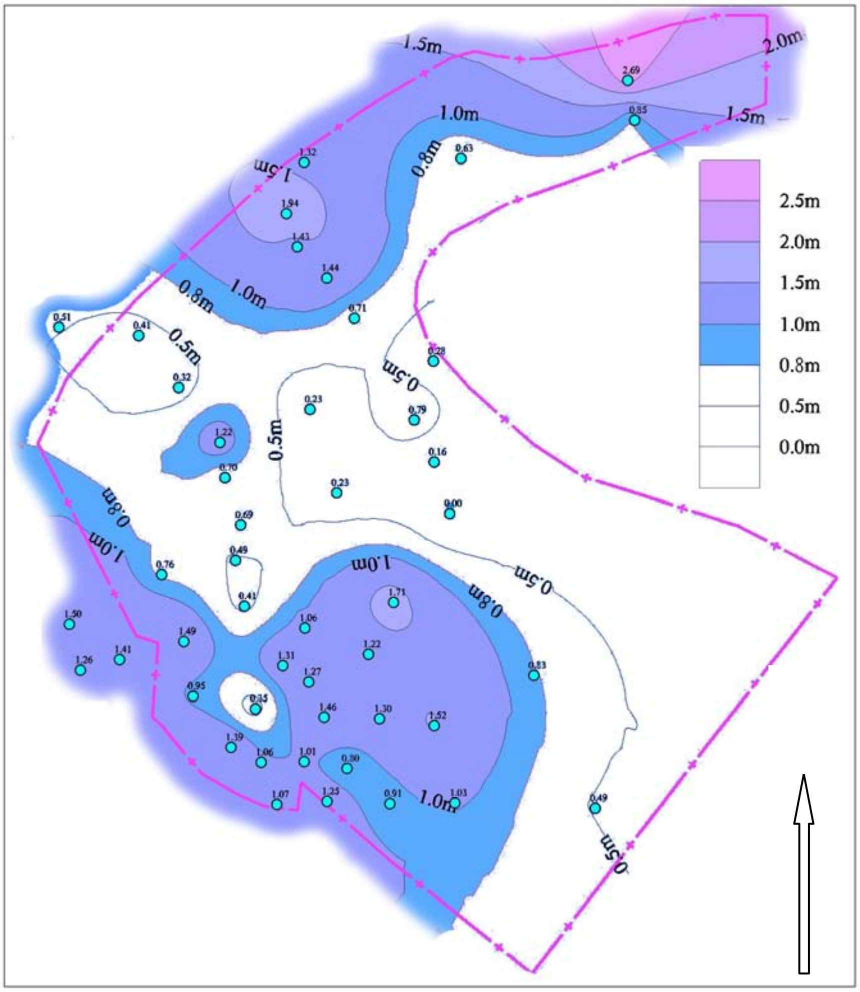

Figure 8: Coal Seam 15 Thickness Map. Source: GGPBICG (2002)

4.4 Coal Quality

The rank of the coal occurring in the Longtan Formation throughout the mining area is anthracite; however, coal quality (**Table 2**) varies relative to depth. Approximate analysis of mined coal showed ash content and volatile matter decrease with depth within the shallower seams: 4, 5 and 9. Conversely ash and volatile matter increase with depth within the deeper seams, 13 and 15. The ash content and volatile matter is lowest overall in the 9 seam. The 4 seam exhibited the highest measured ash content of 38.9 percent, and the 15 seam showed the highest measured volatile matter of 17.2 percent.

A sulfur analysis shows a high sulfur content in coal seams 13 and 15 (average 2.5 - 4.3 percent) with a lower sulfur content (average 0.9 - 1.2 percent) in the shallower seams. Overall, the lowest measured sulfur content occurs in the 9 seam, at 0.9 percent concentration; and, a maximum value of 10.2 percent sulfur recorded in the 15 seam.

Table 2: Coal Quality Summary

		Seam 4			Seam 5			Seam 9			Seam 13			Seam 15			Mine		
		From	To	Avg	From	To	Avg	From	To	Avg	From	To	Avg	From	To	Avg	From	To	Avg
Mined Coal	%Moisture$_{ad}$	0.64	4.34	1.99	0.39	3.35	1.41	0.48	3.68	1.81	0.78	3.83	2.29	0.44	2.6	1.34	0.44	4.34	1.8
	%Ash$_{d}$	14.57	38.9	23.9	14.02	38.4	20.9	12.08	25.1	16.5	17.96	35.9	27.3	21.49	37.8	30.1	12.08	38.86	23.72
	%Volatiles$_{daf}$	5.11	8.7	6.72	4.34	11.3	6.74	4.18	13.3	5.93	4.07	12.2	7.77	6.29	17.2	10.8	4.07	17.22	7.6
	%Sulfur	0.36	3.58	1.15	0.32	4.01	1.2	0.34	2.03	0.88	1.24	4.01	2.47	1.19	10.2	4.33	0.34	10.16	2.01
	Heating Value (MJ/kg)	18.67	28.9	25.4	19.61	28.7	26.2	25.1	29.7	27.9	20.42	27.7	23.8	16.74	32.8	22.9	16.74	32.79	25.25
Clean Coal	%Moisture	0.43	4.01	1.49	0.22	2.89	1.41	0.61	4.19	1.64	0.71	3.7	2.09	0.35-	2.17	1.15	0.22	4.19	1.56
	%Ash	7.19	10.7	8.87	5.49	8.86	7.46	6.12-	14.1	7.31	5.93	12.8	8.25	7.04-	10.5	8.6	5.49	12.76	8.1
	%Volatiles $_{daf}$	4.21	7.56	5.53	4.41	6.97	5.12	3.96	7.73	4.98	3.89	5.64	4.79	4.19	7.09	5.59	3.9-	7.73	5.2
	%Sulfur$_{t,d}$	0.37	1.32	0.67	0.37	2.09	0.73	0.33	0.7	0.52	0.6	1.47	1.1	1.00	6.92	2.81	0.33	6.92	1.17
	Heating Value (MJ/kg)	30.1	31.7	30.8	30.34	31.9	31	30.58	32	31.1	29.46	32.2	30.7	27.59	34.5	30.5	27.59	34.48	30.81

Source: GGPBICG (2002)

4.5 Coal Reserves

Total coal reserves in the mining area are estimated at 174.5 million metric tons. According to work done by Guizhou Geology Prospecting Bureau of the Institute of Coal Geology (GGPBICG), the Linhua Mining area reserves were classified based on the proximity of each point of observation during exploration. For a complete description of the reserves classification system, see **Appendix 1**.

As can be seen from **Table 3**, class A reserves are estimated only for the coal seam 9 below a depth of 950 m. This will present even more difficult conditions for mining due to higher probability of sudden outbursts. Additional exploration needs to be performed.

Table 3: Mineable Reserves by Depth and Grade

Level	Seam No.	Recoverable Reserves				
		Grade A (million t)	Grade B (million t)	Grade C (million t)	Grade D (million t)	Total (million t)
Above 700 m	4	--	1.29	3.17	1.83	6.29
	5	--	--	7.29	2.09	9.38
	9	--	4.68	15.47	7.02	27.17
	13	--	--	8.45	--	8.45
	15	--	--	1.06	--	1.06
	Total	***--***	***5.97***	***35.44***	***10.94***	***52.35***
700 - 950 m	4	--	4.47	13.65	0.73	18.85
	5	--	3.56	4.14	1.6	9.3
	9	--	17.52	17.08	--	34.6
	13	--	--	3.69	--	3.69
	15	--	--	6.17	--	6.17
	Total	***0***	***25.55***	***44.73***	***2.33***	***72.61***
Below	4	--	1.39	8.05	--	9.44

Level	Seam No.	Recoverable Reserves				
		Grade A (million t)	Grade B (million t)	Grade C (million t)	Grade D (million t)	Total (million t)
950 m	5	--	4.14	5.74	--	9.88
	9	1.51	13.8	8	--	23.31
	13	--	--	2.05	--	2.05
	15	--	1.64	3.18	--	4.82
	Total	***1.51***	***20.97***	***27.02***	***0***	***49.5***
Total		**1.51**	**52.49**	**107.19**	**13.27**	**174.46**

Source: GGPBICG (2002)

4.6 Hydrology

The three major aquifers in the mining area occur within the Yulong Mountain Section of the Yelang Formation, the Changxing Formation and the Maokou Formation. In perspective, the coal bearing Permian age Longtan Formation (106 m thickness) is relatively thin compared to the combined thickness of the overlying Triassic age limestones of the Yulong Mountain Section (217 m thick) and Changxing (39 m thick) formations (**Table 4**).

The Changxing formation aquifer has been known to flood the 4 and 5 coal seam mine workings through fractures created as a result of mining. Fracturing is estimated to grow upward from the number 4 and 5 coal seams to heights of 30.6 m and 35.5 m above the mined seams, respectively, while the distance from the top of the 4 seam to the bottom of the Changxing is approximately 29 m, making this situation a serious threat to safety.

Underlying the coal-bearing Lower Longtan Formation is the Permian age Maokou Formation. The Maokou contains relatively thick limestone beds. The Maokou limestone is approximately 3.7 m deeper than the 15 seam and approximately 17.5 m deeper than the 13 coal seam. The 15 seam floor has been measured to withstand only about 4.6 MPa of hydrostatic pressure, which indicates that the strata is too weak to prevent inrush of water from the Maokou aquifer up into the overlying coal seam(s).

In general, the 9 coal seam does not appear to have significant problems with water incursion. Trickling water and small continuous streams after a rain are seen in the mine roadways. Also, during construction of the roadways through the Yulong Mountain Section and the Changxing Formation limestones, there was slight evidence of water flow. Water found in the mine shaft comes from these overlying limestones, with flow rates usually less than 5.0 l/s. Water flow into the Linhua Coal Mine generally ranges from 2.8 l/s to 13.9 l/s, while discharge of water from the Linhua Mine averages 125.0 l/s. There were 29 water monitoring wells drilled in the mining area. For a complete listing of the well numbers and total depths, see **Appendix 2**.

Table 4: Hydrologic Formation Summary

Age	Formation	Thickness (m)	Geological and Hydrological Description
Triassic	Maocaopu Formation	432 ~ 495	The upper facies is dolomite, middle and lower facies consists of limestone interbedded with dolostone and brecciated limestone. Caves, underground river and water in the fractures within the caves. The flow rate of underground river is greater than 100L / S; the flow rate of a spring is normally 20 ~ 100L/S. The chemical content of water is HCO3-Ca.
	Yulong Section	372 ~ 504	**Yulong Section**: the upper facies is mudstone, the lower facies is limestone and argillaceous limestone (caves on top of limestone and underground rivers are in moderate growth, the flow rate of underground river is less than 100 L /S), the bottom is mudstone and mud limestone. **Changxing Formation** is limestone; **Longtan Formation** is sandstone, claystone, and mudstone and coal seams, with water in fractures. Most springs flow from the limestone at flow rate of 10 ~ 20L/S; the underground modulus of runoff is 1~61 ~ 6 L/S km^2; the water flow from borehole is 0.027 ~ 0.079L/S. Chemical content of water is HCO_3-Ca and the salinity 0.11 ~ 0.26 G/L.
Permian	Changxing Formation	40 ~ 74	
	Longtan Formation	44 ~ 110	
	Maokou Formation	181 ~ 258	**Limestone**: karst, caves, underground river development, fissure water. Flow rate of underground river is usually greater than 100 L/S; flow rate of a spring is 20 ~ 100 L/S, the underground modulus of runoff is 4 ~ 10 L/S.km^2; the water flow into borehole is 30 ~ 0.175L/S.M. Chemical content of water is HCO_3-Ca and salinity 0.07 ~ 0.39G/L.

Source: GGPBICG (2002)

4.7 Coal Mine Development in Jinsha County

Exploration

Between the years 1967 through 1999 there were four exploration campaigns in the area west of Jinsha. These exploration campaigns comprised of drilling, trenching and geological mapping to determining the existence and distribution of the mineable coal seams in the Linhua Mining area.

Coal Mining

Since 1966, coal mining in the Jinsha County area has consisted of extracting coal where the seams were exposed in outcrop. There have been 40 mines operating, all mining coal from seams 9, 4 and 15. The mine entries were mostly from slope entries (declines) with a few horizontal design entries, or adits. The mining depth generally ranged from 40 to 60 m with a maximum depth ranging from 150 to 200 m. The amount of coal produced annually ranged from 10,000 to 90,000 thousand metric tons, with blasting and pick and shovel as the prevalent methods of mining employed.

In 1999, construction began on the Linhua 1 Mine, originally designed as a 600,000 metric ton per year mine, primarily utilizing blasting and pick and shovel methods of mining. To date, the mine is still not operational.

Development operations began in the Linhua 2 Mine in 2001, originally designed as a 1.5 million metric ton per year mine with 51 years of reserves. During the period from 2001 through 2006 as the first longwall panel was being developed, 24 gas and rock outbursts occurred, 23 occurring in the 9 seam, and one while trying to open up the 5 seam (**Exhibits 2 and 3**); the last outburst episode in 2006 killed eight miners**.** Each outburst averaged 85 metric tons of coal and over 12,000 m^3 of methane. Following these outbursts, the mine was idled and eventually sold to Guizhou Nengfa Power Fuel Development Co. Ltd. In-mine drilling operations resumed in May 2009, and mining operations began in September of the same year. The mining company is currently in the later stages of testing prior to resuming commercial mining operations.

4.8 Coal Mine Methane

This Linhua Mining area has had a history of methane and CO_2 gas outbursts and mine methane explosions. The Linhua Mine has produced significant methane emissions. From 2001 to 2006, 24 methane-related outbursts have occurred during mining; 23 of these occurred in the 9 seam and one in the 5 seam. Methane gas has become a major obstacle for mine safety.

The Linhua Mine signed a contract with the Mine Safety Research Institute of Guizhou Province, titled *Research on Technology to Prevent Methane Outbursts in the Linhua Mine*, which included designing a methane drainage system.

Preliminary results of this work indicate that the reserves of coal mine methane are reported at 5.94 billion m^3, with recoverable reserves estimated at 3.03 billion cubic meters. Accordingly, the net volume of coal mine methane that can be drained should be 122 m^3/min, of which 85.4 m^3/min is of high negative pressure (70 percent) and 36.6 m^3/min of low negative pressure (30 percent). The concentration of methane in the drained gas under the high negative pressure system should be 40 percent in air and under the low negative pressure system should be 20 percent in air.

According to the Chongqing Branch of the Coal Science Research Institute, in May 2004, the 9 coal seam was characterized as an outburst seam, while 4 and 5 coal seams are temporarily considered seams without any danger of outbursts. However, according to the information provided by Linhua Mine management, an outburst had also occurred while developing the 5 seam for mining in December 2004.

4.9 Linhua Mine

The average gas content of the coal in the Linhua Mine is 16.38 cubic meters per metric ton. The maximum gas content observed in the 4 seam was 33.3 cubic meters per metric ton; in the 5 seam was 21.9 cubic meters per metric ton; in the 9 seam was 31.0 cubic meters per metric ton and in the 15 seam, 20.5 cubic meters per metric ton. No desorption testing was carried out for the 13 seam in the Linhua Mining area (**Table 5 and Table 6**).

Table 5: Gas content in District 1 and District 2 mining areas (+800 m elevation)

Coal Seam	District 1 Coal Mining Area		Total	District 2 Coal Mining Area		Total
	Gas Content (m^3/t)	Residual Gas Content (m^3/t)		Gas Content (m^3/t)	Residual Gas Content (m^3/t)	
4	22.63	4.14	26.77	15.38	4.07	19.45
5	11.55	4.32	15.87	15.60	4.82	20.42
9	20.22	4.37	24.59	17.00	4.50	21.50
13	16.40	3.54	19.94	16.40	3.76	20.16
15	16.40	2.54	18.94	16.40	2.54	18.94

Source: GCMDI (2002)

Table 6 lists the coal and methane resources for each mineable coal seam at the Linhua Mine, and the amount of methane that each seam can potentially produce (GCMDI, 2002 and MSRIGP, 2006).

Table 6: Gas (Methane) Resource by Coal Seam

Coal Seam	Coal Resource (10,000 tons)	Gas Content (m^3/t)		Potential Gas Produced (10,000 m^3)*	Gas Resource (10,000 m^3)		Range of Drainage Efficiency (%)[1]	
		2002*	2006**		2002*	2006**	2002*	2006**
4	3,360	22.63	33.3	54,013.6	76,036.8	111,888	71.0%	48.3%
5	2,799	11.55	21.9	30,955.8	32,328.5	61,298.1	95.8%	50.5%
9	8,684	20.22	31.0	152,039.3	175,590.5	269,204	86.6%	56.5%
13	1,347	16.40	20.5	10,811.9	22,090.8	27,613.5	48.9%	39.2%
15	1,217	16.40	20.5	14,380.0	19,958.8	24,948.5	72.0%	57.6%
Wall Rock	N/A	13.08	N/A	N/A	48,900.8	N/A	N/A	N/A
TOTAL	17,407	N/A	N/A	262,200.6	374,906.2	N/A	N/A	N/A

*Source: *GCMDI (2002), ** MSRIGP (2006)*

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[1] Drainage Efficiency is calculated using the Potential Gas Produced, as shown in Table 5-3-1 of the Linhua Mine Design Report (GCMDI, 2002), and dividing it by the total Gas Resource determined in each source report.

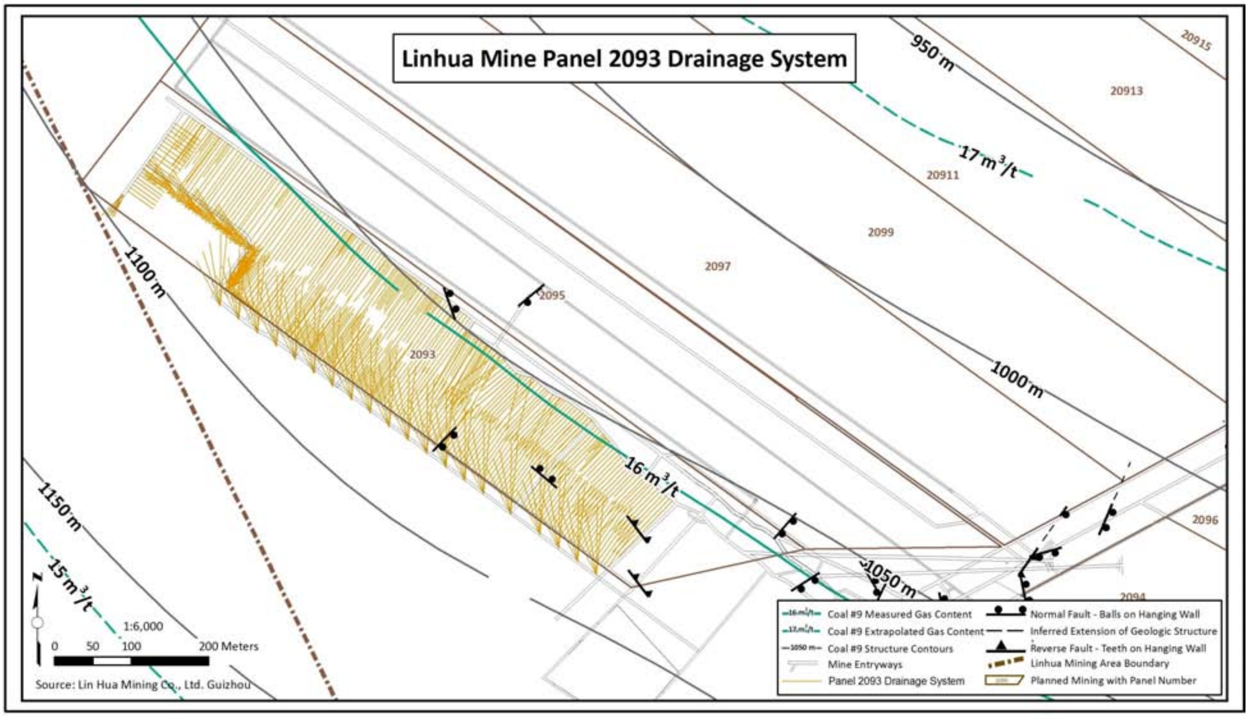
4.9.1 Mine Ventilation and Methane Emissions

The Linhua Mine uses a partitioned exhausting ventilation system with two fans. In 2006 the mine reported air volumes and methane concentrations at two fans during mining operations. The volume at the first fan measured 5,316 m^3/min at the inlet and 5,673 m^3/min in the air-return. The methane concentration at this fan was 0.4 - 0.58 percent and absolute methane emissions were 25.6-33.6 m^3/min. At the second fan the volume of air was measured at 540-740 m^3/min. Methane concentration was 0.46 - 0.76 percent in the return air and absolute methane emissions were 4.24 m^3/min. The mine design is based on relative emissions of 40 cubic meters per metric ton of coal mined.

Relative emissions are the total volume of methane liberated during mining activities, measured in cubic meters, divided by the tonnes of coal mined within a given period. The volume of methane liberated includes that which is emitted from the coal being mined as well as all the surrounding rock strata disturbed by mining. According to China Coal Mine Safety regulations, a coal mine is considered a high gas coal mine if the relative gas emission rate is greater than 10 cubic meters per metric ton or the absolute gas emission rate is 40 m^3/min. A coal mine is considered an outburst mine if outbursts have occurred or the in-seam gas pressure is greater than 0.74 MPa. According to these criteria, the Linhua Mine is a high gas outburst mine.

4.9.2 Methane Drainage

Methane drainage at the Linhua Mine consists of a combination of a series of cross-measure boreholes drilled from the return gate road, and cross-panel, in-seam boreholes also drilled from the gate roads. Both types are drilled in advance of mining (**Figure 9**). More than 400 cross-panel and 140 cross-measure boreholes have been drilled at the first panel planned for mining - panel 2093. The total length of boreholes drilled in panel 2093 is more than 22,000 m. The cross-measure boreholes are drilled in sets, with each set consisting of five boreholes drilled in a fan-pattern, and each borehole ranging in length from 65 to 100 m. Each set is drilled at an upward angle ranging from 50 degrees to 58 degrees into the overlying 4 and 5 seams, in order to drain these seams prior to mining of the 9 seam. The in-seam boreholes are drilled at five meter intervals for the entire length of the longwall panel in advance of mining as the gate roads are driven and at an angle approximately parallel to the dip of the seam, with borehole lengths ranging from 50 to 100 m. Once both types of boreholes are drilled, standpipe is inserted several meters into each borehole and grouted. A small number of boreholes (4 to 5) are then plumbed to a single manifold, which are spaced at regular intervals along the gate-roads. Each manifold is in turn connected to the underground gas gathering system, which is connected to the surface degasification pumping station where the pumps drain all in-mine boreholes. The gas quality of the drained gas varies significantly depending on the quality of the seal around the standpipe, the extent of fracturing around the borehole, which increases as the seam is degassed and dewatered, and the length of time that each borehole is in operation. Records of gas production are available for only the last two years of the drainage history of longwall panel 2093. These records show more than 4,000,000 m^3 of gas on a pure methane basis was drained.


Linhua Mine Panel 2093 Drainage System

Source: Lin Hua Mining Co., Ltd. Guizhou

Figure 9 : Drainage System of Linhua Mine Panel 2093

5.0 Proposed Modifications to Gas Drainage, Production and Recovery

Given the enormous amount of drilling and elapsed drainage time required to drain a longwall panel, Linhua Mine management sought an alternate approach to gas drainage. Through discussions with the Guizhou Coal Mine Safety Bureau and Nengfa and Linhua management, the Raven Ridge team decided that a surface to inseam drilling program should be investigated to determine if it is a technologically and economically viable alternative. The following sections detail the approach proposed by the Raven Ridge team.

5.1 Background

The Linhua Coal Mine is located in relative isolation and a significant distance separates it from the oilfield and drilling services located in the Sichuan basin in southwest China, and even further from the services available in the petroleum industry hubs of the northeast part of the country. However, the Guizhou Provincial Geologic Bureau owns and operates a modern and well-equipped directional drilling rig. This rig is currently being used in a program that requires drilling boreholes similar to the ones proposed in this feasibility study.

The object of the proposed drilling program is to pre-drain the exploitable coal seams: the 9 (2.5 m thick); and the overlying 5 and 4 coal seams (each 1.5 m thick). The inseam cross panel drilling that has been conducted in the 9 coal seam has been relatively successful in draining gas; however this approach is limited by the diameter of the boreholes that can be drilled, the spacing that can be achieved, and the length of time that the boreholes can be allowed to drain the coal. The proposed program envisions drilling across several planned longwall panels using directionally drilled boreholes comprised of "trunk" wells and directionally drilled branching extensions, or “sidetracks”. The sidetracks will be drilled at approximately 60 m spacing (or less) along the trunk. These sidetracks provide borehole penetration into the coal lying between the main trunk wells. The proposed plan incorporates eight clusters of wells comprising the trunks and sidetracks. These clusters of wells, or directionally drilled well array (DDWA), will be drilled for each of the three exploitable coal seams. Schematic plan views of the DDWAs can be seen by reviewing maps 3A, 3B, and 3C. **Figure 10** below is a block diagram depicting the proposed layout showing trunk wells and sidetracks. In order to conserve costs associated with construction of drilling pads and extensive road building, pads will be constructed in such a way as to offset the wellheads by constructing the pads progressively outward away from the toe of the wells, sequentially drilling the 4 seam, then the 5 seam and finally the 9 seam.

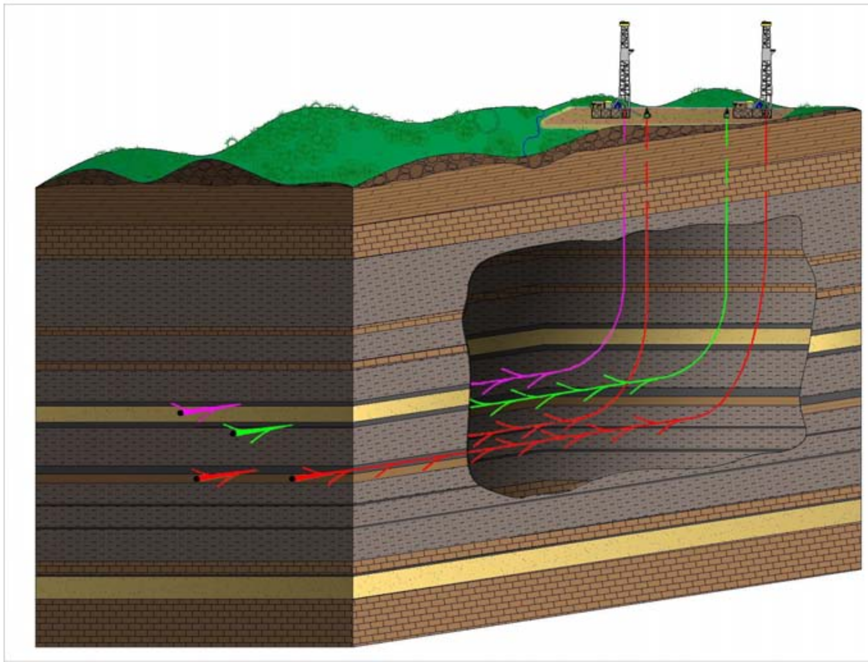


Figure 10 : Block Diagram Showing Conceptual Layout of Boreholes

The approximate true vertical depth (TVD) of the 9 seam is 450 m. The 5 seam is approximately 20 m above the 9 seam, and the 4 seam is approximately 30 m above the 9 seam, thus it is imperative to drill and place the wells carefully and in a nested fashion, as depicted in the figure. Available geologic data indicates that the coals are fairly flat and uncomplicated, although drilling will undoubtedly encounter unmapped faults and structural rolls in the coal. A proposed detailed drilling procedure can be found in **Appendix 3,** and **Appendix 4** contains a detailed longitudinal engineering well diagram number C located in proposed DDWA1.

5.2 Basis for Cost Inputs for Proposed Horizontal Drilling Program

The Raven Ridge team enlisted the help of a professional drilling engineer with 20 years experience of planning and conducting drilling programs in China, to develop a drilling program that suits the conditions found at Linhua. His analysis of the drilling data that was available for the Linhua Mining area led him to develop a drilling program and a detailed Authorization For Expenditure (AFE) produced as a live spreadsheet that can be altered to accommodate changes in drilling plans. AFEs are used to list the equipment and services that are needed to successfully perform a planned drilling program and are essential for planning a drilling campaign and developing a credible budget. A detailed AFE (**Appendix 3**) and a graphic that depicts days required for drilling versus depth are provided as a part of the proposed program. These tools were used to develop a comprehensive drilling model and produce cost estimates for input into the Raven Ridge economic model. These costs are listed as input assumptions in **Section 9.2 Table 12.** These costs are considered to be indicative and intended to be used for scoping purposes and economic model inputs to test potential options.

5.2.1 Logistics and Costing Assumptions

The following parameters are the basis for laying out a drilling program and developing reasonable costs for input into the economic models.

- Costs are project based. This means an on-going, minimum 1 rig program. Costs are not based on actual historical drilling performance because the recommended program has not been attempted in China. For this reason, a substantial contingency of 20% (approximately $400 thousand USD) is included in the well costs due to uncertainty associated with implementing a project of this scope for the first time. This contingency might be reduced, based on the actual availability of ancillary equipment and services. A net savings of 10% is assumed after the first DDWA is drilled because it has been shown in industry studies that directional drilling programs can be optimized as an understanding of the efficacy of certain drilling procedures are developed and appropriate adaptations are made to conform the geological and drilling conditions.
- DDWAs will be drilled from multi-well pads constructed parallel to the panels so that boreholes can be drilled across the planned longwall panels. For this project, as many as 11 wells and as few as one well will be drilled from each pad. There will basically be no difference in the costs between wells drilled in the 9 seam and wells drilled in the 4 and 5 seams as the depth is only approximately 15-30 m shallower. A top-drive rig is required to drill this well, which is available from the Guizhou Provincial Geologic Bureau. Its 2,000 m or 2,500 m depth capacity will be adequate for drilling this project. In North America, advanced, "next generation" rigs are being used to facilitate moving the rig from one borehole to the next while drilling a directional well array. Typically these rigs can be skidded laterally, without completely down-rigging the mast. Unfortunately these rigs are not yet available in China. Air-mist drilling might be used for this project; nevertheless, If air-mist can be substituted for conventional fluids, drilling times should be reduced significantly. Unfortunately, air-mist drilling is not common in China and significant upfront costs would be incurred as equipment would have to be located and mobilization; charges are likely to be high. This might offset any savings in drilling time until the rig crew gains experience using air-mist. If air-mist were to be used, electromagnetic measurement while drilling (MWD)/logging while drilling (LWD) would be required, and this capability does not exist currently in China and would have to be imported. Daily electromagnetic MWD/LWD costs

would also increase due to the logistics of mobilization. For these reasons, costs are based on using conventional water-based fluids.

- Assuming that conventional western MWD/LWD (non-electromagnetic) equipment will be used, the closest support for this service is Chongqing or Chengdu. However, the Geologic Bureau has this equipment available, but if additional services are needed, equipment and personnel located in Shekou and Tianjin (about five days away by truck) would have to be mobilized, increasing MWD/LWD costs.
- Western manufactured drill bits should be used, as they have been shown to provide consistent performance and can drill the entire hole without costly replacement.
- Days drilling versus depth curves are conservative, but surface sediments appear to have some significant drilling problems. Drilling time in the horizontal portion of the hole is assumed to be slower due to the need to keep the borehole in the coal while drilling, which sometimes can be problematic..
- Chinese drilling crews generally have difficulty with concurrent operations and operate at a much lower speed than Western crews. This particularly affects a shallow well where there are more non-drilling procedures than rotating time. This significantly affects days versus depth and total well costs. In order to provide training, additional costs have been provided for use of Western drilling supervision for the first DDWA.
- Terrain in the area is rugged with 200 m of relief from ridges to valleys. Locations for drilling pads will be located on the ridges so road construction is an important element of overall costs. It is important to optimize the use of the roads by building pads so that one road can serve multiple sites.

Drilling pad location construction costs and rig mobilization are split amongst the wells as appropriate. Purchase of land for drilling locations and pipelines in China is fairly expensive; costs for the Jinsha are been used. Any completion would be open hole, natural (unstimulated completion), with the possibility of installing a fiberglass liner, and utilizing artificial lift.

5.3 Proposed Drilling Program Implementation Issues

Maximum drainage from horizontal wells can normally be achieved by drilling perpendicular to the main cleat system. Mining plans will tend to dictate well position rather than the orientation of the cleat system. This can lead to less than optimal well placement for drainage and can lead to drilling additional wells.

Ideally, multi-well pads will be used to drill both east and west into different panels. Horizontals may not be able to cover the full length of the panels due to shallow depths. Since the coal contained in the present mine plan is relatively shallow (450 m true vertical depth), drilling pads should be located on high spots to give the maximum vertical distance for the borehole to be guided into a horizontal orientation.

In addition, there appears to be the potential for numerous drilling fluid circulation problems in the shallow limestone intervals. The Yulong Mt. section has abundant karstic structures that may cause lost circulation. These DDWAs will not be easy wells to drill to total length or keep positioned in the coal, so detailed planning is crucial and experienced personnel must be selected to provide expertise and support for directional drilling program. This all will increase probability of success.

Coals that are encountered while drilling the high angle portion of the hole can become unstable and could become problematic if they slough into the hole as drilling progresses. As a precaution, casing is planned to cover the curve prior to drilling the production hole. Damage to coal that might adversely affect gas production (not mining) from drilling fluids can be a problem. In order to avoid these problems, water will be used as the primary constituent of the drilling fluid accompanied by pumping periodic viscous fluid sweeps to clean and condition the hole. Offsetting borehole or well data needs to be examined for problems relating to lost circulation, etc., in the shallower sections.

The first logical step to ensuring productivity of the boreholes is to plan for a natural, open-hole, completion. However it is unlikely that this will be possible without developing a non-damaging drilling process that meets the challenges of the Linhua Mining area. Industry experience informs that mechanical stability of the borehole and appropriate selection of drilling fluids through the production zone is key to success. From experience it is known that drilling with electromagnetic MWD/LWD underbalanced with water/mist would be ideal, but it is unknown whether the coals have enough mechanical stability to withstand this approach; moreover, at this point in time, this equipment is not currently available in China, but may be available from other areas located in Australasia.

6.0 Coal Market

6.1 Demand for Coal from Linhua Mine

The Linhua Coal Mine, situated seven km southwest of the Jinsha County seat, is designed to supply the Qianbei (4 x 300 MW units) and Jinsha (4 x 135 MW units) power plants owned by the Guizhou Jinyuan Group Subsidiary of China Power Investment Company (Linhua's parent company), which are located adjacent to each other on the outskirts of the county seat. A portion of the output of these plants is sold into the Guizhou Provincial grid, and a portion is transmitted through China Southern Power Grid 500 kilovolt transmissions lines for sale into coastal Guangdong Province under the "West to East" electricity program sponsored by the central government. As **Table 7** shows, electricity output from these plants has been quite robust, both in absolute terms and in comparison to other Jinyuan plants.

The 2007 *capacity utilization factor* of 71.8 percent places Qianbei-Jinsha in the top ranks of large Chinese coal-fired power plants, which as a whole averaged only 58.8 percent in 2006 (the latest year for which statistics are publicly available). Even in 2008, when output dropped 15.6 percent due to the national economic slowdown, Qianbei-Jinsha capacity utilization exceeded the national average, and production rebounded in 2009 together with the economy as a whole.

Table 7: Guizhou Coal-Fired Power Plant Output, 2007-2008

Plant	Capacity (MW)	Output (million MWH)			Capacity Utilization (equivalent hours at full load, percent)		
		2007	2008	2009	2007	2008	2009
Jinyuan Group Total (majority owned)	6280	36.8	28.8	39.1	5860 (66.9%)	4586 (52.4%)	6226 (71.0%)
Qianbei-Jinsha	1740	10.9	9.2	10.5 (est.)	6264 (71.8%)	5287 (60.4%)	NA
Guizhou Province, total	NA	82.5	81.1	NA			

Source: China Power Investment Company, Guizhou Jinyuan Group

The Guangdong market is in effect an insurance policy for Qianbei and other Guizhou "West to East" electricity plants in the event of future unforeseen shocks to the Guizhou local market. As noted in the Electricity section of this report, the Chinese Southern Grid authorities increased the allotment of electricity from "West to East" plants such as Qianbei to Guangdong Province when the local Guizhou market contracted in second-half 2008.

The Jinyuan group has announced its intention to close the 135 MW units at the Jinsha plant in line with national policy to phase out small inefficient power generators. As the plant will be replaced by two higher efficiency 600 MW generating units, this move will have no negative impact on the power plant's demand for coal (CPI Jinyuan Group 2010). The Qianbei – Jinsha plant consumed 5.5 million metric tons of coal in 2007, and 4.5 million metric tons in 2008, when power generation declined temporarily due to market conditions. Jinyuan company officials indicate that it procures all but 10 percent under short-term contracts from small mines owned either by sub-provincial governments or private interests. The dependability of these mines, as well the quality of their coal is less than optimal; much of the coal received by Qianbei-Jinsha and other Jinyuan plants is 4000-4500 kcal/kg, indicating ash levels of over 25 percent. On occasion, production at the power plants has been constrained by coal shortages.

The Linhua Mine is designed precisely to provide higher quality, more reliable supply; Linhua's entire output up to its 1.5 million ton design capacity will immediately and permanently replace coal from the power plants' current suppliers. In short, based on the characteristics of both the coal and the electric power markets in Guizhou, there is no realistic risk of a downturn in demand for the coal output of the Linhua Mine.

7.0 Gas Market

7.1 Recent Trends in China’s Natural Gas Market

7.1.1 National Demand

The Chinese central government’s decision at the turn of the twenty-first century to develop long-distance pipelines to transmit gas from rich fields in remote areas of Northwest and North-Central China to the eastern heartland and to introduce imported LNG into the southern coastal areas has sparked an historic boom in China’s natural gas consumption which was unaffected by the economic turbulence of 2008-2009 and appears poised to continue for the foreseeable future. Natural gas usage increased at an average rate of almost 16 percent from 23.5 billion cubic meters in 2000 to approximately 88 billion in 2009 (CESY 2008 Table 5-12, NBSC 2010 Table 2, China Daily July 5 2010).

Even this impressive growth only brought the natural gas proportion of China’s primary energy supply to 4-5 percent, compared to 23-24 percent in Europe and the USA. According to semi-official projections by the China National Development and Reform Commission’s (NDRC) Energy Research Institute, demand for natural gas could rise by 20 billion cubic meters annually to a total of 300 billion by 2020 (People’s Daily March 2010).

Demand for natural gas is currently driven primarily by:

- Residential and commercial use: The substitution of clean, convenient natural gas for coal gas, LPG, or coal briquettes as a household fuel has proven extremely popular as residential natural gas distribution networks have been constructed for the first time in the major eastern population centers. Nonetheless, only about one in six residents of the country’s constantly expanding cities and townships enjoyed access to natural gas as of 2007 (CESY 2008, Table 3-13).
- Industrial use: Where available, natural gas fuel is being systematically substituted for liquid hydrocarbons or coal gas in petrochemical factories, glass plants, steel mills, etc.

Secondary end-use sectors include:

- Electric power generation: At central government direction, dozens of state-of-the-art combined cycle power plants were constructed between 2000 and 2010 to provide guaranteed offtakers for the new long-distance pipelines and LNG terminals. The pace of construction, however, will likely slow down in coming years now that the scale of demand from the residential sector has become apparent.

- Automotive: The low price of natural gas relative to gasoline in China has stimulated the development of a compressed natural gas (CNG) distribution infrastructure in a number of Chinese cities. Under central government prodding, however, local governments are taking administrative measures to ensure that automotive consumption does not crowd out usages such as household fuel that are considered higher priority.

7.1.2 Domestic Conventional Natural Gas Production and Transmission

China enjoys only modest domestic endowments of conventional natural gas, and the great majority of known deposits are located distant from population and industrial centers. The consumption growth over the past 10 years has depended primarily on exploitation of previously virgin fields in the remote northwestern Tarimince and Ordos basins. These fields, together with a smaller field in the Qaidam Basin of Qinghai Province and the existing fields in Sichuan and Chongqing, accounted for over 90 percent of China's reported 85.1 billion cubic meter conventional natural gas output in 2009.

The China National Petroleum and Gas Corporation, the largest of the state-owned upstream oil and gas producers (also known as CNPC or PetroChina), has over the past 10 years completed interconnected pipelines from Xinjiang to Shanghai (3900 km long, 17 billion cubic meters capacity throughput) and from northern Shaanxi Province to Beijing (900 km length, 15.5 billion cubic meters capacity throughput) to bring gas from Tarim and Ordos basins respectively to major load centers in the east. Additional long-distance pipelines constructed both by CNPC and by Sinopec, the number two upstream producer, transmit gas from Sichuan/Chongqing along the Yangzi River valley to Shanghai and provinces in between.

Through mid-2010, however, entire provinces in the south, such as the economic powerhouse of Guangdong, as well as Fujian, Guangxi, Yunnan and Guizhou, have remained unconnected to the rudimentary national pipeline grid. Even in provinces with access to long-distance pipelines, the intra-provincial distribution pipelines constructed by local governments and private interests extend neither to many medium and small-sized cities nor to all neighborhoods in the larger cities. This incomplete coverage of the pipeline network has created market openings for over a dozen small LNG plants constructed over the last five years, which ship their product by tanker truck to cities in the east and the south of China which have no other access to natural gas. Gas sources for these plants include small onshore or offshore gasfields, coalbed methane (CBM), and in some cases pipeline gas resold by local government companies attracted by the high prices that can be commanded in areas unconnected to the pipeline grid.

7.1.3 Coalbed and Coal Mine Methane

CBM and CMM are gradually emerging as a complementary natural gas resource. Approximately one billion cubic meters of over 90% methane concentration CBM were recovered nationally in 2009 from surface wells drilled by either by coal mines or other concession holders, almost entirely from the Qinshui Basin near Jincheng in Southeast Shanxi Province (**Table 8**). Only about half of this quantity was utilized, but the percentage will increase considerably in the near future upon completion by the CNPC of a major processing center hooked up to the Xinjiang-Shanghai trunk pipeline. Three of the small-scale LNG plants mentioned in Section 7.1.2.1 above will process over 600 million cubic meters of CBM from Jincheng Coal Mining Group and other operators when fully operational (NDRC 2009, World Bank 2009, China LNGNet 2009).

The vast majority of China's liberated CMM is emitted to the atmosphere as low-concentration ventilation air methane (VAM). But recovery of between 10 to 50 percent concentration CMM by drainage in association with mining doubled to 6.45 billion cubic meters (100 percent methane basis, same with all numbers below) between 2006 and 2009, with usage rising to almost two billion cubic meters.

Table 8: CBM/CMM Recovery and Utilization in China (billion m^3)

	2005	**2006**	**2007**	**2008**	**2009**
CMM from Coal Mines (excluding VAM)					
-- Recovery	2,300	3,200	4,700	5,300	6,450
-- Utilization	600	1,100	1,400	1,600	1,930
CBM from Surface Wells					
-- Recovery				490	1,010
-- Utilization				370	580
TOTAL CMM and CBM					
-- Recovery				5,790	7,460
-- Utilization				1,970	2,420

Source: NDRC 2010.2

Most CMM is consumed in the immediate coal mining areas either in small distributed power stations or as household, commercial or industrial fuel, with a small number of mines with high recovery volumes having developed central station power plants or industrial facilities to burn CMM.

Cryogenic technologies to purify and liquefy medium-methane content CMM that are already proven outside of China, offer the potential to integrate CMM into the national natural gas market. Chinese domestic companies are also developing the technology. A 100 million cubic meter plant is in the advanced planning phase at the Songzao Coal and Electricity Company in Chongqing Municipality.

7.1.4 LNG and Pipeline Gas Import Markets

The central government has recognized since the turn of the century that imports would be a necessary component of the natural gas supply when it committed to building massive LNG import terminals along the southern coast. The achievement of the very ambitious gas supply targets over the next 10 years are likely to depend at least as much on imports as on increased domestic production.

Imports of LNG into the first three coastal terminals in Guangdong, Fujian and Shanghai reached eight billion cubic meters equivalent in 2009, close to ten percent of total national consumption (China Daily July 5, 2010). An additional 15.9 million metric tons (21.2 billion cubic meters equivalent) of large import LNG receiving capacity have been permitted by NDRC and are under construction by the three state-owned oil companies in other coastal locations. The companies have moved steadily to lock up long-term supply contracts with major producers in Australia, Indonesia, Malaysia, and Qatar.

In addition to importing LNG, the Chinese government is introducing imported pipeline natural gas through the following transactions:

- Long-term contract by CNPC to purchase 30 billion m^3 of gas per year from Turkmenistan, coupled with construction of nearly 8,000 km of pipelines to transmit the gas to the eastern and southern coastal provinces, including Guangdong. This pipeline is coming onstream in stages during the 2010-2011 period.
- Agreements with the government of Burma and a Daewoo offshore gas production consortium for CNPC to purchase 12 billion cubic meters per year from two Burmese offshore blocks and to construct approximately 2,800 km of pipelines through Burma to the southwestern provinces of Yunnan, Guizhou, and Guangxi. Work on the pipeline is reported to have begun in 2010, and is projected to be completed in 2013.

7.2 Guizhou Regional Market for Natural Gas

As of early 2010, Guizhou is a virtually untapped gas market. The province has no known conventional oil or natural gas deposits. Despite Guizhou’s proximity to the gasfields in neighboring Sichuan Province, the central government has chosen to allocate the output of these fields to more populated, developed provinces. As a result, no pipelines link Guizhou to the Sichuan with the exception of a short, dedicated pipeline across the Yangzi River to an ammonia/urea fertilizer complex in the city of Chishui on the Sichuan border. This single facility accounts for the vast majority of the reported 500 million m^3 of natural gas reported to have been consumed in Guizhou in 2007 (CESY 2008 Table 5-22, Cnlist 2010).

Token amounts (perhaps 10-20 million cubic meters per year) of LNG from several small Chinese plants have been trucked into Guizhou since 2006 to serve only a small number of residential customers and automotive CNG users in various cities. With the commissioning of the Dazhou small-scale LNG plant in Sichuan in 2010, these shipments may increase on the order of 100 million m^3 per year.

CMM is a major potential source of non-traditional natural gas for Guizhou. But at present, the vast majority of liberated CMM is lost as VAM. Of the 684 million m^3 recovered in 2009 province-wide, all but 84 million were reported to be vented to the atmosphere (Xinhuanet Economic News 2010). No CMM is known to have been used outside of the immediate mining areas.

7.3 China's Natural Gas Prices

The combination of booming consumption and growing dependence on imports of both pipeline gas and LNG are putting strong pressure on China's historically tightly controlled natural gas pricing system. Market forces are already driving retail prices higher in many parts of the country, and it appears inevitable that over time, both upstream and retail prices will be increasingly more aligned with those outside China.

7.3.1 Upstream, Pipeline, and LNG Import Pricing

The Chinese central government, through the NDRC, still controls well-head and pipeline prices from the major gasfields operated by CNPC and Sinopec. Traditionally, the government has striven to ensure cost recovery and modest returns to producers while containing costs to consumers as much as possible. It now wishes to change towards more market-driven pricing, but is doing so only gradually to avoid shock.

After the latest increases in May of 2010, wellhead prices fell in the range of 0.8 to 1.5 yuan per cubic meter (approximately $3.2 - $6.1 per mmbtu), depending on the field and the end-use, with residential consumers and fertilizer plants enjoying the most favorable prices. When pipeline costs are added in, the city-gate prices to the major eastern cities range from approximately 1.5 – 1.8 yuan per cubic meter (NDRC 2010, NDRC 2003).

As of 2010, the NDRC has chosen not to regulate the prices charged by the small onshore LNG, such as those owned by coalbed methane producers in southeastern Shanxi Province (**Sections 7.1.2** and **7.1.3** above). These producers are free to sell to local distribution companies in underserved areas and in the southern provinces for which the price has been driven by imported LNG.

City gate prices on the Southeast coast for LNG imported under the first long-term contracts in the early 2000s were approximately 1.65 to -20 yuan per cubic meter ($6.75 – 8.15/mmbtu) (Guangdong News Net 2007, Fujian Contract 2007). Landed prices for LNG imported under more recent contracts from Qatar and other suppliers are as high as 3 yuan per cubic meter ($12 /mmbtu), which would raise city-gate costs to at least 3.5 yuan per cubic meter ($14/mmbtu)(Trading Markets 2009) .

Gas imported through the international pipelines will have a comparable price impact in broad areas across China. Reports indicate that the Chinese border price for gas imported through the newly commissioned pipeline from Turkmenistan will be 2.2 yuan per cubic meter based on $68 per barrel oil, and that average city-gate delivery costs in the heartland will be in the vicinity of 3 – 3.2 yuan per cubic meter (Chingate 2009). This implies a price of at least 3.5 yuan per cubic meter ($14 per mmbtu) city-gate in Guangdong and Guangxi Provinces in the south.

Delivered prices for Burma offshore gas transported to the southwestern provinces of Yunnan, Guizhou, and Guangxi, while higher than domestic gas prices, are not likely to be as high those for Central Asian gas due to shorter transport distance. CNPC will reportedly acquire the offshore gas from the Daewoo Production Consortium at a benchmark price of $7.73 per mmbtu (1.9 yuan per m^3), a figure that excludes all pipeline costs in both Burma and China (BusinessWorld 2010). The CNPC is reported to have promised that retail prices in the Yunnan provincial capital of Kunming “should not exceed 3.5 yuan” per cubic meter (Kunming News 2009). This implies a city-gate price of approximately 2.5 to 3 yuan per cubic meter in Kunming based on typical mark-ups by distribution companies (**Section 7.3.2** below), and perhaps 2.8 – 3.0 yuan in Guizhou.

City gate prices to medium sized cities in Guangdong and other eastern which depend on LNG imported either on the international spot market or produced by the domestic small scale plants have been highest of all at as much as 3.5-4 yuan per cubic meter (Zhanjiang 2009). The price for the limited volumes of domestic small-plant LNG price to Guizhou, by contrast, appears to have averaged approximately 2.5 yuan per cubic meter (Chemnet 2009, private sources).

7.3.2 Retail Prices

Local distribution companies offer a wide variety of ownership, ranging from offshoots of the upstream majors to local government companies to private companies of both national and local scope. Provincial and municipal governments, rather than the central government, regulate retail prices charged by the distribution companies.

The provincially owned Guizhou Gas Group is the predominant distribution company both for coal gas and for the limited volumes of pipeline natural gas currently distributed in the major cities of Guizhou such as Guiyang, Zunyi County. The prices it can charge its customers for both coal gas and natural gas are fixed by The Guizhou Provincial Price Bureau.

Due to their political sensitivity, prices to residential consumers are lower than costs in many locations. Nonetheless almost all distribution companies throughout the country operate with at least a small profit due to the willingness of the local regulators to allow significantly higher charges to industrial and commercial customers in order to ensure full cost recovery.

The difference between the wholesale prices paid by the distribution companies and the prices that they charge to residential customers typically fall in the 05.-1.0 yuan per cubic meter range. The comparable mark-ups to industrial users can be as high as one to two yuan. Generally speaking, wholesale price increases are passed on to final consumers, sometimes with a time lag.

In view of the varying costs of the upstream gas source, retail prices vary widely by region. The range for prices to residential users near year-end 2010 is approximately as follows:

- 1 - 2 yuan per cubic meter in cities such as Chongqing, located near major gasfields;
- 2.5 - 3.0 yuan per cubic meter in heartland cities served by long-distance domestic pipelines;
- 3.5 - 4.0 yuan per cubic meter in cities dependent on LNG imported under long-term contracts;
- 4.5 – 6.0 yuan per cubic meter in certain cities in Guangdong and eastern provinces dependent on spot LNG purchases or LNG from the small domestic plants.

Natural gas prices to residential and commercial users in the city of Kaili, Guizhou at a reported 3.18 yuan per cubic meter and 3.49 yuan per cubic meter respectively, fall roughly in the middle of this spectrum (Chemnet 2009). After a round of increases in 2010, Guiyang pipeline coal gas distribution prices reached rough equivalence with the Kaili natural gas distribution prices on a heating value basis (Guizhou Price Bureau 2010.1, 2010.2). These prices will inevitably shape Guizhou price regulatory authority expectations for price of natural gas from new sources.

7.4 Future Demand and New Supply in Guizhou Province

Significant volumes of natural gas will enter Guizhou starting from approximately 2013 when the CNPC pipeline from Burma is scheduled to be completed. Guizhou political leaders have made a preliminarily commitment to purchase up to three billion cubic meters of the pipeline's 12 billion annual flow by 2020 (Guizhou Capital City Newspaper 2008). Initial volumes will undoubtedly be lower; between one and two billion cubic meters is a reasonable estimate.

The trunk pipeline will enter Guizhou from Yunnan Province to the west and run a reported 300 km eastward through Anshun Municipality, Guiyang, Duyun Municipality, Dushan and Libo Counties and onward to Guangxi Province. The Guizhou Gas Group (**Section 7.3.2**) has developed preliminary plans for a network of branch pipelines from the trunk line, including a line that would run north from Guiyang towards the city of Zunyi.

A proposed 15 billion cubic meter per year pipeline from Ningxia Province in the north to the Guizhou capital city of Guiyang would open up Guizhou to significant quantities of gas from the northwest. The central government is unlikely to grant the CNPC final permission to proceed with the line until it has secured a gas source, most likely from Turkmenistan through the so-called third "West to East" pipeline, currently in the planning and negotiation phase. Officials in Guizhou have expressed the hope that this pipeline could be completed at approximately the same time as the pipeline from Burma in 2013, but the firming up of the gas source could delay the project for several years (Sichuan News 2010, International Gasnet 2010).

Total demand is difficult to determine in the absence of supply, which itself tends to stimulate latent demand. Based on current estimated usages in Guizhou natural gas substitution for other fuels would create demand in the vicinity of 1.5 billion cubic meters, as follows:

- About 1 billion cubic meters of natural gas to replace the estimated 2 billion cubic meters per year of coal gas currently burned as fuel in the province.
- 470 million cubic meters of natural gas to replace the estimated 400,000 tons per year of fuel oil currently consumed in the province.
- 175 million cubic meters of natural gas to replace the estimated 125,000 metric tons per year of liquefied petroleum gas (LPG) such as propane and butane currently consumed in the province (CESC 2008 Tables 3-14, 3-15, 5-18, GSB 2010 Table 5).

Residential consumption, which has been a major driver for natural gas development in many other locations, is likely to play a somewhat more modest role in Guizhou, with its small population and low urbanization level. If all of Guizhou's reported 11.4 million urban residents were to consume natural gas at the approximately 70 cubic meters per year per capita level of residential customers in Chonqqing, total residential demand would be about 800 million m^3. Consumption at commercial facilities such as stores and restaurants would amount to an additional 100 million m^3, judging by the ratio of commercial to residential consumption in other parts of China.

Rapid development of industrial and other non-residential markets will therefore be necessary to absorb the considerable volume of new supply of natural gas likely to enter Guizhou starting from 2013. The significant number of heavy industry factories in Guizhou, which, in addition to the ones that the CNPC is reported to be working with, include aircraft and other military equipment facilities, steel mills, cement plants, and phosphorous processing plants offer particularly promising potential markets.

Guizhou Gas Group will be partially responsible for the development of these markets. The CNPC itself, however, appears to be taking direct responsibility for the marketing of some of its Burmese gas in Guizhou.

Reports indicate that the CNPC plans to:

- Set up a network of 12 major CNG production sites and 120 to 150 CNG automotive filling stations throughout the province;
- Construct four combined cycle power generation stations to be used for peaking power;
- Develop residential distribution networks in a number of localities;
- Create natural gas industrial parks, and sell directly to existing major industrial energy users such as the Guizhou Aluminum Factory and the Maotai Spirits Factory (Huaxia, 2010).

In sum, the size of the market in Guizhou is likely to exceed initial expectations once natural gas is actually present and the convenience and environmental benefits of natural gas are experienced for the first time. The speed at which this transformation occurs, however, is hard to predict, and there remains some possibility that the supply of new pipeline gas may temporarily exceed in-province demand.

7.5 Market for Gas Produced by Proposed Project

7.5.1 Pipeline Injection

The planned in-Province pipeline network that will be constructed to distribute Burmese gas does not extend to area of the Linhua Mine. The Guizhou Gas Company has contemplated a pipeline network that would extend to Renhuai County, approximately 30 km east of Linhua, but has not indicated how quickly this network will be constructed.

7.5.2 Sale of LNG to Local Guizhou Distribution Company

Prior to the anticipated arrival of gas from Burma in 2013, Guizhou should be able to absorb LNG produced by Linhua. Even if supply temporarily outstrips demand for the first few years after the arrival of pipeline gas, local distribution companies under the Guizhou Gas Group – and possibly even those under the CNPC - will have an interest to retain a reliable local supplier like Linhua in order to:

- Hedge against the risks of supply interruption from Burma
- Supply the parts of the province that are not initially covered by the new pipeline network

The estimated city-gate Guizhou price of 2.8 to 3.0 yuan per meter for Burmese gas will establish the baseline for the ex-LNG plant price that Linhua would be able to charge a distribution company. Given the reported 0.1 yuan per 100 km tanker truck transport cost for LNG produced by other CBM producers in China and the approximately 300 km distance from Linhua to Guiyang, 2.5 yuan per cubic meter is represents a reasonable estimate for the price that Linhua could expect to receive.

7.5.3 Sale of LNG into More Distant Markets

Locations outside of Guizhou may offer attractive markets for Linhua. Shortages of gas in larger, more developed provinces such as Guangdong, or even Guangxi are likely to remain acute even as supply of imported gas pipeline gas and LNG increases. The unserved or underserved medium-sized cities in these provinces offer particular possibilities.

Wholesale prices to Guangdong/Guangxi for imported LNG or pipeline gas from Central Asia and the Northwest will likely be 3.5-4.0 yuan rather than 3.0 yuan as in Guizhou (Section 7.2.1 above). This would compensate for the higher transport costs to the markets in Guangdong and Guangxi, located 1,000 to 1,500 km distance from Linhua. Private natural gas distribution companies with franchises in these areas have indicated informally those prices as high as 3.0 yuan per cubic meter could be considered for LNG produced in the Chongqing – Guizhou area.

8.0 Electricity Market

8.1 Changes in National Patterns of Economic and Electricity Consumption Growth

During the sustained boom fueled by exports and domestic capital investment between 2000 and 2007 (Figure 12), China's electricity consumption grew by an average of 13.5 percent, a full 30 percent higher than overall economic growth (CESY 2008 Table 1-1). The surge in production of iron and steel (21 growth), non-ferrous (17 percent growth) and other energy intensive raw materials used in capital investment projects was the major reason for this differential. Led by these commodities, industry's share rose from 71.7 percent of total electricity consumption in 2000 to 75.3 percent in 2007 (CESY 2008 Table 5-13).

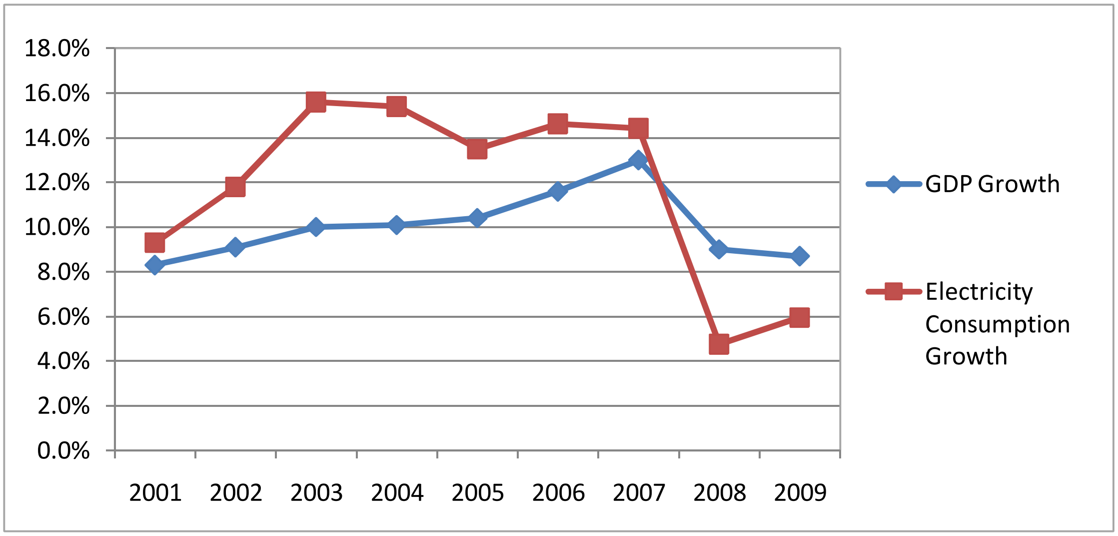


Figure 11: China: Economic Growth and Electricity Consumption Growth, 2000-2009. Sources: CESY 2008 Tables 1-1 and 5-13, NBSC 2009, NBSC 2010, NDRC 2010.1

Patterns of growth changed abruptly under the impact of the global economic slowdown in the second half of 2008, carrying through into the first half of 2009 (**Figure 11**). Year-on-year economic growth decelerated to a low of 6.1 percent in the first quarter of 2009. As new investment spending and factory orders for steel and the other electricity intensive commodities dried up, electricity consumption declined in absolute terms during both fourth quarter 2008 and first quarter 2009.

The government's four trillion yuan (approximately $600 billion) infrastructure investment stimulus program gradually revived both the economy as a whole and electricity consumption starting from the second half of 2009. Just as electricity consumption had fallen more drastically than the economy as a whole during the bad months, it rose more rapidly after the stimulus kicked in as orders for steel and other energy-intensive products rebounded (**Figure 12**).

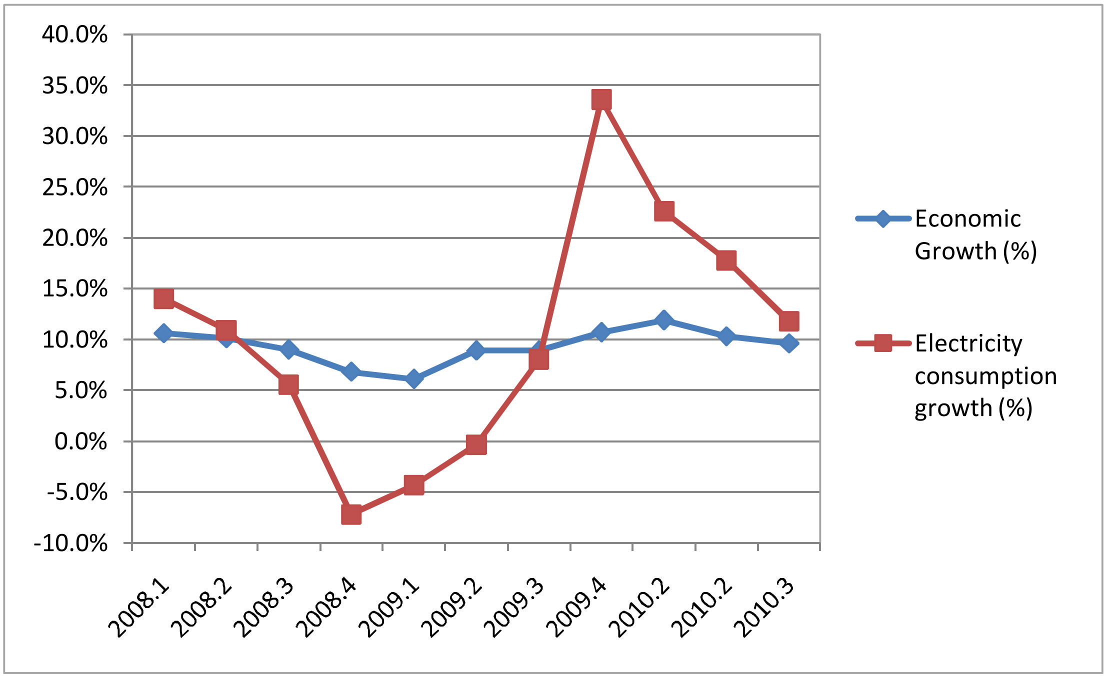


Figure 12: China: Year on Year Quarterly Economic and Electricity Consumption Growth, 2008 – 2010. Sources: NBSC 2009 and 2010, NBSC Monthly 2008-2010, NBSC Quarterly 2010

The two curves even out considerably, however, when compounded two-year growth is calculated for the period of recovery starting from third quarter 2009 (**Figure 13**). For the first three quarters of 2010, in fact, average two-year compounded growth for the economy as whole and for electricity were virtually identical at 9.1 and 8.83 percent, respectively.

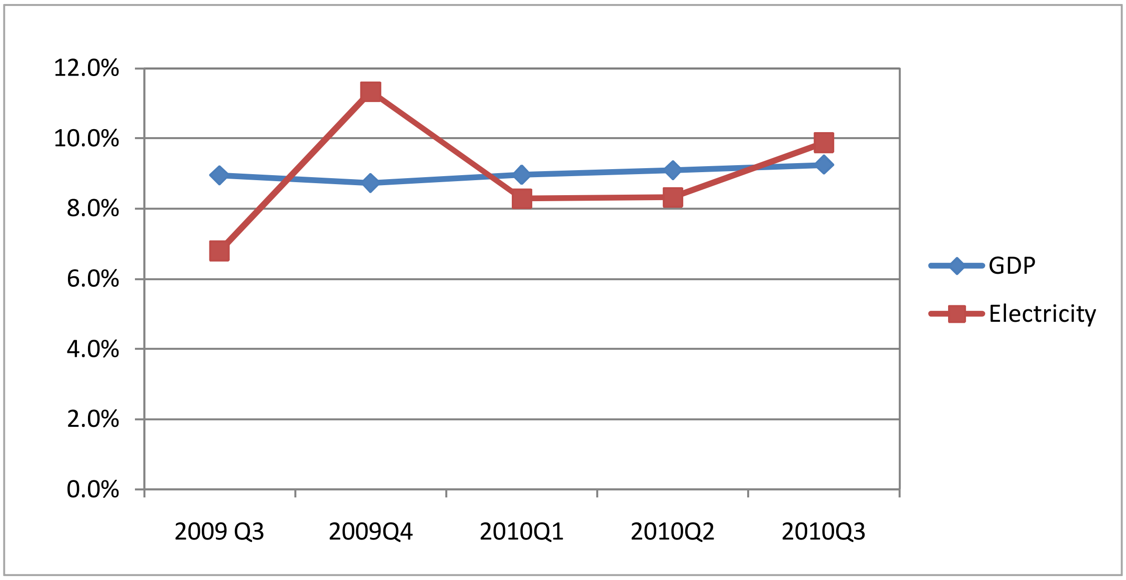


Figure 13: China: Year on Year Quarterly Economic and Electricity Consumption Growth, 2008 – 2010. Sources: NBSC 2009 and 2010, NBSC Monthly 2008-2010, NBSC Quarterly 2010

As the stimulus program winds down, the trends reflected in these two year compounded numbers – economic growth in the eight – ten percent per year range and electricity consumption growth at a ratio of approximately 1:1 compared to the period from 2000 through 2007 – could persist into the medium-term future. Reputable international organizations such as the World Bank are in fact already predicting that overall economic growth will fall in this range after 2010 (World Bank, 2010).

While the Chinese government has not as yet published the growth targets for the twelfth five-year plan covering the years 2011 through 2015, all its public comments reflect a desire to alter the country's growth trajectory from one dominated by investment to one more heavily weighted towards growth in consumption and standards of living in all areas of the country. It has furthermore made clear its concerns to control real estate investment, which rebounded strongly starting from the second half of 2009. All of these measures would have the effect of moderating electricity consumption growth.

8.1.2 Guizhou in the China Southern Grid Regional Market

The Guizhou power grid is one of five interconnected provincial grids which are controlled by the state-owned China Southern Power Grid Company (CSPGC). While the Guizhou Power Grid Company (GPGC) under CSPGC manages the distribution of electricity within the province, the CSPGC controls the substantial electricity transfers between the provinces. Demand for power from generating plants in Guizhou should therefore be considered in a regional context.

Electricity consumption in the 5 CSPGC provinces grew at an average 9.5 percent per year 2005-2009, led by Guangdong Province, the regional economic powerhouse, which accounted for 57.5 percent of the CSPGC area's 627 Terawatt-Hours (TWH) electricity usage in 2009. As in the rest of China, growth exceeded 12 percent from 2005 to 2007, dropped sharply in 2008 and 2009, and rose again in the second half of 2009 and in 2010, as China's economy rebounded strongly. Both the regional economy and regional power consumption can be reasonably projected to grow at 8-10 percent per year over the medium-term in line with anticipated national trends.

Within the CSPGC system, Guangdong is a significant net importer of electricity from the other provinces, while Guizhou is a significant net exporter. Overall, Guangdong relied on Guizhou for approximately 55 TWH, or 21 percent of its electricity 2009. These exports to Guangdong accounted for about 40% of Guizhou's electricity output.

Table 9: China Southern Power Grid Electricity Balances (Terawatt Hours)

	2007		**2008**		**2009**	
	Output	Usage	Output	Usage	Output	Usage
Guangdong	273,197	339,405	266,288	350,482	266,640	360,940
Guangxi	68,281	68,114	84,800	76,082	92,299	83,637
Guizhou	116,632	71,409	119,208	67,918	138,002	77,440
Yunnan	90,450	74,552	103,970	82,948	117,382	89,119

Sources: CESY Tables 3-10 and 5-23, GDSB 2009, GSB 2010, Guangxi Economic Net 2010, GXSB 2010, YSB 2010

Guizhou's emergence as a major supplier to Guangdong is a direct result of central government directed investment to promote economic development in the poorer western provinces. Starting from 2000, state-owned power generation companies supported by government loans have built or are building 21,000 MW in 8 hydro and 12 coal-fired power plants in Guizhou, which sell the bulk of their output to Guangdong under long-term contracts (Guizhou Daily, 2008; China Energy Net, 2006).

To the extent possible, the CSPGC appears to manage the distribution of the electricity from these plants for Guizhou's benefit. In 2008 and early in 2009, when electricity consumption in Guizhou declined particularly sharply, the CSPGC increased the volume of power exported to Guangdong at the expense of local Guangdong plants, whereas in the latter part of 2009 and 2010, as demand in Guizhou surged, the CSPGC decreased the proportion exported to Guangdong.

Regardless of these short-term adjustments, Guangdong will continue to depend on significant volumes of electricity purchase from Guizhou and other CPSGC provinces for the foreseeable future, given the political commitments of the central government to Guizhou's development and the difficulties of installing sufficient in-province capacity to fully meet Guangdong's needs. Guizhou's electric power, furthermore, will remain strongly cost competitive in the Guangdong market in view of the availability in Guizhou of inexpensive local coal and water resources.

The CSGPC currently pays slightly over 0.50 yuan per kilowatt hour for power from the new plants in Guangdong, burning coal shipped from North China or abroad, compared to 0.324 yuan per kWh for power generated from local coal in Guizhou. Hydropower is even less expensive (NDRC 2008.1, 2008.2).

8.2 Guizhou Provincial Electric Power Market

Although Guizhou is one of China's smallest, poorest, and least urbanized provinces, its interconnections with the rest of the country have grown stronger in recent years, and its economic growth has closely tracked that of China as a whole. Electricity consumption within Guizhou has likewise followed the national/regional pattern, with strong double digit growth 2005-2007 giving way to a temporary decline in the second half of 2008 and the first half 2of 009 under the impact of the global economic slowdown, followed by a rebound carrying through into 2010 (**Table 10**).

Table 10: Guizhou Province Electricity Supply

	2007	**2008**	**2009**
Installed Capacity (MW)	NA	NA	28,000 (est.)
- **Connected to Provincial Power Grid**	NA	NA	26,190
Peak Load (MW)	NA	NA	11,870
Consumption (TWH)	71,409	67,918	77,440
Output (TWH	116,632	119,208	138,002

—Hydro Output (TWH)	34,062	38,086	NA
—Thermal Output (TWH)	82,571	81,122	NA

Sources: CESY 2008 Tables 3-10, 3-11 and 3-12; GSYB 2009, GSB 2010, GPC 2009

Given this history, it is reasonable to assume that Guizhou's economy and its electricity consumption will grow within the projected eight to ten percent range for the country as a whole in the medium term. At the lower end of the range, electric load would increase from order of magnitude 12,000 MW in 2010 to 20,500 in 2016, and electricity consumption from approximately 77,440 TWH to 132,800 TWH.

The province's disproportionate economic dependence on energy-intensive extraction and manufacture of commodities such as coal, chemical fertilizers and their inputs/associated products, and aluminum, however, creates the potential for some volatility in electricity demand. Industry as a whole has consistently accounted for close to 80 percent of Guizhou's electricity consumption, the above-mentioned commodities for an estimated 55 percent, and a single massive aluminum smelter near Guiyang for about 15 percent (GSYB, GSB 2009).

Even a moderation in demand growth for these commodities, not to mention a sudden decline such as in the second half of 2008, would have a significant impact on electricity consumption in Guizhou The more rapidly that Guizhou's economic base broadens and incomes and consumption rise, the less likely Guizhou is to deviate from national patterns of electricity consumption.

8.2.1 Guizhou's Electricity Supply: Present and Future

The Guizhou province electricity industry experienced an investment boom during the first decade of the 21st century, with generating capacity rising more than four-fold from 5,000 megawatts in 2000 to 28,000 by year-end 2009 (**Table 10** above). The bulk of this newly added capacity was either totally or partially dedicated to Guangdong Province under the "West-to-East" electricity program (Section 8.1.1 above).

Approximately 60 percent of the generating capacity burns coal from Guizhou's mines, with the remainder hydro, including about 2000 MW of small scale (under 50 MW) typical river hydro-plants. Because of fluctuations in river water levels, however, hydro only accounts for an estimated 31-32 percent of actual power generation. With the exception of the economic slowdown from the second-half of 2008 through the first-half of 2009, the major coal-fired plants in Guizhou have operated in a range of 6000-7000 hours a year, a high utilization rate by Chinese standards that reflects strong demand both inside and outside the province.

In 2009, Guizhou Governor Lin Shusen set a goal for the Province to add 10,000 MW of additional electricity generating capacity “in the near term” in order to “turn Guizhou into one of China’s premier energy producers”. Nine large plants with an approximate 8,000 MW in aggregate capacity (1,850 MW hydro, the remainder coal-fired) were under construction in 2010, with expected completion by 2013. An additional 4 large coal plants with aggregate capacity of 5,720 MW were in the planning phase, with possible completion by 2015-2016 if all proceeds smoothly, including a 2 x 1,000 MW plant to be owned by China Power Investment Jinyuan Company, the parent of the Linhua Mine (Guizhou Power Plants).

Even if all 13,700 MW were to be completed according to schedule, however, only about 9,300 MW would represent additions to the capacity subject to dispatch by the CSPGC. One of the new plants would sell its entire electricity output to Chongqing Municipality to the north. An additional five of the new plants will replace an aggregate 3100 MW of existing coal-fired capacity composed of inefficient generating units of 200 MW or less, which are to be shut down under national policies mandating their retirement in favor of larger, more efficient units. The replacement units include two of 600 MW capacity at Jinsha Power Plant supplied by Linhua Mine in place of four 125 MW units which will be shut down.

Annual growth of eight percent would increase the Guizhou provincial electrical load by about 8,500 MW from the year-end 2009 level of 11,870 MW. In other words, Guizhou’s own demand would likely account in whole or in part for the output of all but 800 MW of the 9,300 MW (net) generating capacity to be added by 2015-2016.

There is a high probability that output from the remaining capacity, or even additional capacity could be absorbed by Guangdong Province, whose load, at eight percent growth rates, would rise by 35,000 MW between 2009 and 2015. Approximately 32,000 MW of capacity (slightly less than 25 percent nuclear, the remainder coal) are either under construction or in advanced planning for completion by 2015 in Guangdong, but at least 3,000 MW of capacity composed of smaller, inefficient generating units are likely to be shut down when the new units come onstream. The above analysis strongly suggests that the Guizhou/CSPGC market should be able to absorb up to 30 to 50 MW of CMM power from the Linhua Coal Mine.

8.3 Potential for Power Generated from Coal Mine Methane

Coal mine methane is among the more promising source of new, lower carbon energy sources in Guizhou Province. Most of the 138 million metric tons of coal mined in Guizhou during 2009 came from mines with high methane concentration that pose a considerable safety risk. Under the relatively conservative assumption that 15 cubic meters of methane were liberated per ton of coal mined, Guizhou

Province emitted approximately 2 billion m^3 of CMM in 2009 (pure methane), enough to supply over 1,300 MW of power capacity operating at 6000 hours per year at 40 percent energy conversion efficiency.

Approximately 52 MW of CMM-fired power generation capacity were in operation in Guizhou in 2010, as follows:

Table 11: Guizhou CMM Power Plant Capacity, 2010

Mining Company	**Installed Capacity**	**Comment**
Shuicheng Coal Group	26 MW	7 distributed plants
Panjiang Coal and Electricity	13.2 MW	Distributed at 2 mines
Liuzhi Industry and Mining	3 MW	Distributed at 2 mines
Hongguo Mining	5 MW	Township-owned mine with 450,000 metric tons production
Qianxi Energy Development	3.8 MW	Qinglong Mine
Zhenxing	1 MW	

Sources: Xinhuanet Economic News 2010, Shuicheng Mining Group Website, China CoalNet2009, Qianxi Qinglong PDD, Shengdong Reference List

Panjiang, the largest coal mining company and the largest CMM emitter in the province, reports that it is building additional facilities at eight separate locations that will increase the company's total CMM power capacity to 31 MW (Guizhou Daily 2009).

The April 2007 "Opinions Regarding Use of Coalbed Methane and Coalmine Methane" put forth by the NDRC called for public grid companies such as GPGC to:

- Purchase all power generated in excess of the mining companies' own needs by CMM generation plants, and to pay the purchase price in a "timely manner."
- Pay the CMM power generators the same prices as for power from biomass generation plants, equivalent to the regulated wholesale purchase prices for power from new coal-fired plants, plus a 0.25 yuan per kwh surcharge.

The Guizhou regulatory authorities, however, have not yet taken concrete measures to enforce these requirements. Only six of the 20 distributed power plants (including the eight under construction at Panjiang) are reported to have reached interconnection agreements with the GPGC. The terms of the agreements reportedly designate even these six as dedicated primarily to the power needs of the mines themselves, which absolves the grid from obligation to pay for excess power that it takes (Xinhuanet Economic News 2010).

Virtually all power generated by Guizhou CMM plants, therefore, is being distributed through the mining companies' own grids for their own consumption. Some mining companies with the capability to generate excess power have been forced to idle capacity due to their inability to reach interconnection and sales agreements with the GPGC.

Disputes over the technical specifics of interconnection with the grid appear to be one reason for the difficulties experienced by CMM power plant operators. Commercial considerations also play a significant role, particularly the failure of price regulatory agencies to allow the GPGC to pass the costs of the NDRC-mandated 0.25 yuan per kwh surcharge for CMM power on to the grid's final customers. This creates considerable disincentive for the grid to consider CMM power.

8.3.1 Power from Proposed Linhua CMM Power Plant

As noted in Section 8.2.1, the probability is high that the CSPGC and GPGC will be able to absorb the power that would be produced by a 30-50 MW plant in Linhua. The prospects for Linhua's sales, however, depend critically on smoother implementation of policies designed to promote the integration of CMM power plants into the grid.

Overall trends in China suggest that pressures from the government will increase to utilize all possible sources of electricity that result in lower CO_2 emissions than coal, including CMM. The CSPGC itself, while not mentioning CMM specifically, publicly called in December 2009 for its operating companies to integrate "new" energy sources such as renewable, nuclear, and "clean coal" into its future grid development plans, and to eliminate obstacles to purchase of power from smaller distributed plants.

This study therefore assumes that the proposed Linhua CMM plant would be able to market all of its excess power to the GPGC. In view of the complexities regarding GPGC's recovery of the proposed 0.25 yuan per kwh surcharge to CMM power generators, however, the base case sales price to the grid is specified at the 2010 offtake price of 0.3244 yuan per kwh for new coal fired power plants with flue gas desulfurization, without adding the surcharge.

9.0 Proposed End- Use Options and Economic Performance

9.1 CMM End-use Options and Analysis

Through thorough evaluation of the regional and local energy markets, and through consultation with mine management, the Raven Ridge team determined that there were three principal options for using methane gas drained from the Linhua Mine. The Linhua Mine's ventilation system and gas drainage plan were designed around a relative emission value estimated to be approximately 40 cubic meters per ton of coal mined. Gas drainage began at the mine during 2005. Gas drainage records for the period of October 2007 through February 2009 were used to develop a gas liberation model for the Linhua Mine employing the National Institute of Occupational Safety and Health (NIOSH) methane control and prediction (MCP) software for longwall coal mines (see **Appendix 5** for a full report of the work conducted by NIOSH). NIOSH analysis of the available drainage data yielded an in situ gas content for the 9 seam, prior to mining, of 18.27 m^3/ton. This value closely agrees with the measured and interpolated gas content values displayed on Map 2, but is less than the reported values used by the Mine Safety Research Institute of Guizhou Province (table 1-3-1, 2006). This gas content value was then incorporated into an algorithm developed to estimate the amount of gas that could be drained given the coal production and ventilation rates, or to estimate the ventilation rate given the drainage rate and coal production. When estimated values for future coal production are input, the output estimates of drainage and ventilation do not agree with Linhua Mine's engineering staff estimates.

The Raven Ridge team took another approach to forecasting the amount of gas that could be drained using surface to in-seam directional drilling. The team took the following steps to estimate the amount of gas that could be produced over time by successfully drilling and completing each of the planned DDWAs:

- **Estimated the amount of gas that can be drained from coal exposed along each meter of borehole.** Closer examination of the gas drainage data, which is collated and averaged by mine personnel over ten-day intervals, revealed that there was a time period during which there was continuous drilling activity accompanied by records of persistent and increasing gas production. Prior to this interval, drained gas production had nearly ceased due to a break in mining activity at the mine; but, from the ten-day intervals beginning 20 March 2008 and extending to 20 January 2009, gas production was continuous and increasing. During this same period, uninterrupted records were kept for daily drilling activity. This complete data set was analyzed to determine the cumulative relation between meters of borehole drilled and gas produced. As a part of the analysis, cumulative daily meters drilled is plotted against daily gas production for 20 March through 20 January and is shown in **Figure 14** below.

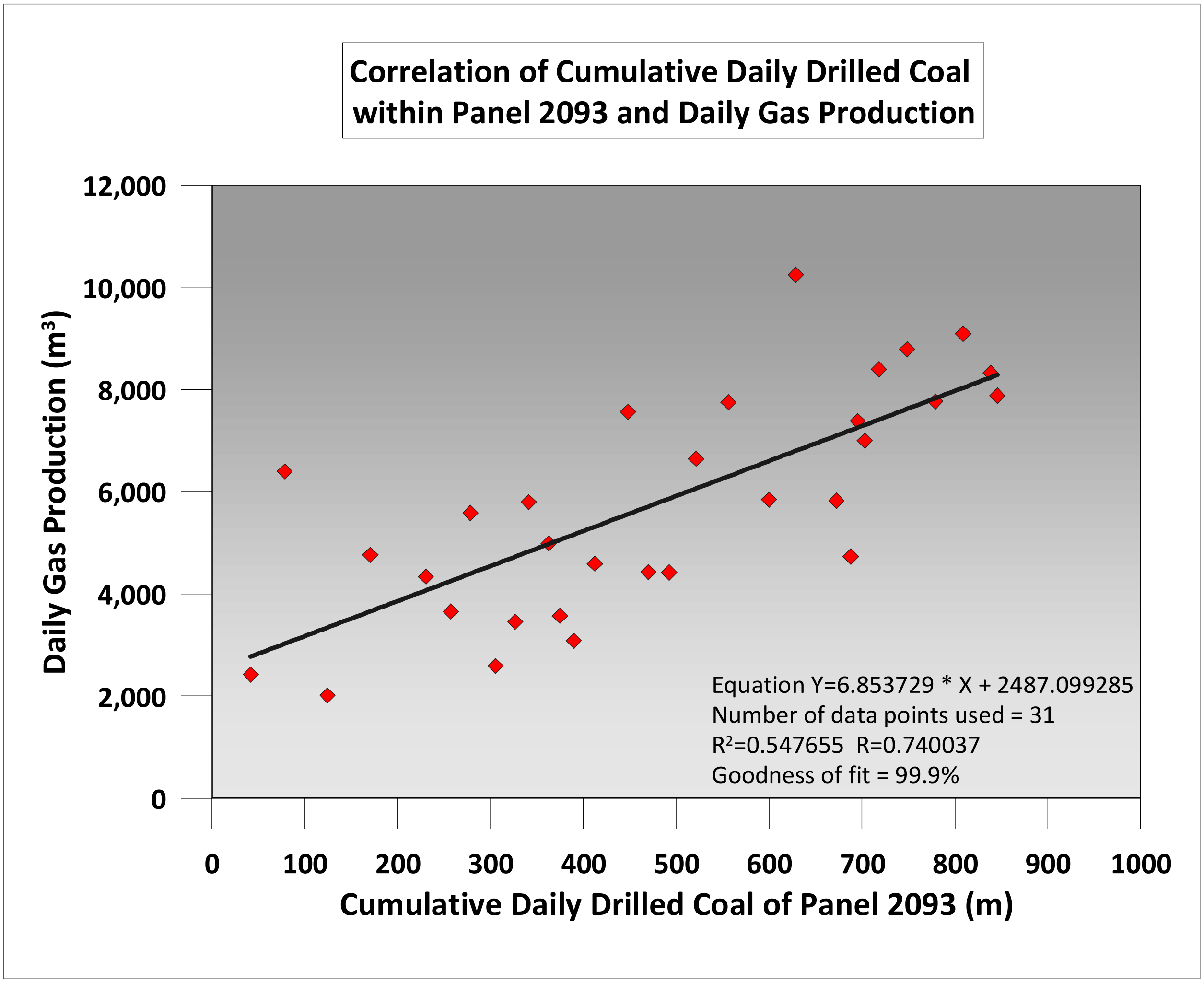


Figure 14: Graph showing daily gas production as a function of borehole meters drilled.

A line was fit to the data which mathematically describes the relationship between gas production and meters of coal drilled. This equation is used to estimate the amount of gas that could be produced by boreholes in each of the DDWAs, expressed as cubic meters of gas drained per meter of borehole drilled. Additionally, a scalar is adopted to account for the increased diameter of the borehole that will be drilled in the proposed plan.

- **Model production decline based on cross-panel borehole data.** Although drainage data appears to have been collected prior to 2007, only data from one borehole was sufficiently complete to allow meaningful analysis. Cross panel borehole #22 began production on 25 September 2007 and the last production was recorded on 26 August 2009. A hyperbolic decline curve was fitted to this data as shown in **Figure 15** below; the goodness of fit for this curve is greater than 99.9%. The curves describing the p90, p 50, and p 10 percentiles are drawn in this figure to illustrate production decline functions that model the volume of gas that may be produced from coal seam 9. Since no production data is available for the overlying exploitable seams 4 and 5, and because they are similar in coal rank and quality, these decline curves have been used as models for those seams as well.

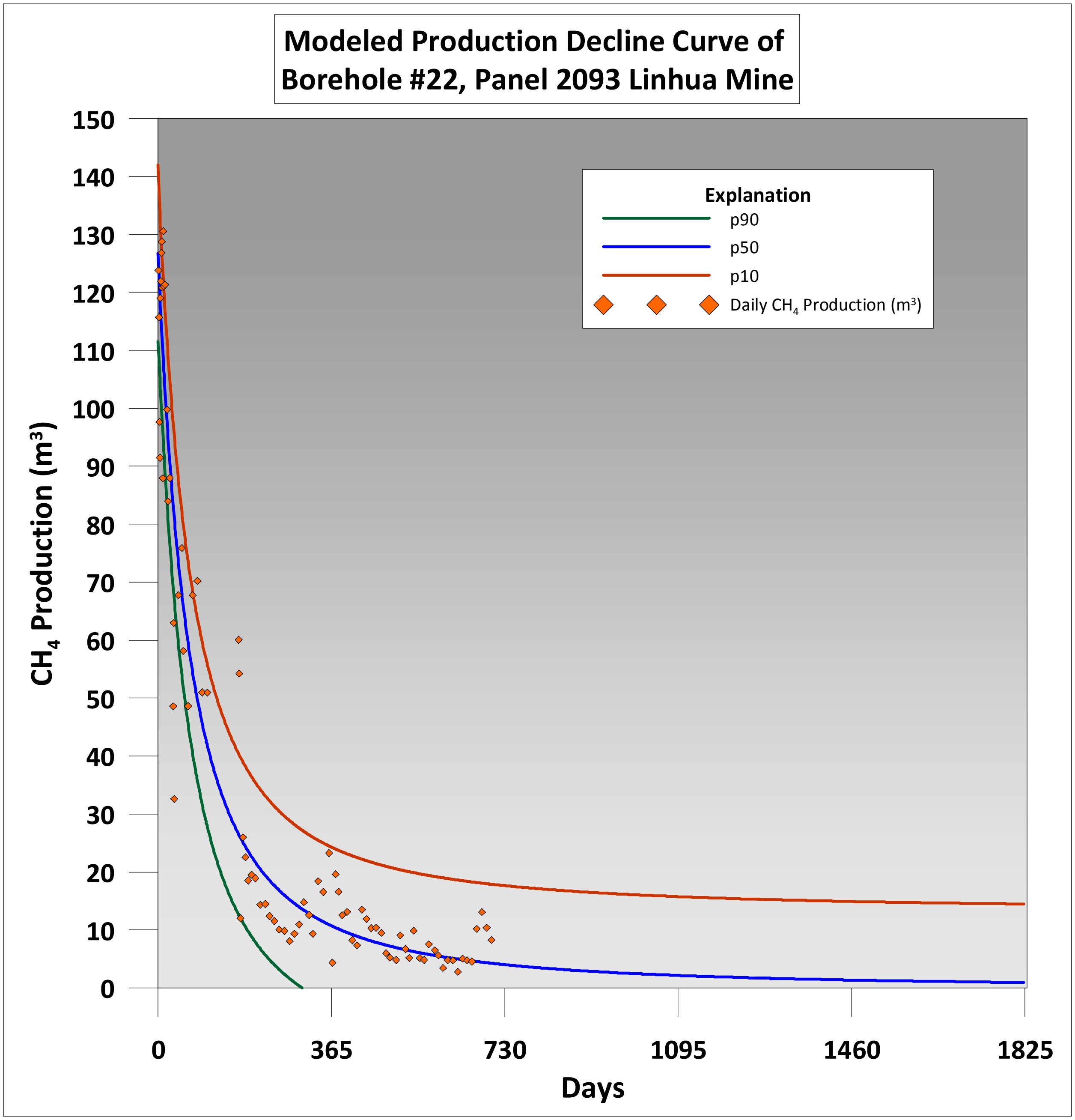


Figure 15: Hyperbolic decline function used for production modeling.

- **Used mathematical models to forecast three year production volumes**. The DDWAs described in Section 5 are designed to drain gas from the coal that will be mined as planned longwall panels are developed. Each DDWA was designed with the necessary borehole length to drain the coal contained within the shaded areas shown on Maps 3a, 3b and 3c. The equation described in Step 1 was used to calculate the amount of gas that could flow into the borehole based on the gas content of the coal and the intercept length of the borehole. The volume of gas that would be available at the moment of initial production is calculated for the p10, 50 and 90 percentiles. This initial production is input into the equation described in Step 2 to calculate the p10, 50 and 90 volumes that could be produced in an ever-declining fashion over a three year period. A three year time interval was selected only for coal seam 9 as the gas production period because this amount of time can be accommodated by the mining plan without causing coal production delays and it is sufficiently long to allow the majority of the gas available to the borehole to be produced; boreholes producing from seams 4 and 5 were allowed to produce for six years. In fact, based on this production decline model, if gas were produced from a DDWA for six years, 73% of the gas would be produced in the first year, and 93% would be produced in the first three years.
- **Develop production forecasts to model drilling and construction**. Output from the calculations in the previous steps (**Table 12**) were input into a spreadsheet to model the timing that would be necessary to accomplish the drilling process, gathering pipeline construction, and produce gas from each of the eight DDWAs. This spreadsheet was used as the production module in the economic analysis described below.

Table 12 : Calculated gas resources and forecasted production from proposed drilling.

Coal Seam	Length of Borehole in Coal (m)	Percentiles	Total Gas Resource (m^3)	3 Year Gas Drainage (m^3)	Drainage Efficiency (%)
4	69,901	**P90**	199,456,760	88,850,129	43%
		P50	204,019,752	89,837,167	44%
		P10	209,067,443	90,827,295	45%
5	39,310	**P90**	95,300,711	57,756,485	59%
		P50	97,180,835	58,435,855	60%
		P10	99,354,452	59,101,566	61%
9	160,028	**P90**	504,081,938	198,277,024	38%

		P50	517,368,805	200,545,170	39%
		P10	531,948,876	202,740,799	40%

Three end-use scenarios were evaluated based on the premise that coal mine methane is produced from surface boreholes in advance of mining and transported to one central location, which is at the northern end of the Linhua Mining property. The three end-use options evaluated are described below.

- *Power Generation and Electricity Sales Option*- This option entails installing a CMM-fueled internal combustion power generation facility in close proximity to the mine's surface facilities, which would be designed to supply power to the mine as well as sell any unused electricity to the grid.
- *LNG Option*- Under this scenario, all coal mine methane produced, with the exception of the volume of gas required to operate the existing Shengli engines will be converted to liquefied natural gas (LNG) for sale on the market. The LNG facility will be built in close proximity to where the mine's surface facilities are located in the northern end of the property. Construction will begin in 2011 and will be completed in 2012, sized to fit the CMM production rates forecasted during peak production reached in 2015.2015
- *Natural Gas Sales Option*- Under this scenario, all coal mine methane produced, other than the gas required to operate the Shengli engines, will be sold to Guizhou Gas (Group) Company LTD (Guizhou Gas). The sales price is structured in our analysis with the assumption that the transaction will take place at the central gathering location at the mine; any additional transportation costs will be borne by Guizhou Gas.

Each option is discussed in the following three subsections, where background information and conceptual design is provided, and the economic performance of each end-use project is discussed. The final subsection compares the economic performance of the three end-use options.

9.2 Inputs and Assumptions Used in the Economic Model for All Options

There are certain inputs and assumptions used in the economic model that are applicable to all three scenarios. These are listed in

Table 13 below.

Table 13: Inputs and Assumptions Used in Economic model

Project Duration	2011 – 2020	
Project ownership and financial structure	Power plants and LNG plant are profit centers, independent from the Linhua Mining operations.	IRR is calculated against entire project investment. Base case assumes that 80 percent of capital costs would be financed at a five percent interest rate with a ten-year term.
Gas flows to project	According to p50 probability threshold	
Drilling & Completion costs	2,068,473 USD for first well in each array 1,813,872 USD each additional well drilled in the array. A ten percent cost savings was applied to all drilling costs with exception of first array.	Quote from drilling engineer with extensive experience in China.
Land acquisition costs (right-of-ways) for gathering and transportation	1.5 million RMB for each 1 meter x 30 meter section. Costs were determined by assuming that all pipelines require a 30 meter width right-of-way; therefore, the total length of pipelines is multiplied by the cost per meter of pipe to determine overall land acquisition costs.	A total of 15,160,350 RMB for 10.11 km (2,213,108 USD).
Gas gathering costs	Main transportation line (40.6 cm) – 685,256 RMB per km Gas gathering lines (10.2 cm) – 171,256 RMB per km	Utilize general rates adjusted for project conditions – total of 6,872,722 RMB (1,003,280 USD).
Depreciation Method	15 year straight line	
Certified Emission Reduction (CER) Sales Price	13.00 USD per tonne of CO_2 equivalent	CER sales in years 2010-2012 only.
Verified Emission Reduction (VER) Sales Price	6.00 USD per tonne of CO_2 equivalent	VER sales in years 2013-2020.
Project Emissions	0.1784 metric tons/MWh	Factor used to determine project emissions resulting from power consumed by LNG plant, and for all power generated by the CMM power generation plants.
Conversion of methane to CO_2 equivalent	0.01428 metric tons CO_2e per m^3 of methane	
Value added Tax (VAT)	None	Base case assumes that government

special incentives		regulations calling for refund of all VAT taxes paid by CMM producers do not apply to the project as a CMM processor; (MOF, 2007).
VAT Refund on Project Inputs	VAT component of purchase price for gas, electricity, and water inputs to the project are refunded	Per government VAT regulations.
VAT Rates	CMM (LNG and natural gas sales): 14.04% Electricity generation and sales: 18.36%:	Inclusive of 8 percent surtaxes for urban construction, education, etc. CMM base rate: 13% Electricity base rate: 17%
Income Tax	25 percent per year	

9.3 Linhua Mine's Existing CMM to Power Project

Linhua Mine management is currently installing 10 Shengli 500 kW engines (Model 500GFI-3RW) for a total combined output of 3.91 MW. The annual hours in operation for these engines is assumed to be 6,000 hours, which totals 23,460 kW per year of output. The Shengli engines require 0.353 cubic meters of methane per kWh of operation for an annual total of 8.28 million cubic meters consumed. This annual volume is subtracted from the amount of drained gas that is produced annually to determine the net amount of gas that would be available for this project.

9.4 Power Generation and Electricity Sales Option

9.4.1 Technology and Deployment Options

A power generation and electricity sales project was the first end-use option evaluated by the Raven Ridge team. The project is conceptually designed to utilize all available CMM drained from the Linhua Mine to generate power for use at the mines and for sale to the national grid.

The annual electricity requirement of the mine is 43,840 kWh; thus, if all of the electricity generated by the Shenglis is consumed at the mine, there remains a total of 20,380 kWh of demand. Power generating equipment from two western suppliers was evaluated based on price and performance. Costs from the lowest priced system (RMB/kWh installed) were used in the analysis. This equipment has a fuel consumption factor of 0.2475 cubic meters per kWh installed; therefore, assuming that all remaining coal mine methane drained will be used for power generation, with 6,500 operating hours, 666,300 MWh of electricity will be generated annually. After supplying the remaining electrical demand to the mine, a net of almost 646,000 MWh is available for sale to the grid. This equates to an installed capacity of just over 30 MW of combined electrical and thermal generating capacity.

The unit costs for this equipment were derived from correspondence with a representative of a western company with offices in China. Included in the capital cost (CAPEX) estimates are equipment purchase, installation and testing, gas gathering, land purchase, as well as all drilling and completion costs. Installation of the internal combustion power generation facilities was done in stages, from 2012 through 2015. This was done to match the growth in methane drainage volumes over time.

9.4.2 Risk Factors and Mitigants

As with any project there are risks associated with developing a successful project. **Table 14** lists the risks that have been identified, an assessment of the level of risk, and possible mitigants to each identified risk. Overall, the Raven Ridge team has determined that the risks associated with technology and implementation are low to moderate, but the risk due to market issues is high. High market risk is a strong reason to reject power generation as an option.

Table 14: Risk Factors and Mitigants: Power Generation and Electricity Sales Options

Risk	Assessment	Mitigant
Market:		
Access to and the ability to dispatch all available generated power to the grid	High	Use power locally and avoid sale to national grid.
Access to national electricity market	High	Use power locally and avoid sale to national grid.
Ability to get rational prices for power sold to grid	High	Avoid selling power to the grid, but sell only locally.
Technology:		
Reliability and dependability of equipment:	Low	Very dependable equipment, train local technicians to monitor, maintain, and repair engines and associated systems.
Fluctuations in gas concentrations	Low	The concentrations of gas drained in advance of mining should not fluctuate significantly.
Implementation:		
Fluctuation in pricing of equipment and services	Moderate	Current trend for prices is downward; Procure contracts that lock in favorable prices.
Procurement of permits and right-of-ways	Low	Develop timeline that incorporates time necessary to secure all necessary permits and right-of-ways, allow for delays.
Delays in deliverability of equipment	Low	Detailed planning; incorporate necessary lead time into orders.
Delays in installation	Low	Detailed planning: Nengfa has experience in installing power gen equipment.

9.4.3 Economic Analysis

The project was modeled to determine the economic performance of this option. The subsections below list the assumptions and inputs used for the modeling, followed by a subsection reporting the resulting estimates of economic performance.

Inputs and Assumptions

When available, actual costs and pricing are used in the model. Otherwise reasonable estimates based on industry standards were used. The following assumptions were used to model this option:

Table 15: Inputs & Assumptions: Power Generation Scenario

Project Duration	2011-2020	
Plant construction	Site construction and installation begins in 2012 and is completed in 2014	
Capital Investment for p50 scenario (million RMB)	Power Stations & auxiliary facilities: 165.4 RMB (24.124.1 million USD)	Power station investment based on unit costs 5,440.96 RMB per kilowatt.
Annual Power Sales	Electricity sales to mine: 20,3505 MWh Sales to public grid: 177,197 MWh at peak production	
Hours of operation for sale to public grid	6,500 per year	Cost estimates provided by western equipment supplier.
Western equipment engine specifications:	10,144 MW output per unit 0.2475 m^3 per kWh generated Utilizes 5.0% of gas stream as fuel for engines	Based on manufacturer's representatives.
Power sales price, sold to mine	0.458 RMB per kWh	Source: November 2009 announcement by NDRC.
Power sales price to public grid	0.324 RMB per kWh	Source: June and August 2008 notifications on Southern Grid wholesale prices and across the board wholesale price increases.
Annual equipment repair & maintenance costs	2.5 percent of the purchase price for the equipment	
Annual equipment operating costs	Gen sets: 81 RMB/kWh Turbine: 167 RMB/kWh	Based on information provided by manufacturer's representative.
Water consumption and cost	0.0038 m^3 per kWh generated at 2.5 RMB per m^3	Consumption per Chongqing Coal Design Institute 2007 study.

Probabilistic Forecast Results

Table 16 below summarizes the results of the modeling performed to determine the economic performance of a power generation option. Using the p50 CMM production forecast, a series of internal combustion engines are installed at one location, totaling 30.4 MW, fueled by all available CMM. A percentage of the power generation is used by the mine to meet the needs that are not met by the Shengli engines, and the remainder is sold to the grid. At the p50 production rate, the project returns a negative value for the NPV at -16.7 million USD, while the IRR is not computed[2].

Table 16: Power Generation Option Base Case Forecast Results

Power Generation Option	
Evaluation Scenario	Base Case
Percentage of CAPEX Financed @ 5% Interest Rate	80%
Gas Forecast - P50 (million m^3)	51.5
Total CAPEX (million USD)	200.1
Tons of CO_2e (x million)	3.88
Plant Size (MW)	30.40
CAPEX/Tons CO_2e	51.57
Electricity Sales Price (¥/kWhr)	0.324
NPV/Tons CO_2e	-4.30
NPV (Million USD) @ 10%	-16.67
IRR (%)	N/A

9.4.4 Sensitivity Analysis of Power Generation Option

The Raven Ridge team performed a sensitivity analysis on this option using the p50 CMM production forecast utilizing Microsoft Excel's What-If Analysis tool (**Table 17**). Under the base case scenario, 80 percent of the CAPEX was financed at an interest rate of five percent, and revenue from the sale of carbon emission reductions was included in the analysis. Four other scenarios were also evaluated: one scenario where only fifty percent of the CAPEX was financed; a second scenario where the revenues from the sale of VERs and CERs were was not included in the analysis; a third scenario where the interest rate for the money borrowed (80% of CAPEX) is 7.5 percent; and a fourth scenario where the interest rate is 10 percent. The NPV for all four scenarios is negative; however, the economic

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[2] In a case where Excel cannot compute the IRR, the NPV becomes increasingly asymptotic to zero. This means that as the rate of return increases, more and more of the future annual cash flows are near equal and remain negative instead of converging on zero.

performance is most favorable under the base case scenario. All other scenarios having a less favorable impact on the overall economic performance of the project.

Table 17: Power Generation Scenario Summary

Power Gen Scenario Summary	Base Case Values:	No Carbon Sales	7.5% Interest Rate	10% Interest Rate	% Borrowed
Variables					
Carbon Sales	Yes	No	Yes	Yes	Yes
Interest Rate	5.0%	5.0%	7.5%	10.0%	5.0%
% of CAPEX Financed	80.0%	80.0%	80.0%	80.0%	50.0%
Economic Indicators					
NPV (8%)	($17.868)	($29.863)	($27.482)	($37.451)	($54.749)
NPV (10%)	($16.663)	($27.567)	($25.270)	($34.188)	($51.158)
NPV (12%)	($15.579)	($25.520)	($23.315)	($31.322)	($47.905)
NPV (14%)	($14.603)	($23.690)	($21.580)	($28.796)	($44.949)
IRR (%)	N/A	N/A	N/A	N/A	N/A

9.5 Sales of LNG Produced from CMM

Figure 16 below depicts a conceptual design for installing an LNG production facility to be sited at the mine. One CMM liquefaction processing plant would be built, with construction starting in 2011 and finishing in 2012, with a capacity to handle 45.2 million m^3 of CMM annually.

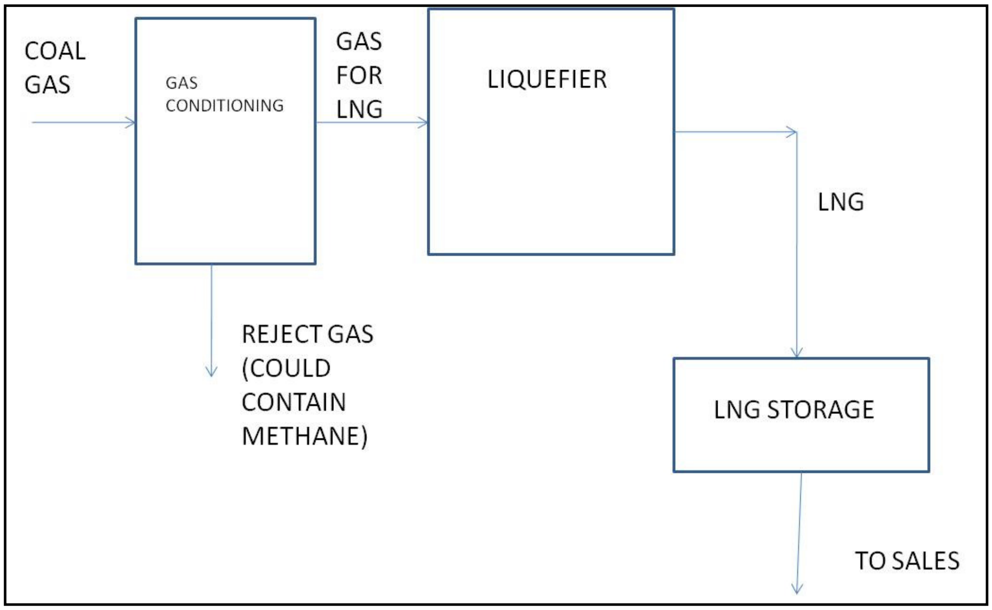

Figure 16: General Schematic of proposed plant employing an LNG Liquefier

9.5.1 Technology and Deployment Options

The second methane use option evaluated by the Raven Ridge team is the generation of LNG utilizing a western-designed plant, and selling the gas to a buyer that will transport the product to market.

Liquefying CMM to produce LNG is a multi-step process requiring a sophisticated system that integrates contaminating gas removal with methane liquefaction. For the purposes of this analysis, it is assumed that the feed gas contains 96 percent methane, and that a molecular gate clean-up system will prepare the feed gas for liquefaction. The basic principle of liquefaction is to cool the processed gas to approximately -160 degrees C. The basic liquefier module can be described as a closed-cycle refrigerator with one or more expansion valves, phase separators and a heat exchanger (**Figure 17**). The methane feed is cooled and liquefied by a series of J valves and exits the unit into appropriate storage tanks. The energy for the liquefaction is supplied by an external power source fueled by the working fuel, which is a mixture of gases selected to match the LNG feed gas properties.

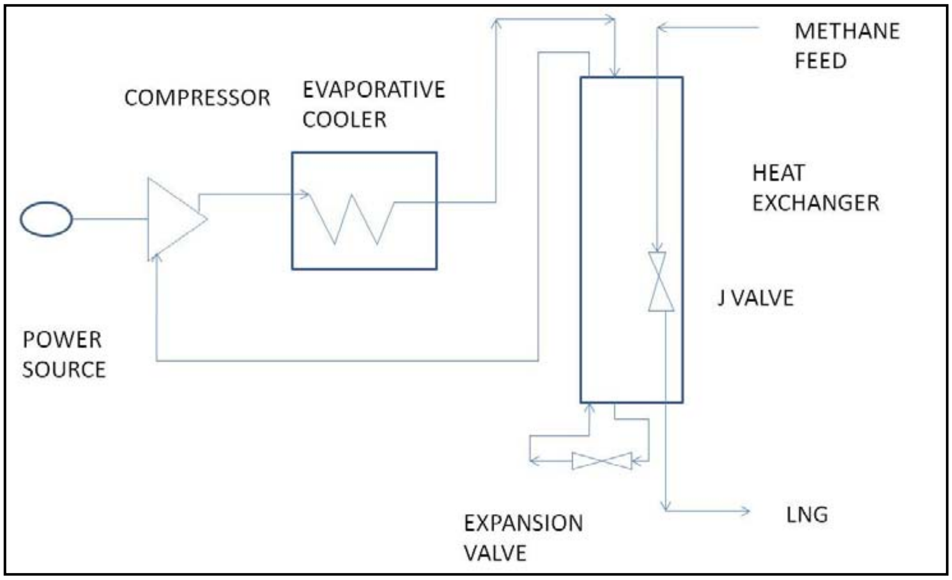

Figure 17: General Flow Diagram of Liquefier with J Valve Inclusion

In addition to the capital cost (CAPEX) of the liquefier, unit costs for initial gas clean-up, construction, installation, storage, scales, and a control system and office derived from earlier studies were included. A scaler was derived from plant cost estimates for other projects of various sizes to determine the capital costs for the liquefier and other plant equipment for this project[3]. Also included in the CAPEX

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[3] The Rule of six-tenths: Approximate costs can be obtained if the cost of a similar item of different size or capacity is known. A rule of thumb developed over the years known as the rule of six-tenths gives very satisfactory results when only an approximate cost within plus or minus 20% is required.

are the cost of drilling and completing the wells, as well as gathering and transportation of the gas to the LNG plant location.

The power required to operate the LNG plant is supplied by gensets sited next to the plant, and fueled by CMM. The annual electricity requirements of the plant are 25,184 MWh, with 8,300 operating hours, which translates to an installed capacity of 6.2 MW. Once the plant is running at full capacity, the fuel requirements will be 6.2 million m^3 annually; this gas volume is subtracted from total gas available for processing by the LNG plant. The same CAPEX and OPEX assumptions and inputs are used for this power plant as stated above in the power generation scenario, and are included in the economic evaluation for this option.

9.5.2 Risk Factors and Mitigants

Table 18 lists the associated risks that are identified for an LNG processing project located at the Linhua Mine site. The table includes an assessment of the level of risk, and possible mitigants to each identified risk. Overall, the Raven Ridge team has determined that the risks associated with technology and implementation is low to moderate, but the risk due to market issues is moderate to high. The Raven Ridge team has made the assumption that the project economics should be based on product offtake at the plant gate. The uncertainty associated with the potential for a temporary over-supply of LNG to the market exists, but probably only poses a moderate threat to the economic performance. On-site storage tanks should help to reduce this risk; thus, tanks are included in the design. However, the ability for an LNG gas purchaser to transport commercial quantities of LNG in tanker trucks along the existing road linking Linhua to the interprovincial highway poses high market risk, which could unfavorably impact the economic performance of the project. Fortunately, corrective measures such as widening the existing road and controlling local traffic, or developing an alternate restricted and secure route are relatively simple to implement; however, these costs have not been included in the analysis. Rail transport is an additional possibility, and other LNG producers are petitioning the central government to make regulatory changes that will allow this mode of transport for LNG.

Table 18: Risk Factors and Mitigants: Sales of LNG Produced from CMM

Risk	Assessment	Mitigant
Market:		
Ability to transport LNG via tanker to major highway along existing local roads	High	Present roads cannot accommodate heavy tanker traffic. They must either be improved or alternate route constructed.
Reliability of gas purchaser to move LNG product so as to avoid plant stoppages	Moderate	Establish long-term contracts with clauses that guarantee sale of gas. Install storage tanks to handle minor lags in transportation.
Technology:		
Reliability and dependability of equipment	Low	Train local technicians to monitor, maintain and repair equipment.
Fluctuations in gas concentrations	Low	Pre-mine drainage production does not have the fluctuations in volumes that are seen in gob drainage.
Implementation:		
Fluctuation in pricing of equipment and services	Moderate	Current trend for prices is downward; Procure contracts that lock in favorable prices.
Procurement of permits and right-of-ways	Low	Develop timeline that incorporates necessary time to secure all necessary permits and right-of-ways, allow for delays.
Delays in deliverability of equipment	Low	Plan for delays when placing orders.
Delays in installation	Moderate	Plan for delays when laying out timeline for construction and installation.

9.5.3 Economic Analysis

The CMM end-use option was modeled to determine its economic performance. Below is a list of the assumptions and inputs used for the modeling, followed by reporting the resulting estimates of economic performance.

Inputs and Assumptions: Sales of LNG Produced from CMM

The following inputs and assumptions were used as a basis for the economic analysis of this end-use option.

Table 19: Inputs & Assumptions for LNG Scenario

Capacity	51.4745.4 million m^3 input 39.8 million m^3 output 6.2 million m^3 used for power generation	Full operation by end of 2012; peak production capacity by 2015.
Construction timing	LNG Plants Gas production – gathering and transportation	2 years for the plant (2011 – 2012). 2 years for main transportation lines, steady production is reached, 5 years until peak production is reached and all gathering is in place.
Project ownership	Power plants and LNG plant are profit centers, independent from the Linhua Mining operations;	IRR is calculated against entire project investment, including drilling.
Capital investment, purification/LNG plant	11.5 million USD	Cost estimates supplied by third-party LNG consultant.
Hours of operation	8,300 hours per year	
Methane gas losses in purification/LNG plant	CMM gas is assumed to contain 96% methane 12% of methane gas flow is lost during processing	Amount is deducted from total gas processed to determine sales volume.
Electricity consumption, LNG plant	0.45 kWh per liter of gas processed	Supplied by LNG consultant.
Electricity purchase price for plant operations	Self-generated power – no cost to plant	
O & M costs for LNG plant (excluding power plant)	5% of capital costs annually	Includes all operating and maintenance expenditures, including labor.
Power plant O & M costs	Gen sets: 81 RMB/kWh Turbine: 167 RMB/kWh	Based on information provided by manufacturer's representative.
Water consumption and costs	0.0038 m^3 per kWh generated, 2.5 RMB per m^3	Consumption per Chongqing Coal Design Institute 2007 study.
LNG sales price	3.00 RMB per m^3 (gas phase, including VAT)	Sold ex-factory, with customer taking responsibility for transportation.

Probabilistic Forecast Results

Table 20 below summarizes the results of the modeling performed to determine the economic performance of an LNG end-use option. Using the p50 CMM production forecast, one processing plant can be built to process all available CMM for sale. An LNG plant that will produce 173.6 million m^3 of LNG will be completed in 2012. The economic model estimates an NPV of -$4.32-4.32 million USD and an IRR that cannot be calculated.

Table 20: LNG End-use Option Base Case Forecast Results

Evaluation Scenario	Base Case
Percentage of CAPEX Financed @ 5% Interest Rate	80%
Gas Forecast - P50 (million m^3)	51.5
Total CAPEX (million USD)	189.3
Tons of CO_2e (million)	3.10
Plant Size (million m^3/yr)	45.20
CAPEX/Tons CO_2e	61.06
LNG Sales Price (¥/m^3)	2.75
NPV/Tons CO_2e	-1.39
NPV (Million USD)	-4.32
IRR (%)	N/A

9.5.4 Sensitivity Analysis of LNG Sales Option

The Raven Ridge team performed a sensitivity analysis on the LNG Sales option using the p50 CMM production forecast (Table 21). This analysis was performed in the same fashion as was described in the power generation section. As is the case with power generation, the NPV for this option is negative for all four scenarios; however, the economic performance is most favorable under the base case scenario, with all other scenarios having a less favorable impact on the overall economic performance of the project.

Table 21: LNG Sales Scenario Summary

LNG Scenario Summary	Base Case Values:	No Carbon Sales	7.5% Interest Rate	10% Interest Rate	% Borrowed
Variables					
Carbon Sales	Yes	No	Yes	Yes	Yes
Interest Rate	5.00%	5.00%	7.50%	10.00%	5.00%
% of CAPEX Financed	80.00%	80.00%	80.00%	80.00%	50.00%
Economic Indicators					
NPV (8%)	($4.11)	($14.77)	($14.11)	($24.50)	($38.76)
NPV (10%)	($4.31)	($14.05)	($13.28)	($22.58)	($36.83)
NPV (12%)	($4.48)	($13.40)	($12.56)	($20.92)	($35.06)
NPV (!$%)	($4.63)	($12.83)	($11.93)	($19.48)	($33.43)
IRR (%)	N/A	N/A	N/A	N/A	N/A

9.6 Natural Gas Sales

The third end-use option evaluated is the sale of CMM as natural gas to the grid. As in the other two scenarios, all gas produced is transported to a single location, located close to the surface facilities of the mine.

9.6.1 Configuration and Deployment Option

For the natural gas sales option, the Raven Ridge team assumes that gas enrichment is not necessary; the produced gas meets pipeline specifications. Under this scenario, all available gas will be sold to Guizhou Gas, the only authorized company in the province to distribute gas. The transfer of ownership of gas to Guizhou Gas will occur at the gas compressor station at the mine site.

9.6.2 Risk Factors and Mitigants

In the case of natural gas sales, the risks identified in **Table 22** below are moderate and the mitigants can satisfactorily provide assurance that the risks will not adversely impact the economic performance of the project. However, these actions will take active forethought on the part of the operator for the project to be successful.

Table 22: Risk Factors and Mitigants: Optimized Option

Risk	Assessment	Mitigant
Market:		
Natural Gas: Price is down due to economic conditions	Moderate	Establish long-term contracts.
Access to market	Moderate	The market for natural gas in the region is being developed; the demand is projected to increase steadily over the next several years.

9.6.3 Economic Analysis

This end-use option was modeled to determine its economic performance. Below, the assumptions and inputs used for modeling are listed, followed by a report of the resulting estimates of economic performance.

Inputs and Assumptions

The following inputs and assumptions serve as the basis for this economic performance model.

Table 23: Inputs & Assumptions for Natural Gas Sales

Project Duration	2009 – 2025	
CMM gas production	According to p50 probability threshold	Gas required to operate Shengli engines is subtracted from total CMM production to determine net volumes available for sale to market.
Gas Sales Price	2.050 RMB per m^3	

Probabilistic Forecast Results: Natural Gas Sales

Table 24 below lists key indicators of the economic performance for CMM gas sales. Using the p50 CMM production forecast, all gas that is available for sale is sold to Guizhou Gas. The economic model estimates an NPV of $6.266.26 million USD and an IRR of 34.6 percent. This indicates a strong economic performance and results in an estimated net reduction of 3.48 million metric tons of CO_2e over the life of the project.

Table 24: Natural Gas Sales Base Case Forecast Results

Natural Gas Sales	
Evaluation Scenario	Base Case
Percentage of CAPEX Financed @ 5% Interest Rate	80%
Gas Forecast - P50 (million m^3)	51.5
Total CAPEX (million USD)	175.9
Tons of CO_2e (million)	3.48
CAPEX/Tons CO_2e	50.56
Natural Gas Sales Price (¥/m^3)	2.50
Break Even Natural GasNG Sales Price (¥/m^3)	1.93
NPV/Tons CO_2e	1.80
NPV (Million USD)	6.26
IRR (%)	34.55

Sensitivity Analysis of Natural Gas Sales

The Raven Ridge team performed sensitivity analysis on the optimized option using the p50 CMM production forecast. The same four scenarios were evaluated in this option as in the other two options; and similarly, the base case scenario exhibits the best economic performance over all other scenarios. The same four scenarios were evaluated in this option as in the other two options. Similarly, the base case scenario exhibits the best economic performance over all other scenarios. One additional sensitivity analysis was performed to determine what the natural gas sales price would need to be where the project breaks even. With a natural gas sales price of 1.93 RMB per cubic meter, the IRR approaches 0.0 percent.

Table 25: Natural Gas Sales Scenario Summary

Natural Gas Scenario Summary					
	Base Case Values:	No Carbon Sales	7.5% Interest Rate	10% Interest Rate	% Borrowed
Variables					
Carbon Sales	Yes	No	Yes	Yes	Yes
Interest Rate	5%	5%	7.5%	10%	5%
% of CAPEX Financed	80%	80%	80%	80%	50%
Economic Indicators					
NPV (8%)	$7.33	($3.24)	($1.01)	($9.66)	($24.98)
NPV (10%)	$6.26	($3.35)	($1.21)	($8.94)	($23.93)
NPV (12%)	$5.32	($3.44)	($1.39)	($8.33)	($22.94)
NPV (14%)	$4.49	($3.52)	($1.56)	($7.81)	($22.01)
IRR (%)	34.55%	N/A	-2.12%	N/A	N/A

9.7 *Comparison of Economic Performance of End-Use Options*

The Raven Ridge team has concluded that the best economic performance would result from natural gas sales, as all economic indicators strongly support this option. This project option requires the least amount of CAPEX, very little gas is lost to processing, and the option exhibits strong gas sales for the life of the project. From a market perspective, the market for LNG is already established in the region, and a CMM to LNG project is underway just to the north in Songzao, which supports this option's viability.

Table 26: Comparison of End-use Options

Comparison of Economic Performance for Three End-Use Options (Base Case)			
End-Use Option	**Power Generation**	**LNG Sales**	**Natural Gas Sales**
Gas Forecast - P50 (million m^3)	51.5		
Total CAPEX (million USD)	200.1	189.3	175.9
Tons of CO_2e (million)	3.88	3.10	3.48
CAPEX/Tons CO_2e	51.57	61.06	50.56
NPV/Tons CO_2e	-4.30	-1.11	1.61
NPV (Million USD)	-16.67	-4.32	6.26
IRR (%)	N/A	N/A	34.55

10.0 Conclusions, Recommendations, and Next Steps

10.1 Mining

Detailed information regarding outbursts that have occurred in the mine workings during initial mine development was provided by mining personnel. The Raven Ridge team believes that understanding the probability of occurrence and the most likely magnitude and orientation of high angle normal and reverse faults is a crucial undertaking to minimize the impact of outbursts. It is important to continue mapping and developing a database of faults that are discovered in the mining block. Additional exploration drilling is necessary to better define the geometry and size of the northerly trending series of reverse faults which bisect the mine plan. To complement this, mine management should also consider a 3-D seismic program over the mine property.

10.2 Drilling

Linhua Mine should implement a drilling program which consists of a series of long boreholes drilled from the surface to pre-drain the coals in advance of mining. When designing the program, consideration should be given to the following aspects of a drilling program:

- The instability of the coals and determining the ideal azimuth of the wells. This can be inferred from the extensive in-mine drilling experience and from proposed geological investigative work.
- The directional portion of the drilling design needs higher level engineering. Drilling with directional drilling equipment while drilling underbalanced with water/mist would be ideal, but it is unknown whether the coals are sufficiently stable for this approach.
- While it is known that the required equipment and technology to carry out a drilling program recommended in this report are available in China, it is clear that the expertise and know-how to design and manage such a project may not be readily available. Prior to commencing with the commercial program, a pilot program should be executed for training and capacity building, to insure success once the commercial drilling operations begin. Drilling the recommended first DDWA could comprise the pilot project. Adjunct to determination of availability of expertise, engineering design must take into account successful practices and avoid problems that have occurred in similar geologic settings. This higher level engineering should be performed by an engineer who is familiar with both the geologic issues and the availability of specialized equipment in China, in order to determine best available option(s) and to maximize gas recovery.

10.3 Marketing

Based on an extensive market survey, the Raven Ridge team concluded that conversion of the gas to electricity is not an economically attractive option for produced CMM. However, two viable options for sales of gas exist: 1) conversion of CMM to LNG and transporting the product to markets which are experiencing an under-supply of natural gas; or 2) injecting produced CMM into a pipeline that connects with the Burma-China Pipeline. It is important to determine as early as practicable which of the two market approaches is the best use for Linhua's gas, as both options will require extensive infrastructural upgrades and each will need to be implemented and completed before any gas can be sold. For LNG, the off taker will need to be able to get trucks to the mine, and get permission to utilize the new road currently under construction from Jinsha County up to the mine. For natural gas sales, a pipeline will need to be constructed from the mine site to a main transportation line in Jinsha County, which is scheduled to be completed by the end of 2012. One action that could aid in advancing the project is to identify a project developer and/ or investment partner with experience in China. The partner will need to face the challenges of introducing new drilling technology into the region along with the challenges associated with delivering the gas to market. The success of either option will require considerable planning and active involvement of mine management and a project developer/investment partner.

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