A Regional Handbook for Coalbed Methane Degasification in the Southern Shanxi Province, China

Prepared by Virginia Center for Coal and Energy Research

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EXECUTIVE SUMMARY

The release of methane to the atmosphere from producing and abandoned coal mines accounts for ten percent of global anthropogenic methane emissions. Methane adsorbed to coal's internal surface matrix can be captured and recovered prior to the mining process, enhancing the health and safety of the underground workforce and decreasing greenhouse gas emissions while providing a clean burning energy source. China's Qinshui Basin holds coals of significant thicknesses and gas contents. Additionally, the permeability of these coals is relatively low, complicating the degasification process. Regulatory standards require that prospective coal beds be degasified to a threshold value of 280 cubic feet per ton (8 cubic meters per ton) prior to the underground mining process. The development of a strategic degasification plan is crucial to the success of both coalbed methane extraction and coal mining. Multiple pre-mining degasification techniques have been successfully implemented in the Qinshui Basin. Namely, hydraulically fractured vertical wells enhance the effective permeability of the coal seam proximal to the wellbore and horizontal drilling patterns provide a large exposure to the coal bed, allowing sustained gas production. The handbook that follows outlines optimum strategies for coalbed methane extraction prior to mining through a case study analysis of a greenfield property in the southern Shanxi Province. From three-dimensional modeling in the case study analysis, it is concluded that multilaterally drilled horizontal wells offer the best option for coal gas recovery. A conceptual drilling schedule, type-curve analysis, market analysis, and associated financial model for the case study property suggest that commercial scale CBM production is economically feasible. Ultimately, the presented findings in this work can be used as a guideline for parties interested in developing CBM opportunities. Expansion of CBM capture may result in reduced greenhouse gas emissions and provide an expanded domestic energy resources portfolio.

Chapter 1. INTRODUCTION AND BACKGROUND

The **United States Environmental Protection Agency (*USEPA*)** commissioned **Virginia Tech**'s **Virginia Center for Coal and Energy Research (*VCCER*)** to complete a project outlining the best practices for coalbed methane (*CBM*) degasification prior to mining in China's Qinshui Coal Basin in an effort to decrease global methane emissions. VCCER's collaborative research partners, including **Marshall Miller & Associates, Inc. (*MM&A*)**, conducted a detailed CBM reserve analysis on a gas-bearing coal property in China's southern Shanxi Province considered to be representative of the region. Throughout the project, American and Chinese energy professionals engaged in technology exchange during meetings and short courses. This handbook provides a project summary and guidelines which can be utilized by parties interested in the CBM resource of the Qinshui Basin. The project's scope of work addresses the following areas of interest articulated by the USEPA:

- Projects that demonstrate methane capture and use, such as pre-feasibility studies, feasibility studies, or technology demonstrations.
- Identifying cost-effective opportunities to recover methane emissions for energy production and potential financing mechanisms to encourage investment.
- Identifying and promoting areas of bilateral, multilateral, and private sector collaboration on methane recovery and use.
- Projects that improve emissions estimates and identify the largest relevant emission sources to facilitate project development.
- Identifying the legal, regulatory, financial, or institutional and other conditions necessary to attract investment in international methane recovery and utilization projects.
- Identifying collaborative projects aimed at addressing specific challenges to methane recovery, such as raising awareness in key industries, improving local expertise and knowledge, and demonstrating methane recovery and use technologies and management practices.

1-1. Acknowledgements

This handbook was compiled by the Virginia Center for Coal and Energy Research (VCCER) at Virginia Tech under the direction of Dr. Michael Karmis. Dr. Kray Luxbacher and Steven Keim served as researchers throughout the course of the project. Marshall Miller and

Associates (MM&A) served as subcontractor to VCCER, compiling raw data and developing geologic models from data provided by a coalbed methane producer in China. Additionally, reviewers with significant international experience in coalbed methane production and mine interaction, drilling design, and coalbed methane production practices in China provided input and advice.

1-2. Introduction

CBM degasification of active or projected coal mines, and the subsequent capture and use of the gas in lieu of venting it to the atmosphere, has the potential to significantly reduce methane exhausted to the atmosphere. Underground mine ventilation systems are designed to dilute, render harmless, and remove methane from mines. Methane (CH_4) is a greenhouse gas and is 21 times more effective at trapping heat than carbon dioxide. Experts have estimated that approximately ten percent of all human-related methane emissions are from underground coal mines (Milich 1999). Capture of this methane prior to its dilution with ventilation air can considerably reduce methane emissions. Additionally, degasification and capture of CBM allows for utilization of a local clean energy source and improves safety at underground mines. Methane is explosive over a wide range of concentration and has been a factor in many underground mine disasters.

China's Qinshui Coal Basin, located in southern Shanxi Province, contains coal seams of significant thickness and gas content. The coal and CBM resources have the potential to provide sustained energy sources to China. Safely mining the coal seams utilizing underground mining methods will necessitate CBM extraction plans to ensure the health and safety of miners. Although CBM development has proven successful in the Basin over the past decade, continued CBM extraction in deep, lower permeability coals will present challenges. The Chinese CBM industry is still largely in its infancy, but is expected to grow significantly.

This handbook evaluates appropriate degasification techniques by developing a case-study analysis of a greenfield CBM area in Shanxi Province. Geological characteristics of the region and case study area are analyzed. Specific outlines and documentation are included to assist others in developing reserve and financial analyses for CBM capture opportunities.. An overview of government-related legal issues and incentives is included to support those efforts.

1-3. Project Benefits

Captured methane has a proven track record as a clean-burning fuel source for domestic and industrial use. Methane degasification also provides increased industrial safety and efficiency. Reducing methane content of coal seams in advance of mining reduces the amount of methane available for liberation during mining, thus reducing the potential for explosions. Reduced methane liberation during mining reduces the potential for production interruptions ("gas-offs"), because modern coal mining equipment is designed to automatically de-energize if the methane content in the air passes a certain limit. Additionally, lower methane liberation during mining can reduce mine ventilation cost because less air may be required to dilute the methane, possibly resulting in reduced energy consumption by mine fans. In summary, the benefits of the project to the public include:

- Reduced methane emissions to atmosphere.
- Availability of clean-burning methane for domestic and industrial use.
- Improved mine safety – reducing methane content in mine reduces potential for explosion.
- Improved mine production efficiency – less potential for production interruption "gas-offs."
- Reduced mine ventilation cost – reduced air requirements reduces energy consumption by mine fan(s).
- Development of a regional handbook for degasification.

1-4. Definitions and Acronyms

Table 1-1: Definitions and Acronyms

Acronym	Definition
ARB	As-Received Basis
CBM	Coalbed Methane
CNG	Compressed Natural Gas
DAF	Dry and Ash Free
DMMF	Dry and Mineral Matter Free
EA	Environmental Assessment
EP	Equator Principles
EPFI	Equator Principle Financial Institutions
EUR	Estimated Ultimate Recovery
GHG	Greenhouse Gas
GIP	Gas in Place
IFC	International Finance Corporation
LNG	Liquefied Natural Gas
MLD	Multilaterally Drilled
MM&A	Marshall Miller and Associates
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
USEPA	United States Environmental Protection Agency
VCCER	Virginia Center for Coal and Energy Research

Chapter 2. CHARACTERISTICS OF THE CBM REGION REFERENCED IN THIS HANDBOOK

2-1. Delineation of the Study Area

The southern portion of the Qinshui Basin, Shanxi Province, China, was selected for study due to the high level of deep coal mining activity occurring in conjunction with recent CBM development projects (see *Figure 2-1*). The deep coal mines in this region are known to be very gassy and several hundred vertical CBM wells and over twenty multilaterally drilled (*MLD*) horizontal wells have been drilled in the region to degasify the coal seams prior to mining. Some of the local CBM operators include **Asian American Gas, Inc. (*AAGI*)**, **China United Coalbed Methane Corporation, Ltd.** (***CUCBM***), **Jincheng Mining Group** (***JMG***), and **PetroChina**.

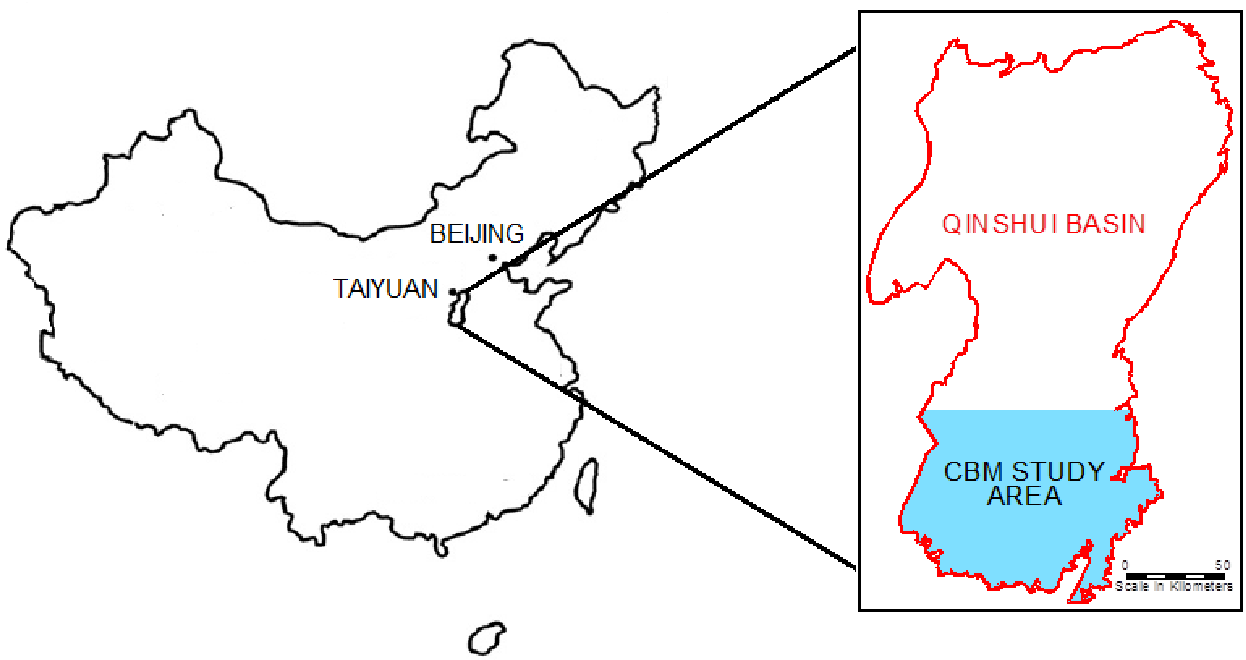


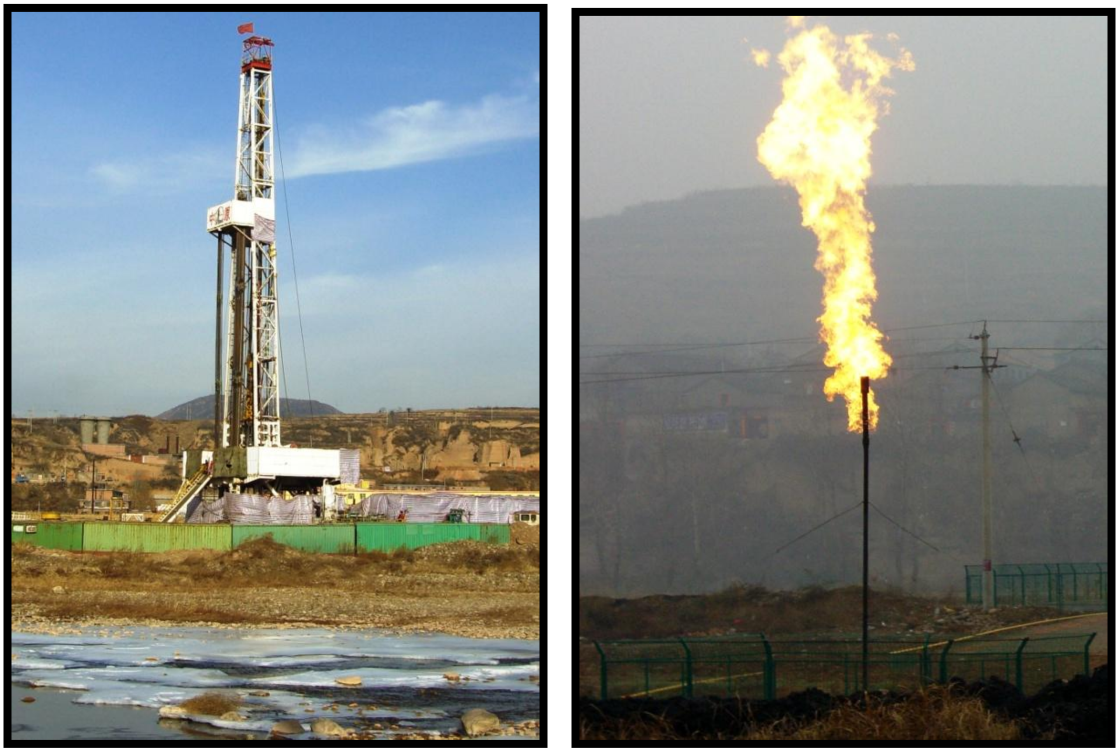
Figure 2-1: Southern Qinshui Basin Study Area

JMG and CUCBM have been actively testing the CBM potential of the region and as of July 2007 had drilled approximately 340 CBM wells. Subsequent vertical CBM development by JMG and CUCBM has occurred over the last few years. The research team has not been able to quantify the total number of CBM wells drilled to date in the region. The vertically-drilled CBM wells are completed primarily in the No. 3 coal seam. Gas production from the wells is flared or sold at compressed natural gas stations located within the projects. The wells typically produce at initial rates ranging from 50 to 100 thousand cubic feet per day (*Mcf/d*) (1,400 to 2,800 cubic meters per day (*m^3/d*)). Photographs depicting a typical well configuration and water disposal pit for a vertical CBM well located within the southern Qinshui Basin are provided in *Figure 2-2*.

Left: Typical vertical CBM well configuration and equipment
Right: Water production into disposal pit from a vertical CBM well

Figure 2-2: Typical Vertical CBM Well, Southern Qinshui Basin

In addition to the vertical CBM development occurring in the region, AAGI and PetroChina have drilled over 20 horizontal CBM wells in the southern Qinshui Basin. Initial production rates for some of the MLD horizontal test wells are reported to exceed 2,000 Mcf/d (57,000 m^3/d). Some of the MLD wells drilled in the region are associated with coal mining degasification projects, while other MLD wells have been drilled in deeper portions of the basin to produce marketable gas. Photographs depicting a typical drilling rig and a methane gas flare from a horizontal CBM well located within the southern Qinshui Basin are provided in *Figure 2-3*.



Left: Horizontal drilling rig in the southern Qinshui Basin
Right: Methane gas flare from a horizontal well; initial production rate over 2.0 MMcf/d (57,000 m^3/d)

Figure 2-3: Typical Horizontal CBM Well, Southern Qinshui Basin

2-2. <u>Geological Aspects of the Region</u>

2-2.1. Stratigraphy of Prospective CBM Targets

The coal beds evaluated within the southern Qinshui Basin occur in the Lower Permian Shanxi and the Upper Carboniferous Taiyuan Formations. The contact for the two formations is delineated a few meters below the base of the No. 3 coal seam. An unconformity at the base of the Carboniferous section and the Ordovician Limestone typically occurs 30 to 100 feet (10 to 30 meters) below the base of the No. 15 coal seam. A generalized stratigraphic column for the Qinshui Basin (*Figure 2-4*) was developed using coal thickness data from the core holes drilled in the region.

The No. 3 seam is the most prominent and economically important coal bed in the southern portion of the Qinshui Basin in terms of both mining and CBM development. The No. 3 seam is well developed and has a fairly consistent thickness distribution over the region, ranging from 1.6 to 22 feet (0.5 to 6.7 meters) and averaging approximately 14.8 feet (4.5 meters). The No. 15 seam will likely provide a secondary CBM target within the southern portion of the Qinshui Basin. The No. 15 seam thickness ranges from 2.6 to 20.3 feet (0.8 to 6.2 meters) and the seam averages approximately 9.8 feet (3.0 meters) across the region.

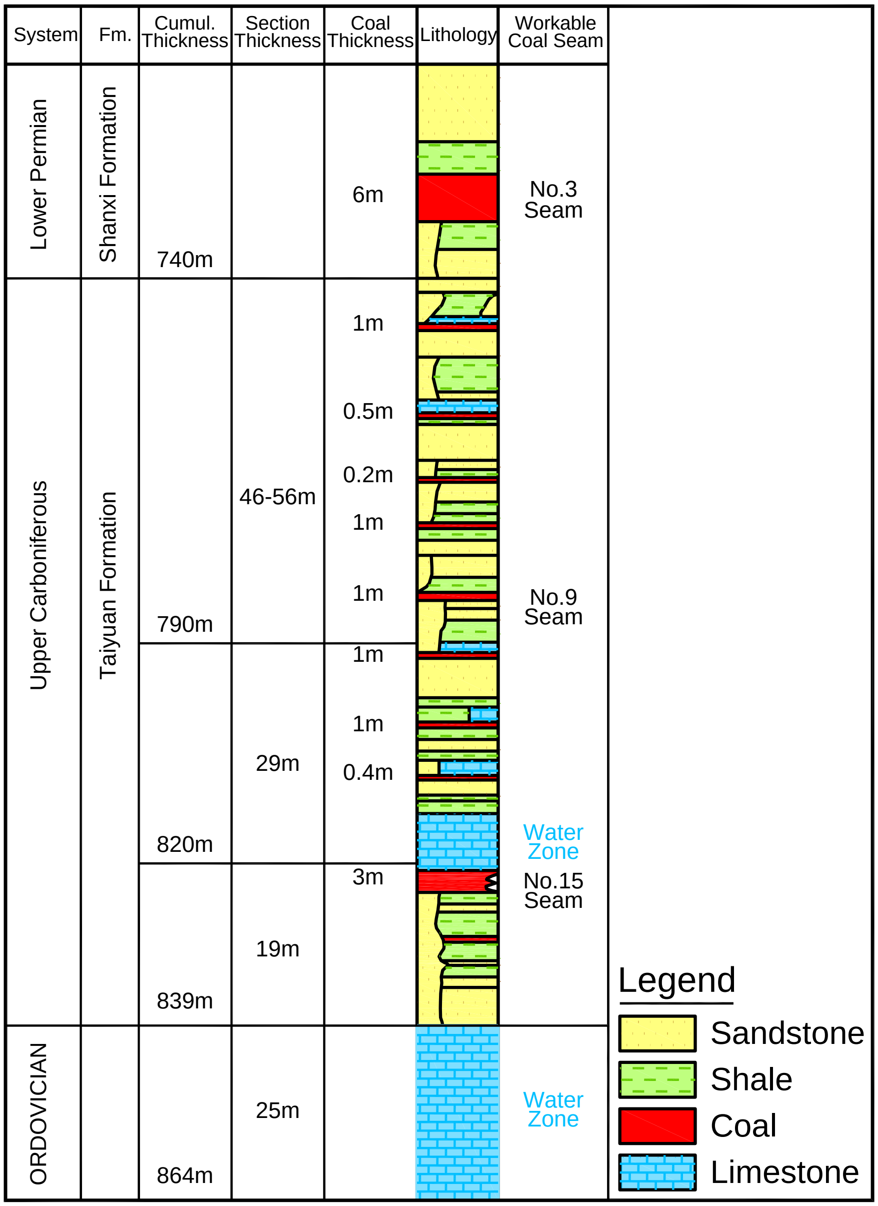


Figure 2-4: Stratigraphic Column – Qinshui Basin

2-2.2. Structural Setting

The regional CBM study area is located along the southern margin of the Qinshui Basin. The structural deformation of the region is characterized by a series of north to northeasttrending anticlines and synclines. Numerous normal and reverse faults with significant amounts of throw and displacements are present within the study area. Some smaller-scale normal faults also have been identified on the surface. Overall, the compressional structural regime occurring in the southern Qinshui Basin indicates a favorable tectonic setting for both vertical and horizontal CBM development.

The depth to the No. 3 seam within the southern Qinshui Basin ranges from 0 (at coal outcrop along the basin margin) to over 3,900 feet (0 to over 1,200 meters) towards the basin axis. Coal seam depth is a function of both topographic expression and structural elevation of the seam above sea level. The optimum depth range for economic CBM development is believed to occur between 1,000 to 3,000 feet (300 to 1,000 meters), as this range of depths provides sufficient gas content and permeability.

2-2.3. Coal Permeability

In terms of coal permeability, regional data indicate relatively low to moderate coal permeability across the southern Qinshui Basin, compared to most CBM-producing regions of the world. However, the permeability values appear to be higher than normally encountered in anthracite coals, which generally have little cleat development. Physical examination of some No. 3 seam coal samples from the mining regions indicates a well-developed cleat structure, while other samples exhibit poor cleat development. Based on the limited injection-falloff permeability data reviewed and recent CBM production results, the average permeability for the southern Qinshui Basin is estimated to be in the 1.0 to 3.0 millidarcy (*mD*) range, but should vary across the region. It appears that sufficient permeability is present to enable economic gas production levels from either vertical or horizontal CBM development, considering the presence of thick coal seams with extremely favorable gas contents.

2-2.4. Coal Rank and Gas Content

Rank of the prospective coals occurring in the southern Qinshui Basin is semi-anthracite to anthracite, based on vitrinite reflectance data and volatile content. Gas contents appear to increase from the basin margin (shallower coal depths) towards the deeper portion of the basin. Gas contents for the No. 3 seam range from around 350 standard cubic feet per ton *(scf/t)* to 780 scf/t (11.0 milliliters per gram (*ml/g*) to 24.4 ml/g) based on regional core hole data. Gas contents for the No. 3 seam within the southern Qinshui Basin average approximately 570 scf/t (17.8 ml/g). Gas contents for the No. 15 seam are slightly higher, ranging from 370 to 855 scf/t (11.6 to 28.6 ml/g), and average approximately 615 scf/t (19.2 ml/g) within the study area.

2-3. Geographical Aspects of the Region

2-3.1. Climate

The study area falls in a semi-arid region that is affected by monsoons and characterized as having a continental climate. During the summer, the area is dominated by wind from the southeast and by rain. Spring and autumn are generally windy and dry. Winter months are generally cold, with a northwestern wind accompanied by occasional rain and snow.

2-3.2. Topography

The topography of the area is represented by hilly and mountainous rural terrain. The flatter areas are generally used for farming applications, as this type of terrain is limited. Terraced-style farming is used in the mildly sloping areas. Steeper areas generally remain vegetated to prevent erosion and rarely provide any positive agricultural benefit.

2-3.3. Land Use

Land use proximal to the study area largely consists of agriculture, forest lands, and grasslands. A small portion of the study area is populated, with small villages and towns sparsely located between water features and road infrastructure.

2-3.4. Principal Industries

The main industrial sectors represented in the study area include agriculture, fish farming, sand and gravel quarrying, brick making kilns, and pig iron furnaces. The main cash crops of the region include hemp, tobacco, cotton, and beets. Grain crops include wheat, corn, millet, sorghum, and soybeans. Vegetables are generally grown for personal household consumption, while some are exported from the region. These industries are important to the local economy. In addition, coal mines in the region employ some of the local workforce.

2-4. Market and Transportation Considerations of the Region

Several pipelines (*Figure 2-5*) have been built or are under construction in the southern portion of the Shanxi Province that provide substantial market access for the sale of CBM production. Additional pipelines currently exist or are being built in adjacent Henan Province. PetroChina's #1 W-E pipeline is a main line to Zhejiang and Jiangsu coastal areas. The Yuji pipeline built by **China Petroleum & Chemical Corporation Limited (*Sinopec)*** provides an outlet to Shangdong coastal areas, while the BoAi pipeline is the outlet to the markets in the Henan Province.

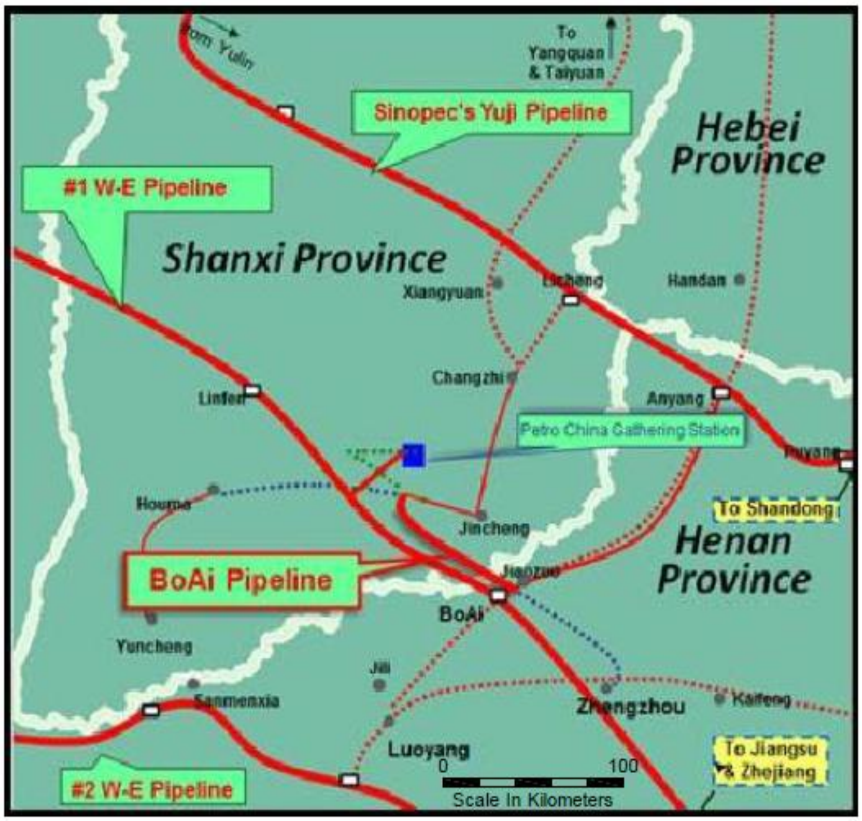


Figure 2-5: CBM Pipelines of Study Area

Pipeline transmission of gas from the southern part of Shanxi Province will provide the principal means to sell gas from the area. By 2015, pipelines are expected to serve about 80 percent of the market demand. Liquefied Natural Gas (*LNG*) and Compressed Natural Gas (*CNG*) are expected to comprise the remaining 20 percent of the market for produced CBM gas.

The current market size is more than twice the anticipated production capacity in this area. Production in 2011 is estimated to be 52 billion cubic feet (*Bcf*) (1,483 million cubic meters (*MMm*^{3})) while the current market size is approximately 117 Bcf (3,304 MMm^3). The market for the PetroChina pipeline is expected to increase by 35 Bcf (1,000 MMm^3) in 2012 and then increase again by 35 Bcf (1,000 MMm^3) in 2014. Similarly, the size of the BoAi pipeline is expected to increase by 35 Bcf (1,000 MMm^3) in 2013 to serve markets such as Luoyang, Jiaozuo, Jiyuan, and Xinxiang in Henan Province. The Shandong market will be available once construction is completed to connect Qinshui to the Yuji pipeline. The first segment of pipe from Qinshui to Changzhi was built in March 2011. The remaining segment to Licheng is planned for completion in late 2011. The initial market for this pipeline is estimated at 18 Bcf (500 MMm^3) in 2012. However, that market is anticipated to double in 2013 and then double again in 2015.

The LNG market, which is currently larger than any of the three pipeline markets in this area, is expected to increase by 28 percent over the next four years to 59 Bcf (1,667 MMm^3) per year. The market size over the next several years is projected to remain at least 2.2 times larger than the forecasted CBM production from the southern Shanxi Province area.

Table 2-1 identifies the projected gas market size by segment and the forecasted CBM production volumes for 2011-2015. As CBM development continues, additional pipelines and LNG plants will be required to handle the additional produced volumes.

Table 2-1: CBM Market Size vs. Supply

	2011 (MMm^3)	2012 (MMm^3)	2013 (MMm^3)	2014 (MMm^3)	2015 (MMm^3)
Forecasted CBM Production	1,483	2,221	2,817	3,147	3,899
Market Size					
BoAi Pipeline	1,000	1,000	2,000	2,000	2,000
PetroChina	1,000	2,000	2,000	3,000	3,000
Yuji Pipeline	---	500	1,000	1,000	2,000
LNG/CNG	1,304	1,389	1,667	1,667	1,667
Projected Gas Market	3,304	4,889	6,667	7,667	8,667

	2011 (Bcf)	2012 (Bcf)	2013 (Bcf)	2014 (Bcf)	2015 (Bcf)
Forecasted CBM Production	52	78	99	111	138
Market Size					
BoAi Pipeline	35	35	71	71	71
PetroChina	35	71	71	106	106
Yuji Pipeline	---	18	35	35	71
LNG/CNG	46	49	59	59	59
Projected Gas Market	117	173	235	271	306

Chapter 3. CASE STUDY

3-1. Introduction and Background

A CBM case study area was selected to assist in development of a model for CBM resource assessment and optimized degasification system design in southern Shanxi Province. The selected CBM case study area is representative of the geologic conditions occurring in the southern portion of the Qinshui Basin and covers approximately 49,421 acres (200 km^2). Technical data used for this is proprietary and the property location has not been disclosed at the request of the mineral owner. The underlying geologic and CBM data utilized in this evaluation were procured from Chinese geologic maps, reports, and databases assembled from mining and CBM evaluations conducted on the CBM case study area. This primary data set includes geophysical logs, coal thickness, gas content, permeability, and seismic data. Structural interpretations delineating the locations and magnitudes of normal and reverse faults were also provided. These data were assumed to be reliable and accurate for the purposes of the resource assessment.

To conduct the preliminary resource assessment of the CBM case study area, the following components have been analyzed:

- Review of geophysical logs from exploration core holes
- Cross- section analysis
- Coal thickness mapping for the No. 3 and No. 15 seams
- Structural interpretation and seismic control
- Review of gas content and permeability data
- Recommendation and site delineation for new exploration core holes
- Gas initially-in-place and recoverable resource estimates for the No. 3 and No. 15 seams
- Modeling for vertical and horizontal CBM development
- Volumetric analysis to estimate horizontal CBM reserves
- Development of CBM production curves based on simulation results
- Drilling plan for horizontal CBM development
- Economic analysis for horizontal CBM development

3-2. Rationale and Components of the Current Exploration, Strata Sampling and Testing Plan in the Study Area

Geophysical and coal reservoir data are obtained to enable quantification of the CBM resource, the optimum means for exploiting it, the recoverable gas reserves, and the economic feasibility of resource development. The components of this plan and the rationale of each are as follows:

3-2.1. Core Holes

The first component of the plan is to obtain cores from the property considered for potential CBM development. The optimum means for obtaining cores for coal reservoir analyses is to drill continuous, small-diameter cores holes to a sufficient depth below the base of the deepest known coal seam. The number and placement of recommended core holes will depend on the areal size and other geologic factors occurring on the prospective property. The coal cores may be used to determine coal thickness, gas content, and coal-seam density, three factors required to calculate the potential size of the CBM resource. The coal cores may also be used to determine the permeability variance within individual coal seams, chemical sensitivity of the coal to completion fluids, adsorption isotherms, and confining stresses of coal seams and bordering strata to assist in determining optimum means of well completion and expected gas recoveries.

3-2.2. Geophysical Logs

Geophysical logs should be obtained on all core holes and in all subsequent vertical test wells and development wells drilled on the property. Wellbore-caliper, gamma-ray, and high-resolution bulk-density logs should always be obtained. The geophysical logs will be used to confirm and better define the coal thickness and density and to enable mapping of the structure of the various coal seams as well as the general characteristics of the host rock. Compensated-neutron, electrical-resistivity, and formation-temperature logs should also be obtained in selected wells to better determine the lithologies, gas and water influx, porosity, and water saturation of bordering strata.

3-2.3. Coal Seam Thickness

The coal thickness, obtained from the cores and geophysical logs, is generally measured in feet (*ft*) or meters (*m*). When adequate thickness data have been obtained, coal isopach maps (individual seams or a composite map for multiple seams) are developed so that the gas-in-place (*GIP*) and the amount of the potentially recoverable CBM resource can be determined.

3-2.4. Coal Seam Density

The density of the coal, which is dependent on coal rank and ash content and obtained from cores and geophysical logs, is generally measured in tons per acre-foot (*tons/af*) or grams per cubic centimeter (g/cm^3). The coal density may vary considerably from area to area and even vertically within the coal section. The density varies depending on the amount and nature of ash, shale or other non-coal components inter-bedded within the gross coal seam. It is one of the factors used to calculate the GIP and is also an indicator of permeability, the ability of fluids (gas and water) to flow through a coal seam. High density coal intervals, indicating shale or other rock inter-bedding, generally will have lower permeability.

3-2.5. Gas Content

The coal-seam gas content or amount of gas compressed into cleats or micro-pores and adsorbed on the coal surfaces by the van der Waals force is measured in standard cubic feet per ton or cubic centimeters per gram (cm^3/g). This component is also a factor used to calculate GIP. It commonly will vary from coal seam to coal seam and laterally within a given coal seam. Gas contents calculated directly by core analysis, including calculated lost gas during core retrieval, desorbed gas, and residual gas components are referenced by “as received basis” (*ARB*) gas contents. Calculated gas contents after accounting for removal of moisture and non-coal constituents are referred to as “dry and ash-free” (*DAF*) or “dry and mineral-matter free” (*DMMF*) gas contents. When adequate gas content data have been obtained, gas content maps are developed to facilitate more accurate calculation of GIP.

3-2.6. Adsorption Isotherms

Measured on coal cores in the laboratory, adsorption isotherms are a measure of the coal seam’s ability to contain CBM gas at various applied pressures. Generally presented graphically, the adsorption isotherm indicates the maximum (fully saturated) potential gas content of the evaluated coal seam and amount (or percentage) of the adsorbed gas that will be released (or desorbed) as the coal-seam pressure is incrementally lowered during production operations. The sorption time, the number of days when 63.2 percent of the total gas has been desorbed, is also calculated. The sorption time is an indicator of reservoir diffusivity and coal permeability.

3-2.7. Pressure Transient Testing

Various types of pressure transient tests may be conducted to determine average coal-seam permeability, reservoir pressure, and drilling/completion damage. It is recommended to conduct injection-falloff tests in core holes and in selected subsequent test and development wells prior to hydraulic fracturing. These tests should be conducted individually on potentially productive coal seams.

3-2.8. Permeability

The permeability determined from pressure transient testing is generally measured in millidarcies (*mD*) and represents the average total conductivity of the tested coal seam, including the effects of coal cleating and natural fractures. These data are used to determine the expected water and CBM gas flow rates, recovery percentage of the GIP, and optimum well spacing. Permeabilities obtained from laboratory testing of cores are not reliable indicators of the true permeability of a coal seam, but can guide in the selection of completion (casing perforation) intervals by determining the relative permeabilities of various coal seams and of vertical intervals within individual coal seams.

3-2.9. Vitrinite Reflectance

The level of thermal maturation exerted on a coal seam during times of burial, or coal rank, is another important reservoir parameter. The primary method to determine the coal rank, or thermal maturation of a coal seam, is virtrinite reflectance, which measures the amount of light reflected by the vitrinite present in the coal's organic component. Higher vitrinite reflectance values indicate higher coal rank and, generally, higher gas content values.

3-2.10. Coal Seam Pressure

The original coal seam pressure may be determined by the various pressure transient tests or by simply recording the stabilized bottom hole pressures of single-seam completed wells. When determining the coal-seam pressure at a shut-in well, it is important to either record the pressure with a down-hole gauge or measure the wellbore liquid level to ensure that the hydrostatic pressure exerted by any wellbore liquids may be added to the recorded surface pressure. Analyzing the coal-seam pressure data together with the adsorption isotherm will enable better determination of the gas content of the coal seam and its expected production characteristics.

3-2.11. Gas Composition

Chromatographic analyses of gas samples obtained from coal cores or at the wellhead of core holes and wells will determine the CBM composition, including the percentage of methane, ethane, propane, carbon dioxide, nitrogen, and other possible constituents in the gas mixture. This testing will allow determination of the CBM heating value and whether treatment other than dehydration will be required to make the gas marketable.

3-2.12. Water Analysis

Laboratory testing of water from the various coal seams, which may be initially obtainable from coal cores, is recommended to allow determination of the extent and nature of dissolved salts and minerals. These analyses may indicate whether scaling problems are likely to occur from commingling the water from the various coal seams.

3-2.13. Seismic Testing

If horizontal well development is planned in heavily faulted areas, it may be necessary to conduct 2-D or 3-D seismic testing to determine the location and nature of geologic faults and to optimize the location and pattern of horizontal wells. The interpreted seismic data should be integrated with known surface faults and other structural data. Detailed structure mapping should include all surface and seismically-delineated faults, as well as all structure elevation control from core holes or drilled CBM wells.

3-3. Coal Geology of the Study Area

3-3.1. Stratigraphy

The coal beds evaluated within the CBM case study area occur in the Lower Permian Shanxi and the Upper Carboniferous Taiyuan Formations. The contact for the two formations is delineated a few meters below the base of the No. 3 coal seam. An unconformity at the base of the Pennsylvanian section and the Ordovician Limestone typically occurs approximately 30 to 100 feet (10 to 30 meters) below the base of the No. 15 coal seam.

The No. 3 seam is the most prominent and economically important coal bed in the southern portion of the Qinshui Basin in terms of both mining and CBM development. The No. 3 seam is well developed on the CBM case study area property, with coal thickness ranging from 1.5 to 18.7 feet (0.46 to 5.70 meters). The No. 15 seam will likely provide a secondary CBM target within the CBM case study area as the seam thickness ranges from 6.0 to 13.3 feet (1.83 to 4.04 meters).

3-3.2. Cross Section Analysis

Four stratigraphic cross sections were prepared and located across the CBM case study area as delineated on *Map 1*. In order to build stratigraphic columns for the cross sections, lithologic interpretations were made from the geophysical logs. The datum for all of the cross sections is the base of the No. 3 seam. Cross sections A-A′ (*Exhibit 1*) and B-B′ (*Exhibit 2*) demonstrate that the No. 3 seam splits and thins towards the west. Cross section C-C′ (*Exhibit 3*) illustrates that the No. 3 seam on the western half of the CBM case study area is comprised of three primary benches or splits. In the second core hole located along this line, the No. 3 seam appears to have been eroded by an overlying sandstone unit and is absent. Cross section D-D′ (*Exhibit 4*), located on the eastern half of the CBM case study area, demonstrates that the No. 3 seam has a more consistent thickness and fewer coal seam splits in this area. Seam splits with greater than 3.3 feet (1.0 meter) in-seam separation may have an adverse affect on horizontal CBM development.

The stratigraphic cross sections demonstrate that the No. 15 seam has partings, but they do not develop into major seam splits. The primary concern in regard to CBM development of the No. 15 seam is the overlying K2 Limestone aquifer, which appears to be in communication with the coal seam. Any communication between the overlying K2 Limestone aquifer and the No. 15 seam could significantly increase dewatering time prior to gas production, decreasing profitability. The cross-section analysis is integrated into the geologic interpretation and development of the No. 3 and No. 15 seam thickness models.

3-3.3. Coal Thickness Data

Coal isopach maps for the No. 3 and No. 15 seams were prepared to quantify the CBM reserve potential of the CBM case study area. Coal thicknesses for the No. 3 and No. 15 seams were procured primarily from Chinese exploration core-hole data and processed coal isopach maps. Additionally, the project team incorporated coal thickness data from 27 new exploration core holes recently drilled within the CBM case study area.

3-3.3.1. No. 3 Seam Isopach

A No. 3 seam total coal isopach (*Map 2*) was generated by processing detailed coal thickness data from previous Chinese mining studies, plus new thickness data from the recently drilled exploration core holes. The thickness values denoted on this map represent the total meters of clean coal. The No. 3 seam thickness ranges from 1.5 to 18.7 feet (0.46 to 5.70 meters) and averages approximately 11.3 feet (3.43 meters) across the CBM case study area. The coal seam splits into two or three distinct benches to the east and west. The project team omitted coal thicknesses from the No. 3 seam model for seam splits with over 3.3 feet (1.0 meter) of separation from the primary bench.

The project team identified an area where the No. 3 seam occurs as a full seam with only minor partings (green shaded area on *Map 2*). This exploration fairway is considered the optimum area for horizontal CBM development of the No. 3 seam. The fairway is characterized by a laterally consistent, thick coal seam with minimal partings. The blue shaded area represents conditions where the No. 3 seam consists of multiple benches with greater than 8.2 feet (2.5 meters of total coal) and less than 3.3 feet (1.0 meter) of seam separation. An area located to the northwest that requires additional exploration is identified on the map.

3-3.3.2. No. 15 Seam Isopach

The No. 15 seam total coal isopach (*Map 3*) was also developed by processing coal thickness data from previous mining studies with new data gathered from the recent CBM exploration program. The No. 15 total coal thickness ranges from 6.0 to 13.3 feet (1.83 to 4.04 meters) and averages approximately 9.4 feet (2.88 meters) within the CBM case study area. The No. 15 seam contains minor carbonaceous shale partings, but does not split into multiple benches with appreciable seam separation. Portions of the CBM case study area where the No. 15 seam has thickness greater than 8.2 feet (2.5 meters) and are considered conducive for horizontal CBM development are shaded in green on *Map 3*. Areas where the No. 15 seam thickness is less than

8.2 feet (2.5 meters) are shaded in blue and are secondary targets for horizontal CBM development.

3-3.4. Structural Interpretation and Coal Depth

The structural deformation of the CBM case study area is characterized by a primary series of northeast- to southwest- trending normal and reverse faults and a perpendicular set of northwest- to southeast- trending faults (see *Map 1*). The faults in the region were delineated by an extensive seismic program conducted by the mineral owner. One large normal fault is located just south of the CBM case study area that has approximately 750 to 820 feet (230 to 250 meters) of vertical displacement. Within the CBM case study area, most of the faults have 30 to 160 feet (10 to 50 meters) of throw. Faulting within the region may adversely affect some areas for horizontal CBM development.

The No. 3 and No. 15 seams occur at adequate depths for CBM development. The depth to the base of the No. 3 seam ranges from 1,000 to over 3,000 feet (300 to over 1,000 meters) in the CBM case study area. The No. 15 seam depth ranges from 1,300 to 3,800 feet (400 to 1,150 meters) across the property.

3-3.5. Coal Permeability

Overall, the compressional structure regime occurring in the CBM case study area indicates a favorable tectonic setting for development of natural fractures and coal permeability. A limited data set indicates relatively low to moderate coal permeability across the CBM case study area, compared to most CBM-producing regions of the world. Based on the data provided by the mineral owner, the average permeability in the CBM case study area is estimated to be in the 1.0 to 3.0 mD range, but should vary across the property.

3-3.6. Coal Rank and Gas Content

Rank of the prospective coals occurring within the CBM case study area is anthracite to semi-anthracite based on vitrinite reflectance data. At this time, there are 10 core holes located in the CBM case study area from which the data are deemed to be adequate to allow a reliable gas content determination and CBM resource assessment. The averages used for the resource assessment are 505 scf/t (15.8 ml/g) for the No. 3 seam and 489 scf/t (15.3 ml/g) for the No. 15 seam.

3-4. Case Study Area Resource Assessment

3-4.1. No. 3 Seam

The project team conducted a resource assessment on the CBM case study area using the No. 3 seam thickness model *(Map 2*) and the average gas content values calculated from the reliable desorption data. The GIP for each potential 247-acre (1.0km^2) horizontal drilling unit was derived using volumetric methods in which the average coal density equals 1.49 g/cm^3 (2,026 tons/af) and the average gas content equals 505 scf/t (15.8 ml/g). The average coal thickness occurring in each potential 247 acre (1.0 km^2) horizontal-unit was calculated using GIS software and was applied to the GIP volumetric equation. Assuming an 80 percent recovery factor based on analogous CBM projects for multilateral horizontal drilling development, the GIP and the estimated recoverable gas values for the No. 3 seam within each prospective horizontal drilling unit are presented on *Map 2*.

The project team identified 122 potential 247-acre (1.0 km^2) multilateral horizontal drilling units on the CBM case study area for No. 3 seam development. CBM resources were not assigned to potential units containing significant faulting. Based on the volumetric analysis, the CBM case study area has a GIP resource estimate of 412.2 Bcf (11.7 billion m^3) for areas with coal thickness greater than 8.2 feet (2.5 meters) in the No. 3 seam. The recoverable CBM resource for the No. 3 seam in the CBM case study area is estimated at 329.8 Bcf (9.3 billion m^3). The resource assessment for horizontal CBM development in the No. 3 seam is summarized below in *Table 3-1*.

Table 3-1: Resource Assessment - No. 3 Seam Horizontal Development

Drilling Locations	Drainage Area Per Well (Acres)	Gas-in-place (Bcf)	Recovery Factor (%)	Recoverable Gas (Bcf)
122	247	412.2	80	329.8

3-4.2. No. 15 Seam

A preliminary resource assessment was also conducted for the No. 15 seam in the CBM case study area using a similar methodology as that stated above. The project team identified 114 potential 247-acre (1.0 km^2) multilateral horizontal drilling units for the No. 15 seam in the CBM case study area in which the No. 15 seam average coal thickness is greater than 8.2 feet (2.5 meters). The GIP for each potential 247-acre (1.0 km^2) horizontal drilling unit was derived using volumetric methods in which the average coal density equals 1.49 g/cm³ (2,026 tons/af) and the average gas content equals 489 scf/t (15.3 ml/g). The average coal thickness occurring in each potential 247 acre (1.0 km^2) horizontal drilling unit was calculated and applied to the GIP volumetric equation. Assuming an 80 percent recovery factor for multilateral horizontal drilling development, the GIP and the estimated recoverable gas values for the No. 15 seam are presented within each prospective horizontal drilling unit on *Map 3*.

Based on the volumetric analysis, the CBM case study area has a GIP resource estimate of 274.8 Bcf (7.8 billion m^3) for areas with greater than 8.2 feet (2.5 meters) thickness for the No. 15 seam. The recoverable CBM resource for the No. 15 seam in the CBM case study area is estimated at 219.8 Bcf (6.2 billion m^3). The resource assessment for horizontal CBM development in the No. 15 seam is summarized below in *Table 3-2*.

Table 3-2: Resource Assessment – No. 15 Seam Horizontal Development

Drilling Locations	Drainage Area Per Well (Acres)	Gas-in-place (Bcf)	Recovery Factor (%)	Recoverable Gas (Bcf)
114	247	274.8	80	219.8

3-4.3. Reserve Definitions

The reserve designations included herein conform to the definitions of reserve categories approved by the Society of Petroleum Engineers (*SPE*) and the Society of Petroleum Evaluation Engineers (*SPEE*).

- Proved reserves include the estimated quantities of crude oil, condensate, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing operating and economic conditions. Reserves categorized as producing are expected to be recovered from the completion intervals, which are open and producing at the time of the estimate.
- Non-producing reserves include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from completion intervals open at the time of the estimate, but either had not started producing, were shut in for market conditions or pipeline connections, were not capable of production for mechanical reasons, or the timing when sales will commence is uncertain.
- Undeveloped reserves are expected to be recovered from new wells on undrilled acreage or from deepening existing wells to a different reservoir. Undeveloped reserves may also be identified where a relatively large

expenditure is required to either recomplete an existing well or install production facilities for primary or improved recovery projects. To be qualified as *proved undeveloped reserves*, reserves on undrilled acreage or improved recovery projects shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled.

- Probable reserves are less certain than proved reserves and can be estimated with a degree of certainty sufficient to indicate they are more likely to be recovered than not.
- Possible reserves are less certain than probable reserves and can be estimated with a low degree of certainty, insufficient to indicate whether they are more likely to be recovered than not.

3-4.4. No. 3 and No. 15 Seam Reserves

The GIP and Estimated Ultimate Recovery (*EUR*) values were determined for each 247 acre (1.0 km^2) drilling unit delineated for the No. 3 and No. 15 seams. The project team did not assign any Proved reserves in the CBM case study area due to the lack of MLD horizontal drilling on the properties. The No. 3 seam well locations were divided into two reserve categories based on the coal thickness model. "No. 3 Seam Probable" locations (green shaded blocks on *Map 4*) generally have coal thicknesses ranging from 9.8 to 18.7 feet (3.0 to 5.7 meters) with good density of well control, sufficient to indicate they are more likely to be recovered than not, and are therefore assigned as Probable reserves. "No. 3 Seam Possible" locations (blue shaded blocks on *Map 4*) generally have coal thicknesses ranging from 8.2 to 13.1 feet (2.5 to 4.0 meters) and the density of well control in these areas is insufficient to indicate whether they are more likely to be recovered than not, and are therefore assigned as Possible reserves. The "No. 15 Seam Possible" locations (blue shaded blocks on *Map 5*) generally have coal thicknesses ranging from 8.2 to 12.5 feet (2.5 to 3.8 meters) and have been classified as Possible reserves due to the lack of established, economic horizontal development for the No. 15 seam in the southern Qinshui Basin. In addition, there are concerns regarding CBM development of the No. 15 seam due to potential communication with the overlying K2 Limestone aquifer. If the K2 Limestone effectively communicates with the No. 15 seam, dewatering of this CBM reservoir may take longer than anticipated and thus reduce the economic value of No. 15 seam development.

The average per-well EUR values were calculated for each of the three reserve categories listed above based on results obtained from the volumetric analyses. The average No. 3 Seam

Probable and No. 3 Seam Possible EUR values were calculated to be 3.348 Bcf (94.8 MMm^3) and 2.285 Bcf (64.7 MMm^3) per well, respectively. The average No. 15 Seam Possible EUR was calculated to be 1.928 Bcf (54.6 MMm^3) per well. A summary of EUR values for each reserve category is presented below in *Table 3-3.*

Table 3-3: Average Estimated Ultimate Recovery per Reserve Category

Reserve Category	Average EUR (Bcf)
No. 3 Seam Probable	3.348
No. 3 Seam Possible	2.285
No. 15 Seam Possible	1.928

3-4.5. Recommended Coal Exploration Drilling Program

The project team selected ten additional exploration corehole sites to help delineate the CBM reserve potential of the CBM case study area (see *Map 2*). Recommended corehole Nos. 1, 3, 4, and 5 are located along the anticipated split line for the No. 3 seam and will help delineate this geologic feature. Core hole Nos. 2, 6, 7, 8, 9, and 10 will provide additional thickness data. Data from each of the recommended core holes will enhance the No. 3 and No. 15 seam thickness models, which will in turn result in an improved resource assessment and also aid in the selection of MLD horizontal well locations. Selection of the proposed locations did not consider topography and may require repositioning.

3-5. <u>Case Study Area Reservoir Modeling</u>

Reservoir modeling utilized **Advanced Resources International**'s **(*ARI*)** commercially available COMET3 reservoir modeling software. COMET3 utilizes a dual porosity, single permeability model to accurately model the flow of gas and water in coal beds. Model iterations were executed for the No. 3 and No. 15 coal seams to determine production curves factored into the financial model referenced in the preceding sections. Modeling inputs were obtained by several methods, including:

- Measurement data from the study area
- Data from neighboring properties and producing concessions
- Estimations based on operator experience

The measured and estimated parameters contribute to a model which accurately predicts the CBM production potential of the study area. Modeled production curves for the No. 3 seam have been compared to actual production data from the area and are considered to be accurate according to initial production values, peak production values, and initial decline rates. *Table 3-4* contains a summary of the governing modeling inputs utilized by the COMET3 reservoir simulator for the No. 3 and No. 15 coal beds.

Table 3-4: Summary of Reservoir Modeling Parameters

Parameter	No. 3 Probable	No. 3 Possible	No. 15 Possible
Depth (ft)	2,225	2,030	2,290
Coal Thickness (ft)	16.7	11.4	9.9
Water Saturation	85%	85%	85%
Fluid Pressure Gradient (psi/ft)	0.3	0.3	0.3
Reservoir Pressure (psi)	668	609	687
Permeability Anisotropy Ratio	1:1	1:1	1:1
Permeability (mD)	2	2	2
Fracture Porosity	3%	3%	3%
Langmuir Volume (scf/t)	1,100	1,100	1,100
Langmuir Pressure (psi)	290	290	290
Gas Content (scf/t)	505	505	489

The No. 3 Probable and Possible cases vary based on the spatial location of the modeled wellbores with respect to thickness. The No. 3 probable case reflects the fairway-like zone of the No. 3 seam, whereas the No. 3 possible case represents the thinner coals outside of the fairway area. Depth and thickness values for each model were obtained through advanced GIS software by averaging grid values in the respective areas. Water saturation, fluid pressure gradient, permeability and the Langmuir coefficients were obtained by an analysis of multiple data points provided to the research team by the mineral owner. Modeled gas contents are equivalent to the average gas contents presented in *Section 2-2.4* for the No. 3 and No. 15 seams.

Modeled wells are representative of those considered standard for multilateral horizontal CBM production in the study area. A Z-Pinnate® (Pinnate®) pattern draining 247 acres (1 km^2) of coal was modeled with laterals spaced at intervals of 600 feet (180 meters) (*Figure 3-1*). The Pinnate® pattern was developed and patented by CDX (Zupanick, 2002) for gas drainage in the

Central Appalachian Basin in the United States. The majority of multilaterally drilled horizontal coalbed methane wells in China are designated as having a herringbone or fishbone pattern, similar in geometry to the Pinnate® pattern (Zhiming and Zhang, 2009). Therefore, modeling in this work for multilaterally drilled horizontal development is based upon the better known Pinnate® pattern. The aforementioned well geometry yields a well with approximately 20,000 feet (6,000 meters) of in-seam drilling. Individual grids are modeled as blocks with dimensions of 100-feet by 100-feet (30.5 meters by 30.5 meters).

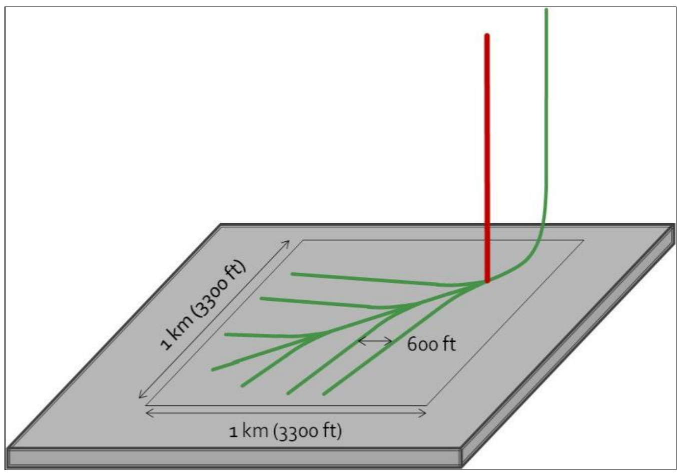


Figure 3-1: Modeled Pinnate® Well for Financial Analysis

Well pressure and pumping constraints were applied to the model. Wells were assumed to pump water from the coal bed at a rate of 250 barrels per day (40 m^3 per day) until each wellbore's bottomhole pressure reaches atmospheric pressure. At this point, the wells continue to pump enough water to maintain atmospheric conditions. Modeling results are shown in *Figure 3-2*, *Figure 3-3* and *Figure 3-4*.

3-6. Case Study Area Economic Model and Financial Analysis

An economic model and template was designed by the project team in order to estimate the financial value of a CBM development enterprise within the selected CBM case study area. To optimize the degasification system design for the southern Shanxi Province, the model assumes that the gassy coal seams are partially depleted with MLD horizontal CBM wells prior to mining. Because the selected CBM case study area is representative of the geologic conditions occurring in the southern portion of the Qinshui Basin, it should provide a reasonable economic forecast for the project.

3-6.1. Horizontal Drilling Schedule

The project team developed a drilling schedule in which the wells with the most favorable reserves (No. 3 Seam Probable) are scheduled to be drilled first, followed by the No. 3 Seam Possible and then by the No. 15 Seam Possible wells. No. 3 seam test wells were scheduled to be drilled in 2010 with full-scale development beginning in 2012. No. 15 Seam test wells are scheduled to be drilled in 2013 and 2014 with full-scale development beginning in 2019 after all No. 3 Seam wells have been drilled. A production flaring period has been incorporated into the plan to allow testing of the four No. 3 seam exploration wells scheduled to be drilled in 2010. These test wells will flare produced gas until the last well drilled has produced for six months. The results obtained from this testing phase will help determine if economic production rates are achieved. The development drilling schedule (*Table 3-5*) will proceed as presented below if the test wells meet economic expectations. The economic analysis is based upon the proposed drilling schedule. Development delays due to regulatory issues, capital constraints, gas market capacity limitations, or time required to build infrastructure could significantly reduce the present value of the reserve base.

Table 3-5: Horizontal Well Drilling Schedule

Year	No. of Wells			Cumulative No. of Wells
	3-Seam	15-Seam	Total	
2010	4	0	4	4
2011	0	0	0	4
2012	12	0	12	16
2013	12	2	14	30
2014	12	2	14	44
2015	14	0	14	58
2016	20	0	20	78
2017	20	0	20	98
2018	20	0	20	118
2019	8	12	20	138
2020	0	20	20	158
2021	0	20	20	178
2022	0	20	20	198
2023	0	20	20	218
2024	0	18	18	236

3-6.2. Financial Model and Economic Analysis

The financial model for the CBM case study area incorporates output parameters (including forecasted future production volumes, operating expenses, and capital expenditures from OGRE®, a reservoir engineering model) into a Microsoft Excel® spreadsheet that generates financial analysis of net income and free cash flow. Economic analyses were performed separately for each seam. Probable locations were evaluated separately from Possible locations in order to calculate the risk-free present value and risk-sensitive fair market value based upon reserve classification. Three primary cases (Runs 1 through 3) were evaluated. Run 1 (*Appendix*) is an economic analysis of 80 Probable No. 3 seam locations. Run 2 (*Appendix*) is an economic analysis of 46 Possible No. 3 seam locations. Run 3 (*Appendix*) is an economic analysis of 110 Possible No. 15 seam locations. Annual cash flows are discounted at 10 percent.

3-6.3. Production Type Curves

The production profiles obtained from the COMET3 reservoir simulator were incorporated into OGRE® to create production type curves for each MLD well category. In general, a type curve is a representative production profile that reflects the relationship between recoverable reserves, production rates, and time. Similar decline parameters were used for each type curve; however, each curve has a different initial production rate corresponding to its EUR value. The type curves for each horizontal well category are presented below in *Figure 3-2*, *Figure 3-3*, and *Figure 3-4*.

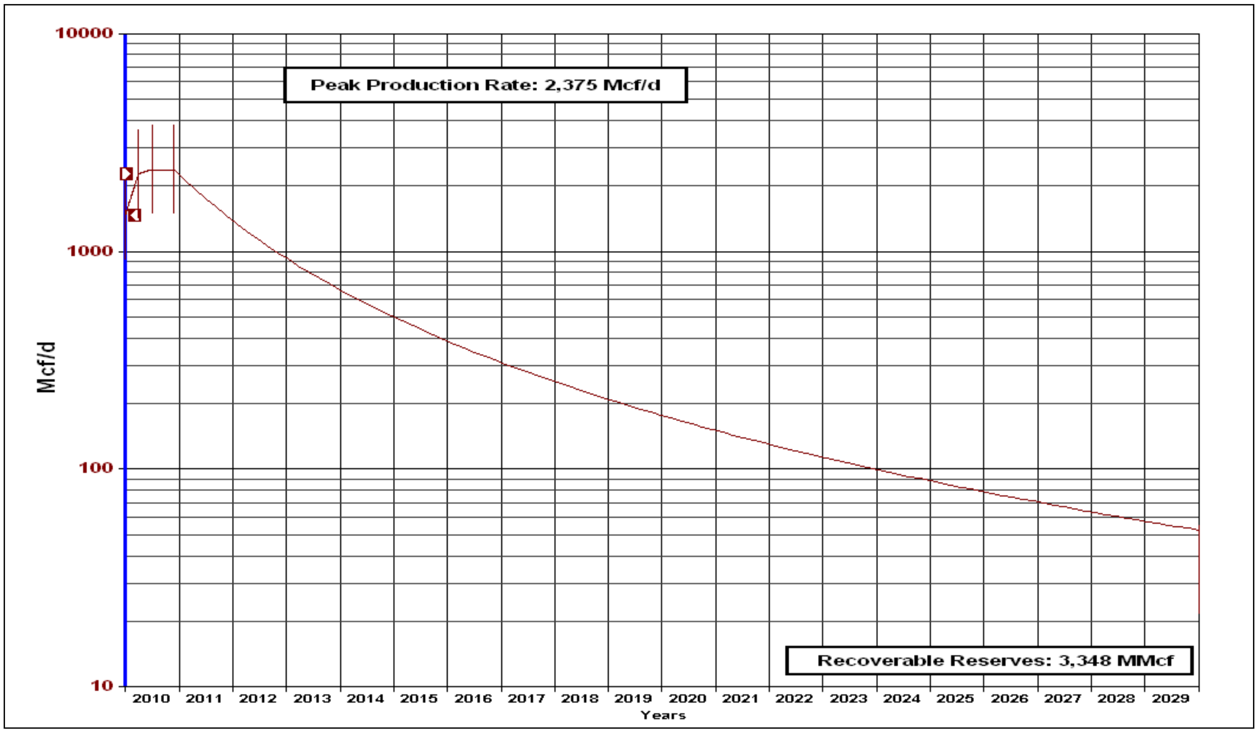


Figure 3-2: No. 3 Seam Probable Type Curve

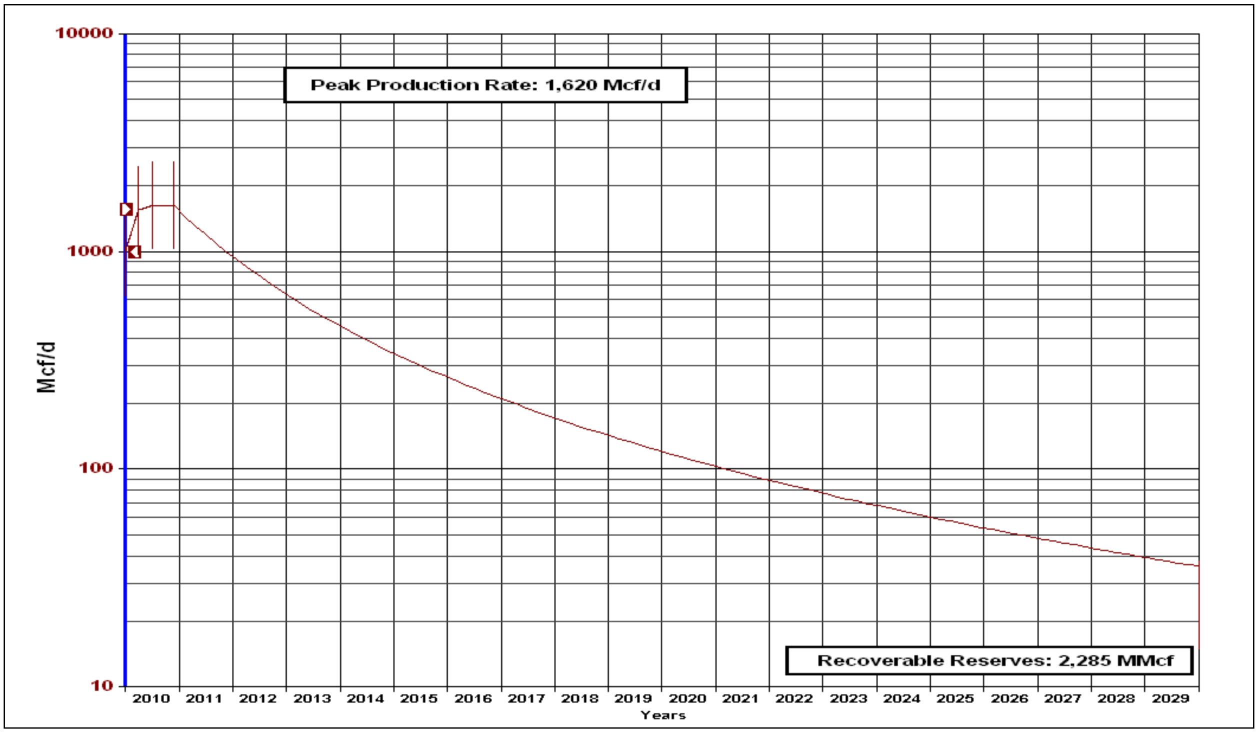


Figure 3-3: No. 3 Seam Possible Type Curve

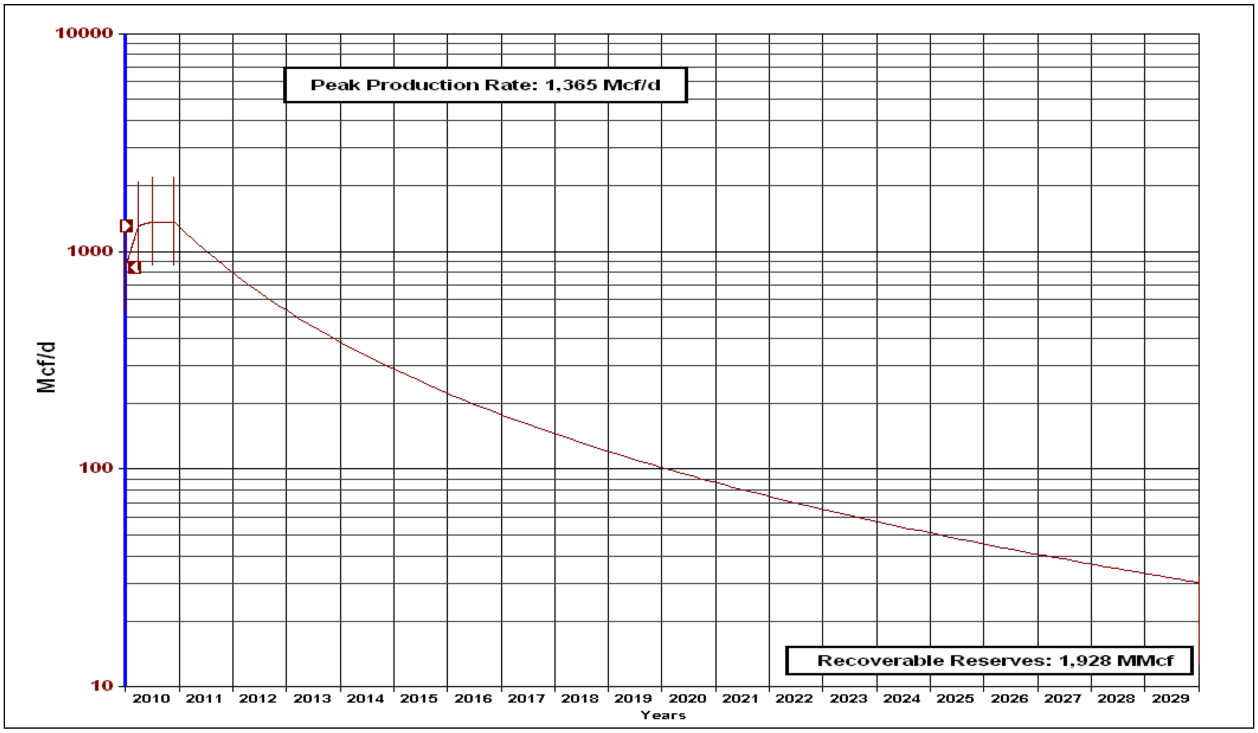


Figure 3-4: No. 15 Seam Possible Type Curve

3-6.4. Economic Assumptions

The project team assumed values for natural gas prices, subsidies, capital development timing, drilling costs, gathering infrastructure costs, operating expenses, gas-price and cost escalation, and shrinkage percentages based on similar CBM development projects undertaken in the United States and China. The primary economic assumptions contained within the financial analysis are summarized below. *(Note: this study was completed in 2009. Hence, the effective project evaluation date is stated to begin in January of 2010. Additionally, the currency exchange rate is no longer accurate.)*

- Effective evaluation date: January 1, 2010
- Currency exchange rate: 6.83 RMB/USD
- Cash flow discount rate = 10% per year
- Working interest: 100%
- Net revenue interest: 100%
- Initial gas price: $5.60 per MMBtu (1.35 RMB/m^3, Btu adjusted)
- Gas price escalation: 3% per year from 2011 through 2025 (see *Table 5-1* and *Figure 3-5* for gas price scenario)

- Gas price subsidy: \$0.829 per MMBtu (based on prior year production)
- Gross heating value adjustment: 950 Btu/scf
- Gas shrinkage (compressor fuel): 7%
- Gas gathering expense: \$.33 per Mcf
- Overhead cost: \$0.45 per Mcf
- Fixed operating expenses: \$11,800/well/month (year 1); \$8,200/well/month (year 2); \$5,400/well/month (year 3); \$2,500/well/month (year 4 and thereafter)
- Drilling schedule: see *Table 3-5*
- Investment to production delay: 2 months
- Drilling and completion costs: \$1,850,000 per well (No. 3 seam); \$1,900,000 per well (No. 15 seam)
- Cost escalation: 3% per year, beginning in 2011
- Depreciation period: 6 years
- Value added tax: 13% of sales revenue
- Value added tax refund: 75 percent of current year value added tax in addition to 25 percent of previous year value added tax
- Income tax: 0% (2010-2011), 12.5% (2012-2014), 25% (2015-thereafter)
- After-tax production sharing costs: 20% of after-tax income

Table 3-6: Gas Price Assumptions, 2010 through 2025

Year	2010	2011	2012	2013	2014	2015	2016	2017
USD/Mcf	\$5.60	\$5.76	\$5.94	\$6.12	\$6.30	\$6.49	\$6.68	\$6.88
RMB/m^3	1.35	1.39	1.43	1.48	1.52	1.57	1.61	1.66
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
USD/Mcf	\$7.09	\$7.30	\$7.52	\$7.75	\$7.98	\$8.22	\$8.47	\$8.72
RMB/m^3	1.71	1.76	1.81	1.87	1.92	1.98	2.04	2.10

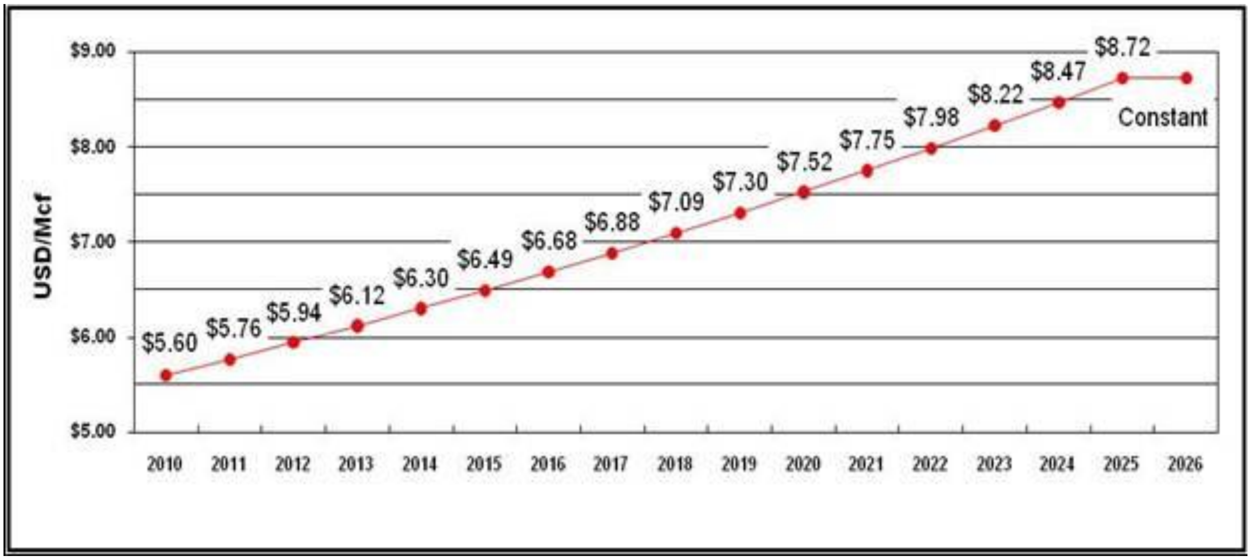


Figure 3-5: Gas Price Assumptions Through 2026

3-6.5. Financial Analysis Results, CBM Case Study Area

Financial summaries of the three reserve categories are presented below in *Table 3-7*. Both risk-free and risk-adjusted valuations are presented below for each reserve case. The after-tax (*ATAX*) valuations are based upon cash flows discounted at ten percent per year (PV10) after the effective date of January 1, 2010. A risk adjustment percentage was applied to the discounted values for each of the reserve categories. The risk adjustments consider uncertainty related to reserve estimates, production profiles, geologic variability, development timing, and reservoir quality, and reflect "industry standard" methodologies for oil and gas valuations. Probable locations are valued at 50 percent of PV10 and possible locations are valued at 20 percent of PV10.

Table 3-7: Summary of Economic Results, CBM Case Study Area

Reserve Category	Gross Reserve (Bcf)	ATAX Net Cash Flow (USD)	Unrisked ATAX PV10 (USD)	Risk Factor (%)	Risked Net Present Value (USD)
Probable No. 3 Seam	217.9	$695,596,852	$286,571,532	50%	$143,285,766
Possible No. 3 Seam	111.9	$363,437,533	$121,339,127	20%	$24,267,825
Possible No. 15 Seam	219.8	$670,594,758	$138,456,313	20%	$27,691,263
Total	**549.6**	**$1,729,629,143**	**$546,366,972**		**$195,244,854**

The risk-adjusted, after-tax Probable No. 3 Seam reserve case is estimated to have a $143.3 million net present value (*NPV*). The Possible No. 3 Seam reserve and Possible No. 15

Seam reserve cases are estimated to have risk-adjusted NPVs of $24.3 million and $27.7 million, respectively. Therefore, the risk-adjusted total reserve case is estimated to have a $195.3 million NPV for the CBM development enterprise within the selected case study area.

Chapter 4. REGULATORY POLICIES AFFECTING CBM INDUSTRIES IN THE STUDY AREA

The Chinese government has promulgated a series of policies to encourage CBM development and utilization. The policies are summarized in *Table 4-1*.

Table 4-1: Summary of China's Policies on CBM Development and Utilization

No.	Date of Enforcement	Document No.	Name	Issuing Authority
1	October 1, 1986	Order of the President of the People's Republic of China No. 74	Mineral Resources Law of the People's Republic of China (Revised on January 1, 1997)	State Council
2	April 4, 1994	-	Provisional Regulations on CBM Exploration, Development and Administration	Ministry of Coal Industry
3	June 5, 2006	Fa Gai Ban [2006] No. 1044	Eleventh Five-Year Plan for CMM (Coalmine Methane) Development and Utilization	National Development and Reform Commission
4	June 15, 2006	Guo Fa Ban [2006] No.47	Guidance on Acceleration of CBM/CMM Development and Utilization	General Office of the State Council
5	July 1, 2007	Cai Shui [2007] No. 16	Notice on the Issues Regarding Acceleration of Tax Policies for CBM Extraction	Ministry of Finance /State Administration of Taxation
6	April 2, 2007	Fa Gai Neng Yuan [2007] No. 721	Notice on Utilization of CMM for Power Generation	National Development and Reform Commission
7	April 17, 2007	Guo Tu Zi Fa [2007] No. 96	Notice on Strengthening Comprehensive Prospecting, Extraction and Administration of Coal and CBM Resources	Ministry of Land and Resources
8	April 20, 2007	Cai Jian [2007] No. 114	Opinion of Coal Bed Gas Exploitation Subsidy	Ministry of Finance
9	2007	Fa Gai Jia Ge [2007] No. 826	Notice on CBM Price Management	National Development and Reform Commission
10	April 14, 2008	Cai Ban Jian [2008] No. 34	Notice on Declaration of Financial Subsidies for CBM Development and Utilization	Ministry of Finance

No.	Date of Enforcement	Document No.	Name	Issuing Authority
11	July 15, 2010	Cai Guan Shui [2010] No. 28	Notice on Duties and Import VAT Exempted for Major Science and Technology Special Projects	Ministry of Finance; Ministry of Science and Technology; National Development and Reform Commission General Administration of Customs; State Administration of Taxation
12	November 30, 2010	Shang Zi Han [2010] No. 984	Notice on Approving Three Companies including CNPC to Engage in a Pilot Program Concerning Foreign Cooperation in Coal Bed Methane Exploitation	Ministry of Commerce; National Development and Reform Commission; Ministry of Land and Resources; National Energy Administration
13	February 28, 2010	An Jian Zong Ting [2010] No. 22	Notice on Specifying CBM Extraction Enterprises' Functions and Duties in Safety Supervision	State Administration of Work Safety

The major policies are classified as follows:

4-1. China's Policies on Management of CBM Mining Rights

4-1.1. Management of CBM Resources

In accordance with the Rules for Implementation of the Mineral Resources Law of the People's Republic of China, mineral resources exist in five forms: energy, metal, non-metal, groundwater, and gas. CBM, one of the energy minerals, has been listed as No. 6 in the category (34 coal types) approved and licensed by the Competent Department of Geology and Mineral Resources under the State Council.

The Mineral Resources Law of the People's Republic of China took effect on October 1, 1986, and prescribes that:

1. Mineral resources are owned by the State. The right of ownership is exercised by the State Council.
2. Anyone who wishes to explore or mine mineral resources shall separately make an application according to law and shall register after obtaining the right of exploration or mining.
3. The State practices a system where the exploration right and mining right shall be obtained with compensation.

4. The exploration licensees shall have the right to carry out specified exploration within the designated exploration areas and have priority to obtain the right to mine the mineral resources in the exploration areas.
5. The department in charge of geology and mineral resources under the State Council (currently Ministry of Land and Resources) shall be responsible for supervision and administration of the exploration and mining of the mineral resources throughout the country.

The *Measures for the Area Registration Administration of Mineral Resources Exploration and Survey* has provided that CBM exploration, survey, and registration shall be subject to the first-class administration system as well as examination, approval, and administration of the department in charge of geology and mineral resources under the State Council, currently the Ministry of Land and Resources (*MOLR*).

4-2. CBM Extraction Prior to Coal Mining

The *Guidance on Acceleration of CBM/CMM Development and Utilization* issued by the General Office of the State Council (Guo Ban Fa [2006] No. 47) prescribes that the following policy of CBM extraction prior to coal mining and a mixture of governance and utilization shall be followed:

- Adopt various incentives and supporting measures to guard against gas accidents in coal mines, make the best use of energy resources, and effectively protect the ecological environment (Article 1).
- Coal mining cannot be started until the gas content in coal seams is lower than the standard rate of 8 m^3/t (Article 5).
- The new exploration right shall be approved under the condition that a comprehensive survey, evaluation and reserve identification are carried out. Where the gas content in coal seams exceeds the standard rate and the coal is qualified for ground mining, a unified CBM and coal development and utilization plan shall be formulated with priority given to CBM extraction (Article 6).

4-3. Overlapping of Two Rights (Mining Rights of Coal and CBM)

The *Notice on Strengthening Comprehensive Prospecting, Extraction and Administration of Coal and CBM Resources* published by the MOLR on April 17, 2007 (Guo Tu Zi Fa [2007] No. 96) requires proper resolution of the issue of overlapping of two rights, namely, mining rights of coal and CBM, of which:

- The newly approved coal exploration and mining rights shall not involve the survey of the specified coal seams and mining areas as announced by the state (Article 11).
- Before this Notice is released, if the exploration and mining rights of coal and CBM overlap and the two parties cannot reach a development agreement, a comprehensive survey of the coal and CBM resources may be conducted. The survey will be conducted through consultation and based on the principle of "CBM extraction prior to coal mining."
- If the two parties fail to reach an agreement within 6 months after the Notice is issued, MOLR may conduct negotiations between them pursuant to some relevant rules and progress of the survey. If the negotiations fail, the two parties shall support the comprehensive survey of the coal and CBM resources based on the principle of integration and balance in coal mining and CBM production (Article 15).
- If a coal/CBM survey report is submitted 6 months after the Notice is issued, MOLR may decline to review or make a record of the reported mineral reserves (Article 16).

4-4. Foreign Cooperation Policies of CBM Development in China

4-4.1. Principal Chinese Enterprises to Cooperate with Foreign Companies in CBM Projects

On September 23, 2001, the State Council released Order No. 317 which prescribed that China United Coalbed Methane Co., Ltd. (CUCBM) will be endowed with an exclusive right to cooperate with foreign companies to explore, develop, and produce CBM.

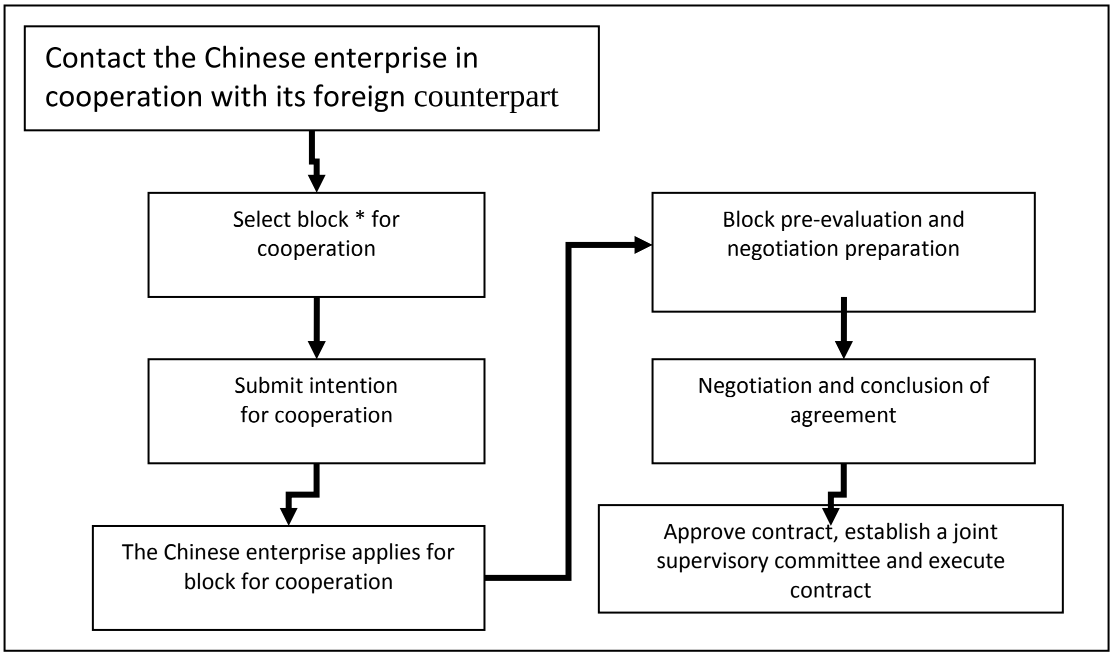
On November 30, 2010, the document (Shang Zi Han [2010] No. 984) announced that China National Petroleum Corporation, China Petroleum & Chemical Corporation, and Henan CBM Development and Utilization Co., Ltd., would conduct pilot CBM extraction with foreign companies in the areas approved by the State Council.

At that time, there were four Chinese enterprises qualified to conduct foreign cooperation in CBM projects. The model of establishing a domestic connection while introducing foreign capital has become a trend in China's CBM development. While encouraging foreign companies to invest in domestic CBM extraction and development projects, the Chinese government also participates in technological cooperation and infrastructure construction in an effort to push forward the modernization progress in the CBM upstream and downstream sectors. Since opening the market to global investors, the Chinese CBM industry has attracted a significant amount of overseas capital.

4-4.2. Procedures for Cooperating with Foreign Enterprises in CBM Projects

The necessary procedures are shown in the *Table 4-2*:

Table 4-2: Procedures for Cooperating with Foreign Enterprises in CBM Projects



*Note: 'block' refers to the divided scope of mining right

CUCBM has defined production sharing contracts as a preferred model in foreign cooperation.

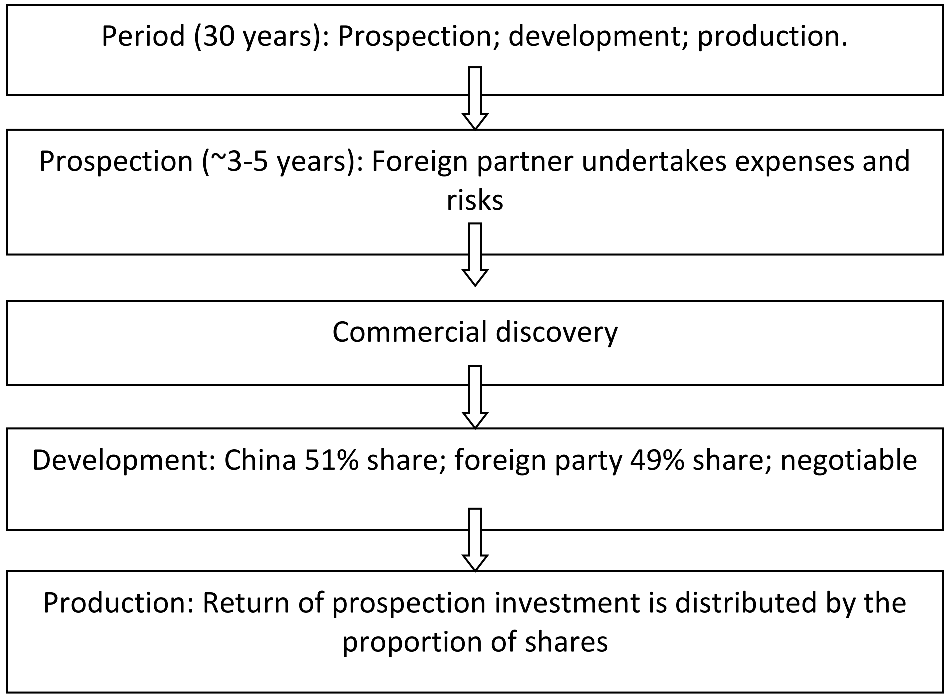


Figure 4-1: Model of Production Sharing Contracts Defined by CUCBM

1. General Principle on CBM Production Sharing Contracts
    - The CBM resources deposited in the contracted areas jointly developed by the Chinese and foreign companies are owned by the People's Republic of China.
    - The laws of China protect the rights and interests of the foreign company which is required to obey the laws of the host country.
    - The foreign company shall provide the exploration investment and bear the associated risks. Both parties shall input funds for joint extraction and production after a CBM field with commercial value is discovered.
    - The foreign company may withdraw from the contract after it has completed the minimum contractual requirements.
    - The contracted areas (excluding the exploration and producing areas) shall be sold to the Chinese party during the exploration period at a higher price.
    - The foreign company shall be the operator under the administration of the Joint Administration Commission which is charged by the Chinese party. After the investments on exploration and development are returned, the Chinese party may take over operations.
    - All data and materials obtained while executing the contract shall be owned by the Chinese party.

- After the development investments are returned or the contract is terminated, the assets in the contracted areas shall belong to the Chinese party.
- The validity of the CBM contract on mining areas, assignment of rights, and all development plans shall be subject to the approval of the relevant departments of the Chinese government.
- The foreign company shall give priority to employing Chinese workers, contractors, and service companies.
- The foreign company shall train the Chinese employees and transfer technology to the Chinese party.
- In accordance with the contract, the foreign company may receive the return of its investments and expenditures from the CBM production.
- As provided for in the Chinese laws, the foreign company shall pay all of the taxes and fees for using the mining areas.
- The Chinese party is obligated to assist the foreign company to resolve problems that occur during CBM operations.

2. Financial Model for the Standard Contracts

    1) The foreign company is required to pay a minimum amount and fund all of the exploration costs. The Chinese party has no obligation to compensate the foreign company if no commercial CBM production is discovered.
    2) When a commercial CBM project is discovered, the Chinese party may join in the development with no more than 51% of stock shares while the foreign company will hold a share of 49%. The foreign company can increase its share through additional investment on the condition that the shares of the Chinese party do not fall below 30%.
    3) The CBM sales revenue shall be distributed in order to pay taxes, fees, and expenses. Revenue will initially be paid for the VAT (5%) as stipulated by the Chinese government. The fees for using the mining areas shall be paid based on the annual CBM production. The expenditures for operations, exploration, and development may also be recovered from the remaining revenue. Upon termination of the contract, if the revenue is insufficient to pay back the total investment and interests of both parties, it shall be regarded as a loss by the two parties.
    4) The surplus revenue, after paying taxes, fees, expenses, and investments, will be shared by both Chinese and foreign companies. The shared ratio is decided through negotiations and is an important item for the foreign companies to consider during the bidding process.

3. Terms of Standard Contract

1) The contracted mining areas: the ground mining areas with geographic coordinates are to be used for joint CBM development as designed by the local government
2) Condition of contract: refers to the exploration, development and production period
3) The pledged minimum exploration commitment: the foreign company shall agree to a minimum amount of exploration and provide funds for conducting the work
4) Economic profit: the profit is obtained through the cooperation of the two parties after paying taxes, fees and expenses
5) Return of investments: accounted for through a certain proportion of the total CBM production
6) CBM price (including quality and quantity): calculated as FOB
7) Taxes and fees
8) Priority shall be given to employing Chinese workers and service companies and purchasing Chinese supplies
9) Train the Chinese employees and transfer technologies to the Chinese party
10) Ownership of capital and data
11) Methods to resolve disputes
12) Others

4-5. China's Policies for CBM Development and Utilization

4-5.1. China Encourages CBM Development and Utilization

In order to encourage CBM development and utilization, China has included this sector as one of its sixteen key special programs for national long-term scientific and technological development. The Central Government formulated a special plan for CBM development for 2011 through 2015, namely, the Fifth Five-Year Plan Period.

The *Provisional Regulations on CBM Exploration, Development and Administration* (issued by the Ministry of Coal Industry on April 4, 1994) states that CBM, a kind of symbiotic gas resource associated with coal, is able to serve as energy and chemical raw material due to its clean and high quality nature. As a state-owned resource, the Chinese Central Government encourages its exploration and development. The coal and CBM enterprises located in the same area shall, by following a principle of mutual understanding and mutual accommodation, collaborate in a close manner to properly deal with the relationship of coal mining and CBM extraction and exchange development plans and necessary drawings.

The *Coal Law of the People's Republic of China* (effective December 1, 1996) stipulates that the State encourages coal enterprises to develop coal preparation and processing as well as comprehensive development and utilization of CBM, gangue, coal slime, stone coal, and peat.

4-5.2. Policy for Project Approval

On June 15, 2006, the General Office of the State Council issued the *Guidance on Acceleration of CBM/CMM Development and Utilization* (Guo Ban Fa [2006] No. 47), which states that:

1. In terms of self-extracting and self-consuming CBM projects, the coal enterprise may make decisions by itself and report to the investment department of the local people’s government for archival purpose.
2. Where a grid-connected CBM power generation project is concerned, it shall be subject to the approval of the investment department of the local people’s government.
3. Where a pipeline network is trans-provincial (regional/municipal) or has an annual transmission capacity of over 500 MM m^3 of CBM, it shall be subject to the approval of the investment department of the State Council. If the pipeline network transmits no more than 500 MM m^3 of CBM, it shall be approved by the investment department of the local people’s government.

4-5.3. Preferential Policy for CBM Development

1. In accordance with the state’s *Land Allocation Catalogue*, the land-use priority shall be given to the CBM extraction and utilization project.
2. The safety production fee drawn by a coal enterprise shall be used for constructing the CBM extraction system used in and under the pit.
3. If the CBM reaches the prescribed quality standard after being treated, it may be given priority to be incorporated into the natural gas pipelines and the urban public gas supply pipelines.
4. The enterprises which explore for CBM directly on the ground may apply for a deduction in fees for using coal mine exploration and mining rights pursuant to some relevant national regulations prior to 2020.
5. The enterprises which extract CBM on the ground may be exempt from the resource tax.

4-5.4. Subsidy Policy for CBM Development

On April 20, 2007, the Ministry of Finance issued the *Opinion of Coal Bed Gas Exploitation Subsidy* (Cai Jian [2007] No. 114), in which Article 3 states that the Ministry of Finance will subsidize CBM extraction enterprises according to the standard of 0.2 yuan/m^3 (purified). On this basis, the local department of finance may again offer proper subsidies to these enterprises in light of the local CBM development and utilization situation. The specific standard and measures shall be determined by the department independently. Article 4 stipulates that the subsidy allocated by the Ministry of Finance is calculated by the following formula: subsidy amount = (sales volume + self-consuming amount − the amount consumed for power generation) × subsidy standard.

4-5.5. Subsidy Policy for CBM Power Generation

On April 18, 2007, the National Development and Reform Commission issued the *Notice on Utilization of CMM (Coalmine Methane) for Power Generation* (NDRC [2007] No. 721). Clause 1 in the Notice presents that the State will encourage the enterprises to develop and utilize CMM (coalmine methane) through various means. Clause 9 requires that the power grid enterprises shall offer convenient conditions for CMM to be incorporated into their power systems. Clause 11 prescribes that the price for grid power generated from the use of CMM shall be referred to as the price of power generated by biomass projects, which is provided in the *Tentative Management Measures for Price and Sharing of Expenses for Power Generation from Renewable Energy* as formulated by the National Development and Reform Commission (Fa Gai Jia Ge [2006] No.7).

4-5.6. Policy for Utilization of Low Quality CMM

On January 21, 2010, the State Administration of Work Safety (*SAWS*) promulgated the *Decisions on Revising Certain Clauses of the Coal Mine Safety Rules*, which, in accordance with the relevant norms on safe utilization of low quality CMM issued by the Administration, has revised the original clause from, "The CMM concentration may not be lower than 30% when being utilized…" to, "Where the concentration of the extracted CMM is lower than 30%, it cannot be directly burnt as fuel gas." If being used for power generation by internal-combustion engines or for any other purpose, the CMM utilization and transportation shall abide by the relevant regulations and technical safety measures shall be drawn. The revised version has removed the restrictions on utilizing low quality CMM for power generation by internal-combustion engines and re-utilizing the condensed low quality CMM.

In March 2010, the SAWS issued ten industry standards on low quality CMM transportation and utilization, including Technical Specifications of Coal Mine Non-metal Pipeline Materials for Transportation and Utilization of Low Quality CMM; Technical Specifications of Automatic Explosion-resistant Device for Gas Pipeline Transportation; Design Criterion for Safety Guarantee System for Low Quality CMM Pipeline Transportation; and Technical Specifications of Low Quality CMM and Water-mist Transportation Hybrid System. They took effect on July 1, 2010.

4-5.7. VAT Preferential Policy

The *Notice on the Issues Regarding Acceleration of Tax Policies for CBM Extraction* (Cai Shui [2007] No.16) states that a policy of VAT refund after collection shall be applied to the CBM extraction enterprises; the refunded VAT shall then be used for developing CBM technologies and expanded production. No enterprise income tax shall be collected.

4-5.8. Preferential Policy for Enterprise Income Tax

The *Law of the People's Republic of China on Enterprise Income Tax* (new version) stipulates that any enterprise engaged in qualified environmental protection or energy and water conservation projects shall be exempt from paying the enterprise income tax from the first to the third year. Its enterprise income tax shall be reduced by half from the fourth to the sixth year. Enterprises that have benefitted from the previous preferential low tax rate policies shall be gradually transitioned to the statutory tax rate within 5 years after carrying out the EITL. Among them, the enterprises which had been required to pay the enterprise income tax rate of 15 percent were subject to the tax rate of 18 percent in 2008, 20 percent in 2009, and 22 percent in 2010. They shall be subject to a rate of 24 percent in 2011 and 25 percent in 2012.

4-5.9. Tariff Reduction and Exemption Policies

The *Notice on the Taxation Policy for Key Scientific and Technological Import Projects* (Cai Guan Shui [2010] No. 28) prescribes that any imported equipment for key scientific and technological projects as listed in the *Program Outline for National Medium and Long-term Scientific and Technical Development (2006-2020)* shall be exempt from tariff and import VAT.

4-5.10. Acceleration of Depreciation of CBM Extraction and Utilization Equipment

In February 2007, the Ministry of Finance issued the *Notice on the Issues Regarding Acceleration of Tax Policies for CBM Extraction* (Cai Shui [2007] No. 16). Clause 2 states that the enterprise engaged in CBM extraction may use a unified accelerated depreciation measure to depreciate equipment. Either the double declining balance or sum-of-the-years-digits method may be used. Purchased equipment used for well drilling, logging, and completions, as well as CBM extraction pumps, monitoring devices, and generator sets may be included under these depreciation methods. Chapter 3 allows for an enterprise income tax exemption of 40 percent of the investment in local equipment that is used in a technology transfer project. The investment money may be from bank loans or self-collected funds. The enterprise income tax is applied in the year that the technology transfer project is launched. Clause 4 allows a CBM extraction enterprise that follows the account checking and tax collection policy and develops new technologies and processes to deduct resultant expenses from the enterprise income tax. A deduction of 50 percent of the actual incurred expense is allowed.

4-5.11. Price Policy

In 1997, the General Office of the State Council issued document No. 8 (Guo Ban Tong [2007]), which prescribes that the CBM price shall be determined by the principle of market economy. The CBM gas supply and demand and thus the market price will be determined by the parties involved. The state will not impose any price limits.

On April 20, 2007, the National Development and Reform Commission published the *Notice on Strengthening Management of Civil CBM Price* (Fa Gai Jia Ge [2007] No. 826). The notice requires that the CBM price, excluding factory prices, shall be determined by the supplier and consumer. In cases where the CBM price is controlled by the local government, it shall actively create conditions to remove the price control (Clause 1).

Chapter 5. REGIONAL GUIDELINES FOR DEVELOPING A COALBED METHANE EMISSION REDUCTION PROGRAM

5-1. CBM Quantification Methods Applicable to the Region

The southern portion of the Qinshui Basin was selected for study due to the high level of deep coal mining activity occurring in conjunction with recent CBM development projects. Volumetric calculations were used in the report to quantify the GIP and recoverable resources to justify future development within the study area. The method used to quantify the resources, which will be described below, may be applied throughout the Qinshui Basin to calculate a preliminary resource assessment for the region.

Several parameters must be defined to perform the volumetric calculations necessary to estimate the CBM resources and recoverable reserves on a property. The primary reservoir parameters include coal thickness, gas content, coal density, well spacing or drainage area, and a recovery factor. Coal isopach maps should be prepared to assist in quantifying the reserve potential of the subject area. The coal thickness data should be obtained from core-hole control, geophysical logs if available, and coal seam mapping from mining operations. Coal isopach maps should be created that cover the entire subject area for all prospective coal seams. Composite coal isopach maps of multiple seams may be used to define the vertical-well CBM potential.

Gas content data should be determined by conducting desorption analysis of coal seam cores in a laboratory. A sufficient number of samples should be tested from across the property, and at various depths of cover in order to obtain a representative sampling. The gas content measurements for each respective coal seam should then be averaged and applied to the volumetric equation. If gas content data are not available from the subject area, regional data from other properties with similar depth and coal rank characteristics may be used to estimate the CBM resource.

Coal density is determined from laboratory tests or from geophysical logs and is a function of the rank of the prospective coals that are being evaluated. Coal density values may be available from data from active and previous mining operations. The equivalent densities of coals with various rank designations, determined by the United States Geological Survey, are provided below in *Table 5-1*. An average coal density of 1.49 g/cm^3 was used in the resource evaluation for the study area.

Table 5-1: Equivalent Coal Density at Various Coal Rank

Rank	Density (g/cm^3)	Density (tons/acre-foot)
Anthracite	1.47	2,000
Bituminous	1.32	1,800
Sub-bituminous	1.30	1,770
Lignite	1.29	1,750

An average well unit size must be determined in order to calculate the GIP per well. Within the study area, the research team assumed development in 247 acre (1.0 km^2) horizontal drilling units. The size of the unit may be adjusted after analyzing sufficient production and well cost data to determine the optimum unit size. 247 acre horizontal drilling units may be used as a starting point to estimate the recoverable CBM reserves. If vertical wells will be drilled, the unit size may be 80 acres (0.3 km^2) or less, depending on permeability and other coal seam characteristics..

Finally, a recovery factor must be applied to calculate the estimated reserves or quantity of gas that will be recovered from the total GIP. This factor can be based on the actual gas recovered from analogous CBM projects. The factor depends upon whether the development is with horizontal or vertical wells. The research team assumed an 80 percent recovery factor based on analogous CBM projects developed with multilateral horizontal wells. Vertical well development can typically be expected to recover between 40 and 60 percent of the GIP, depending on the permeability and well spacing. As CBM development projects expand in China, experience from development areas will assist in better determining recovery factors..

The following example illustrates the GIP and reserves calculation for the No. 3 seam for a single horizontal well unit located within the study area. Using an average net thickness of 11 feet (3.4 m) for the seam, the GIP was volumetrically determined using the assumed well spacing, gas content, and coal density. The estimated GIP for a horizontal well unit in the study area is 2.744 Bcf (77.7 MMm^3). Assuming an 80 percent gas recovery factor, the projected recovery is 2.195 Bcf (62.2 MMm^3) per well unit. This assessment is presented below in *Table 5-2.*

Table 5-2: CBM Gas Well Resource Assessment

Well Spacing (acres)	Coal Thickness (feet)	Gas Content (scf/ton)	Coal Density (tons/af)	GIP (MMcf)	Recovery Factor (%)	Recoverable Reserves (MMcf)
247	11	505	2,000	2,744	80	2,195

The total GIP and recoverable gas reserve estimate for the entire project area can be determined as follows. If sufficient data points are available to develop a detailed coal isopach map, then calculations can be made for each horizontal-well drilling unit by using its respective coal seam thickness in the calculation. The GIP results from the defined horizontal-well units would then be summed to determine the total resource for the property. Otherwise, an average coal seam thickness for the entire property may be used and applied to all of the well units. In this case, the GIP for each well unit would be multiplied by the total number of horizontal-well units delineated on the property to calculate the total resource.

5-2. Reserve Compliance Methodology – Competent Person's Report

5-2.1. Overview

Mineral companies that wish to be listed on the Hong Kong Stock Exchange are required to submit a Competent Person's Report (*CPR*). Companies involved in the exploration and extraction of CBM resources and reserves must provide relevant information in this report in order that potential investors can make a reasonable and balanced judgment regarding the exploration results and value of the gas reserves being reported. The Competent Person's Report must be prepared in conformance with guidelines set forth in codes recognized by the Exchange.[1]

The Competent Person's Report for CBM reserves and resources must provide information for the following sections:

1. Table of Contents
2. Executive Summary
3. Introduction

[1] For mineral reserves and resources: JORC Code (Australasian Code for Reporting of Exploration Results, Mineral Resources and Ore Reserves); NI43-101(Canadian) Standards of Disclosure for Mineral Projects; SAMREC Code (South African Code for the Reporting of Exploration Results, Mineral Resources and Mineral Reserves). For petroleum resources and reserves: PRMS (Petroleum Resources Management System). For valuations: VALMIN Code (Australasia), CIMVAL Code (Canadian), and SAMVAL Code (South African).

4. Summary of Assets
5. Discussion
6. Fields, Licenses, and Assets
7. Business Aspects
8. Economic Evaluation
9. Social and Environmental Aspects
10. Basis of Opinion
11. Illustrations and Maps

5-2.2. Table of Contents, Executive Summary, and Introduction

The Table of Contents and Executive Summary are typical of those in any professionally prepared report. The introduction deals primarily with the Competent Person's qualifications and technical information used to perform the analysis. The Competent Person must be independent of the mineral company and its senior management. This section must detail all data which were used to prepare the report, including any data provided by the mineral company. The Introduction section should contain details of any site visits, the effective dates of the estimates and report, and the reporting standard used in the report along with definitions of the reserves and resources.

5-2.3. Summary of Assets

The Summary of Assets section must include a description, or table, of assets that are held by the company along with the respective ownership percentages. The data should include the gross and net acreage and reserves associated with each asset. The reserves are to be categorized as Proved reserves (1P) and Proved plus Probable reserves (2P). The gross production profiles and net present values should be presented for the same categories. The summary should identify any upside potential with respect to Possible reserves, and Contingent and Prospective CBM resources.

5-2.4. Discussion

The Discussion section relates to the geology and productive CBM reservoirs that are present for the fields under review. A general description of the region's CBM development history should be prepared. Details of the regional geology and reservoir characteristics should be discussed here. The regional coal stratigraphy, number and thickness of prospective coal seams, and the primary structural features of the basin should be addressed in this section.

5-2.5. Fields, Licenses, and Assets

The Fields, Licenses, and Assets section should be comprehensive. It must be divided into four separate sub-sections that address CBM reserves, contingent resources, prospective resources, and other assets that are material to the property. Other material assets include facilities that are not part of the producing assets. For each of the three sub-sections pertaining to reserves or resources, certain information must be provided.

First, a description of the properties and the rights to explore and produce CBM must be provided. The duration, terms, and conditions of the concessions or a description of the licenses should also be presented. The geological and reservoir characteristics should be identified and include, at a minimum, a stratigraphic column, formation thickness, porosity, permeability, and pressure data. Exploratory drilling data, including the depth of tested formations, strata encountered, and whether CBM was discovered or recovered, should also be provided. If production has commenced, the starting date must be provided along with the details of any development. Commercial or geological risks for any contingent or prospective resources, respectively, should be explained.

A description of the methods used to explore and extract CBM and plans and maps for each field should be provided. A summary of existing wells, other bore holes, pipelines, and other facilities should be included. A discussion of the field development plan with production schedules, sales capacity, and system maintenance requirements needs to be provided. Production forecasts are also to be included. Finally, this section requires a statement of the Proved and Proved plus Probable reserves. The Competent Person’s report may include Possible reserves.

5-2.6. Business Aspects of the Company

The Business Aspects of the Company section should include a discussion of the general nature of the business and distinguish between different activities which are material to the business regarding profits or losses and assets employed. The company’s long-term prospects, competency of the technical staff, and any other factors that could affect value should also be discussed here.

5-2.7. Economic Evaluation

If an economic evaluation is based on discounted cash flow analyses, the section should include separate net present value calculations for Proved and Proved plus Probable reserves. The gas price assumptions used for the evaluation should be clearly stated along with details of discounts or premiums applied. The fiscal terms relevant to the project license should be stated. Either a fixed or varying discount rate may be applied. A base case economic analysis should be prepared using either forecasted or constant gas prices and all economic assumptions applied in the analysis should be identified. A table should be provided that summarizes the net present value for each reserve category. The parameters of any gas-price sensitivity analyses should also be discussed. Finally, a separate evaluation should be conducted on plant and machinery that are not essential to the extraction of hydrocarbons.

5-2.8. Social and Environmental Aspects

The Social and Environmental Aspects section must include a discussion of environmental issues or liabilities that are relevant and may have a potential impact on the development of the project. For example, a social issue may be the resistance from people living near the project who want to restrict access. An example of an environmental concern may be the potential to contaminate fresh water supplies during project development.

5-2.9. Basis of Opinion

The Competent Person preparing the report must provide statements that form the basis of his opinion for the project. He must understand the effects of legislation, taxes, and regulations that apply to the assets that are being evaluated. He must also be in a position to attest that the company has the rights to explore and produce the reserves. The final statement made by the Competent Person must be an assurance that the opinion is independent of the company.

5-2.10. Illustrations and Maps

Illustrations in the form of maps, technical drawings, and graphs should be included to supplement the information provided in the text. The illustrations should contain clear scales, legends, and references so they can be easily understood.

5-3. Techniques & Methods Applicable to the Region for Mine Area Degassing Overview

Multiple completion methods are available to effectively degasify coalbed methane targets in the study area. Surface degasification and mine-level degasification methods both exhibit advantages and disadvantages with respect to recovery, cost, gas quality, required technology, and additional factors. As Palmer (2010) discussed in detail, the applicable degasification strategy is governed by the coal's permeability.

The measured permeability in the study area and reported permeability in the region are low. Regional studies find that permeability ranges between 0.1 and 2.0 mD (Su et al. 2005, Yao et al. 2008). The study area's expected permeability, approximately 1.0 to 3.0 mD, is representative of regional findings. Still, isolated sweet spots throughout the region could hold higher permeability coals while limited cleat development and high in-situ stresses could cause localized zones where permeability is considerably lower.

5-3.1. Vertical Fracture Wells

Globally, vertical fracture wells have been used to effectively degasify coals in the 3.0 to 10.0 mD range (Palmer 2010). While this permeability range exceeds that of the study area and region, vertical fracture wells have been effective in the Qinshui Basin. The high gas contents of the region, reported to be between 280 to 350 cubic feet per ton (8.8 and 11.0 ml/g) (Lu et al. 2010, Su et al. 2005, Yao et al. 2008), may somewhat offset the low permeability and allow for financially feasible CBM production. *Figure 5-1* represents a generalized type curve for a vertical fracture degasification well in the study region. In comparison to vertical to horizontal completions, vertical fracture wells require less capital and drain multiple coal horizons. Vertical wells can result in lower recovery values due to less coal exposure, but require less capital than horizontal type completions. Multiple combinations of fracture fluid and proppant (material which holds fractures open) exist which can be optimized for various geologic conditions. *Figure 5-2* presents a cross-sectional schematic of a typical vertical fracture well, depicting wellbore casings, tubing, and cement.

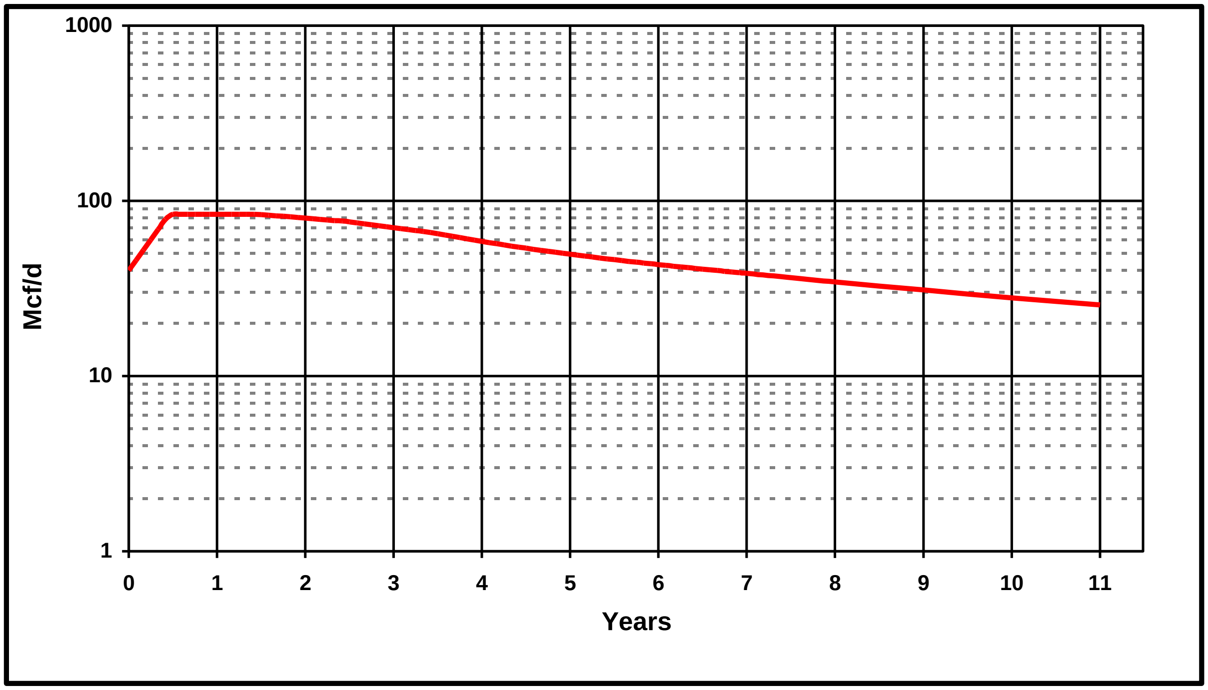


Figure 5-1: Generalized Vertical Fracture Well Production Curve for Study Area

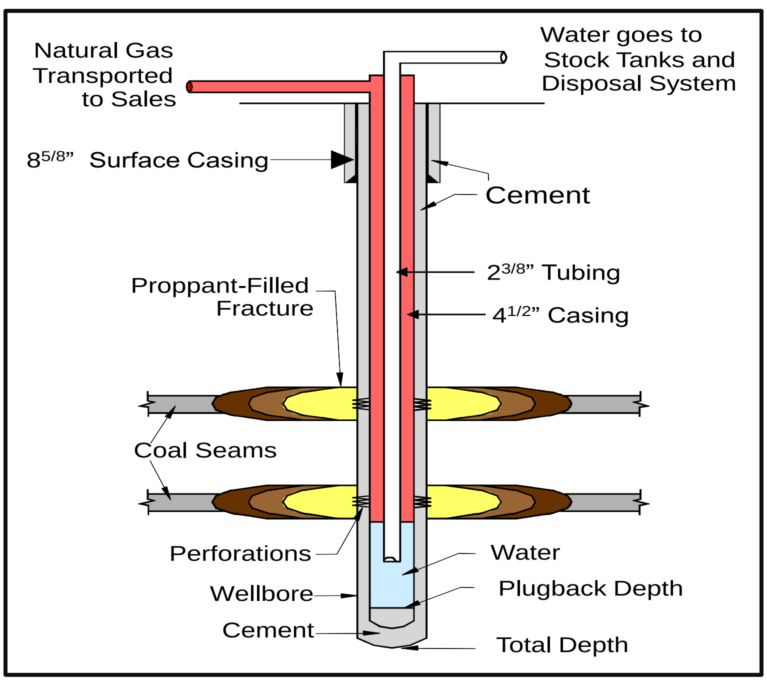


Figure 5-2: Vertical Fracture Well Schematic

5-3.2. Multilateral Horizontal Wells

As permeability drops below the 3.0 mD threshold, horizontal degasification patterns become more applicable (Palmer 2010). Multiple patterns exist for horizontal drainage and are selected on a site specific basis according to permeability, structure, depth, cost, and available technology. MLD wells can produce up to ten times the volume of gas produced by vertical fracture wells (Diamond et al. 1977). Based on higher production rates and success in lower permeability coals, MLD degasification wells have been implemented in the study area and are recommended for future development.

Horizontal degasification completions in the Qinshui Basin utilize a dual-well configuration. *Figure 5-3* depicts a 3-dimensional schematic of the dual-well configuration as applied to a Pinnate®-style drainage pattern.

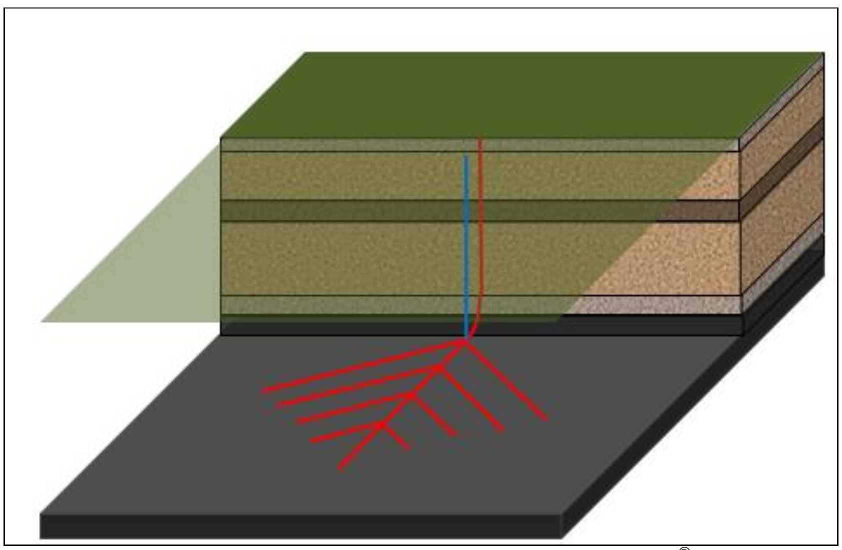


Figure 5-3: Dual Well Vertical to Horizontal Completion with Pinnate®-Style Drainage Pattern

During development of MLD wells, an initial vertical well is first drilled (as depicted by the blue vertical well in *Figure 5-3*). A second well is then drilled approximately 300 feet (100 meters) from the initial vertical well. The second well is turned horizontal, intercepts the coal bed and is guided to intersect the original vertical well. The dual well configuration accommodates dewatering and allows underbalanced drilling, if desired. Pumping water to the surface via the red horizontal to vertical wellbore is difficult due to the high angle at which the pumps would have to operate. The initial blue vertical well can more readily utilize an electric submersible pump or sucker-rod pumping configuration for dewatering and to depressurize the coal. *Figure 5-4* contains a more detailed cross-section illustration of an MLD well.

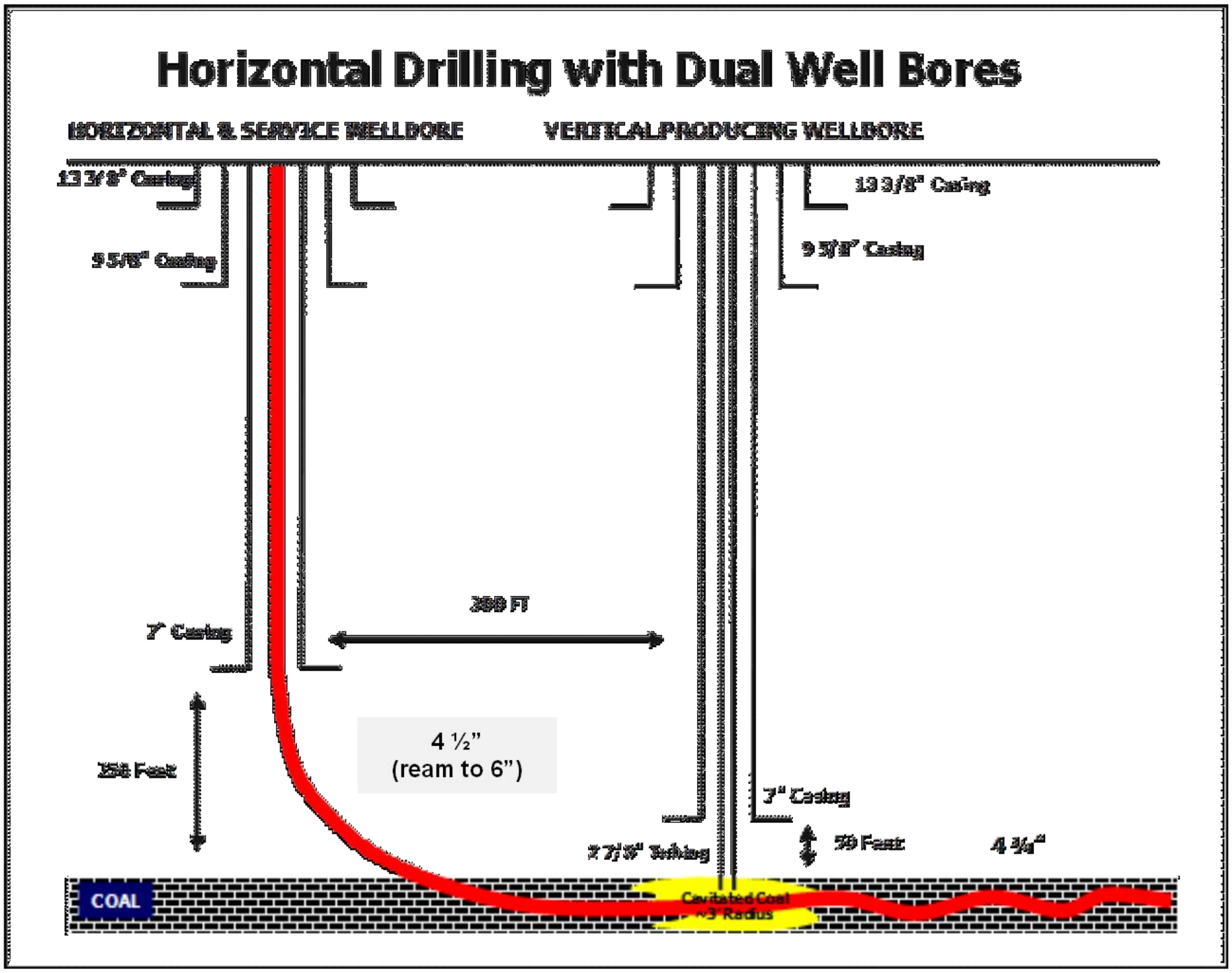


Figure 5-4: Dual Wellbore Schematic for Horizontal CBM Wells

Figure 5-5 depicts an array of common drainage patterns associated with MLD drainage wells. As applied to the Qinshui Basin, the Pitchfork and Pinnate®-style patterns best drain methane by providing closer lateral spacing and greater coal exposure. These patterns can be modified to include additional laterals. Modeling shows that patterns with close lateral spacing can effectively drain coals with permeability less than 1 mD (Keim et al. 2011). Additional drilling required to complete Pitchfork and Pinnate® patterns increases cost but improves gas recovery potential for low permeability coals of the Qinshui Basin.

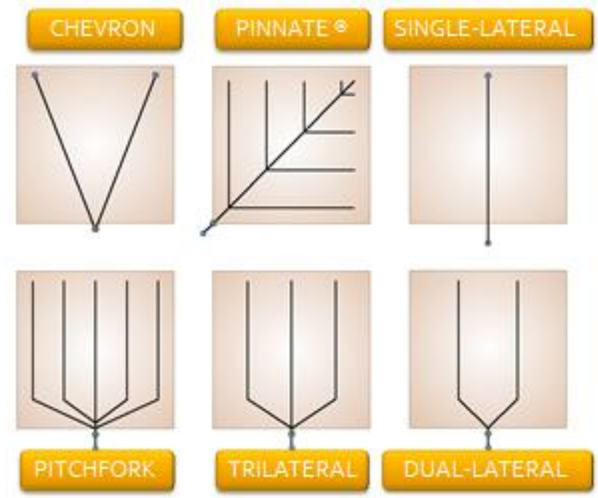


Figure 5-5: Common Vertical to Horizontal Degasification Patterns

5-3.3. In-Mine Drainage

Mines operating in thick, gassy coals often require supplemental degasification to prevent unsafe concentrations of methane in the mine air. Limited lead time for surface-drilled wells prior to mine-through can limit recovery of the original GIP, leaving significant volumes of methane in the coal bed. The remaining methane may increase the risk of mine ignitions and increase greenhouse gas emissions when vented. Combinations of surface drainage methods and in-mine drainage methods can be used to degasify the coal seam and increase methane recovery.

In-mine degasification can be accomplished by application of short-hole and long-hole techniques. Short-hole drilling is accomplished by drilling relatively short holes (less than 1,000 feet) from development gate roads across longwall panels. Water or gels may be injected before the wells are cut through to reduce the probability of igniting methane in the wells. Borehole spacing is governed by permeability and the quantity of methane in the coal bed.. *Figure 5-6* is a schematic of cross panel boreholes in a longwall mine.

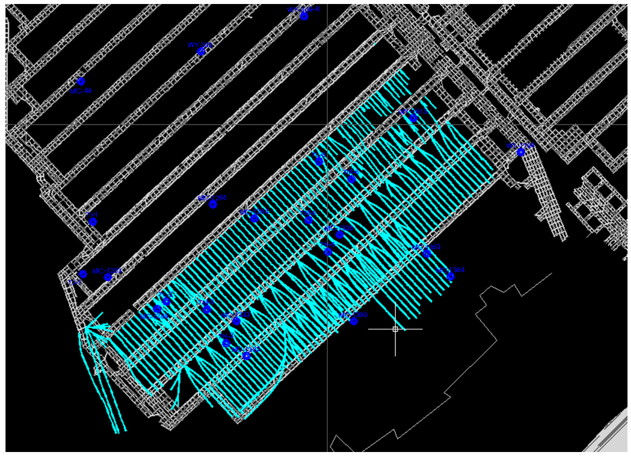


Figure 5-6: Short-Hole (Cross Panel) Degasification Boreholes

Long-hole drilling provides the benefit of longer lead-times prior to mine-through and the opportunity for higher recovery rates compared to short-hole drilling.. Boreholes can be more widely spaced and can simultaneously degasify future gate roads and longwall panels. Longhole drilling generally utilizes a 3-inch (7.62 mm) diameter hole with individual boreholes extending beyond 2,500 feet (750 meters).. *Figure 5-7* illustrates longhole drilling as applied in the Qinshui Basin.

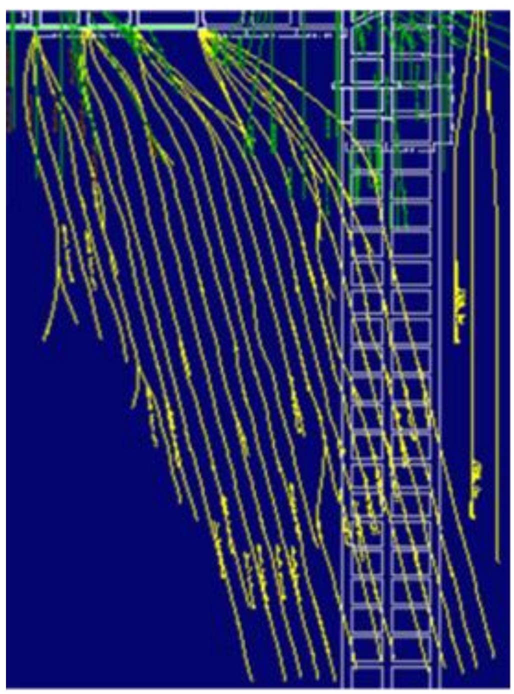


Figure 5-7: Longhole Drilling Example

In-mine degasification requires an extensive underground pipeline network to transport methane to the surface. Methane pipelines present a potential safety hazard. A pipeline rupture could cause a significant influx of methane into the mine atmosphere. To mitigate this risk, systems of automatic shutoff valves are incorporated into the pipeline network. Specific to the study area, methane concentrations from in-mine drainage generally range from 30 to 60 percent. Additional processing is required to upgrade the gas to pipeline quality. The lower quality gas may alternatively be used to operate coal dryers or to generate electricity on site.

5-3.4. Gob Wells

Subsidence during longwall mining can cause methane from overlying strata to flow into mine workings. As rock fractures propagate upward during subsidence, gas can desorb from overlying seams and travel through the new fractures to the mine atmosphere. Longwall mining creates high vertical stresses that can fracture the mine floor. The fractures may extend to gas-bearing strata below the coal seam and provide conduits for methane to enter the mine atmosphere. To mitigate the risk presented by additional methane, gob wells are drilled from the surface prior to longwall panel mining. Vacuum pumps are often used at the surface to exhaust the methane mixtures from the negative pressure mine workings. Compared to in-mine boreholes, gob-gas ventholes generally produce a poor quality gas product with methane concentrations ranging from 30 to 50 percent (Hartman et al. 1997). The required number of gob wells per panel will vary based on factors including coal thickness, gas content of overlying seams, the vertical proximity of overlying and underlying gas-bearing strata, panel length, and panel width. *Figure 5-8* presents a schematic of gob well casings and layout while *Figure 5-9* displays a schematic of gob wells and associated gas flow from overlying strata

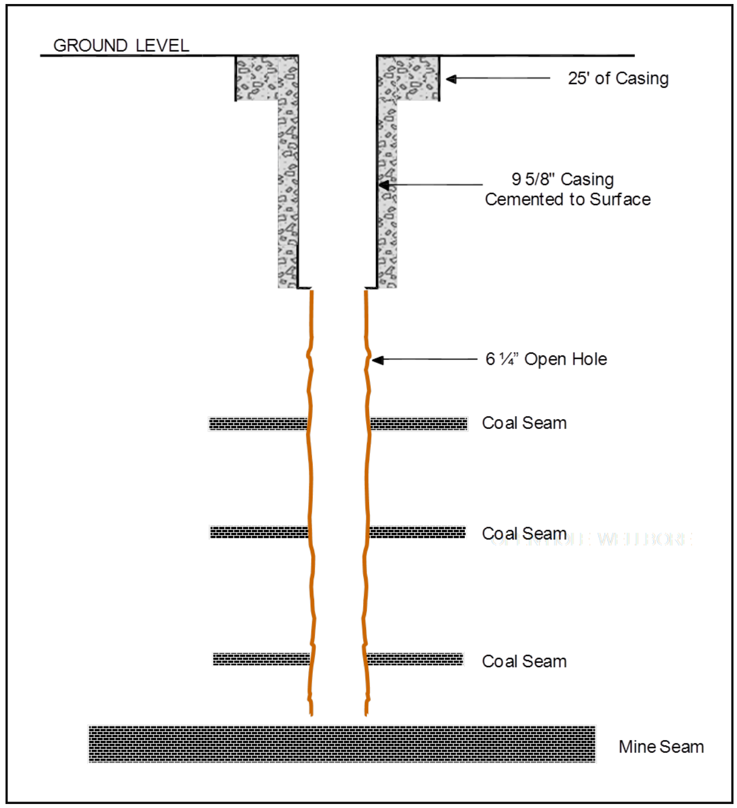


Figure 5-8: Casings and Layout of Gob Well

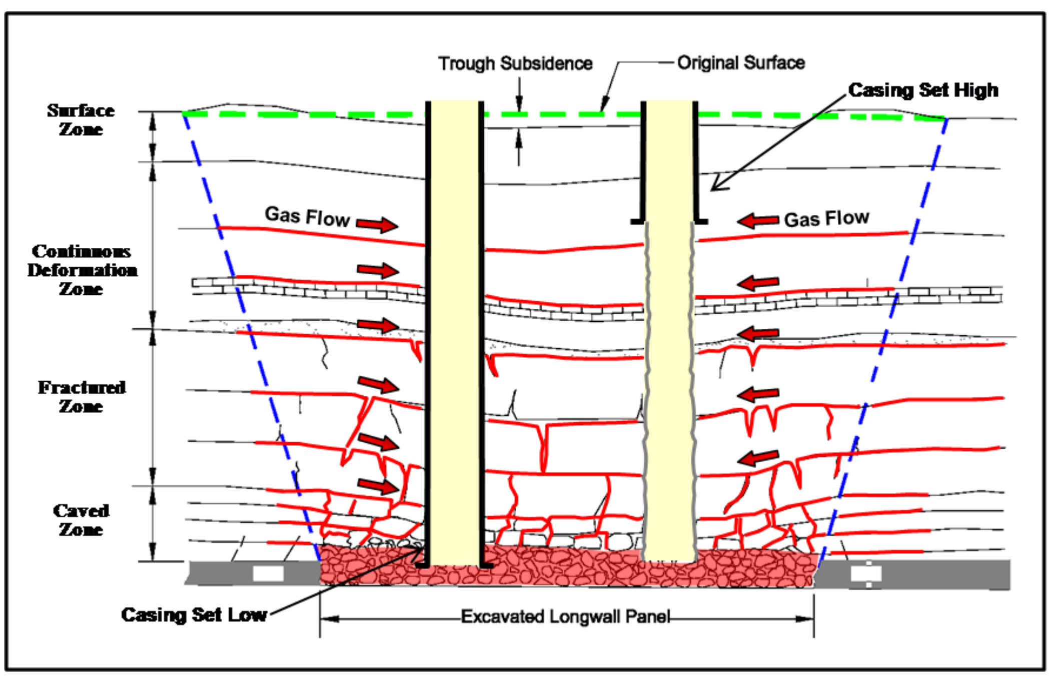


Figure 5-9: Gob Well Gas Flow Schematic

5-4. Options for the Collection and Use of CBM In Lieu of Venting

Provided that transportation infrastructure and market are available, processed pipeline quality gas may be delivered to population centers.. The rural setting of the Qinshui Basin requires that additional options be considered, especially where pipelines are not available. Listed are alternative potential uses for CBM.

- *Industrial Thermal Applications*. Pre-processed recovered coal gas can be used for thermal applications near the wellhead site requiring limited pipeline infrastructure. Within the case study area, a local brick factory uses raw recovered gas for the firing of a kiln.
- *Residential Thermal Applications.* Similar to industrial thermal applications, residents of villages and towns near producing coalbed methane wells can use produced coal gas for heating applications. Providing CBM for local consumption can help garner public support for coal mining and coalbed methane projects.
- *Industrial energy applications.* In conjunction with coal mines, power generating facilities can be constructed near coalbed methane gathering stations to produce electricity to power coal mines and villages. Power generating facilities can be designed to accept methane concentrations ranging from 25 to 100 percent. A power plant within the study area consumes 1 million cubic meters of gas per day of 40 percent methane.
- *Flaring*. At a minimum, produced CBM should be flared instead of ventilated to the atmosphere at the wellhead if alternative applications are unavailable. The flaring of CBM converts methane to carbon dioxide and water thereby decreasing greenhouse gas emissions. While energy is not harnessed through flaring, the radiative trapping capacity of the resulting carbon dioxide is approximately 5 percent of that of methane.
- *Trucking LNG.* Liquefied natural gas offers an alternative means of transporting gas to market when pipeline infrastructure does not exist. Currently, trucks are utilized to transport LNG in the Qinshui Basin. Trucks can hold approximately 140,000 cubic feet (4,000 cubic meters) of methane at standard conditions.

5-5. Methodology to Estimate Reductions in Greenhouse Gas Emissions due to CBM Capture and Use

To assess the reduction of equivalent greenhouse gas emissions from a CBM capture and use project, two key factors must be determined. These factors are:

1. *Estimated (or Measured) Volume of Produced Gas*. Prior to gas production, estimates of the production capacity for CBM wells can be generated by reservoir modeling software or by estimates based on wells in areas with similar geologic characteristics.
2. *Quality of the Produced Gas*. While the methane concentrations of adsorbed gas in the Qinshui Basin are relatively high, various degasification strategies will produce gas of different qualities. The quantity of produced methane, not of total produced gas, represents the key variable in determining emission reductions.

Once the volume and quality of gas are determined, simple stoichiometric relationships can be used to convert recovered gas to equivalent carbon dioxide emissions. A baseline case that assumes that methane is ventilated to the atmosphere must be established. The USEPA provides Global Warming Potential values for multiple gasses. This value associates the global heat trapping impact of a specified gas in relation to the same mass of carbon dioxide. Methane has a Global Warming Potential of 21, making it a 21-times more potent greenhouse gas than carbon dioxide (USEPA, 2011). The following relationship converts the volume of recovered gas (assuming that the gas was ventilated and not recovered) to equivalent tons of carbon dioxide.

$$VentCO_2e = RG * {}^{\%CH_4}/_{100} * 4.045 * 10^{-4} \qquad \text{(Equation 1)}$$

Where *VentCO₂e* represents the equivalent carbon dioxide metric tons released to the atmosphere by ventilating the recovered gas, *RG* (cubic feet). The constant value of $4.045*10^{-4}$ converts the volume of methane to a tonnage of methane and also utilizes the global warming potential value of 21 to convert the methane tonnage to a CO_2e tonnage. For example, ventilating 1 million cubic feet (28,000 cubic meters) of pure methane results in a CO_2e emission of 404.5 metric tons.

Once the baseline case has been established, the CO_2 emissions from the recovered methane must be calculated. Recovered methane will be combusted regardless of downstream use (flaring, power generation, or thermal applications). The combustion of methane is represented by the following balanced chemical equation:

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O \qquad \textit{(Equation 2)}$$

Realizing that a single molecule of carbon dioxide is created for every combusted molecule of methane, a ratio of the molecular masses of carbon dioxide to methane can be used to calculate the mass of carbon dioxide emissions through combustion from a given mass of methane. This relationship is summarized in Equation 3:

$$CombCO_2 = RG * {}^{\%CH_4}/_{100} * 5.31 * 10^{-5} \qquad \textit{(Equation 3)}$$

In Equation 3, *CombCO₂* represents the metric tonnage of carbon dioxide emitted by combusting the estimated volume of recovered gas, *RG* (cubic feet) at a specified methane concentration, $\%CH_4$.

Utilizing Equations 1 and Equations 3, the net reduction in carbon equivalent emissions, $CO_2eReduction$ (metric tons) can be determined, as shown in Equation 4.

$$CO_2eReduction = VentCO_2e - CombCO_2 \qquad \textit{(Equation 4)}$$

As expressed above, decreases in carbon dioxide equivalent emissions are directly proportional to increases in gas recovery.

5-6. Methodology to Assess the Environmental and Social Issues of a CBM Capture and Use Program

5-6.1. Overview

The CBM potential of southern Shanxi Province represents a world class energy reserve. Commercial scale CBM production requires an extensive capital investment for site preparation, well drilling, pipeline infrastructure, and gas processing equipment. Environmental and social impacts must be studied and understood during the development, production, and closure phases of a gas production operations. Environmental and social impacts can affect the economic feasibility of a proposed project.

5-6.2. Equator Principles

The Equator Principles (*EPs*) are a voluntary set of guidelines adopted by the Equator Principle Financial Institutions (*EPFIs*) used to determine, assess, and manage the environmental and social risks of projects financed by the institutions. Developed by international banks, the EPs are aligned with the environmental standards of the World Bank and the social policies of the International Finance Corporation (*IFC*). EPFIs require borrowers to comply with the social and environmental standards set forth by the EPs prior to project funding. Although the principles were developed for international finance, they are globally recognized as a baseline standard and can be used as a framework for environmental and social impact and mitigation, regardless of the source of funds. The EPs are listed below. Additional details corresponding to the derivation, implementation, and specifics of the EPs can be found online at http://equator-principles.com.

- Principle 1: Review and Categorization of Project Risks
- Principle 2: Social and Environmental Assessment
- Principle 3: Applicable Social and Environmental Standards
- Principle 4: Action Plan and Management System
- Principle 5: Consultation and Disclosure
- Principle 6: Grievance Mechanism
- Principle 7: Independent Review
- Principle 8: Covenants
- Principle 10: EPFI Reporting

5-6.3. Environmental Assessment

To comply with the EPs, a detailed environmental assessment (EA) must be completed. For example, Principle 2 calls for an environmental and social assessment. This assessment should address the applicable social and environmental standards set forth through Principle 3. The findings of the EA should be incorporated into the action plan and management system outlined in Principle 4. With respect to coalbed methane production and utilization, the issues that should be addressed in an EA include, but are not limited to:

1. Baseline environmental conditions
   a. Climate
   b. Geology
   c. Soils
   d. Topography
   e. Vegetation
   f. Surface water
      i. Establishment of baseline sampling points

        ii. Monitoring and verification plan
    g. Ground water
        i. Establishment of baseline sampling points
        ii. Monitoring and verification plan
    h. Air quality
        i. Evaluation of air pollution sources
        ii. Establishment of baseline sampling points
        iii. Monitoring and verification plan
    i. Ecology
2. Baseline social conditions
    a. Local land use patterns
        i. Local land uses
        ii. Baseline data pertaining to social impacts caused by:
            1. Road construction
            2. Well site development
            3. Pipeline construction
            4. Gas processing facilities
    b. Infrastructure, services and facilities
        i. Highway
        ii. Electricity
        iii. Water supply
            1) Drilling operations
            2) Hydro-fracturing operations
        iv. Solid and liquid waste disposal
            1) Coal fines and rock cuttings
            2) Produced water
        v. Produced methane for commercial and residential applications
    c. Characteristics of affected communities
        i. Employment
        ii. Health
        iii. Income
        iv. Demographics
    d. Public interaction and consultation
        i. Public forums and meetings
        ii. Assessment of and addressing public concerns
        iii. Public comments and response
    e. Culturally sensitive sites within project area (archaeological and historical)
3. Local legal requirements and regulations, and international treaties and agreements

4. Land acquisition and land use
5. Sustainable development
6. Protection of human health, cultural properties, and biodiversity, including endangered species and sensitive ecosystems
7. Use of dangerous substances
8. Major hazards
9. Occupational health and safety
    a. Baseline information
        i. Relevant data and regulations
            1. Noise and vibration level exposure
            2. Chemical and materials handling
            3. Temperature exposure
            4. Personal protective equipment
            5. Emergency response
            6. Accident prevention
                a. Fire prevention
                b. Life safety
            7. Accident reporting
        ii. Anticipated sources of:
            8. Noise and vibration
            9. Chemical and materials handling
            10. Temperature exposure
        iii. Health and safety plan based on
            11. Relevant data and regulations
            12. Anticipated sources
10. Socioeconomic impacts and impact mitigation
    a. Impacts on indigenous peoples and communities
        i. Impacts on community by employees
        ii. Impacts on community structure
        iii. Public consultation practices
        iv. Impacts on local infrastructure
        v. Involuntary resettlement
        vi. Employment
            1. Multiplier effect
            2. Employment of local citizens
    b. Impact mitigation measures of proposed operations
        i. Change in community census
        ii. Mitigation of impacts on employees
        iii. Participation of the affected parties in the design, review, and implementation of the project

iv. Prevention and mitigation of impacted culturally sensitive sites within project area (archaeological and historical)
v. Mitigation of impediments to road use
vi. Mitigation of noise related issues
vii. Worker health and safety

11. Cumulative impacts of existing projects, the proposed project, and anticipated future projects
    a. Environmental impacts of adjacent operations
    b. General practices with impact potential
        i. Practices with potential to impact surface water
            1. Road construction erosion and storm water
            2. Contaminated runoff from well site
            3. Leaking of drill cutting pit
        ii. Practices with potential to impact groundwater
            1. Drilling mud contamination
            2. Hydro-fracturing fluid contamination
        iii. Practices with potential to impact air quality
            1. Emissions from well site development equipment
            2. Emissions from drilling equipment
            3. Potential gas (methane, carbon dioxide, nitrogen) leaks in pipeline and processing infrastructure
    c. Key issues of proposed operation
12. Consideration of feasible environmentally and socially preferable alternatives
13. Efficient production, delivery, and use of energy
14. Pollution prevention and waste minimization, pollution controls (liquid effluents and air emissions), and solid chemical and waste management

5-7. Template and Exemplar for Cost/Benefit Analyses and Surface Degasification Pattern Design

5-7.1. Overview

A discounted cash flow analysis is used to identify the most economically viable CBM drainage method. The following sections present a template and exemplar which outline the selection process for CBM extraction in the study area based on reservoir modeling output and its incorporation into a discounted cash flow analysis.

Multiple degasification techniques are analyzed. *Figure 5-10* presents a plan view of the well designs to be analyzed. The drainage areas associated with the well configurations are presented in

Table 5-3 along with the required in-seam drilling lengths of horizontal wells. A vertical fracture well was modeled using worst, expected, and best case scenarios based on half fracture lengths. The worst, expected, and best case half fracture lengths were arbitrarily set at 500, 700, and 900 feet (152, 213, and 274 meters), respectively.

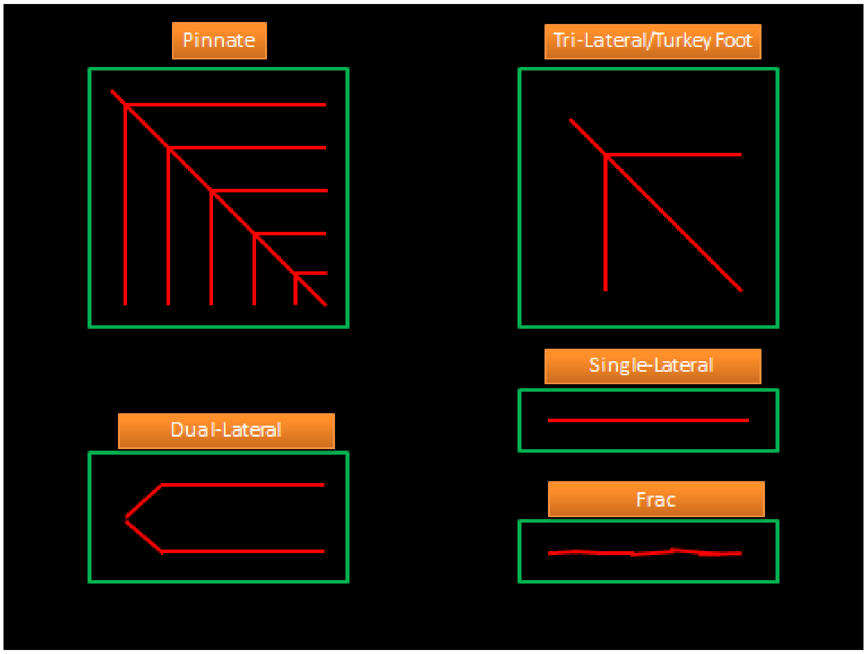


Figure 5-10: Plan View of Modeled Wells for Selection Template

Table 5-3: In-Seam Drilling Length and Drainage Areas of Wells for Selection Template

Well	In-Seam Drilling Length (ft)	Drainage Area (acres)
Pinnate	20,000	250
Turkey Foot	7,100	250
Dual Lateral	6,800	160
Single Lateral	3,200	80
Vertical	<300	80

5-7.2. Reservoir Modeling

Reservoir modeling for the selection template follows a similar methodology as that included in *Section 3-5*. Reservoir characteristics and well operating parameters are those presented in *Table 3-4* . Grids are modeled as square blocks with dimensions of 100 feet by 100 feet (30.5 meters by 30.5 meters). Modeling results associated with the wells are shown in *Figure 5-11* and *Figure 5-12*.

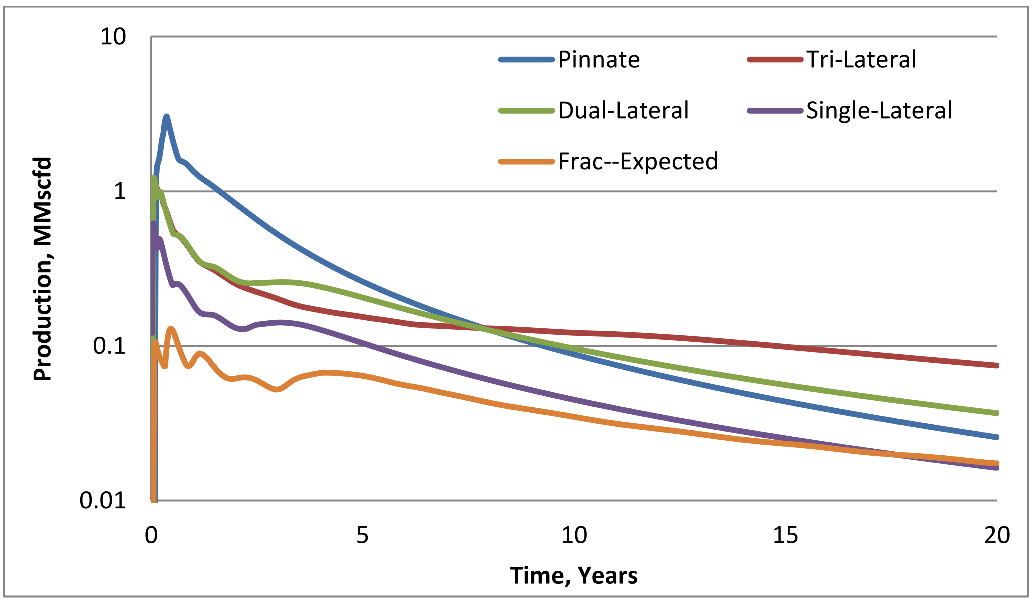


Figure 5-11: Production Rates for Wells in Selection Template

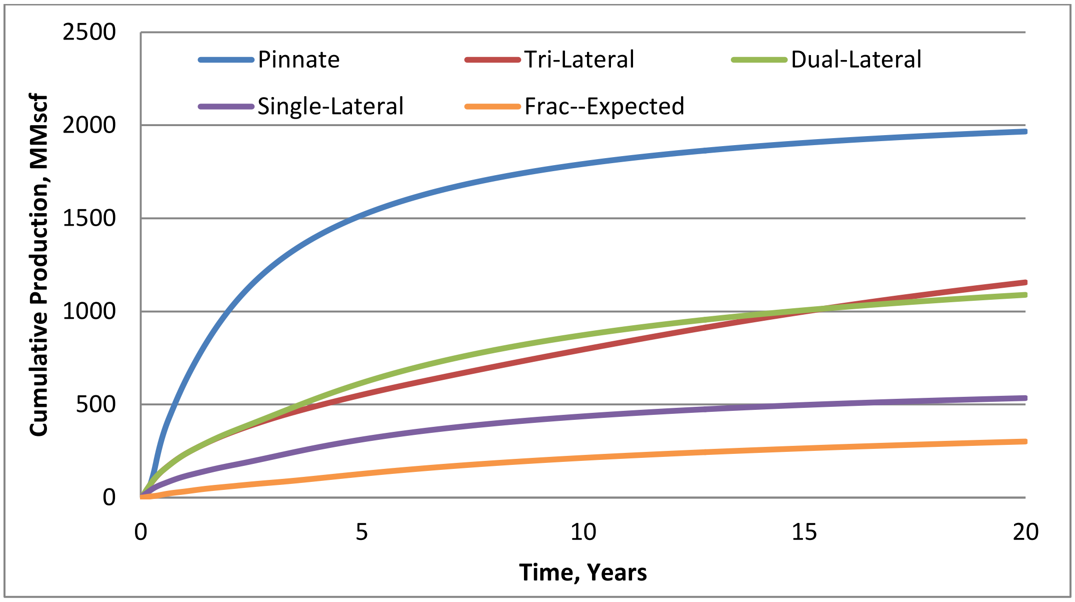


Figure 5-12: Cumulative Production Curves for Wells in Selection Template

5-7.3. Financial Modeling

The financial analysis for the selection template represents a pre-tax and pre-royalty model. Included parameters which are considered constant for each well are outlined below in

Table 5-4. These values are representative of financial parameters in the study area.

Table 5-4: Financial Model Input Parameters

Cash Flow Discount Rate	10%
Initial Gas Price ($/MMBtu)	$5.60
Heating Value Adjustment (Btu/scf)	950
Gas Price Escalation (Years 1-15)	3%
Gas Price Escalation (Years 16-20)	0%
Gas Shrinkage (Compressor Fuel)	7%
Gas Gathering Cost ($/Mcf)	$0.33
Overhead Cost ($/Mcf)	$0.45
Cost Escalation	3%

The capital expenditure requirements for horizontal wells vary based on the required in-seam drilling lengths shown in

Table 5-3. Horizontals capital costs incorporate a baseline $1.85 million dollar cost for a Pinnate®-style well. The cost for the other wells configurations are adjusted by $40 per linear foot ($131 per meter) of in-seam drilling. Vertical wells are assumed to require a capital investment of $400,000. Operating costs are assumed to vary for horizontal and vertical wells. These parameters are summarized in *Table 5-5*.

Table 5-5: Varying Financial Model Inputs

Capital and Operating Expenses	Pinnate	Tri-Lateral/ Turkey Foot	Dual Lateral	Single Lateral	Vertical Fracture
In-Seam Drilling Length (ft)	20,000	7,100	6,800	3,200	630
Drainage Area (acres)	250	250	166	79	79
Base Capital (horizontal wells assume 20,000 ft of in-seam drilling)	$1,850,000	$1,850,000	$1,850,000	$1,850,000	$400,000
Adjusted Horizontal Capital ($/ft)	$40.00	$40.00	$40.00	$40.00	NA
Capital Adjustment	$-	$(516,000)	$(528,000)	$(672,000)	NA
Adjusted Capital	$1,850,000	$1,334,000	$1,322,000	$1,178,000	$400,000
Year 1 Fixed Operating Expenses ($/month)	$7,500	$7,500	$7,500	7,500	$4,000
Year 2 Fixed Operating Expenses ($/month)	$5,000	$5,000	$5,000	$5,000	$2,500
Year 3+ Fixed Operating Expenses ($/month)	$2,000	$2,000	$2,000	$2,000	$1,500

The summarized discounted cash flow analyses for each well are shown in *Table 5-6*. The details of the model, including annual production, sales, and costs are included in the *Appendix*. The well pattern with the highest internal rate of return defines the optimum degasification strategy. Based on the analysis, the Pinnate®-style drainage pattern provides the highest internal rate of return.

Table 5-6: Financial Analysis Summary for Selection Template

Parameter	Pinnate	Turkey Foot	Dual Lateral	Single Lateral	Frac-Low	Frac-Expected	Frac-High
Capital	($1,850,000)	($1,334,000)	($1,322,000)	($1,178,000)	($400,000)	($400,000)	($400,000)
NPV	$4,142,627	$1,421,528	$1,469,992	$56,700	$35,733	$179,260	$328,447
IRR	100%	34%	38%	11%	12%	18%	24%

5-7.4. Financial Sensitivity Analysis

The relative significance and impact of financial model inputs are determined through a sensitivity analysis. The values associated with parameters presented in *Table 5-7* were changed to represent possible minimum and maximum values. A graphical representation of the sensitivity analysis applied to the Pinnate® well is presented in *Figure 5-13* and

Figure 5-14. The gas sales price represents the most significant variable in the sensitivity analysis. The Pinnate® well provides an acceptable internal rate of return value of approximately 35 percent with the lowest anticipated initial gas price of $3.36 per million Btu.

Table 5-7: Analyzed Parameters for Sensitivity Study

Parameter	Adjustment
Initial Gas Price	+/- 40%
Gas Price Escalation	+/- 50%
Costs (Gathering and Overhead)	+/- 50%
Cost Escalation	+/- 50%
Capital	+/- 20%
Operating Expenses	+/- 50%

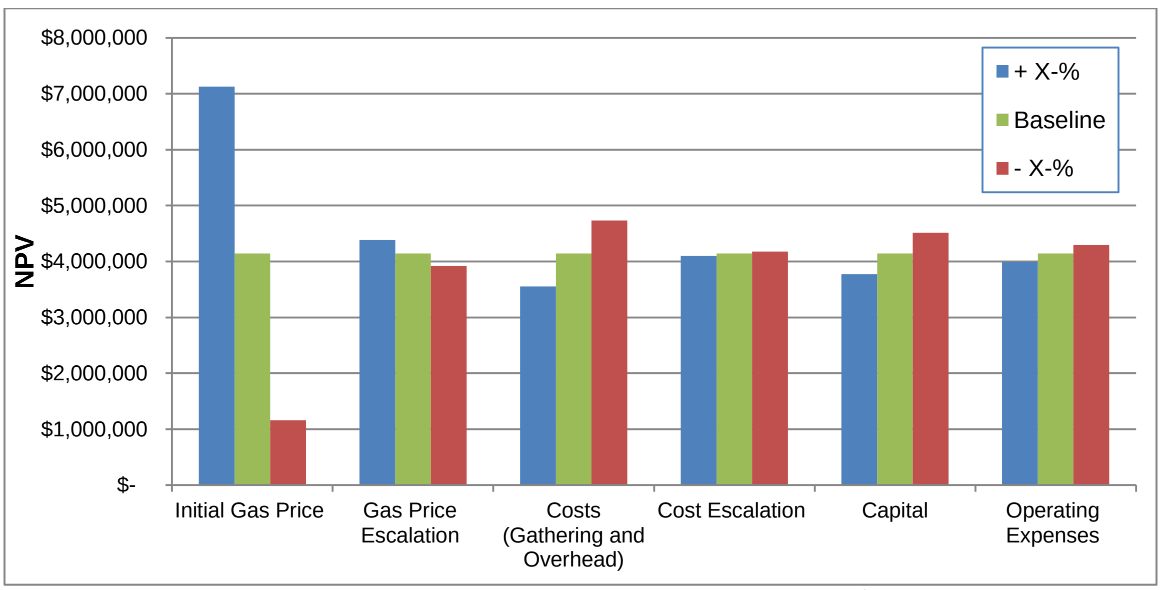


Figure 5-13: NPV Sensitivity Study Results for Pinnate® Well

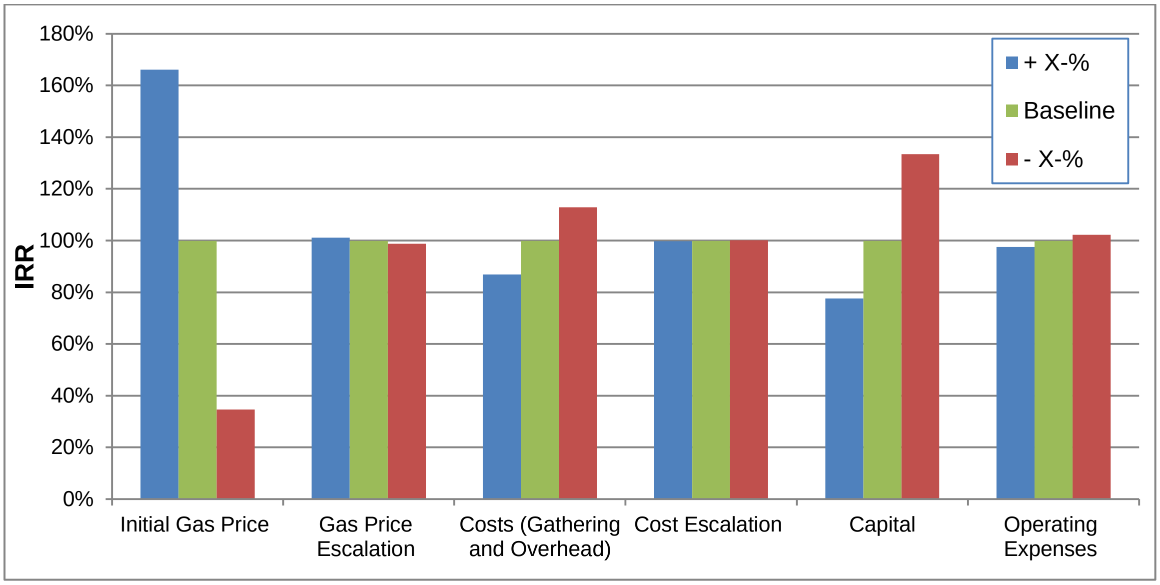


Figure 5-14: IRR Sensitivity Study Results for Pinnate® Well

5-8. Extrapolation of Findings beyond Study Area

The framework for CBM reservoir characterization, reserve analysis, methane emission reduction calculations, socioeconomic and environmental impacts, and regulatory issues apply to a broader region than southern Shanxi Province. The main component of the handbook that cannot be directly related to CBM bearing regions outside of the Qinshui Basin relates to the application of CBM drainage techniques. The selection of drainage techniques is complex and requires consideration of geological characteristics that cannot be extrapolated beyond the study area. The drainage techniques discussed in *Section 5-3* are applicable where seam thickness, permeability, and gas contents are roughly equivalent to those of the Qinshui Basin.

Where the permeability of a gas bearing coal seam is considerably higher or lower than the permeability of study area, well drainage patterns can be modified. Keim et al. (2011) demonstrated relationships between lateral spacing in Pinnate®-style wells and permeability to maintain sufficient gas production within the Qinshui Basin. These relationships and their associated production rate curves are depicted in *Figure 5-15* and *Figure 5-16*. These relationships can be used within and beyond the Qinshui Basin to account for variations in permeability.

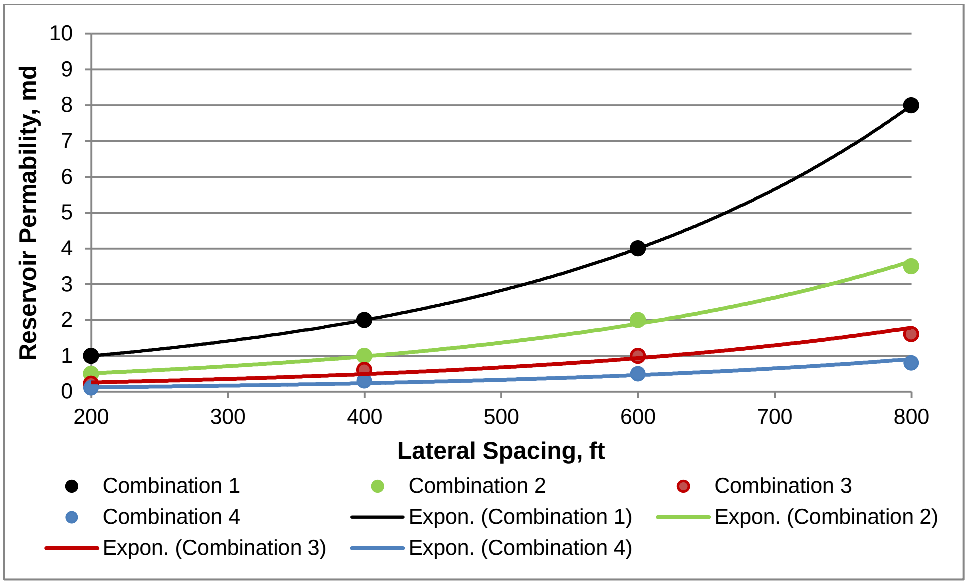


Figure 5-15: Combinations of Horizontal Lateral Spacing and Permeability Yielding Similar Production Curves (from Keim et al. 2011)

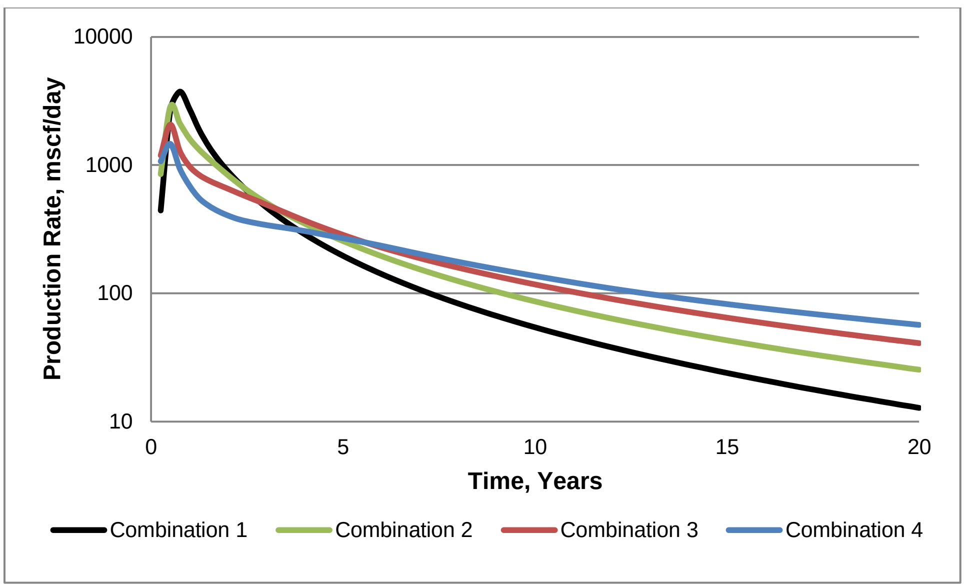


Figure 5-16: Production Curves Associated with Lateral Spacing and Permeability Relationships (from Keim et al. 2011)

The following list outlines additional findings of Keim et al. (2011) with respect to horizontal drainage patterns, and additional guidelines that should be followed when developing CBM resources via horizontal techniques are also included.

- Orient horizontal wells to intersect the face cleats whenever possible. Permeability anisotropy ratios (face cleat to butt cleat) can be as high as 17:1, but are generally in the range of 4:1 (Massarotto et al. 2003). The improper orientation of a Pitchfork-style well can result in the loss of nearly 20% of recoverable reserves over a 10-year period (Keim et al. 2011).

- If few data exist with respect to cleat orientation and permeability anisotropy, Pinnate®-style patterns offer the least production sensitivity with respect to proper orientation. As Pinnate®-style wells have laterals oriented 90 degrees from each other, at least half of the laterals will intersect the face cleat (Keim et al. 2011)
- In conditions where borehole collapse is a concern, Pitchfork-style wells offer a lesser chance of catastrophic well failure from borehole collapse than Pinnate®-style patterns. Pitchfork-style wells do not rely on the structural integrity of a main lateral for gas production.
- Horizontal wells should always be drilled in an up-dip manner, allowing water to flow downhill to the producing wellbore. If drilled in a down-dip manner, accumulated water will exert hydrostatic pressure on the coalbed, significantly decreasing recoverable reserves.
- Drilling from ridge tops allows maximum pressure to be exerted on the drill steel, enabling longer boreholes and larger drainage patterns.
- Developing extremely shallow or extremely deep coalbeds via horizontal drilling can prove difficult. At great depths, higher horizontal stresses make the drilling process difficult. At shallow depths, it becomes difficult to exert sufficient pressure on the drill string to facilitate horizontal drilling. A local drilling expert with experience in the Qinshui Basin indicates that successful drilling in coalbeds occurs at sub-surface depths of between 360 to 2,950 feet (110 and 900 meters).

Chapter 6. CONCLUSIONS

The advantages of coalbed degasification in advance of mining are threefold: reduction of greenhouse gas emissions; enhanced mine safety; and production of a clean-burning energy source. Geologic conditions in the Quinshui Basin are favorable for commercial scale CBM development. Although some CBM development has been demonstrated in the area, many untapped resources exist that could provide the opportunity for sustained production over a significant period. This handbook serves as a guideline for parties interested in the Qinshui Basin's CBM resource, and outlines the methodology to develop a CBM extraction plan.

A detailed reserve analysis on a geologically representative gas bearing coal property in the Qinshui Basin was conducted to determine its GIP and recoverable CBM resources and reserves. Recommendations were made to increase the reserve base through additional exploratory drilling. Multiple degasification strategies for the greenfield property were analyzed through reservoir modeling to determine the optimum well configuration based on economic criteria. Results of a financial study showed that multilaterally drilled Pinnate®-style wells exhibit the highest level of economic viability due to their high production rates, despite higher capital investment than traditional hydraulically fractured vertical wells. Low permeability coals in the region further necessitate horizontal development to effectively drain gas prior to mining, thereby significantly decreasing methane emissions during mining and boosting mine production.

The research team developed a well drilling schedule and an associated detailed financial model for the property, focusing on the No. 3 and No. 15 coal seams. Financial modeling showed a high level of economic feasibility for development of the No. 3 seam. Some uncertainty exists for commercial development of the No. 15 seam because an overlying aquifer could decrease dewatering rates of the coal seam. The No. 15 seam's potential for gas production should be noted. The No. 3 and No. 15 coal seams exhibit consistent thickness across the basin and are the primary targets for coal mining.

An overview of the regulatory framework as applied to CBM development in southern Shanxi Province is provided in addition to a market and transportation analysis. While all steps in the exemplary reserve study are well documented, an overview of the components of a

Competent Person's Report is also included. The Competent Person's Report is a listing requirement of the Hong Kong Stock Exchange for mineral companies. Additionally, a brief introduction to the Equator Principles is included, providing an overview of key social and environmental issues to be addressed for developing projects based upon global standards set forth by the World Bank.

While the handbook identifies the CBM producing potential of the Qinshui Basin, the methodology used to assess a CBM reserve base is applicable on a global scale. Multilaterally drilled horizontal wells are appropriate for the Qinshui Basin due to high gas content and relatively thick coal seams. Many of the principles discussed could be extrapolated to other concessions throughout the world with similar properties. Although the discussed extraction techniques are only relevant for geologic conditions specific to the study area, the documented steps for identifying CBM resources and reserves apply to projects globally.

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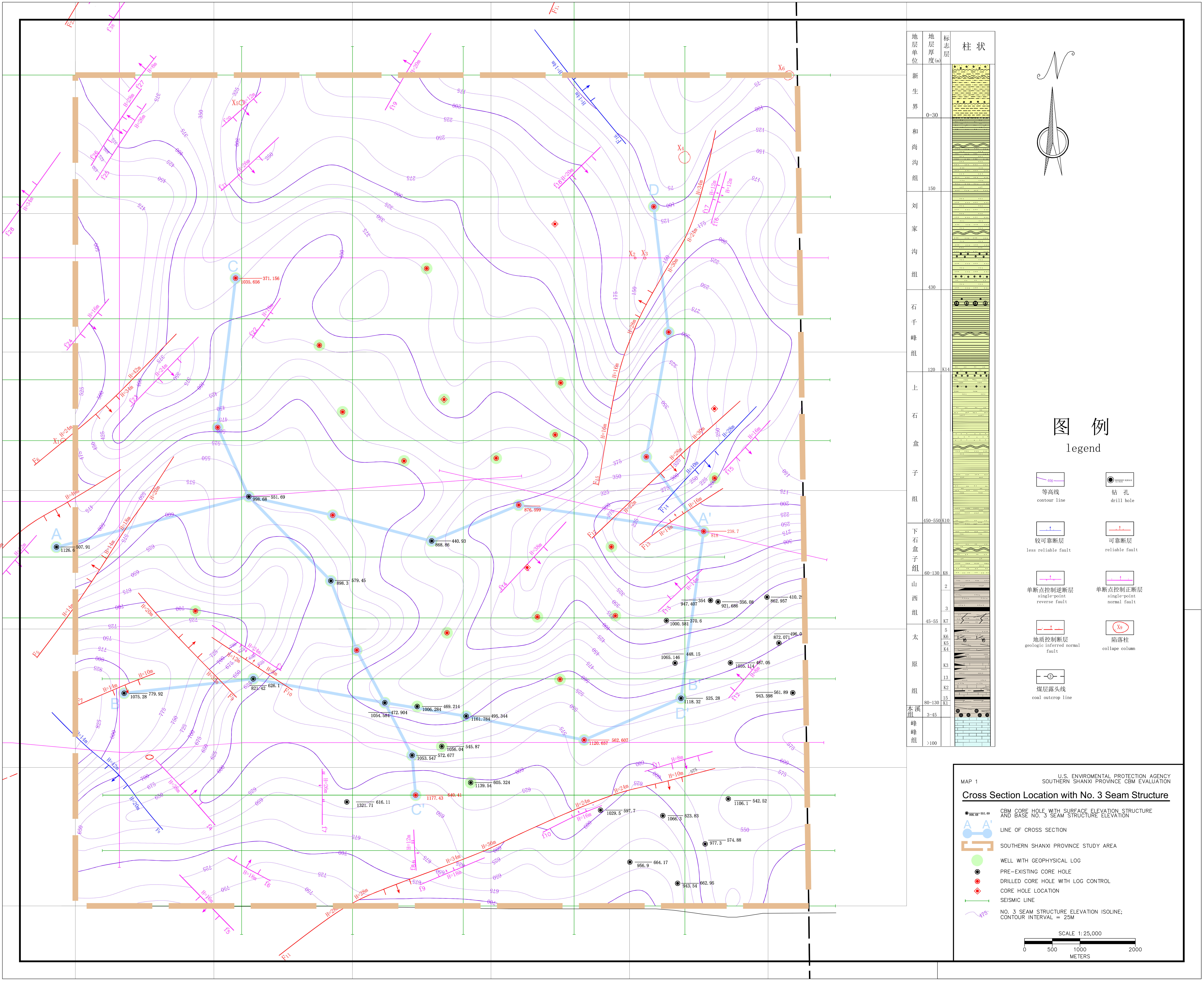
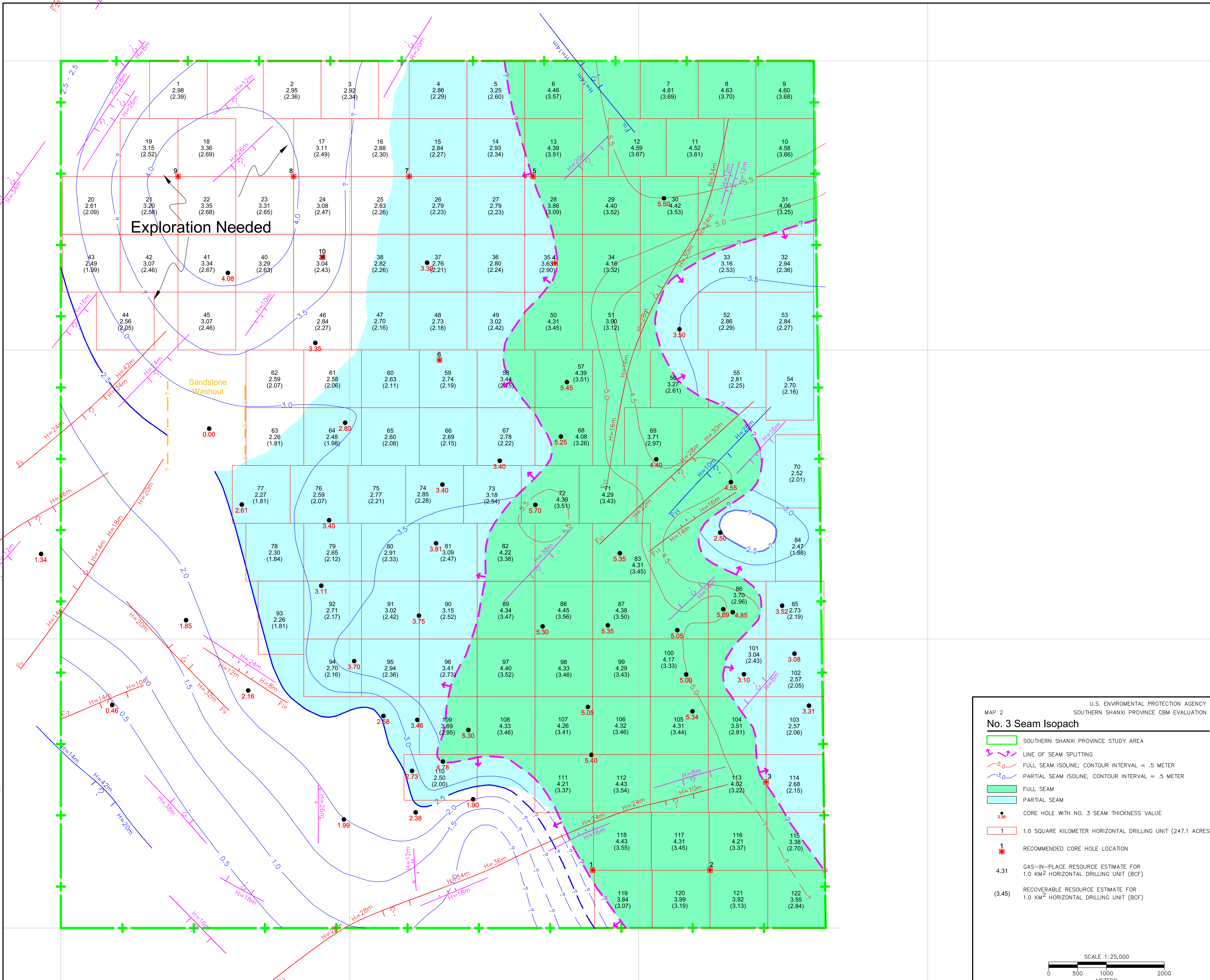
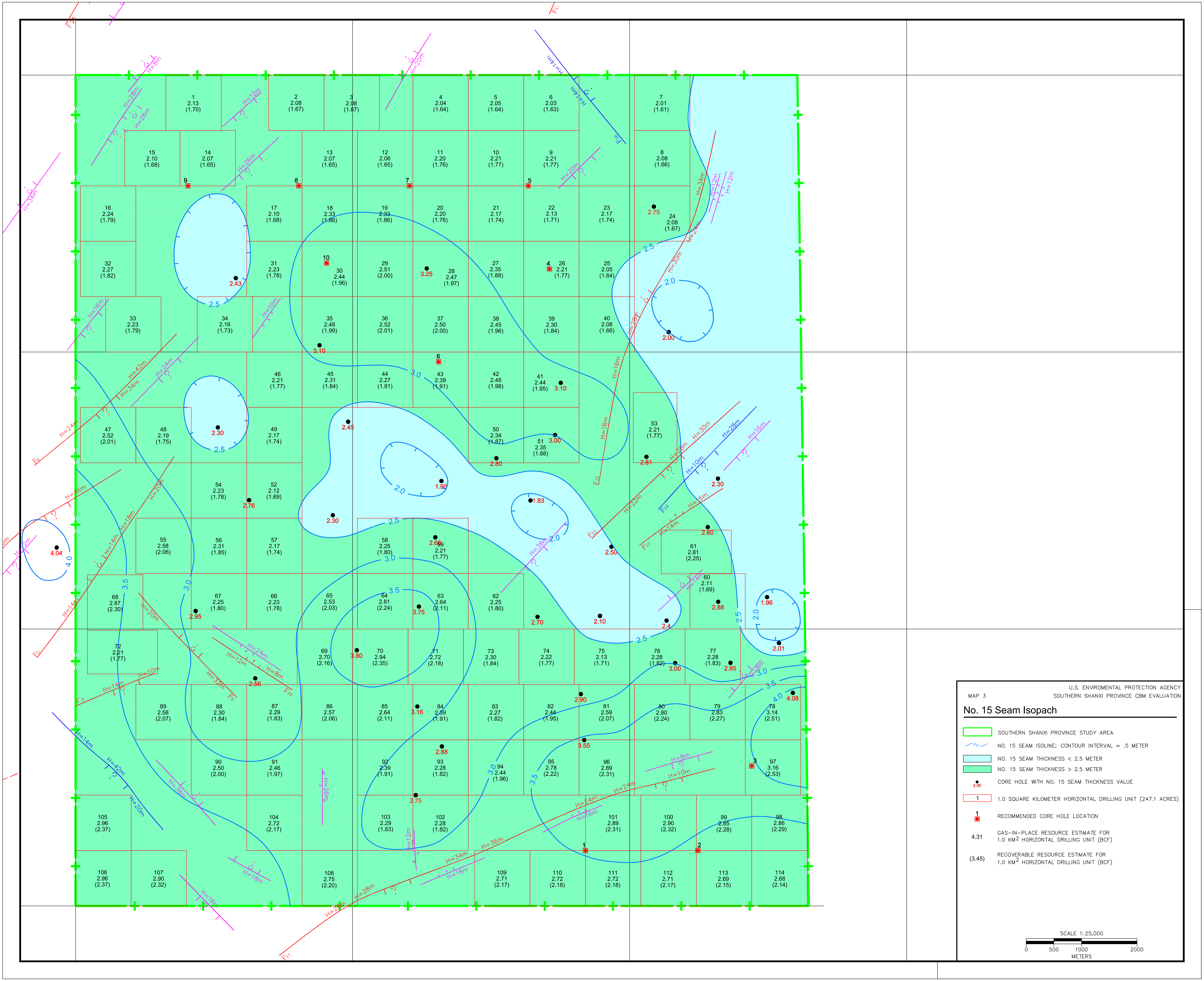
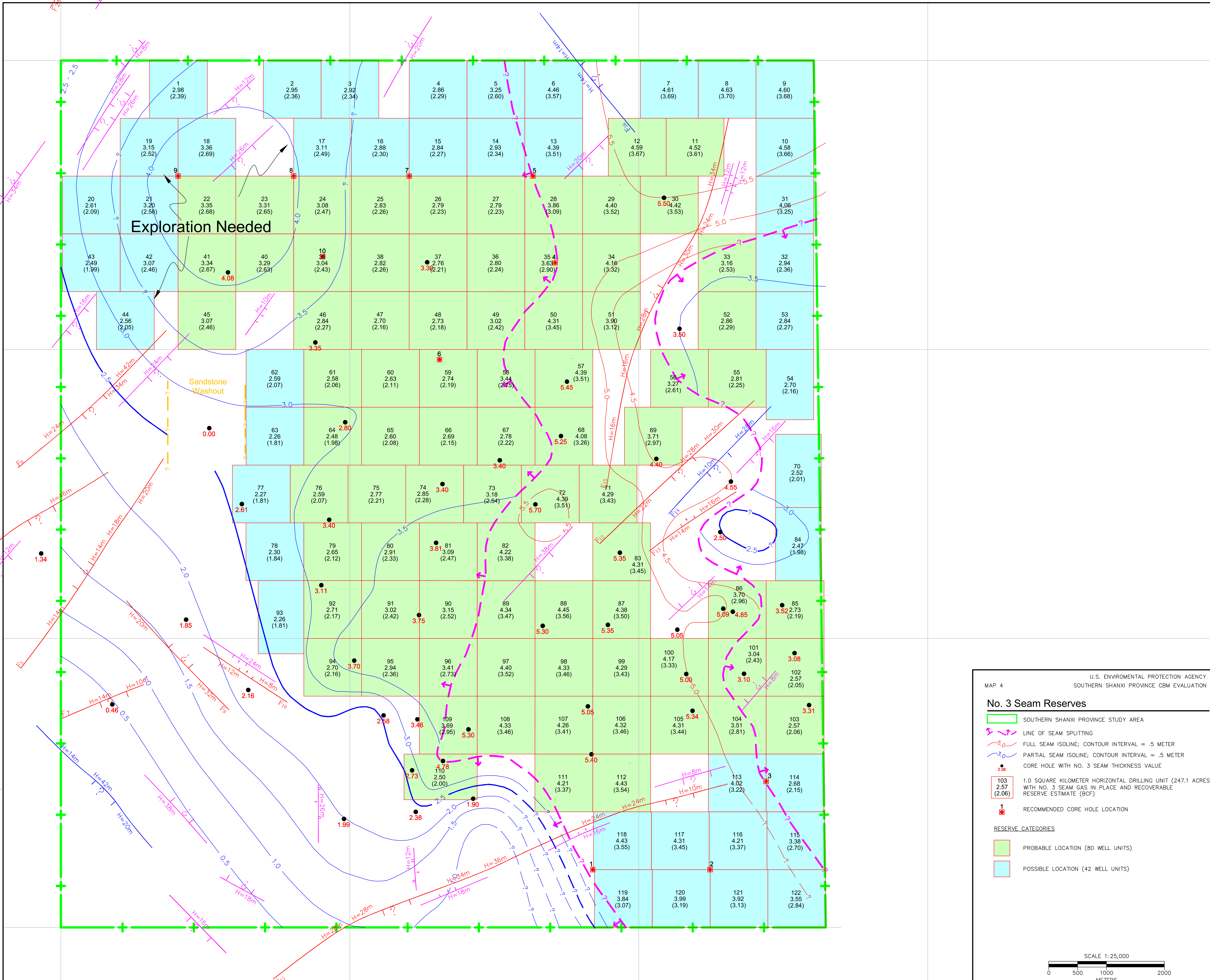


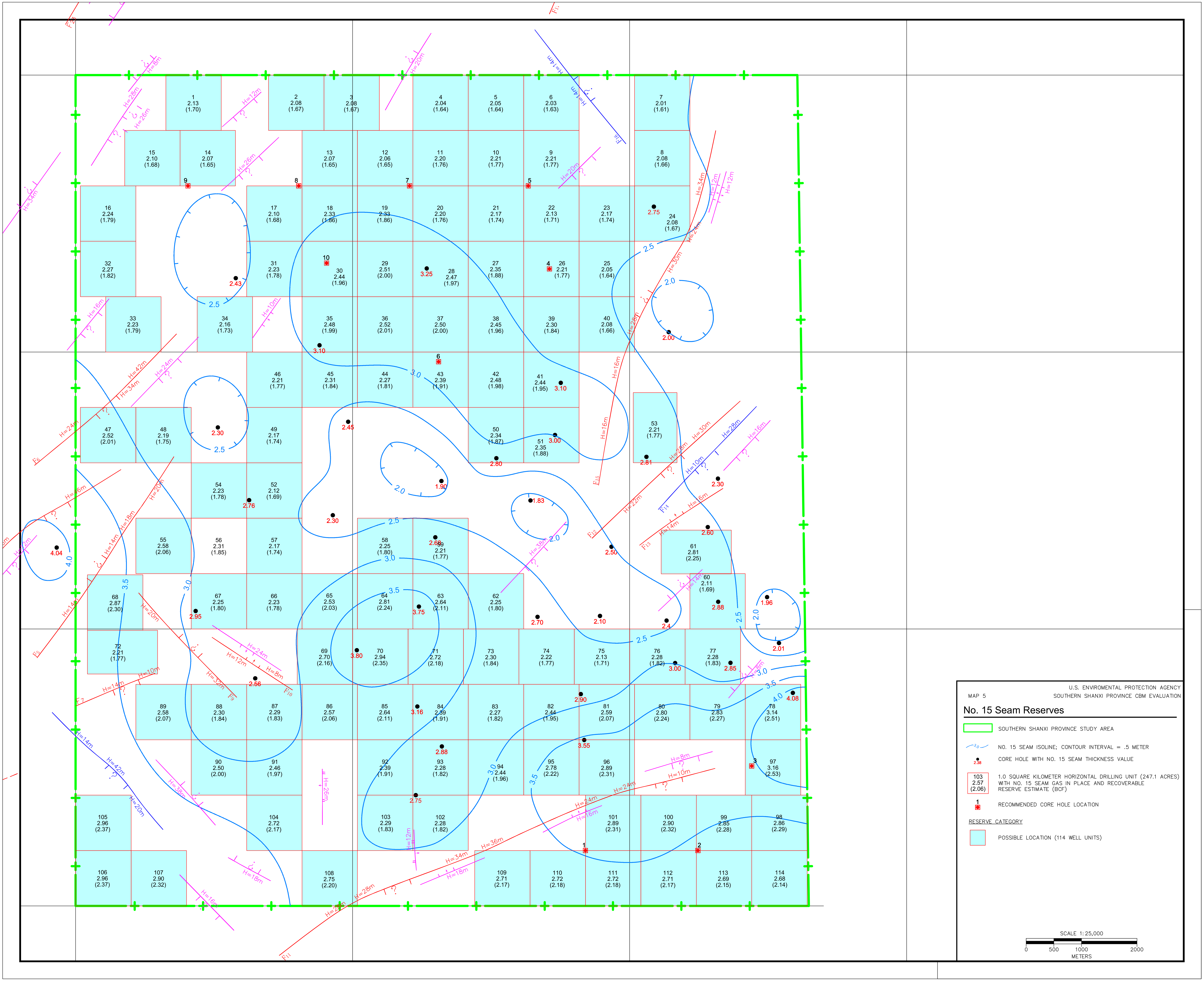
地层单位
地层厚度(m)
标志层
柱状
新生界
0-30
和尚沟组
150
刘家沟组
430
石千峰组
120
K14
上石盒子组
450-550
K10
下石盒子组
60-130
K8
山西组
45-55
K7
太原组
80-130
K1
本溪组
3-45
峰峰组
>100
图 例
legend
等高线
contour line
钻 孔
drill hole
较可靠断层
less reliable fault
可靠断层
reliable fault
单断点控制逆断层
single-point reverse fault
单断点控制正断层
single-point normal fault
地质控制断层
geologic inferred normal fault
陷落柱
collage column
煤层露头线
coal outcrop line
MAP 1
U.S. ENVIROMENTAL PROTECTION AGENCY
SOUTHERN SHANXI PROVINCE CBM EVALUATION
Cross Section Location with No. 3 Seam Structure
CBM CORE HOLE WITH SURFACE ELEVATION STRUCTURE AND BASE NO. 3 SEAM STRUCTURE ELEVATION
LINE OF CROSS SECTION
SOUTHERN SHANXI PROVINCE STUDY AREA
WELL WITH GEOPHYSICAL LOG
PRE-EXISTING CORE HOLE
DRILLED CORE HOLE WITH LOG CONTROL
CORE HOLE LOCATION
SEISMIC LINE
NO. 3 SEAM STRUCTURE ELEVATION ISOLINE; CONTOUR INTERVAL = 25M
SCALE 1:25,000
0
500
1000
2000
METERS

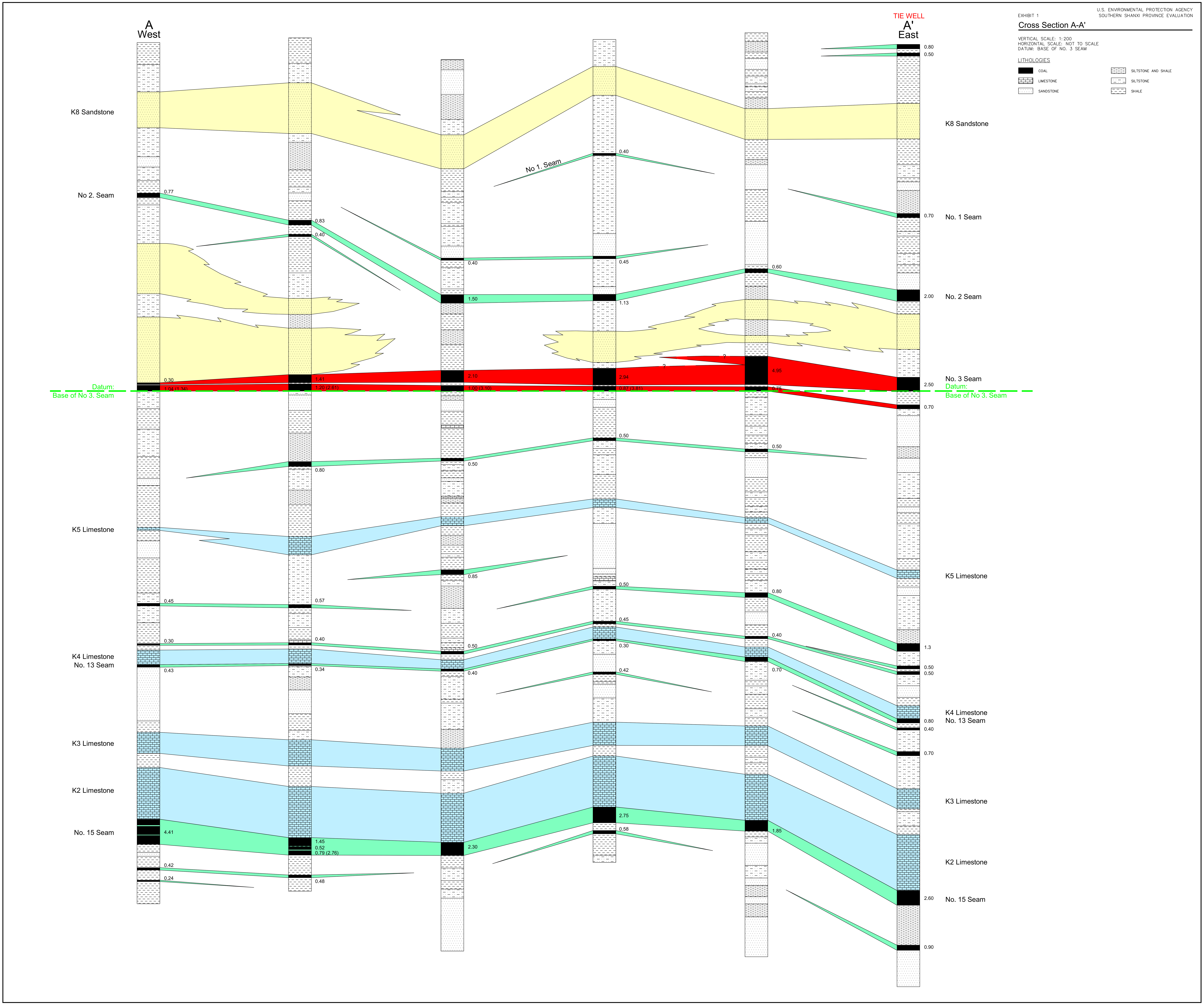

Exploration Needed
Sandstone Washout
U.S. ENVIROMENTAL PROTECTION AGENCY
MAP 2
SOUTHERN SHANXI PROVINCE CBM EVALUATION
No. 3 Seam Isopach
SOUTHERN SHANXI PROVINCE STUDY AREA
LINE OF SEAM SPLITTING
FULL SEAM ISOLINE; CONTOUR INTERVAL = .5 METER
PARTIAL SEAM ISOLINE; CONTOUR INTERVAL = .5 METER
FULL SEAM
PARTIAL SEAM
CORE HOLE WITH NO. 3 SEAM THICKNESS VALUE
1.0 SQUARE KILOMETER HORIZONTAL DRILLING UNIT (247.1 ACRES)
RECOMMENDED CORE HOLE LOCATION
4.31
GAS-IN-PLACE RESOURCE ESTIMATE FOR 1.0 KM2 HORIZONTAL DRILLING UNIT (BCF)
(3.45)
RECOVERABLE RESOURCE ESTIMATE FOR 1.0 KM2 HORIZONTAL DRILLING UNIT (BCF)
SCALE 1:25,000
0
500
1000
2000
METERS


U.S. ENVIROMENTAL PROTECTION AGENCY
MAP 3
SOUTHERN SHANXI PROVINCE CBM EVALUATION
No. 15 Seam Isopach
SOUTHERN SHANXI PROVINCE STUDY AREA
NO. 15 SEAM ISOLINE; CONTOUR INTERVAL = .5 METER
NO. 15 SEAM THICKNESS < 2.5 METER
NO. 15 SEAM THICKNESS > 2.5 METER
2.38
CORE HOLE WITH NO. 15 SEAM THICKNESS VALUE
1
1.0 SQUARE KILOMETER HORIZONTAL DRILLING UNIT (247.1 ACRES)
1
RECOMMENDED CORE HOLE LOCATION
4.31
GAS–IN–PLACE RESOURCE ESTIMATE FOR 1.0 KM2 HORIZONTAL DRILLING UNIT (BCF)
(3.45)
RECOVERABLE RESOURCE ESTIMATE FOR 1.0 KM2 HORIZONTAL DRILLING UNIT (BCF)
SCALE 1: 25,000
0 500 1000 2000
METERS



U.S. ENVIRONMENTAL PROTECTION AGENCY
MAP 4
SOUTHERN SHANXI PROVINCE CBM EVALUATION
No. 3 Seam Reserves
SOUTHERN SHANXI PROVINCE STUDY AREA
LINE OF SEAM SPLITTING
FULL SEAM ISOLINE; CONTOUR INTERVAL = .5 METER
PARTIAL SEAM ISOLINE; CONTOUR INTERVAL = .5 METER
CORE HOLE WITH NO. 3 SEAM THICKNESS VALUE
1.0 SQUARE KILOMETER HORIZONTAL DRILLING UNIT (247.1 ACRES) WITH NO. 3 SEAM GAS IN PLACE AND RECOVERABLE RESERVE ESTIMATE (BCF)
RECOMMENDED CORE HOLE LOCATION
RESERVE CATEGORIES
PROBABLE LOCATION (80 WELL UNITS)
POSSIBLE LOCATION (42 WELL UNITS)
SCALE 1:25,000
0
500
1000
2000
METERS
Exploration Needed
Sandstone Washout


U.S. ENVIROMENTAL PROTECTION AGENCY
MAP 5
SOUTHERN SHANXI PROVINCE CBM EVALUATION
No. 15 Seam Reserves
SOUTHERN SHANXI PROVINCE STUDY AREA
NO. 15 SEAM ISOLINE; CONTOUR INTERVAL = .5 METER
CORE HOLE WITH NO. 15 SEAM THICKNESS VALUE
103
2.57
(2.06)
1.0 SQUARE KILOMETER HORIZONTAL DRILLING UNIT (247.1 ACRES) WITH NO. 15 SEAM GAS IN PLACE AND RECOVERABLE RESERVE ESTIMATE (BCF)
RECOMMENDED CORE HOLE LOCATION
RESERVE CATEGORY
POSSIBLE LOCATION (114 WELL UNITS)
SCALE 1:25,000
0 500 1000 2000
METERS


U.S. ENVIRONMENTAL PROTECTION AGENCY
SOUTHERN SHANXI PROVINCE EVALUATION
EXHIBIT 1
Cross Section A-A'
VERTICAL SCALE: 1:200
HORIZONTAL SCALE: NOT TO SCALE
DATUM: BASE OF NO. 3 SEAM
LITHOLOGIES
COAL
LIMESTONE
SANDSTONE
SILTSTONE AND SHALE
SILTSTONE
SHALE
A
West
TIE WELL
A'
East
K8 Sandstone
No 2. Seam
No 1. Seam
No. 1 Seam
No. 2 Seam
No. 3 Seam
Datum:
Base of No 3. Seam
K5 Limestone
K4 Limestone
No. 13 Seam
K3 Limestone
K2 Limestone
No. 15 Seam

U.S. ENVIRONMENTAL PROTECTION AGENCY
SOUTHERN SHANXI PROVINCE EVALUATION

EXHIBIT 2

Cross Section B-B'

VERTICAL SCALE: 1:200
HORIZONTAL SCALE: NOT TO SCALE
DATUM: BASE OF NO. 3 SEAM

LITHOLOGIES

COAL
LIMESTONE
SANDSTONE
SILTSTONE AND SHALE
SILTSTONE
SHALE

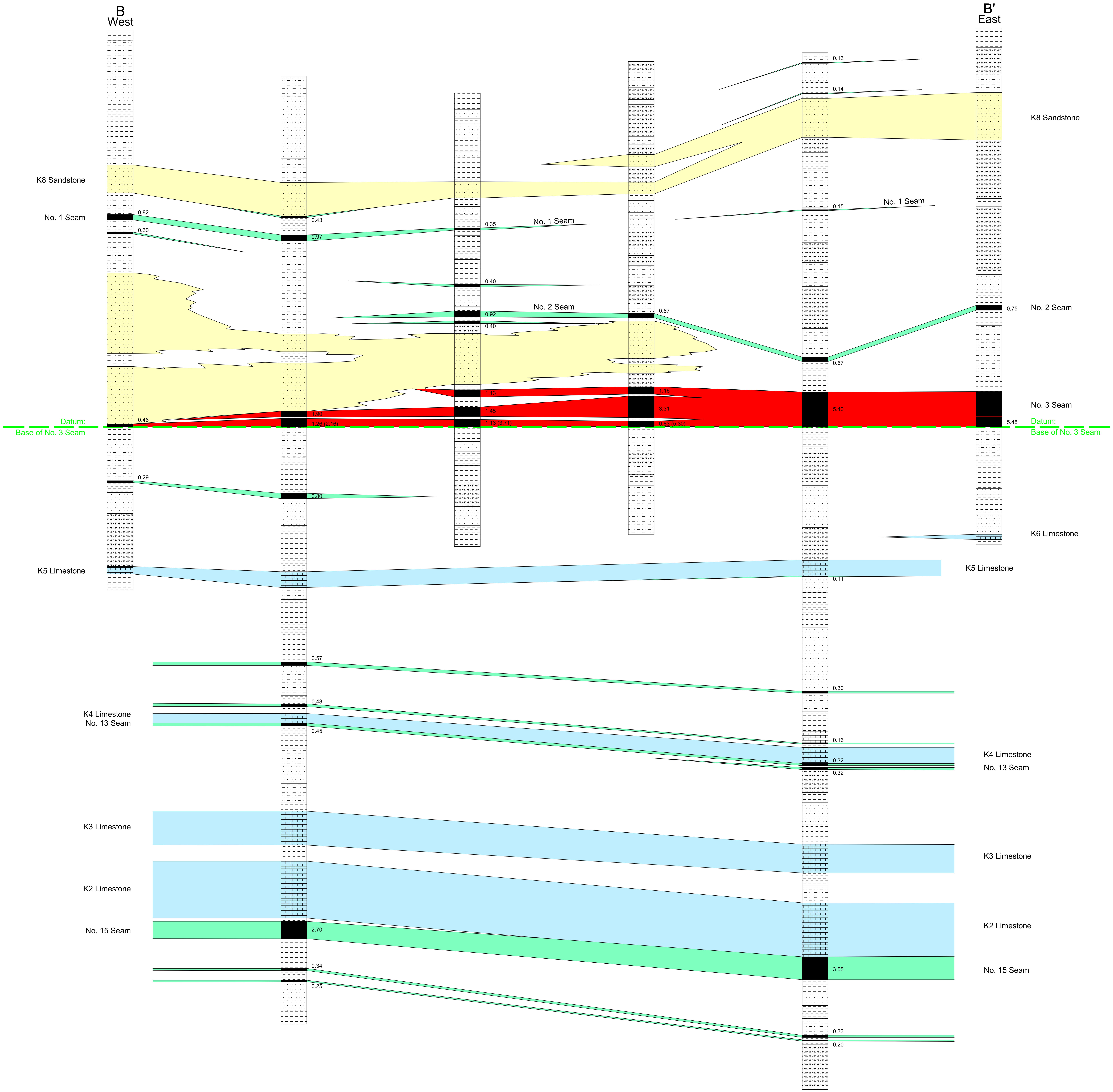


EXHIBIT 3
U.S. ENVIRONMENTAL PROTECTION AGENCY
SOUTHERN SHANXI PROVINCE EVALUATION
Cross Section C-C'
VERTICAL SCALE: 1:200
HORIZONTAL SCALE: NOT TO SCALE
DATUM: BASE OF NO. 3 SEAM
LITHOLOGIES
COAL
LIMESTONE
SANDSTONE
SILTSTONE AND SHALE
SILTSTONE
SHALE
C
North
C'
South
K8 Sandstone
No. 1 Seam
No. 2 Seam
No. 3 Seam
No. 3 Seam Rider
Datum:
Base of No. 3 Seam
K5 Limestone
K4 Limestone
No. 13 Seam
K3 Limestone
K2 Limestone
No. 15 Seam

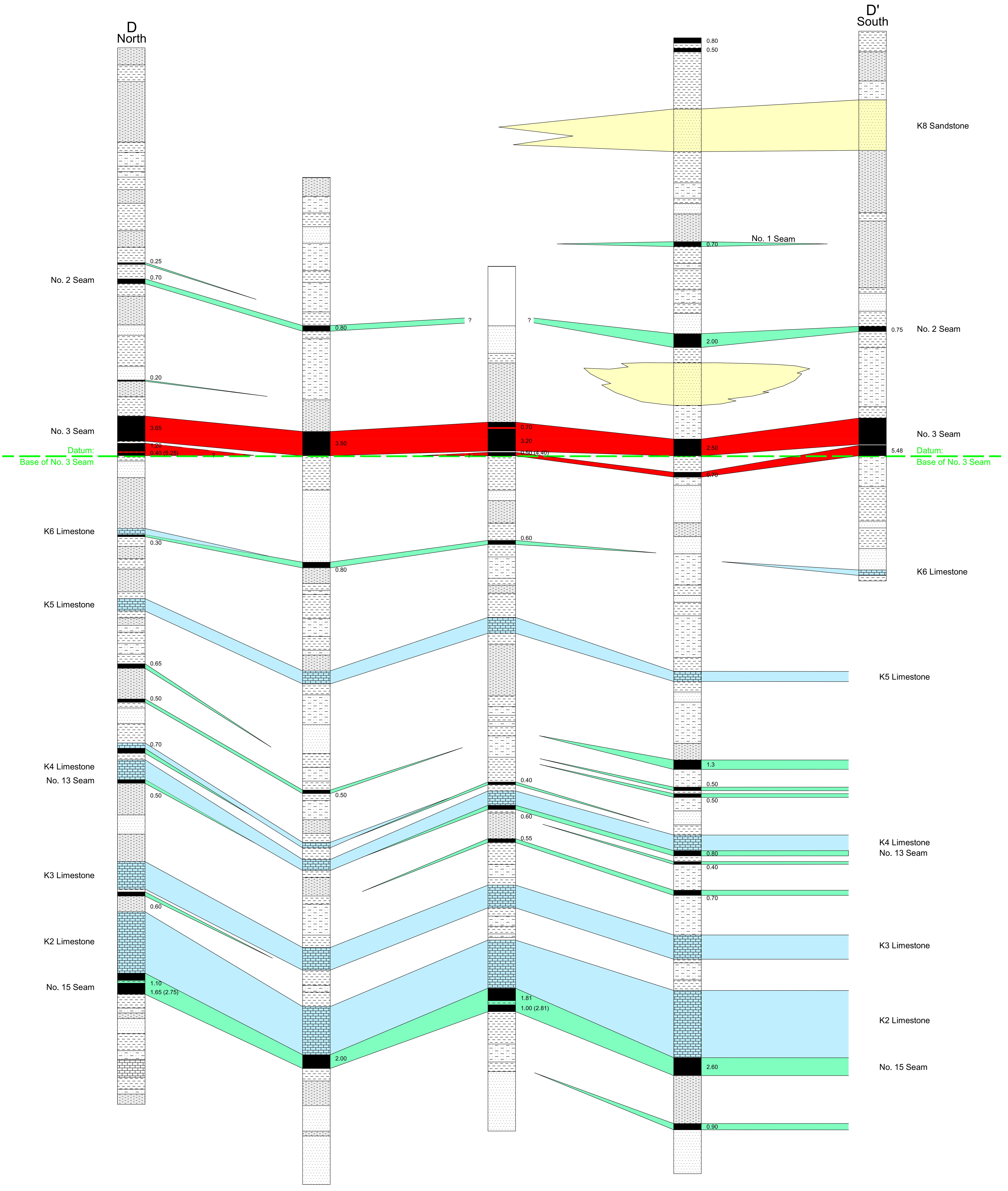


EXHIBIT 4

U.S. ENVIRONMENTAL PROTECTION AGENCY
SOUTHERN SHANXI PROVINCE EVALUATION

Cross Section D-D'

VERTICAL SCALE: 1:200
HORIZONTAL SCALE: NOT TO SCALE
DATUM: BASE OF NO. 3 SEAM

LITHOLOGIES

COAL
LIMESTONE
SANDSTONE
SILTSTONE AND SHALE
SILTSTONE
SHALE

Run 1

Southern Shanxi Province CBM Valuation
No. 3 Seam Probable Reserves Case
(*in USD*)

		Input	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production Allocation	Total Production (MMcf)	Import	904.567	1,410.152	6,407.253	15,024.939	20,056.146	15,748.535	17,562.515	24,594.838	26,026.743	18,534.887	13,149.161	9,856.453	7,681.937	6,164.349	5,060.261	4,230.484	3,590.308	3,085.650	2,680.530	2,350.254	2,077.406
	Gas Energy Value (dth/Mcf)	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945
	Total Production (Mdth)		**854.816**	**1,332.594**	**6,054.854**	**14,198.567**	**18,953.058**	**14,882.366**	**16,596.577**	**23,242.122**	**24,595.272**	**17,515.468**	**12,425.957**	**9,314.348**	**7,259.430**	**5,825.310**	**4,781.947**	**3,997.807**	**3,392.841**	**2,915.939**	**2,533.101**	**2,220.990**	**1,963.149**
	Total Production, Net of 7% Shrink (Mdth)		**794.979**	**1,239.312**	**5,631.014**	**13,204.668**	**17,626.344**	**13,840.600**	**15,434.816**	**21,615.173**	**22,873.603**	**16,289.385**	**11,556.140**	**8,662.344**	**6,751.270**	**5,417.538**	**4,447.210**	**3,717.961**	**3,155.342**	**2,711.824**	**2,355.784**	**2,065.521**	**1,825.728**
Income Statement	Exchange Rate (RMB/USD)	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83
	Gas Price Escalation Rate (%/year)		0.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Gas Sales Price ($/dth)		**$5.60**	**$5.76**	**$5.94**	**$6.12**	**$6.30**	**$6.49**	**$6.68**	**$6.88**	**$7.09**	**$7.30**	**$7.52**	**$7.75**	**$7.98**	**$8.22**	**$8.47**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**
	Sales Revenue		$0	$7,144,559	$33,436,332	$80,760,071	$111,037,246	$89,804,600	$103,153,117	$148,791,061	$162,177,246	$118,958,989	$86,924,578	$67,112,347	$53,875,305	$44,529,051	$37,650,120	$32,420,576	$27,514,548	$23,647,070	$20,542,408	$18,011,317	$15,920,330
	VAT	13.00%	$0	($821,940)	($3,846,658)	($9,290,982)	($12,774,196)	($10,331,503)	($11,867,173)	($17,117,556)	($18,657,559)	($13,685,547)	($10,000,173)	($7,720,889)	($6,198,044)	($5,122,811)	($4,331,430)	($3,729,801)	($3,165,390)	($2,720,459)	($2,363,286)	($2,072,098)	($1,831,542)
	Net Revenue		**$0**	**$6,322,619**	**$29,589,674**	**$71,469,089**	**$98,263,050**	**$79,473,098**	**$91,285,945**	**$131,673,505**	**$143,519,687**	**$105,273,442**	**$76,924,405**	**$59,391,458**	**$47,677,261**	**$39,406,240**	**$33,318,690**	**$28,690,775**	**$24,349,157**	**$20,926,610**	**$18,179,122**	**$15,939,219**	**$14,088,787**
	Gathering Cost Rate, $/Mcf	$0.33	$0.33	$0.34	$0.35	$0.36	$0.37	$0.38	$0.39	$0.41	$0.42	$0.43	$0.44	$0.46	$0.47	$0.48	$0.50	$0.51	$0.53	$0.55	$0.56	$0.58	$0.60
	Overhead Cost Rate ($/Mcf)	$0.45	$0.45	$0.46	$0.48	$0.49	$0.51	$0.52	$0.54	$0.55	$0.57	$0.59	$0.60	$0.62	$0.64	$0.66	$0.68	$0.70	$0.72	$0.74	$0.77	$0.79	$0.81
	Cost Escalation (%)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
	Fixed Production Cost	Import	$177,000	$405,408	$963,508	$2,256,095	$3,009,453	$2,249,168	$3,465,355	$5,606,418	$6,110,779	$4,396,548	$3,412,436	$3,322,160	$3,421,840	$3,524,480	$3,630,240	$3,739,120	$3,851,280	$3,966,800	$4,085,840	$4,208,400	$4,334,640
	Variable Production Cost		$277,612	$445,759	$2,086,139	$5,038,732	$6,927,767	$5,603,033	$6,435,865	$9,283,280	$10,118,462	$7,422,015	$5,423,344	$4,187,232	$3,361,355	$2,778,229	$2,349,043	$2,022,764	$1,768,171	$1,565,224	$1,400,514	$1,264,792	$1,151,497
	Project Overhead Cost		$378,561	$607,853	$2,844,735	$6,870,999	$9,446,955	$7,640,499	$8,776,180	$12,659,018	$13,797,903	$10,120,930	$7,395,470	$5,709,862	$4,583,665	$3,788,494	$3,203,240	$2,758,315	$2,411,142	$2,134,396	$1,909,792	$1,724,716	$1,570,223
	Total Cash Costs		**$833,173**	**$1,459,020**	**$5,894,382**	**$14,165,826**	**$19,384,175**	**$15,492,700**	**$18,677,400**	**$27,548,715**	**$30,027,144**	**$21,939,494**	**$16,231,250**	**$13,219,254**	**$11,366,860**	**$10,091,203**	**$9,182,523**	**$8,520,200**	**$8,030,593**	**$7,666,419**	**$7,396,147**	**$7,197,907**	**$7,056,360**
	EBITDA		($833,173)	$4,863,599	$23,695,292	$57,303,264	$78,878,875	$63,980,397	$72,608,544	$104,124,790	$113,492,543	$83,333,948	$60,693,155	$46,172,204	$36,310,401	$29,315,037	$24,136,167	$20,170,576	$16,318,565	$13,260,191	$10,782,975	$8,741,311	$7,032,427
	Depreciation (6-year recovery)		$1,252,482	$1,252,482	$5,231,497	$9,326,385	$11,068,945	$13,261,685	$19,476,900	$27,168,628	$23,580,201	$19,485,313	$17,742,753	$15,550,013	$8,082,316	$390,588	$0	$0	$0	$0	$0	$0	$0
	BTAX Income		($2,085,655)	$3,611,117	$18,463,795	$47,976,879	$67,809,930	$50,718,713	$53,131,644	$76,956,162	$89,912,342	$63,848,635	$42,950,403	$30,622,191	$28,228,085	$28,924,449	$24,136,167	$20,170,576	$16,318,565	$13,260,191	$10,782,975	$8,741,311	$7,032,427
	Loss Utilization		$0	($2, 085, 655)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Taxable income		**($2,085,655)**	**$1,525,463**	**$18,463,795**	**$47,976,879**	**$67,809,930**	**$50,718,713**	**$53,131,644**	**$76,956,162**	**$89,912,342**	**$63,848,635**	**$42,950,403**	**$30,622,191**	**$28,228,085**	**$28,924,449**	**$24,136,167**	**$20,170,576**	**$16,318,565**	**$13,260,191**	**$10,782,975**	**$8,741,311**	**$7,032,427**
	Income Tax Rate (%)		0.0%	0.0%	12.5%	12.5%	12.5%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
	Income Tax		$0	$0	($2, 307, 974)	($5, 997, 110)	($8, 476, 241)	($12, 679, 678)	($13, 282, 911)	($19, 239, 040)	($22, 478, 086)	($15, 962, 159)	($10, 737, 601)	($7, 655, 548)	($7, 057, 021)	($7, 231, 112)	($6, 034, 042)	($5, 042, 644)	($4, 079, 641)	($3, 315, 048)	($2, 695, 744)	($2, 185, 328)	($1, 758, 107)
	VAT Refund		$0	$616,455	$3,090,478	$7,929,901	$11,903,393	$10,942,176	$11,483,255	$15,804,960	$18,272,558	$14,928,550	$10,921,516	$8,290,710	$6,578,755	$5,391,619	$4,529,275	$3,880,208	$3,306,493	$2,831,692	$2,452,579	$2,144,895	$1,891,681
	Subsidy (0.20 RMB/m^3)		$0	$659,188	$1,027,625	$4,669,178	$10,949,171	$14,615,579	$11,476,480	$12,798,387	$17,923,074	$18,966,550	$13,506,987	$9,582,230	$7,182,724	$5,598,082	$4,492,165	$3,687,580	$3,082,894	$2,616,376	$2,248,615	$1,953,391	$1,712,708
	ATAX Income		($2,085,655)	$4,886,761	$20,273,924	$54,578,848	$82,186,253	$63,596,789	$62,808,468	$86,320,468	$103,629,889	$81,781,577	$56,641,305	$40,839,583	$34,932,543	$32,683,039	$27,123,566	$22,695,720	$18,628,310	$15,393,212	$12,788,426	$10,654,270	$8,878,710
	Production Sharing Costs	20.0%	($417,131)	$977,352	$4,054,785	$10,915,770	$16,437,251	$12,719,358	$12,561,694	$17,264,094	$20,725,978	$16,356,315	$11,328,261	$8,167,917	$6,986,509	$6,536,608	$5,424,713	$4,539,144	$3,725,662	$3,078,642	$2,557,685	$2,130,854	$1,775,742
	Net Income		**($1,668,524)**	**$3,909,408**	**$16,219,139**	**$43,663,078**	**$65,749,002**	**$50,877,431**	**$50,246,774**	**$69,056,375**	**$82,903,911**	**$65,425,262**	**$45,313,044**	**$32,671,667**	**$27,946,035**	**$26,146,431**	**$21,698,853**	**$18,156,576**	**$14,902,648**	**$12,314,570**	**$10,230,741**	**$8,523,416**	**$7,102,968**
Cash Flow Reconciliation	Add Back: Depreciation		$1,252,482	$1,252,482	$5,231,497	$9,326,385	$11,068,945	$13,261,685	$19,476,900	$27,168,628	$23,580,201	$19,485,313	$17,742,753	$15,550,013	$8,082,316	$390,588	$0	$0	$0	$0	$0	$0	$0
	Less: Capex	Import	($7,514,890)	$0	($23,874,091)	($24,569,326)	($10,455,362)	($13,156,438)	($44,806,183)	($46,150,369)	($2,343,525)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Cash Flow		**($7,930,932)**	**$5,161,890**	**($2,423,455)**	**$28,420,137**	**$66,362,585**	**$50,982,678**	**$24,917,491**	**$50,074,634**	**$104,140,587**	**$84,910,575**	**$63,055,797**	**$48,221,679**	**$36,028,350**	**$26,537,018**	**$21,698,853**	**$18,156,576**	**$14,902,648**	**$12,314,570**	**$10,230,741**	**$8,523,416**	**$7,102,968**
	Net Book Value		$6,262,408	$5,009,927	$23,652,521	$38,895,462	$38,281,880	$38,176,633	$63,505,916	$82,487,657	$61,250,981	$41,765,669	$24,022,916	$8,472,903	$390,588	$0	$0	$0	$0	$0	$0	$0	$0
	Current Year Loss		($2,085,655)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Loss Carry Forward		($2,085,655)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Cumulative Net Cash Flow		($7,930,932)	($2,769,042)	($5,192,497)	$23,227,640	$89,590,225	$140,572,902	$165,490,394	$215,565,028	$319,705,614	$404,616,189	$467,671,986	$515,893,665	$551,922,016	$578,459,034	$600,157,887	$618,314,462	$633,217,111	$645,531,680	$655,762,421	$664,285,837	$671,388,805
	Discounted Net Cash Flow @ %/year	10%	($7,561,847)	$4,474,245	($1,909,648)	$20,358,781	$43,217,159	$30,183,033	$13,410,713	$24,500,370	$46,321,455	$34,334,543	$23,179,380	$16,114,857	$10,945,505	$7,329,104	$5,448,072	$4,144,263	$3,092,318	$2,322,990	$1,754,456	$1,328,790	$1,006,676
	Cumulative Discounted Net Cash Flow		**($7,561,847)**	**($3,087,602)**	**($4,997,250)**	**$15,361,531**	**$58,578,689**	**$88,761,722**	**$102,172,435**	**$126,672,805**	**$172,994,260**	**$207,328,803**	**$230,508,184**	**$246,623,041**	**$257,568,546**	**$264,897,650**	**$270,345,722**	**$274,489,985**	**$277,582,303**	**$279,905,292**	**$281,659,748**	**$282,988,538**	**$283,995,214**
	Risked Discounted Net Cash Flow	50%	($3,780,923)	$2,237,122	($954,824)	$10,179,390	$21,608,579	$15,091,516	$6,705,356	$12,250,185	$23,160,728	$17,167,272	$11,589,690	$8,057,428	$5,472,753	$3,664,552	$2,724,036	$2,072,132	$1,546,159	$1,161,495	$877,228	$664,395	$503,338
	Cumulative Risked Discounted Net Cash Flow		**($3,780,923)**	**($1,543,801)**	**($2,498,625)**	**$7,680,765**	**$29,289,345**	**$44,380,861**	**$51,086,217**	**$63,336,402**	**$86,497,130**	**$103,664,402**	**$115,254,092**	**$123,311,520**	**$128,784,273**	**$132,448,825**	**$135,172,861**	**$137,244,992**	**$138,791,151**	**$139,952,646**	**$140,829,874**	**$141,494,269**	**$141,997,607**

*All gas vented in 2010

Run 1

Southern Shanxi Province CBM Valuation
No. 3 Seam Probable Reserves Case
(*in USD*)

		Input	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	Total
Production Allocation	Total Production (MMcf)	Import	1,849.334	1,656.732	1,492.596	1,351.577	1,229.526	1,087.180	926.240	702.162	517.154	450.725	303.209	113.639	1.558	-	-	-	-	-	-	-	217,879.000
	Gas Energy Value (dth/Mcf)	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	
	Total Production (Mdth)		**1,747.621**	**1,565.612**	**1,410.503**	**1,277.240**	**1,161.902**	**1,027.385**	**875.297**	**663.543**	**488.711**	**425.935**	**286.533**	**107.389**	**1.472**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**205,895.655**
	Total Production, Net of 7% Shrink (Mdth)		**1,625.287**	**1,456.019**	**1,311.768**	**1,187.833**	**1,080.569**	**955.468**	**814.026**	**617.095**	**454.501**	**396.120**	**266.475**	**99.872**	**1.369**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**191,482.959**
Income Statement	Exchange Rate (RMB/USD)	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	
	Gas Price Escalation Rate (%/year)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Gas Sales Price ($/dth)		**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	
	Sales Revenue		$14,172,486	$12,696,468	$11,438,602	$10,357,894	$9,422,549	$8,331,671	$7,098,298	$5,381,062	$3,963,242	$3,454,159	$2,323,661	$870,880	$11,940	$0	$0	$0	$0	$0	$0	$0	$1,372,933,781
	VAT	13.00%	($1,630,463)	($1,460,656)	($1,315,945)	($1,191,616)	($1,084,010)	($958,511)	($816,618)	($619,060)	($455,948)	($397,381)	($267,324)	($100,190)	($1,374)	$0	$0	$0	$0	$0	$0	$0	($157,948,134)
	Net Revenue		**$12,542,023**	**$11,235,813**	**$10,122,657**	**$9,166,278**	**$8,338,539**	**$7,373,160**	**$6,281,679**	**$4,762,002**	**$3,507,294**	**$3,056,778**	**$2,056,337**	**$770,690**	**$10,566**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,214,985,647**
	Gathering Cost Rate, $/Mcf	$0.33	$0.61	$0.63	$0.65	$0.67	$0.69	$0.71	$0.73	$0.76	$0.78	$0.80	$0.83	$0.85	$0.88	$0.90	$0.93	$0.96	$0.99	$1.01	$1.05	$1.08	
	Overhead Cost Rate ($/Mcf)	$0.45	$0.84	$0.86	$0.89	$0.91	$0.94	$0.97	$1.00	$1.03	$1.06	$1.09	$1.13	$1.16	$1.19	$1.23	$1.27	$1.30	$1.34	$1.38	$1.43	$1.47	
	Cost Escalation (%)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	
	Fixed Production Cost	Import	$4,464,720	$4,598,640	$4,736,640	$4,878,720	$5,025,040	$4,986,806	$4,756,191	$4,061,143	$3,432,364	$3,358,490	$2,450,183	$981,043	$14,214	$0	$0	$0	$0	$0	$0	$0	$117,881,162
	Variable Production Cost		$1,055,830	$974,245	$904,056	$843,201	$790,069	$719,559	$631,430	$493,034	$374,021	$335,757	$232,645	$89,808	$1,268	$0	$0	$0	$0	$0	$0	$0	$88,355,751
	Project Overhead Cost		$1,439,768	$1,328,516	$1,232,804	$1,149,819	$1,077,367	$981,216	$861,041	$672,319	$510,029	$457,851	$317,243	$122,466	$1,729	$0	$0	$0	$0	$0	$0	$0	$120,485,115
	Total Cash Costs		**$6,960,318**	**$6,901,400**	**$6,873,500**	**$6,871,740**	**$6,892,477**	**$6,687,581**	**$6,248,663**	**$5,226,495**	**$4,316,414**	**$4,152,098**	**$3,000,070**	**$1,193,317**	**$17,212**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$208,840,866**
	EBITDA		$5,581,705	$4,334,412	$3,249,157	$2,294,538	$1,446,062	$685,579	$33,016	($464,493)	($809,121)	($1,095,320)	($943,733)	($422,627)	($6,645)	$0	$0	$0	$0	$0	$0	$0	$888,263,619
	Depreciation (6-year recovery)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$172,870,184
	BTAX Income		$5,581,705	$4,334,412	$3,249,157	$2,294,538	$1,446,062	$685,579	$33,016	($464,493)	($809,121)	($1,095,320)	($943,733)	($422,627)	($6,645)	$0	$0	$0	$0	$0	$0	$0	$715,393,435
	Loss Utilization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,085,655)
	Taxable income		**$5,581,705**	**$4,334,412**	**$3,249,157**	**$2,294,538**	**$1,446,062**	**$685,579**	**$33,016**	**($464,493)**	**($809,121)**	**($1,095,320)**	**($943,733)**	**($422,627)**	**($6,645)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$713,307,780**
	Income Tax Rate (%)		25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	
	Income Tax		($1, 395, 426)	($1, 083, 603)	($812, 289)	($573, 634)	($361, 515)	($171, 395)	($8, 254)	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($162,621,154)
	VAT Refund		$1,680,733	$1,503,107	$1,352,123	$1,222,698	$1,110,912	$989,886	$852,091	$668,450	$496,726	$412,023	$299,838	$141,973	$26,078	$343	$0	$0	$0	$0	$0	$0	$157,948,134
	Subsidy (0.20 RMB/m^3)		$1,513,875	$1,347,671	$1,207,316	$1,087,704	$984,939	$895,996	$792,264	$674,982	$511,689	$376,867	$328,458	$220,958	$82,813	$1,135	$0	$0	$0	$0	$0	$0	$158,775,651
	ATAX Income		$7,380,886	$6,101,588	$4,996,306	$4,031,306	$3,180,397	$2,400,067	$1,669,118	$878,938	$199,294	($306,430)	($315,437)	($59,695)	$102,245	$1,479	($0)	($0)	($0)	($0)	($0)	($0)	$869,496,065
	Production Sharing Costs	20.0%	$1,476,177	$1,220,318	$999,261	$806,261	$636,079	$480,013	$333,824	$175,788	$39,859	($61,286)	($63,087)	($11,939)	$20,449	$296	($0)	($0)	($0)	($0)	($0)	($0)	$173,899,213
	Net Income		**$5,904,709**	**$4,881,270**	**$3,997,045**	**$3,225,045**	**$2,544,318**	**$1,920,053**	**$1,335,294**	**$703,151**	**$159,435**	**($245,144)**	**($252,349)**	**($47,756)**	**$81,796**	**$1,183**	**($0)**	**($0)**	**($0)**	**($0)**	**($0)**	**($0)**	**$695,596,852**
Cash Flow Reconciliation	Add Back: Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$172,870,184
	Less: Capex	Import	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($172,870,184)
	Net Cash Flow		**$5,904,709**	**$4,881,270**	**$3,997,045**	**$3,225,045**	**$2,544,318**	**$1,920,053**	**$1,335,294**	**$703,151**	**$159,435**	**($245,144)**	**($252,349)**	**($47,756)**	**$81,796**	**$1,183**	**($0)**	**($0)**	**($0)**	**($0)**	**($0)**	**($0)**	**$695,596,852**
	Net Book Value		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$432,175,460
	Current Year Loss		$0	$0	$0	$0	$0	$0	$0	($464,493)	($809,121)	($1,095,320)	($943,733)	($422,627)	($6,645)	$0	$0	$0	$0	$0	$0	$0	($5,827,594)
	Loss Carry Forward		$0	$0	$0	$0	$0	$0	$0	($464,493)	($1,273,614)	($2,368,934)	($3,312,667)	($3,735,294)	($3,741,939)	($3,741,939)	($3,741,939)	($3,741,939)	($3,741,939)	($3,741,939)	($3,741,939)	($3,741,939)	
	Cumulative Net Cash Flow		$677,293,514	$682,174,784	$686,171,829	$689,396,873	$691,941,191	$693,861,244	$695,196,538	$695,899,689	$696,059,124	$695,813,980	$695,561,631	$695,513,875	$695,595,671	$695,596,854	$695,596,853	$695,596,853	$695,596,853	$695,596,853	$695,596,853	$695,596,852	$695,596,852
	Discounted Net Cash Flow @ %/year	10%	$760,774	$571,738	$425,609	$312,187	$223,902	$153,606	$97,113	$46,490	$9,583	($13,395)	($12,535)	($2,157)	$3,358	$44	($0)	($0)	($0)	($0)	($0)	($0)	$286,571,532
	Cumulative Discounted Net Cash Flow		**$284,755,988**	**$285,327,727**	**$285,753,336**	**$286,065,523**	**$286,289,425**	**$286,443,031**	**$286,540,144**	**$286,586,633**	**$286,596,216**	**$286,582,821**	**$286,570,286**	**$286,568,130**	**$286,571,488**	**$286,571,532**	**$286,571,532**	**$286,571,532**	**$286,571,532**	**$286,571,532**	**$286,571,532**	**$286,571,532**	**$286,571,532**
	Risked Discounted Net Cash Flow	50%	$380,387	$285,869	$212,805	$156,094	$111,951	$76,803	$48,557	$23,245	$4,791	($6,698)	($6,268)	($1,078)	$1,679	$22	($0)	($0)	($0)	($0)	($0)	($0)	$143,285,766
	Cumulative Risked Discounted Net Cash Flow		**$142,377,994**	**$142,663,863**	**$142,876,668**	**$143,032,762**	**$143,144,712**	**$143,221,515**	**$143,270,072**	**$143,293,317**	**$143,298,108**	**$143,291,411**	**$143,285,143**	**$143,284,065**	**$143,285,744**	**$143,285,766**	**$143,285,766**	**$143,285,766**	**$143,285,766**	**$143,285,766**	**$143,285,766**	**$143,285,766**	**$143,285,766**

*All gas vented in 2010

Run 2

Southern Shanxi Province CBM Valuation
No. 3 Seam Possible Reserves Case
(*in USD*)

		Input	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production Allocation	Total Production (MMcf)	Import	-	-	-	-	986.478	9,367.875	10,296.867	6,662.612	7,920.327	16,407.622	13,868.325	9,348.939	6,717.265	5,070.831	3,968.428	3,192.372	2,624.562	2,196.198	1,864.858	1,603.178	1,392.852
	Gas Energy Value (dth/Mcf)	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945
	Total Production (Mdth)		**-**	**-**	**-**	**-**	**932.222**	**8,852.642**	**9,730.539**	**6,296.168**	**7,484.709**	**15,505.203**	**13,105.567**	**8,834.747**	**6,347.815**	**4,791.935**	**3,750.164**	**3,016.792**	**2,480.211**	**2,075.407**	**1,762.291**	**1,515.003**	**1,316.245**
	Total Production, Net of 7% Shrink (Mdth)		**-**	**-**	**-**	**-**	**866.966**	**8,232.957**	**9,049.402**	**5,855.437**	**6,960.779**	**14,419.839**	**12,188.177**	**8,216.315**	**5,903.468**	**4,456.500**	**3,487.653**	**2,805.616**	**2,306.596**	**1,930.129**	**1,638.930**	**1,408.953**	**1,224.108**
Income Statement	Exchange Rate (RMB/USD)	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83
	Gas Price Escalation Rate (%/year)		0.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Gas Sales Price ($/dth)		**$5.60**	**$5.76**	**$5.94**	**$6.12**	**$6.30**	**$6.49**	**$6.68**	**$6.88**	**$7.09**	**$7.30**	**$7.52**	**$7.75**	**$7.98**	**$8.22**	**$8.47**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**
	Sales Revenue		$0	$0	$0	$0	$5,461,458	$53,419,462	$60,478,464	$40,306,714	$49,352,961	$105,305,963	$91,678,724	$63,656,697	$47,109,824	$36,629,868	$29,526,499	$24,464,941	$20,113,493	$16,830,699	$14,291,455	$12,286,054	$10,674,208
	VAT	13.00%	$0	$0	$0	$0	($628,309)	($6,145,602)	($6,957,699)	($4,637,056)	($5,677,774)	($12,114,845)	($10,547,110)	($7,323,337)	($5,419,714)	($4,214,056)	($3,396,854)	($2,814,551)	($2,313,942)	($1,936,275)	($1,644,150)	($1,413,440)	($1,228,006)
	Net Revenue		**$0**	**$0**	**$0**	**$0**	**$4,833,149**	**$47,273,860**	**$53,520,765**	**$35,669,659**	**$43,675,186**	**$93,191,118**	**$81,131,614**	**$56,333,360**	**$41,690,109**	**$32,415,813**	**$26,129,645**	**$21,650,390**	**$17,799,552**	**$14,894,424**	**$12,647,305**	**$10,872,614**	**$9,446,201**
	Gathering Cost Rate, $/Mcf	$0.33	$0.33	$0.34	$0.35	$0.36	$0.37	$0.38	$0.39	$0.41	$0.42	$0.43	$0.44	$0.46	$0.47	$0.48	$0.50	$0.51	$0.53	$0.55	$0.56	$0.58	$0.60
	Overhead Cost Rate ($/Mcf)	$0.45	$0.45	$0.46	$0.48	$0.49	$0.51	$0.52	$0.54	$0.55	$0.57	$0.59	$0.60	$0.62	$0.64	$0.66	$0.68	$0.70	$0.72	$0.74	$0.77	$0.79	$0.81
	Cost Escalation (%)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
	Fixed Production Cost	Import	$0	$0	$0	$0	$226,323	$1,608,904	$1,521,705	$938,640	$1,741,835	$4,132,635	$3,452,782	$2,274,015	$1,796,466	$1,850,352	$1,905,876	$1,963,038	$2,021,922	$2,082,570	$2,145,066	$2,209,410	$2,275,686
	Variable Production Cost		$0	$0	$0	$0	$340,748	$3,332,914	$3,773,335	$2,514,792	$3,079,199	$6,570,184	$5,719,962	$3,971,629	$2,939,247	$2,285,388	$1,842,199	$1,526,401	$1,292,556	$1,114,041	$974,345	$862,752	$772,052
	Project Overhead Cost		$0	$0	$0	$0	$464,656	$4,544,883	$5,145,457	$3,429,261	$4,198,908	$8,959,342	$7,799,948	$5,415,858	$4,008,064	$3,116,438	$2,512,090	$2,081,456	$1,762,576	$1,519,147	$1,328,652	$1,176,480	$1,052,798
	Total Cash Costs		**$0**	**$0**	**$0**	**$0**	**$1,031,727**	**$9,486,701**	**$10,440,496**	**$6,882,693**	**$9,019,942**	**$19,662,162**	**$16,972,692**	**$11,661,502**	**$8,743,777**	**$7,252,178**	**$6,260,165**	**$5,570,896**	**$5,077,054**	**$4,715,758**	**$4,448,063**	**$4,248,642**	**$4,100,535**
	EBITDA		$0	$0	$0	$0	$3,801,422	$37,787,160	$43,080,268	$28,786,966	$34,655,244	$73,528,956	$64,158,922	$44,671,858	$32,946,333	$25,163,635	$19,869,480	$16,079,494	$12,722,498	$10,178,666	$8,199,242	$6,623,972	$5,345,666
	Depreciation (6-year recovery)		$0	$0	$0	$0	$2,475,174	$5,356,099	$5,356,099	$5,356,099	$12,887,991	$16,123,104	$13,647,930	$10,767,005	$10,767,005	$10,767,005	$3,235,113	$0	$0	$0	$0	$0	$0
	BTAX Income		$0	$0	$0	$0	$1,326,248	$32,431,061	$37,724,170	$23,430,867	$21,767,253	$57,405,853	$50,510,992	$33,904,853	$22,179,327	$14,396,629	$16,634,368	$16,079,494	$12,722,498	$10,178,666	$8,199,242	$6,623,972	$5,345,666
	Loss Utilization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Taxable income		**$0**	**$0**	**$0**	**$0**	**$1,326,248**	**$32,431,061**	**$37,724,170**	**$23,430,867**	**$21,767,253**	**$57,405,853**	**$50,510,992**	**$33,904,853**	**$22,179,327**	**$14,396,629**	**$16,634,368**	**$16,079,494**	**$12,722,498**	**$10,178,666**	**$8,199,242**	**$6,623,972**	**$5,345,666**
	Income Tax Rate (%)		0.0%	0.0%	12.5%	12.5%	12.5%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
	Income Tax		$0	$0	($0)	($0)	($165, 781)	($8, 107, 765)	($9, 431, 042)	($5, 857, 717)	($5, 441, 813)	($14, 351, 463)	($12, 627, 748)	($8, 476, 213)	($5, 544, 832)	($3, 599, 157)	($4, 158, 592)	($4, 019, 874)	($3, 180, 624)	($2, 544, 667)	($2, 049, 811)	($1, 655, 993)	($1, 336, 417)
	VAT Refund		$0	$0	$0	$0	$471,232	$4,766,279	$6,754,675	$5,217,217	$5,417,595	$10,505,578	$10,939,044	$8,129,280	$5,895,620	$4,515,470	$3,601,154	$2,960,126	$2,439,094	$2,030,692	$1,717,181	$1,471,117	$1,274,365
	Subsidy (0.20 RMB/m^3)		$0	$0	$0	$0	$0	$718,879	$6,826,681	$7,503,668	$4,855,266	$5,771,805	$11,956,778	$10,106,308	$6,812,882	$4,895,094	$3,695,283	$2,891,925	$2,326,387	$1,912,605	$1,600,442	$1,358,984	$1,168,289
	ATAX Income		$0	$0	($0)	($0)	$1,631,699	$29,808,454	$41,874,483	$30,294,035	$26,598,300	$59,331,772	$60,779,065	$43,664,228	$29,342,997	$20,208,036	$19,772,213	$17,911,672	$14,307,355	$11,577,297	$9,467,055	$7,798,080	$6,451,903
	Production Sharing Costs	20.0%	$0	$0	($0)	($0)	$326,340	$5,961,691	$8,374,897	$6,058,807	$5,319,660	$11,866,354	$12,155,813	$8,732,846	$5,868,599	$4,041,607	$3,954,443	$3,582,334	$2,861,471	$2,315,459	$1,893,411	$1,559,616	$1,290,381
	Net Income		**$0**	**$0**	**($0)**	**($0)**	**$1,305,359**	**$23,846,763**	**$33,499,587**	**$24,235,228**	**$21,278,640**	**$47,465,417**	**$48,623,252**	**$34,931,382**	**$23,474,398**	**$16,166,429**	**$15,817,770**	**$14,329,338**	**$11,445,884**	**$9,261,837**	**$7,573,644**	**$6,238,464**	**$5,161,522**
Cash Flow Reconciliation	Add Back: Depreciation		$0	$0	$0	$0	$2,475,174	$5,356,099	$5,356,099	$5,356,099	$12,887,991	$16,123,104	$13,647,930	$10,767,005	$10,767,005	$10,767,005	$3,235,113	$0	$0	$0	$0	$0	$0
	Less: Capex	Import	$0	$0	$0	$0	($14,851,043)	($17,285,549)	$0	$0	($45,191,355)	($19,410,676)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Cash Flow		**$0**	**$0**	**($0)**	**($0)**	**($11,070,510)**	**$11,917,313**	**$38,855,685**	**$29,591,327**	**($11,024,723)**	**$44,177,845**	**$62,271,182**	**$45,698,387**	**$34,241,403**	**$26,933,434**	**$19,052,883**	**$14,329,338**	**$11,445,884**	**$9,261,837**	**$7,573,644**	**$6,238,464**	**$5,161,522**
	Net Book Value		$0	$0	$0	$0	$12,375,869	$24,305,320	$18,949,221	$13,593,122	$45,896,486	$49,184,058	$35,536,128	$24,769,123	$14,002,118	$3,235,113	$0	$0	$0	$0	$0	$0	$0
	Current Year Loss		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Loss Carry Forward		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Cumulative Net Cash Flow		$0	$0	($0)	($0)	($11,070,510)	$846,802	$39,702,488	$69,293,815	$58,269,091	$102,446,936	$164,718,119	$210,416,506	$244,657,909	$271,591,343	$290,644,226	$304,973,564	$316,419,447	$325,681,285	$333,254,929	$339,493,393	$344,654,916
	Discounted Net Cash Flow @ %/year	10%	$0	$0	($0)	($0)	($7,209,424)	$7,055,350	$20,912,315	$14,478,358	($4,903,768)	$17,863,807	$22,890,955	$15,271,616	$10,402,626	$7,438,588	$4,783,731	$3,270,691	$2,375,035	$1,747,130	$1,298,794	$972,569	$731,523
	Cumulative Discounted Net Cash Flow		**$0**	**$0**	**($0)**	**($0)**	**($7,209,424)**	**($154,074)**	**$20,758,242**	**$35,236,599**	**$30,332,832**	**$48,196,639**	**$71,087,594**	**$86,359,210**	**$96,761,836**	**$104,200,424**	**$108,984,155**	**$112,254,846**	**$114,629,881**	**$116,377,010**	**$117,675,804**	**$118,648,373**	**$119,379,896**
	Risked Discounted Net Cash Flow	20%	$0	$0	($0)	($0)	($1,441,885)	$1,411,070	$4,182,463	$2,895,672	($980,754)	$3,572,761	$4,578,191	$3,054,323	$2,080,525	$1,487,718	$956,746	$654,138	$475,007	$349,426	$259,759	$194,514	$146,305
	Cumulative Risked Discounted Net Cash Flow		**$0**	**$0**	**($0)**	**($0)**	**($1,441,885)**	**($30,815)**	**$4,151,648**	**$7,047,320**	**$6,066,566**	**$9,639,328**	**$14,217,519**	**$17,271,842**	**$19,352,367**	**$20,840,085**	**$21,796,831**	**$22,450,969**	**$22,925,976**	**$23,275,402**	**$23,535,161**	**$23,729,675**	**$23,875,979**

*All gas vented in 2010

Run 2

Southern Shanxi Province CBM Valuation
No. 3 Seam Possible Reserves Case
(*in USD*)

		Input	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	Total
Production Allocation	Total Production (MMcf)	Import	1,221.241	1,079.382	960.754	860.559	775.155	701.783	638.275	582.946	516.362	349.680	281.871	259.941	176.830	20.632	-	-	-	-	-	-	111,915.000
	Gas Energy Value (dth/Mcf)	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	
	Total Production (Mdth)		**1,154.073**	**1,020.016**	**907.913**	**813.228**	**732.521**	**663.185**	**603.170**	**550.884**	**487.962**	**330.448**	**266.368**	**245.644**	**167.104**	**19.497**	**-**	**-**	**-**	**-**	**-**	**-**	**105,759.675**
	Total Production, Net of 7% Shrink (Mdth)		**1,073.288**	**948.615**	**844.359**	**756.302**	**681.245**	**616.762**	**560.948**	**512.322**	**453.805**	**307.316**	**247.722**	**228.449**	**155.407**	**18.132**	**-**	**-**	**-**	**-**	**-**	**-**	**98,356.498**
Income Statement	Exchange Rate (RMB/USD)	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	
	Gas Price Escalation Rate (%/year)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Gas Sales Price ($/dth)		**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	
	Sales Revenue		$9,359,056	$8,271,911	$7,362,798	$6,594,947	$5,940,448	$5,378,157	$4,891,460	$4,467,443	$3,957,172	$2,679,794	$2,160,136	$1,992,074	$1,355,148	$158,115	$0	$0	$0	$0	$0	$0	$746,156,142
	VAT	13.00%	($1,076,706)	($951,636)	($847,048)	($758,711)	($683,414)	($618,726)	($562,734)	($513,954)	($455,250)	($308,295)	($248,511)	($229,177)	($155,902)	($18,190)	$0	$0	$0	$0	$0	$0	($85,840,972)
	Net Revenue		**$8,282,350**	**$7,320,275**	**$6,515,750**	**$5,836,236**	**$5,257,034**	**$4,759,431**	**$4,328,726**	**$3,953,489**	**$3,501,922**	**$2,371,499**	**$1,911,625**	**$1,762,897**	**$1,199,246**	**$139,924**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$660,315,170**
	Gathering Cost Rate, $/Mcf	$0.33	$0.61	$0.63	$0.65	$0.67	$0.69	$0.71	$0.73	$0.76	$0.78	$0.80	$0.83	$0.85	$0.88	$0.90	$0.93	$0.96	$0.99	$1.01	$1.05	$1.08	
	Overhead Cost Rate ($/Mcf)	$0.45	$0.84	$0.86	$0.89	$0.91	$0.94	$0.97	$1.00	$1.03	$1.06	$1.09	$1.13	$1.16	$1.19	$1.23	$1.27	$1.30	$1.34	$1.38	$1.43	$1.47	
	Cost Escalation (%)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	
	Fixed Production Cost	Import	$2,343,978	$2,414,286	$2,486,736	$2,561,328	$2,638,146	$2,717,316	$2,798,838	$2,882,796	$2,867,175	$2,208,726	$2,025,054	$2,085,804	$1,553,253	$192,229	$0	$0	$0	$0	$0	$0	$65,922,890
	Variable Production Cost		$697,236	$634,733	$581,923	$536,872	$498,099	$464,481	$435,121	$409,324	$373,448	$260,486	$216,272	$205,430	$143,940	$17,298	$0	$0	$0	$0	$0	$0	$48,386,407
	Project Overhead Cost		$950,777	$865,545	$793,531	$732,098	$679,227	$633,383	$593,346	$558,169	$509,248	$355,208	$294,917	$280,131	$196,282	$23,589	$0	$0	$0	$0	$0	$0	$65,981,464
	Total Cash Costs		**$3,991,991**	**$3,914,564**	**$3,862,190**	**$3,830,299**	**$3,815,472**	**$3,815,179**	**$3,827,305**	**$3,850,290**	**$3,749,871**	**$2,824,420**	**$2,536,243**	**$2,571,365**	**$1,893,475**	**$233,116**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$114,367,872**
	EBITDA		$4,290,359	$3,405,711	$2,653,561	$2,005,938	$1,441,562	$944,252	$501,420	$103,199	($247,949)	($452,921)	($624,619)	($808,467)	($694,229)	($93,191)	$0	$0	$0	$0	$0	$0	$480,024,408
	Depreciation (6-year recovery)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$96,738,623
	BTAX Income		$4,290,359	$3,405,711	$2,653,561	$2,005,938	$1,441,562	$944,252	$501,420	$103,199	($247,949)	($452,921)	($624,619)	($808,467)	($694,229)	($93,191)	$0	$0	$0	$0	$0	$0	$383,285,785
	Loss Utilization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Taxable income		**$4,290,359**	**$3,405,711**	**$2,653,561**	**$2,005,938**	**$1,441,562**	**$944,252**	**$501,420**	**$103,199**	**($247,949)**	**($452,921)**	**($624,619)**	**($808,467)**	**($694,229)**	**($93,191)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$383,285,785**
	Income Tax Rate (%)		25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	
	Income Tax		($1, 072, 590)	($851, 428)	($663, 390)	($501, 484)	($360, 390)	($236, 063)	($125, 355)	($25, 800)	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($96,386,011)
	VAT Refund		$1,114,531	$982,903	$873,195	$780,795	$702,238	$634,898	$576,732	$526,149	$469,926	$345,034	$263,457	$234,010	$174,221	$52,618	$4,548	$0	$0	$0	$0	$0	$85,840,972
	Subsidy (0.20 RMB/m^3)		$1,015,017	$889,959	$786,581	$700,133	$627,118	$564,881	$511,413	$465,132	$424,812	$376,290	$254,823	$205,409	$189,428	$128,862	$15,035	$0	$0	$0	$0	$0	$81,556,171
	ATAX Income		$5,347,318	$4,427,145	$3,649,947	$2,985,382	$2,410,528	$1,907,968	$1,464,210	$1,068,681	$646,789	$268,403	($106,338)	($369,048)	($330,581)	$88,289	$19,583	($0)	($0)	($0)	($0)	($0)	$454,296,917
	Production Sharing Costs	20.0%	$1,069,464	$885,429	$729,989	$597,076	$482,106	$381,594	$292,842	$213,736	$129,358	$53,681	($21,268)	($73,810)	($66,116)	$17,658	$3,917	($0)	($0)	($0)	($0)	($0)	$90,859,383
	Net Income		**$4,277,854**	**$3,541,716**	**$2,919,957**	**$2,388,305**	**$1,928,422**	**$1,526,375**	**$1,171,368**	**$854,944**	**$517,431**	**$214,722**	**($85,071)**	**($295,239)**	**($264,465)**	**$70,631**	**$15,666**	**($0)**	**($0)**	**($0)**	**($0)**	**($0)**	**$363,437,533**
Cash Flow Reconciliation	Add Back: Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$96,738,623
	Less: Capex	Import	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($96,738,623)
	Net Cash Flow		**$4,277,854**	**$3,541,716**	**$2,919,957**	**$2,388,305**	**$1,928,422**	**$1,526,375**	**$1,171,368**	**$854,944**	**$517,431**	**$214,722**	**($85,071)**	**($295,239)**	**($264,465)**	**$70,631**	**$15,666**	**($0)**	**($0)**	**($0)**	**($0)**	**($0)**	**$363,437,533**
	Net Book Value		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$241,846,558
	Current Year Loss		$0	$0	$0	$0	$0	$0	$0	$0	($247,949)	($452,921)	($624,619)	($808,467)	($694,229)	($93,191)	$0	$0	$0	$0	$0	$0	($2,921,377)
	Loss Carry Forward		$0	$0	$0	$0	$0	$0	$0	$0	($247,949)	($700,870)	($1,325,489)	($2,133,956)	($2,828,185)	($2,921,377)	($2,921,377)	($2,921,377)	($2,921,377)	($2,921,377)	($2,921,377)	($2,921,377)	
	Cumulative Net Cash Flow		$348,932,770	$352,474,486	$355,394,443	$357,782,749	$359,711,171	$361,237,546	$362,408,914	$363,263,858	$363,781,289	$363,996,012	$363,910,941	$363,615,702	$363,351,238	$363,421,868	$363,437,534	$363,437,534	$363,437,534	$363,437,534	$363,437,534	$363,437,533	$363,437,533
	Discounted Net Cash Flow @ %/year	10%	$551,167	$414,838	$310,920	$231,190	$169,703	$122,111	$85,191	$56,526	$31,101	$11,733	($4,226)	($13,332)	($10,857)	$2,636	$532	($0)	($0)	($0)	($0)	($0)	$121,339,127
	Cumulative Discounted Net Cash Flow		**$119,931,063**	**$120,345,901**	**$120,656,820**	**$120,888,010**	**$121,057,713**	**$121,179,824**	**$121,265,015**	**$121,321,541**	**$121,352,642**	**$121,364,374**	**$121,360,149**	**$121,346,816**	**$121,335,959**	**$121,338,595**	**$121,339,127**	**$121,339,127**	**$121,339,127**	**$121,339,127**	**$121,339,127**	**$121,339,127**	**$121,339,127**
	Risked Discounted Net Cash Flow	20%	$110,233	$82,968	$62,184	$46,238	$33,941	$24,422	$17,038	$11,305	$6,220	$2,347	($845)	($2,666)	($2,171)	$527	$106	($0)	($0)	($0)	($0)	($0)	$24,267,825
	Cumulative Risked Discounted Net Cash Flow		**$23,986,213**	**$24,069,180**	**$24,131,364**	**$24,177,602**	**$24,211,543**	**$24,235,965**	**$24,253,003**	**$24,264,308**	**$24,270,528**	**$24,272,875**	**$24,272,030**	**$24,269,363**	**$24,267,192**	**$24,267,719**	**$24,267,825**	**$24,267,825**	**$24,267,825**	**$24,267,825**	**$24,267,825**	**$24,267,825**	**$24,267,825**

*All gas vented in 2010

Run 3

Southern Shanxi Province CBM Valuation
No. 15 Seam Possible Reserves Case
(in USD)

		Input	2010*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Production Allocation	Total Production (MMcf)	Import	-	-	-	170.893	1,061.573	1,589.682	1,152.028	769.644	549.912	1,247.003	9,139.897	16,707.843	21,571.851	24,923.234	27,065.998	25,103.771	17,751.811	12,778.423	9,670.967	7,587.254	6,117.002
	Gas Energy Value (dth/Mcf)	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945
	Total Production (Mdth)		**-**	**-**	**-**	**161.494**	**1,003.186**	**1,502.249**	**1,088.666**	**727.314**	**519.667**	**1,178.418**	**8,637.203**	**15,788.912**	**20,385.399**	**23,552.456**	**25,577.368**	**23,723.064**	**16,775.461**	**12,075.610**	**9,139.064**	**7,169.955**	**5,780.567**
	Total Production, Net of 7% Shrink (Mdth)		**-**	**-**	**-**	**150.189**	**932.963**	**1,397.092**	**1,012.460**	**676.402**	**483.290**	**1,095.929**	**8,032.598**	**14,683.688**	**18,958.421**	**21,903.784**	**23,786.952**	**22,062.449**	**15,601.179**	**11,230.317**	**8,499.329**	**6,668.058**	**5,375.927**
Income Statement	Exchange Rate (RMB/USD)	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83
	Gas Price Escalation Rate (%/year)		0.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Gas Sales Price ($/dth)		**$5.60**	**$5.76**	**$5.94**	**$6.12**	**$6.30**	**$6.49**	**$6.68**	**$6.88**	**$7.09**	**$7.30**	**$7.52**	**$7.75**	**$7.98**	**$8.22**	**$8.47**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**
	Sales Revenue		$0	$0	$0	$918,562	$5,877,208	$9,065,018	$6,766,416	$4,656,105	$3,426,599	$8,003,405	$60,420,713	$113,763,294	$151,288,671	$180,036,523	$201,380,536	$192,384,304	$136,042,103	$97,928,236	$74,114,055	$58,145,391	$46,878,024
	VAT	13.00%	$0	$0	$0	($105,675)	($676,139)	($1,042,878)	($778,437)	($535,658)	($394,211)	($920,746)	($6,951,056)	($13,087,813)	($17,404,891)	($20,712,166)	($23,167,672)	($22,132,708)	($15,650,861)	($11,266,080)	($8,526,396)	($6,689,293)	($5,393,047)
	Net Revenue		**$0**	**$0**	**$0**	**$812,886**	**$5,201,069**	**$8,022,140**	**$5,987,979**	**$4,120,447**	**$3,032,389**	**$7,082,660**	**$53,469,658**	**$100,675,481**	**$133,883,780**	**$159,324,357**	**$178,212,863**	**$170,251,596**	**$120,391,242**	**$86,662,156**	**$65,587,659**	**$51,456,098**	**$41,484,977**
	Gathering Cost Rate, $/Mcf	$0.33	$0.33	$0.34	$0.35	$0.36	$0.37	$0.38	$0.39	$0.41	$0.42	$0.43	$0.44	$0.46	$0.47	$0.48	$0.50	$0.51	$0.53	$0.55	$0.56	$0.58	$0.60
	Overhead Cost Rate ($/Mcf)	$0.45	$0.45	$0.46	$0.48	$0.49	$0.51	$0.52	$0.54	$0.55	$0.57	$0.59	$0.60	$0.62	$0.64	$0.66	$0.68	$0.70	$0.72	$0.74	$0.77	$0.79	$0.81
	Cost Escalation (%)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
	Fixed Production Cost	Import	$0	$0	$0	$62,351	$319,316	$451,942	$308,067	$190,384	$152,012	$543,841	$3,286,313	$5,690,494	$7,262,439	$8,361,438	$9,371,199	$8,749,147	$6,768,634	$5,767,730	$5,822,322	$5,996,970	$6,176,862
	Variable Production Cost		$0	$0	$0	$57,310	$366,687	$565,579	$422,166	$290,501	$213,790	$499,344	$3,769,732	$7,097,849	$9,439,109	$11,232,727	$12,564,409	$12,003,122	$8,742,490	$6,481,969	$5,052,855	$4,083,088	$3,390,627
	Project Overhead Cost		$0	$0	$0	$78,150	$500,028	$771,244	$575,681	$396,137	$291,532	$680,923	$5,140,543	$9,678,885	$12,871,512	$15,317,355	$17,133,286	$16,367,894	$11,921,577	$8,839,049	$6,890,257	$5,567,848	$4,623,582
	Total Cash Costs		**$0**	**$0**	**$0**	**$197,812**	**$1,186,031**	**$1,788,765**	**$1,305,914**	**$877,022**	**$657,334**	**$1,724,107**	**$12,196,588**	**$22,467,228**	**$29,573,060**	**$34,911,520**	**$39,068,894**	**$37,120,163**	**$27,432,702**	**$21,088,748**	**$17,765,434**	**$15,647,906**	**$14,191,071**
	EBITDA		$0	$0	$0	$615,075	$4,015,038	$6,233,375	$4,682,065	$3,243,425	$2,375,054	$5,358,552	$41,273,070	$78,208,254	$104,310,720	$124,412,837	$139,143,969	$133,131,433	$92,958,540	$65,573,407	$47,822,225	$35,808,192	$27,293,906
	Depreciation (6-year recovery)		$0	$0	$0	$706,110	$1,433,403	$1,433,403	$1,433,403	$1,433,403	$1,433,403	$5,785,444	$13,690,271	$22,581,355	$31,739,171	$41,039,884	$49,410,527	$44,352,376	$35,720,256	$26,829,172	$17,671,356	$8,370,642	$0
	BTAX Income		$0	$0	$0	($91,035)	$2,581,635	$4,799,972	$3,248,662	$1,810,022	$941,652	($426,892)	$27,582,799	$55,626,899	$72,571,549	$83,372,952	$89,733,443	$88,779,058	$57,238,285	$38,744,236	$30,150,869	$27,437,550	$27,293,906
	Loss Utilization		$0	$0	$0	$0	($91,035)	$0	$0	$0	$0	$0	($426,892)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Taxable income		**$0**	**$0**	**$0**	**($91,035)**	**$2,490,600**	**$4,799,972**	**$3,248,662**	**$1,810,022**	**$941,652**	**($426,892)**	**$27,155,907**	**$55,626,899**	**$72,571,549**	**$83,372,952**	**$89,733,443**	**$88,779,058**	**$57,238,285**	**$38,744,236**	**$30,150,869**	**$27,437,550**	**$27,293,906**
	Income Tax Rate (%)		0.0%	0.0%	12.5%	12.5%	12.5%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
	Income Tax		$0	$0	($0)	$0	($311, 325)	($1, 199, 993)	($812, 165)	($452, 505)	($235, 413)	$0	($6, 788, 977)	($13, 906, 725)	($18, 142, 887)	($20, 843, 238)	($22, 433, 361)	($22, 194, 764)	($14, 309, 571)	($9, 686, 059)	($7, 537, 717)	($6, 859, 387)	($6, 823, 476)
	VAT Refund		$0	$0	$0	$79,256	$533,523	$951,193	$844,547	$596,353	$429,572	$789,112	$5,443,478	$11,553,623	$16,325,622	$19,885,348	$22,553,796	$22,391,449	$17,271,323	$12,362,276	$9,211,317	$7,148,568	$5,717,108
	Subsidy (0.20 RMB/m^3)		$0	$0	$0	$0	$124,535	$773,603	$1,158,454	$839,521	$560,865	$400,739	$908,732	$6,660,546	$12,175,559	$15,720,123	$18,162,387	$19,723,890	$18,293,950	$12,936,333	$9,312,060	$7,047,554	$5,529,084
	ATAX Income		$0	$0	($0)	($11,779)	$2,928,369	$5,324,776	$4,439,498	$2,793,390	$1,696,676	$762,959	$27,146,033	$59,934,344	$82,929,843	$98,135,185	$108,016,265	$108,699,632	$78,493,987	$54,356,785	$41,136,529	$34,774,285	$31,716,621
	Production Sharing Costs	20.0%	$0	$0	($0)	($2,356)	$585,674	$1,064,955	$887,900	$558,678	$339,335	$152,592	$5,429,207	$11,986,869	$16,585,969	$19,627,037	$21,603,253	$21,739,926	$15,698,797	$10,871,357	$8,227,306	$6,954,857	$6,343,324
	Net Income		**$0**	**$0**	**($0)**	**($9,423)**	**$2,342,695**	**$4,259,821**	**$3,551,598**	**$2,234,712**	**$1,357,341**	**$610,367**	**$21,716,826**	**$47,947,475**	**$66,343,874**	**$78,508,148**	**$86,413,012**	**$86,959,706**	**$62,795,189**	**$43,485,428**	**$32,909,223**	**$27,819,428**	**$25,373,297**
Cash Flow Reconciliation	Add Back: Depreciation		$0	$0	$0	$706,110	$1,433,403	$1,433,403	$1,433,403	$1,433,403	$1,433,403	$5,785,444	$13,690,271	$22,581,355	$31,739,171	$41,039,884	$49,410,527	$44,352,376	$35,720,256	$26,829,172	$17,671,356	$8,370,642	$0
	Less: Capex	Import	$0	$0	$0	($4,236,658)	($4,363,758)	$0	$0	$0	$0	($30,348,906)	($51,792,720)	($53,346,502)	($54,946,897)	($55,804,281)	($50,223,853)	$0	$0	$0	$0	$0	$0
	Net Cash Flow		**$0**	**$0**	**($0)**	**($3,539,971)**	**($587,660)**	**$5,693,223**	**$4,985,001**	**$3,668,115**	**$2,790,744**	**($23,953,095)**	**($16,385,623)**	**$17,182,327**	**$43,136,148**	**$63,743,751**	**$85,599,685**	**$131,312,081**	**$98,515,445**	**$70,314,600**	**$50,580,579**	**$36,190,070**	**$25,373,297**
	Net Book Value		$0	$0	$0	$3,530,548	$6,460,904	$5,027,501	$3,594,098	$2,160,696	$727,293	$25,290,755	$63,393,204	$94,158,351	$117,366,078	$132,130,474	$132,943,801	$88,591,425	$52,871,170	$26,041,998	$8,370,642	$0	$0
	Current Year Loss		$0	$0	$0	($91,035)	$0	$0	$0	$0	$0	($426,892)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Loss Carry Forward		$0	$0	$0	($91,035)	$0	$0	$0	$0	$0	($426,892)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Cumulative Net Cash Flow		$0	$0	($0)	($3,539,971)	($4,127,632)	$1,565,592	$6,550,593	$10,218,708	$13,009,451	($10,943,643)	($27,329,266)	($10,146,939)	$32,989,209	$96,732,961	$182,332,646	$313,644,727	$412,160,172	$482,474,772	$533,055,351	$569,245,421	$594,618,718
	Discounted Net Cash Flow @ %/year	10%	$0	$0	($0)	($2,535,860)	($382,701)	$3,370,532	$2,682,951	$1,794,725	$1,241,315	($9,685,702)	($6,023,373)	$5,742,039	$13,104,872	$17,605,014	$21,492,069	$29,972,162	$20,442,077	$13,263,970	$8,673,994	$5,641,987	$3,596,059
	Cumulative Discounted Net Cash Flow		**$0**	**$0**	**($0)**	**($2,535,860)**	**($2,918,561)**	**$451,971**	**$3,134,922**	**$4,929,647**	**$6,170,962**	**($3,514,740)**	**($9,538,113)**	**($3,796,075)**	**$9,308,798**	**$26,913,811**	**$48,405,881**	**$78,378,042**	**$98,820,119**	**$112,084,089**	**$120,758,083**	**$126,400,070**	**$129,996,129**
	Risked Discounted Net Cash Flow	20%	$0	$0	($0)	($507,172)	($76,540)	$674,106	$536,590	$358,945	$248,263	($1,937,140)	($1,204,675)	$1,148,408	$2,620,974	$3,521,003	$4,298,414	$5,994,432	$4,088,415	$2,652,794	$1,734,799	$1,128,397	$719,212
	Cumulative Risked Discounted Net Cash Flow		**$0**	**$0**	**($0)**	**($507,172)**	**($583,712)**	**$90,394**	**$626,984**	**$985,929**	**$1,234,192**	**($702,948)**	**($1,907,623)**	**($759,215)**	**$1,861,760**	**$5,382,762**	**$9,681,176**	**$15,675,608**	**$19,764,024**	**$22,416,818**	**$24,151,617**	**$25,280,014**	**$25,999,226**

*All gas vented in 2010

Run 3

Southern Shanxi Province CBM Valuation
No. 15 Seam Possible Reserves Case
(in USD)

		Input	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	Total
Production Allocation	Total Production (MMcf)	Import	5,038.685	4,223.300	3,591.274	3,091.184	2,688.578	2,359.590	2,087.269	1,856.134	1,649.880	1,475.645	1,335.649	1,214.820	1,109.523	999.575	795.976	592.689	406.270	234.741	81.769	0.663	219,792.000
	Gas Energy Value (dth/Mcf)	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	0.945	
	Total Production (Mdth)		**4,761.557**	**3,991.019**	**3,393.754**	**2,921.169**	**2,540.706**	**2,229.813**	**1,972.469**	**1,754.047**	**1,559.137**	**1,394.485**	**1,262.188**	**1,148.005**	**1,048.499**	**944.598**	**752.197**	**560.091**	**383.925**	**221.830**	**77.272**	**0.627**	**207,703.440**
	Total Production, Net of 7% Shrink (Mdth)		**4,428.248**	**3,711.647**	**3,156.191**	**2,716.687**	**2,362.857**	**2,073.726**	**1,834.396**	**1,631.263**	**1,449.997**	**1,296.871**	**1,173.835**	**1,067.645**	**975.104**	**878.476**	**699.544**	**520.885**	**357.050**	**206.302**	**71.863**	**0.583**	**193,164.199**
Income Statement	Exchange Rate (RMB/USD)	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	6.83	
	Gas Price Escalation Rate (%/year)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Gas Sales Price ($/dth)		**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	**$8.72**	
	Sales Revenue		$38,614,275	$32,365,521	$27,521,951	$23,689,480	$20,604,084	$18,082,864	$15,995,915	$14,224,598	$12,643,958	$11,308,697	$10,235,829	$9,309,848	$8,502,898	$7,660,305	$6,100,011	$4,542,109	$3,113,475	$1,798,952	$626,642	$5,081	$1,618,041,655
	VAT	13.00%	($4,442,350)	($3,723,467)	($3,166,242)	($2,725,338)	($2,370,381)	($2,080,329)	($1,840,238)	($1,636,458)	($1,454,615)	($1,301,001)	($1,177,573)	($1,071,044)	($978,210)	($881,274)	($701,771)	($522,543)	($358,187)	($206,959)	($72,092)	($585)	($186,146,385)
	Net Revenue		**$34,171,924**	**$28,642,054**	**$24,355,709**	**$20,964,142**	**$18,233,703**	**$16,002,535**	**$14,155,677**	**$12,588,140**	**$11,189,343**	**$10,007,696**	**$9,058,256**	**$8,238,804**	**$7,524,689**	**$6,779,031**	**$5,398,240**	**$4,019,565**	**$2,755,288**	**$1,591,993**	**$554,550**	**$4,496**	**$1,431,895,270**
	Gathering Cost Rate, $/Mcf	$0.33	$0.61	$0.63	$0.65	$0.67	$0.69	$0.71	$0.73	$0.76	$0.78	$0.80	$0.83	$0.85	$0.88	$0.90	$0.93	$0.96	$0.99	$1.01	$1.05	$1.08	
	Overhead Cost Rate ($/Mcf)	$0.45	$0.84	$0.86	$0.89	$0.91	$0.94	$0.97	$1.00	$1.03	$1.06	$1.09	$1.13	$1.16	$1.19	$1.23	$1.27	$1.30	$1.34	$1.38	$1.43	$1.47	
	Cost Escalation (%)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	
	Fixed Production Cost	Import	$6,362,226	$6,553,062	$6,749,712	$6,952,176	$7,160,682	$7,375,572	$7,596,846	$7,794,589	$7,891,125	$8,014,211	$8,250,220	$8,497,720	$8,752,700	$8,815,169	$7,606,618	$6,095,813	$4,487,583	$2,777,345	$1,031,693	$8,848	$204,055,371
	Variable Production Cost		$2,876,708	$2,483,521	$2,175,212	$1,928,480	$1,727,628	$1,561,713	$1,422,920	$1,303,312	$1,193,243	$1,099,248	$1,024,810	$960,064	$903,154	$838,065	$687,384	$527,186	$372,211	$221,514	$79,476	$664	$109,659,866
	Project Overhead Cost		$3,922,784	$3,386,619	$2,966,198	$2,629,745	$2,355,856	$2,129,609	$1,940,345	$1,777,244	$1,627,149	$1,498,974	$1,397,468	$1,309,178	$1,231,573	$1,142,816	$937,342	$718,890	$507,560	$302,064	$108,377	$905	$149,536,180
	Total Cash Costs		**$13,161,718**	**$12,423,202**	**$11,891,122**	**$11,510,401**	**$11,244,166**	**$11,066,894**	**$10,960,111**	**$10,875,145**	**$10,711,517**	**$10,612,433**	**$10,672,497**	**$10,766,961**	**$10,887,427**	**$10,796,051**	**$9,231,345**	**$7,341,889**	**$5,367,354**	**$3,300,923**	**$1,219,546**	**$10,417**	**$259,196,046**
	EBITDA		$21,010,206	$16,218,852	$12,464,586	$9,453,740	$6,989,537	$4,935,641	$3,195,567	$1,712,994	$477,826	($604,736)	($1,614,242)	($2,528,157)	($3,362,738)	($4,017,020)	($3,833,105)	($3,322,324)	($2,612,066)	($1,708,929)	($664,996)	($5,920)	$968,643,853
	Depreciation (6-year recovery)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$305,063,575
	BTAX Income		$21,010,206	$16,218,852	$12,464,586	$9,453,740	$6,989,537	$4,935,641	$3,195,567	$1,712,994	$477,826	($604,736)	($1,614,242)	($2,528,157)	($3,362,738)	($4,017,020)	($3,833,105)	($3,322,324)	($2,612,066)	($1,708,929)	($664,996)	($5,920)	$663,580,278
	Loss Utilization		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($517,927)
	Taxable income		**$21,010,206**	**$16,218,852**	**$12,464,586**	**$9,453,740**	**$6,989,537**	**$4,935,641**	**$3,195,567**	**$1,712,994**	**$477,826**	**($604,736)**	**($1,614,242)**	**($2,528,157)**	**($3,362,738)**	**($4,017,020)**	**($3,833,105)**	**($3,322,324)**	**($2,612,066)**	**($1,708,929)**	**($664,996)**	**($5,920)**	**$663,062,351**
	Income Tax Rate (%)		25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	
	Income Tax		($5, 252, 552)	($4, 054, 713)	($3, 116, 147)	($2, 363, 435)	($1, 747, 384)	($1, 233, 910)	($798, 892)	($428, 249)	($119, 457)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($171,652,303)
	VAT Refund		$4,680,024	$3,903,188	$3,305,548	$2,835,564	$2,459,121	$2,152,842	$1,900,261	$1,687,403	$1,500,075	$1,339,404	$1,208,430	$1,097,677	$1,001,418	$905,508	$746,647	$567,350	$399,276	$244,766	$105,808	$18,461	$186,146,239
	Subsidy (0.20 RMB/m^3)		$4,457,662	$3,671,857	$3,077,659	$2,617,080	$2,252,648	$1,959,256	$1,719,511	$1,521,062	$1,352,626	$1,202,322	$1,075,351	$973,332	$885,280	$808,546	$728,423	$580,054	$431,912	$296,062	$171,064	$59,588	$160,169,234
	ATAX Income		$24,895,341	$19,739,184	$15,731,647	$12,542,950	$9,953,922	$7,813,829	$6,016,447	$4,493,211	$3,211,072	$1,936,990	$669,540	($457,149)	($1,476,040)	($2,302,966)	($2,358,034)	($2,174,919)	($1,780,878)	($1,168,101)	($388,124)	$72,129	$838,243,448
	Production Sharing Costs	20.0%	$4,979,068	$3,947,837	$3,146,329	$2,508,590	$1,990,784	$1,562,766	$1,203,289	$898,642	$642,214	$387,398	$133,908	($91,430)	($295,208)	($460,593)	($471,607)	($434,984)	($356,176)	($233,620)	($77,625)	$14,426	$167,648,690
	Net Income		**$19,916,273**	**$15,791,347**	**$12,585,317**	**$10,034,360**	**$7,963,137**	**$6,251,063**	**$4,813,158**	**$3,594,569**	**$2,568,857**	**$1,549,592**	**$535,632**	**($365,719)**	**($1,180,832)**	**($1,842,373)**	**($1,886,428)**	**($1,739,935)**	**($1,424,702)**	**($934,481)**	**($310,499)**	**$57,703**	**$670,594,758**
Cash Flow Reconciliation	Add Back: Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$305,063,575
	Less: Capex	Import	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($305,063,575)
	Net Cash Flow		**$19,916,273**	**$15,791,347**	**$12,585,317**	**$10,034,360**	**$7,963,137**	**$6,251,063**	**$4,813,158**	**$3,594,569**	**$2,568,857**	**$1,549,592**	**$535,632**	**($365,719)**	**($1,180,832)**	**($1,842,373)**	**($1,886,428)**	**($1,739,935)**	**($1,424,702)**	**($934,481)**	**($310,499)**	**$57,703**	**$670,594,758**
	Net Book Value		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$762,658,938
	Current Year Loss		$0	$0	$0	$0	$0	$0	$0	$0	$0	($604,736)	($1,614,242)	($2,528,157)	($3,362,738)	($4,017,020)	($3,833,105)	($3,322,324)	($2,612,066)	($1,708,929)	($664,996)	($5,920)	($24,792,160)
	Loss Carry Forward		$0	$0	$0	$0	$0	$0	$0	$0	$0	($604,736)	($2,218,978)	($4,747,135)	($8,109,873)	($12,126,893)	($15,959,998)	($19,282,322)	($21,894,388)	($23,603,317)	($24,268,313)	($24,274,233)	
	Cumulative Net Cash Flow		$614,534,991	$630,326,339	$642,911,656	$652,946,016	$660,909,153	$667,160,216	$671,973,374	$675,567,943	$678,136,800	$679,686,392	$680,222,024	$679,856,305	$678,675,473	$676,833,100	$674,946,672	$673,206,737	$671,782,035	$670,847,554	$670,537,055	$670,594,758	$670,594,758
	Discounted Net Cash Flow @ %/year	10%	$2,566,051	$1,849,625	$1,340,097	$971,335	$700,762	$500,089	$350,051	$237,660	$154,403	$84,672	$26,607	($16,515)	($48,477)	($68,759)	($64,003)	($53,666)	($39,948)	($23,821)	($7,195)	$1,216	$138,456,313
	Cumulative Discounted Net Cash Flow		**$132,562,181**	**$134,411,806**	**$135,751,902**	**$136,723,237**	**$137,423,999**	**$137,924,089**	**$138,274,140**	**$138,511,799**	**$138,666,202**	**$138,750,874**	**$138,777,482**	**$138,760,966**	**$138,712,490**	**$138,643,730**	**$138,579,728**	**$138,526,061**	**$138,486,113**	**$138,462,293**	**$138,455,097**	**$138,456,313**	**$138,456,313**
	Risked Discounted Net Cash Flow	20%	$513,210	$369,925	$268,019	$194,267	$140,152	$100,018	$70,010	$47,532	$30,881	$16,934	$5,321	($3,303)	($9,695)	($13,752)	($12,801)	($10,733)	($7,990)	($4,764)	($1,439)	$243	$27,691,263
	Cumulative Risked Discounted Net Cash Flow		**$26,512,436**	**$26,882,361**	**$27,150,380**	**$27,344,647**	**$27,484,800**	**$27,584,818**	**$27,654,828**	**$27,702,360**	**$27,733,240**	**$27,750,175**	**$27,755,496**	**$27,752,193**	**$27,742,498**	**$27,728,746**	**$27,715,946**	**$27,705,212**	**$27,697,223**	**$27,692,459**	**$27,691,019**	**$27,691,263**	**$27,691,263**

*All gas vented in 2010

Selection Template and Associated Financial Model

Cash Flow Discount Rate	10%
Initial Gas Price ($/MMbtu)	$ 5.60
Heating Value Adjustment (btu/scf)	950
Gas Price Escalation (Years 1-15)	3%
Gas Price Escalation (Years 16-20)	0%
Gas Shrinkage (Compressor Fuel)	7%
Gas Gathering Cost ($/mcf)	$ 0.33
Overhead Cost ($/mcf)	$ 0.45
Cost Escalation	3%

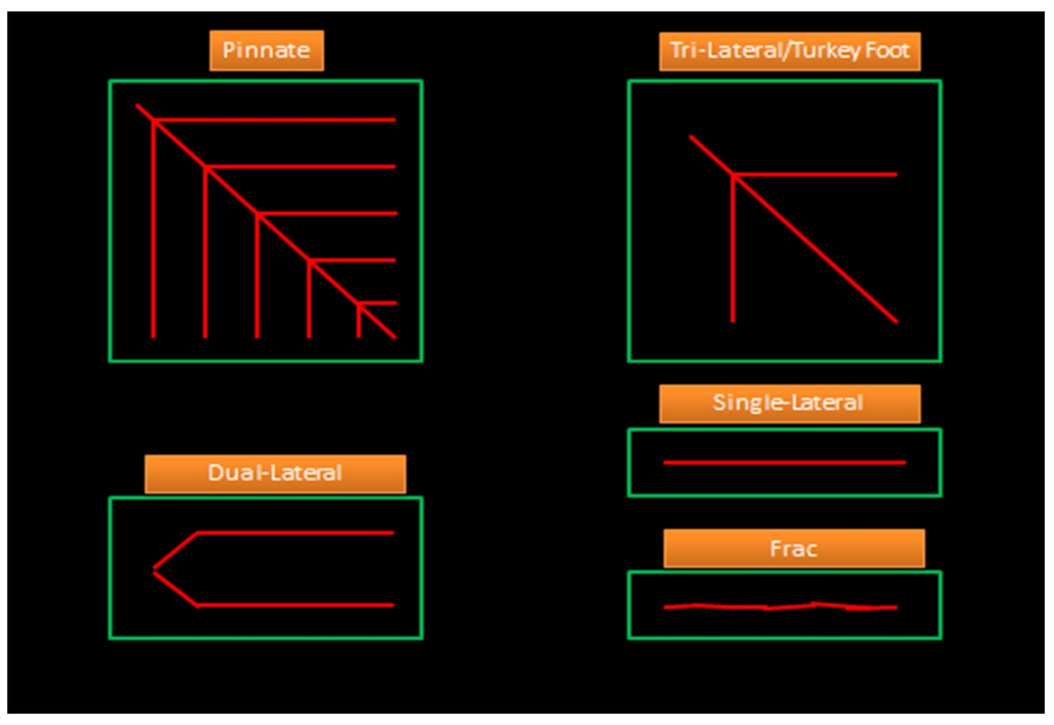
Capital and Operating Expenses	Pinnate	Turkey Foot	Dual Lateral	Single Lateral	Frac-Low	Frac-Expected	Frac-High
In-Seam Drilling Length (ft)	20,000	7,100	6,800	3,200	X	X	X
Drainage Area (acres)	250	250	166	79	79	79	79
Base Capital (Horizontals							
Assume 20,000 ft of in-seam Drilling)	$ 1,850,000	$ 1,850,000	$ 1,850,000	$ 1,850,000	$ 400,000.00	$ 400,000.00	$ 400,000.00
Adjusted Horizontal Capital ($/ft)	$ 40.00	$ 40.00	$ 40.00	$ 40.00	X	X	X
Capital Adjustment	$ -	$ (516,000)	$ (528,000)	$ (672,000)	X	X	X
Adjusted Capital	$ 1,850,000	$ 1,334,000	$ 1,322,000	$ 1,178,000	$ 400,000.00	$ 400,000.00	$ 400,000.00
Year 1 Fixed Operating Expenses ($/Month)	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 4,000.00	$ 4,000.00	$ 4,000.00
Year 2 Fixed Operating Expenses ($/Month)	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 2,500.00	$ 2,500.00	$ 2,500.00
Year 3+ Fixed Operating Expenses ($/Month)	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 1,500.00	$ 1,500.00	$ 1,500.00

Production (mcf)	Pinnate	Turkey Foot	Dual Lateral	Single Lateral	Frac-Low	Frac-Expected	Frac-High
Year 1	621,601	232,698	232,630	114,346	25,594	32,456	39,318
Year 2	386,385	112,198	116,017	55,902	21,146	26,865	32,584
Year 3	240,429	81,607	93,730	49,489	16,809	21,317	25,826
Year 4	157,404	66,583	92,381	49,844	17,547	22,350	27,152
Year 5	111,011	58,891	81,497	42,099	19,475	24,134	28,792
Year 6	82,746	53,625	68,747	34,384	17,844	21,800	25,757
Year 7	64,221	49,750	58,033	28,407	15,789	19,114	22,440
Year 8	51,352	48,084	49,590	23,848	13,930	16,750	19,571
Year 9	42,022	46,758	42,860	20,317	12,377	14,792	17,208
Year 10	35,026	45,166	37,423	17,537	11,280	13,371	15,464
Year 11	29,637	43,919	32,979	15,309	10,195	12,025	13,858
Year 12	25,395	42,725	29,302	13,495	9,380	10,998	12,619
Year 13	21,993	41,073	26,222	11,994	8,749	10,190	11,633
Year 14	19,217	39,105	23,612	10,737	8,083	9,375	10,680
Year 15	16,924	37,032	21,381	9,672	7,575	8,742	10,149
Year 16	15,009	35,011	19,459	8,762	7,191	8,249	9,890
Year 17	13,393	33,087	17,790	7,977	6,729	7,693	9,563
Year 18	12,018	31,269	16,332	7,295	6,385	7,268	9,204
Year 19	10,836	29,559	15,049	6,698	6,144	6,936	8,818
Year 20	9,684	27,588	13,731	6,092	5,743	6,433	8,316

Gas Price by Year and Income from Sales	Gas Price	Pinnate	Turkey Foot	Dual Lateral	Single Lateral	Frac-Low	Frac-Expected	Frac-High
Year 1	$ 5.60	$ 3,075,432	$ 1,151,296	$ 1,150,960	$ 565,738	$ 126,627	$ 160,579	$ 194,531
Year 2	$ 5.77	$ 1,969,026	$ 571,764	$ 591,227	$ 284,876	$ 107,759	$ 136,904	$ 166,051
Year 3	$ 5.94	$ 1,261,988	$ 428,350	$ 491,980	$ 259,764	$ 88,227	$ 111,892	$ 135,556
Year 4	$ 6.12	$ 850,987	$ 359,975	$ 499,449	$ 269,475	$ 94,866	$ 120,833	$ 146,792
Year 5	$ 6.30	$ 618,173	$ 327,936	$ 453,822	$ 234,429	$ 108,448	$ 134,392	$ 160,330
Year 6	$ 6.49	$ 474,599	$ 307,575	$ 394,305	$ 197,211	$ 102,345	$ 125,038	$ 147,732
Year 7	$ 6.69	$ 379,396	$ 293,905	$ 342,842	$ 167,821	$ 93,277	$ 112,921	$ 132,570
Year 8	$ 6.89	$ 312,474	$ 292,586	$ 301,749	$ 145,114	$ 84,762	$ 101,924	$ 119,089
Year 9	$ 7.09	$ 263,369	$ 293,056	$ 268,623	$ 127,334	$ 77,571	$ 92,709	$ 107,853
Year 10	$ 7.31	$ 226,109	$ 291,566	$ 241,581	$ 113,207	$ 72,819	$ 86,316	$ 99,826
Year 11	$ 7.53	$ 197,063	$ 292,026	$ 219,283	$ 101,789	$ 67,788	$ 79,958	$ 92,143
Year 12	$ 7.75	$ 173,923	$ 292,605	$ 200,681	$ 92,420	$ 64,240	$ 75,322	$ 86,422
Year 13	$ 7.98	$ 155,138	$ 289,732	$ 184,970	$ 84,605	$ 61,713	$ 71,878	$ 82,062
Year 14	$ 8.22	$ 139,628	$ 284,122	$ 171,557	$ 78,010	$ 58,725	$ 68,118	$ 77,596
Year 15	$ 8.47	$ 126,653	$ 277,134	$ 160,012	$ 72,381	$ 56,685	$ 65,422	$ 75,950
Year 16	$ 8.47	$ 112,323	$ 262,008	$ 145,627	$ 65,568	$ 53,811	$ 61,734	$ 74,012
Year 17	$ 8.47	$ 100,232	$ 247,609	$ 133,137	$ 59,694	$ 50,357	$ 57,574	$ 71,566
Year 18	$ 8.47	$ 89,936	$ 234,010	$ 122,224	$ 54,592	$ 47,784	$ 54,392	$ 68,877
Year 19	$ 8.47	$ 81,090	$ 221,211	$ 112,623	$ 50,128	$ 45,976	$ 51,909	$ 65,993
Year 20	$ 8.47	$ 72,475	$ 206,460	$ 102,762	$ 45,592	$ 42,981	$ 48,143	$ 62,232

Gathering and Overhead Costs	Costs/mcf	Pinnate	Turkey Foot	Dual Lateral	Single Lateral	Frac-Low	Frac-Expected	Frac-High
Year 1	$ 0.78	$ 484,849	$ 181,504	$ 181,451	$ 89,190	$ 19,963	$ 25,316	$ 30,668
Year 2	$ 0.80	$ 310,421	$ 90,140	$ 93,208	$ 44,911	$ 16,988	$ 21,583	$ 26,178
Year 3	$ 0.83	$ 198,955	$ 67,530	$ 77,562	$ 40,952	$ 13,909	$ 17,640	$ 21,371
Year 4	$ 0.85	$ 134,160	$ 56,751	$ 78,739	$ 42,483	$ 14,956	$ 19,050	$ 23,142
Year 5	$ 0.88	$ 97,456	$ 51,700	$ 71,546	$ 36,958	$ 17,097	$ 21,187	$ 25,276
Year 6	$ 0.90	$ 74,822	$ 48,490	$ 62,163	$ 31,091	$ 16,135	$ 19,712	$ 23,290
Year 7	$ 0.93	$ 59,813	$ 46,335	$ 54,050	$ 26,457	$ 14,705	$ 17,802	$ 20,900
Year 8	$ 0.96	$ 49,262	$ 46,127	$ 47,571	$ 22,878	$ 13,363	$ 16,068	$ 18,775
Year 9	$ 0.99	$ 41,521	$ 46,201	$ 42,349	$ 20,075	$ 12,229	$ 14,616	$ 17,003
Year 10	$ 1.02	$ 35,647	$ 45,966	$ 38,086	$ 17,847	$ 11,480	$ 13,608	$ 15,738
Year 11	$ 1.05	$ 31,067	$ 46,039	$ 34,570	$ 16,047	$ 10,687	$ 12,606	$ 14,527
Year 12	$ 1.08	$ 27,419	$ 46,130	$ 31,638	$ 14,570	$ 10,128	$ 11,875	$ 13,625
Year 13	$ 1.11	$ 24,458	$ 45,677	$ 29,161	$ 13,338	$ 9,729	$ 11,332	$ 12,937
Year 14	$ 1.15	$ 22,013	$ 44,792	$ 27,046	$ 12,298	$ 9,258	$ 10,739	$ 12,233
Year 15	$ 1.18	$ 19,967	$ 43,691	$ 25,226	$ 11,411	$ 8,937	$ 10,314	$ 11,974
Year 16	$ 1.22	$ 18,239	$ 42,545	$ 23,647	$ 10,647	$ 8,738	$ 10,024	$ 12,018
Year 17	$ 1.25	$ 16,764	$ 41,413	$ 22,268	$ 9,984	$ 8,422	$ 9,629	$ 11,970
Year 18	$ 1.29	$ 15,493	$ 40,313	$ 21,056	$ 9,405	$ 8,232	$ 9,370	$ 11,865
Year 19	$ 1.33	$ 14,388	$ 39,251	$ 19,984	$ 8,895	$ 8,158	$ 9,211	$ 11,710
Year 20	$ 1.37	$ 13,246	$ 37,733	$ 18,781	$ 8,333	$ 7,855	$ 8,799	$ 11,374

Fixed Operating Costs	Horizontals	Verticals
Year 1	$ 90,000	$ 48,000
Year 2	$ 60,000	$ 30,000
Year 3	$ 24,000	$ 18,000
Year 4	$ 24,000	$ 18,000
Year 5	$ 24,000	$ 18,000
Year 6	$ 24,000	$ 18,000
Year 7	$ 24,000	$ 18,000
Year 8	$ 24,000	$ 18,000
Year 9	$ 24,000	$ 18,000
Year 10	$ 24,000	$ 18,000
Year 11	$ 24,000	$ 18,000
Year 12	$ 24,000	$ 18,000
Year 13	$ 24,000	$ 18,000
Year 14	$ 24,000	$ 18,000
Year 15	$ 24,000	$ 18,000
Year 16	$ 24,000	$ 18,000
Year 17	$ 24,000	$ 18,000
Year 18	$ 24,000	$ 18,000
Year 19	$ 24,000	$ 18,000
Year 20	$ 24,000	$ 18,000



Net Cash Flow	Pinnate	Turkey Foot	Dual Lateral	Single Lateral	Frac-Low	Frac-Expected	Frac-High
Capital	$ (1,850,000)	$ (1,334,000)	$ (1,322,000)	$ (1,178,000)	$ (400,000)	$ (400,000)	$ (400,000)
Year 1	$ 2,500,583	$ 879,792	$ 879,509	$ 386,548	$ 58,664	$ 87,264	$ 115,863
Year 2	$ 1,598,605	$ 421,624	$ 438,019	$ 179,964	$ 60,770	$ 85,321	$ 109,872
Year 3	$ 1,039,033	$ 336,820	$ 390,418	$ 194,811	$ 56,318	$ 76,252	$ 96,185
Year 4	$ 692,827	$ 279,224	$ 396,709	$ 202,992	$ 61,910	$ 83,783	$ 105,650
Year 5	$ 496,716	$ 252,236	$ 358,276	$ 173,471	$ 73,351	$ 95,205	$ 117,054
Year 6	$ 375,778	$ 235,085	$ 308,142	$ 142,120	$ 68,210	$ 87,325	$ 106,442
Year 7	$ 295,583	$ 223,571	$ 264,792	$ 117,364	$ 60,571	$ 77,119	$ 93,670
Year 8	$ 239,211	$ 222,459	$ 230,178	$ 98,237	$ 53,399	$ 67,855	$ 82,314
Year 9	$ 197,848	$ 222,855	$ 202,274	$ 83,260	$ 47,342	$ 60,093	$ 72,850
Year 10	$ 166,462	$ 221,600	$ 179,496	$ 71,360	$ 43,339	$ 54,708	$ 66,088
Year 11	$ 141,996	$ 221,987	$ 160,713	$ 61,741	$ 39,101	$ 49,353	$ 59,616
Year 12	$ 122,504	$ 222,475	$ 145,043	$ 53,849	$ 36,113	$ 45,447	$ 54,798
Year 13	$ 106,680	$ 220,055	$ 131,809	$ 47,267	$ 33,984	$ 42,547	$ 51,124
Year 14	$ 93,616	$ 215,330	$ 120,510	$ 41,711	$ 31,467	$ 39,379	$ 47,363
Year 15	$ 82,686	$ 209,444	$ 110,786	$ 36,970	$ 29,749	$ 37,108	$ 45,976
Year 16	$ 70,084	$ 195,462	$ 97,980	$ 30,921	$ 27,073	$ 33,709	$ 43,994
Year 17	$ 59,468	$ 182,196	$ 86,869	$ 25,710	$ 23,935	$ 29,945	$ 41,596
Year 18	$ 50,443	$ 169,697	$ 77,169	$ 21,187	$ 21,552	$ 27,022	$ 39,011
Year 19	$ 42,701	$ 157,960	$ 68,639	$ 17,233	$ 19,818	$ 24,698	$ 36,283
Year 20	$ 35,229	$ 144,727	$ 59,981	$ 13,260	$ 17,126	$ 21,345	$ 32,858
NPV	$ 4,142,627.20	$ 1,421,527.54	$ 1,469,991.80	$ 56,700.43	$ 35,733.34	$ 179,259.91	$ 328,446.95
IRR	100%	34%	38%	11%	12%	18%	24%