PART V

COMPETENT PERSON'S REPORT

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CURZON/COOS BAY ENERGY

COOS BAY CBM PROJECT

COMPETENT PERSON'S REPORT

Compiled in accordance with the European and Securities Markets Authority (ESMA) Update of the Committee of European Securities Regulator's recommendations for the implementation of Commission Regulation No.809/2004 implementing the Prospectus Directive (ESMA 2013/319) relating to Mineral Companies dated March 20, 2013

To The Directors of:
Curzon Energy PLC
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Executive Summary

Curzon Energy Plc ("Curzon"), through its U. S. subsidiary Coos Bay Energy, LLC ("Coos Bay") is developing a coalbed methane (CBM) project to recover natural gas held in the coals of the Coos Bay Basin, located along the Pacific coast of southwest Oregon (the "Coos Bay Project"). These geologically young, thermally immature coal deposits are shallow and structurally complex. Major targets are the Upper and Lower Coaledo coals which have been mapped across this area, subjected to limited sampling for coalbed gas contents and adsorption isotherms, and briefly production tested with five wells in August and September of 2008. The production tests were terminated before the full potential of the wells was evident and they remain inactive.

Low, mid, and high estimates of original gas in place volumes for the subject acreage (Table 1) were obtained by adjusting volumes calculated in a Sproule report (1) which assessed coalbed gas in place over a large portion of this basin.

Table 1. Coos Bay Project Coalbed Methane Original Gas In Place, bcf			
Coal Zone	Low	Mid	High
Upper Coaledo	45.5	73.0	101.5
Lower Coaledo	399.7	638.8	888.5
Total	445.2	711.7	989.9

The production test wells were all completed in the Lower Coaledo coals. Reported gas and water volumes from the three week production test were used to anchor type curves based upon analog Powder River Basin coals wells. The resulting type curves appear reasonable and yield low, mid, and high estimates of 30-year cumulative gas recoveries of 301.2 MMCF, 500.9 MMCF, and 747.3 MMCF, respectively. Assuming a 100 acre well spacing, and comparing these technically recoverable volumes with volumetric original gas in place volumes based on low, mid, and high sorption isotherms yields recovery factors of 88%.

Single well economics based upon these type curves, current well capital costs and operating expenses, and the current NYMEX Henry Hub price corrected with the historic differential for this area yielded low, mid, and high net present values at a discount rate of 10% (PV10's) of 181.5 k$, 493.2 k$, and 758.9 k$, respectively, for a 15 year well life. For an 100 acre well spacing, the associated recovery factor for all three cases is 59% of original gas in place. The single well NYMEX Henry Hub breakeven price is 1.006 $/mmb.

Project economics for the first two of three proposed development phases, both in the Lower Coaledo coals, were run based upon the mid type curve, the current natural gas price for this area, and current well capital costs and operating expenses. Produced gas will be marketed via a pipeline running across the property which connects to multiple regional markets. Water produced from the Coaledo coals is fairly fresh and Coos Bay has secured the necessary permit, NPDES #102935, to dispose of all produced water in sloughs on the subject property. Phase I involves returning the five shutin wells to production and drilling an additional two wells located near them. All wells are scheduled to be on production by 4Q 2017. For a 15 year project lifetime, the resulting Phase I PV10 is $5,518,555, the internal rate of return (IRR) 112%, and the time to payout 1.6 years. Dependent on positive results from Phase I and raising additional capital, Phase II will be comprised of 58 wells, stepping out from the Phase I wells and drilled at a rate of 3 wells per month. Based upon a 15 year project life, the Phase II PV10 is $29,066,590, the IRR 46%, and the payout 4.6 years.

None of the existing wells in this project has attained commercial gas production consequently no reserves can be assigned to the subject property. Resources reported herein were estimated in accordance with the Petroleum Resources Management System (PRMS) published by the Society of Petroleum Engineers/World Petroleum Council/American Association of Petroleum Geologists/Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) in March 2007 (Ref 12) and the PRMS Guidelines for Application of the Petroleum Resources Management System published by the SPE/WPC/AAPG/SPEE I November 2011 (Ref 13).

Based upon current data, the Lower Coaledo coals contain substantial coal gas volumes that are technically recoverable with existing technology but lack demonstration of commerciality. Thus, these gas volumes can be classified as Contingent Resources with risked 1C, 2C, and 3C estimates of 85.6 bcf, 273.5 bcf, and 419.4 bcf, respectively.

The Upper Coaled coals, generally thinner and less areally extensive than the Lower Coaledo coals, have not been tested for the presence of coalbed methane (CBM) and may contain undiscovered coalbed methane gas volumes. These gas volumes can be classified as Prospective Resources with risked low, mid, and high estimates of 8.77 bcf, 28.1 bcf, and 43.1 bcf, respectively.

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Introduction

The Coos Bay Project, seeks to recover methane gas from shallow, geologically young, thermally immature coal deposits in southwest Oregon, United States. Exploration activities indicate the presence of two coal sections in this prospect and have estimated original gas in place in both the Upper and Lower Coaledo coals. A total of 5 wells have been completed in selected seams of the Lower Coaledo section and briefly tested. The production tests were of insufficient duration to dewater the coals, precluding attainment of peak gas rates and subsequent decline. The project has lain dormant for nearly a decade with all wells completed but inactive. Current drilling and stimulation costs and operating expenses, reduced from previous levels due to recent drops in oil and gas prices, and reduced water disposal expenses have been incorporated into this report.

This evaluation begins with a review of geological information, then estimates original gas in place and technically recoverable gas volumes, followed by a review of well performance and type curves, and economic analyses for a single well and the proposed field wide Phase I and Phase II developments. Phase I involves returning the 5 existing wells to production followed by drilling and completing 2 new wells the following month. Dependent on positive results from Phase I and raising additional capital, Phase II will encompass development of up to 58 additional wells in the core area.

As none of the existing wells attained commercial gas production during limited testing several years ago, no reserves can be assigned to the subject property. Original gas in place in the Upper and Lower Coaledo coals, estimated as of June 13, 2016, are collected in Table 1 above. Contingent Resources were assigned to the Lower Coaledo coals while Prospective Resources were assigned to the untested Upper Coaledo coals.

Information utilized in the preparation of this CPR include:

1. Sproule letter to Michael D’Ecclesiis, Yorkville Advisors, March 3, 2009, “Estimation of CBM Resources within the Upper and Lower Coaledo Coals, Coos Bay Area, Oregon, for YA Global Investments, L.P. (As of January, 31, 2009)
2. Structure Contour Map on D Coal Bed, Lower Coaledo Formation, Coos Bay Basin, Oregon, Plate 10, Russell Ralls (North Oregon Resources) January 2006
3. Isopach Map – Total Coal Thickness of Lower Coaledo Coal, Plate 9, Dr. Alan Niem (Pacific Northwest Geology), Russell Ralls (North Oregon Resources) January 2006
4. Structure Contour Map on the Beaver Hill Coal, Upper Coaledo Formation, Plate 14, Russell Ralls (North Oregon Resources) June 2005
5. Isopach Map – Upper Coaledo Coals, Coaledo Formation, Plate 13, Russell Ralls (North Oregon Resources) January 2006
6. Westport 09-21-26-13 Injection/Fall-Off Reservoir Test Results Summary, Coal Gas Technology, July 9, 2007
7. Daily Completion and Well Servicing Report, Westport 09-21-26-13, Methane Energy Corp, Coal Gas Technology
8. Westport_corporate_overview – v15.pdf, April 19, 2016
9. “Coos Bay Westport Field Evaluation”, MHA memo to Yorkville Advisors, November 12, 2009.
10. Westport First Pass Forecasts – 15Mar2016 – 2.pdf

11. Bustin, R. M., and Clarkson, C. R., 1999, “Free gas storage in matrix porosity: a potentially significant coalbed resource in low rank coals”, paper 9956, presented at the International Coalbed Methane Symposium, University of Alabama, Tuscaloosa, Alabama.
12. Petroleum Resources Management System (PRMS), Oil and Gas Reserves Committee of the Society of Petroleum Engineers, 2007.
13. Guidelines for Application of the Petroleum Resources Management System (PRMS), Oil and Gas Reserves Committee of the Society of Petroleum Engineers, November 2011.
14. U.S. Energy Information Administration
15. EOG Resources Inc. press release
16. Oil and Gas Financial Journal-WPX Energy Sells PRB Assets
17. Natural Gas Intel 3rd September 2015- New Player Muscles into PR, Buying CBM Wells, Gas plant.

Overview of project and land holdings

The Coos Bay coalbed methane project (Figure 1) is located in the Coos Bay Basin along the Pacific coast of southwest Oregon, U.S.A. Anecdotal reports indicate near surface coals in the basin were intermittently mined from the mid 1800’s through the mid 1900’s but all production has now ceased. To the best of our knowledge, a prior effort by Torrent Energy and Methane Energy Corporation was the sole attempt to exploit coalbed methane held in the Coos Bay coals and no other commercial oil and gas operations, targeting conventional or unconventional reservoirs, are active in this area. Two brief production pilots conducted by Methane Energy Corporation in late August and early September 2008 were shut in quickly when the project encountered financial difficulties and have lain dormant since. Anecdotal reports indicate some wells have been tested sporadically since then, producing both gas and water.

The subject project is comprised of two major leases covering approximately 45,370 acres and three smaller ancillary leases covering approximately 370 acres across T 26 – 28 S and R 12 - 14W (Figure 2). The 2004 Lease, located to the north, covers roughly 16,000 acres while the Coos County Lease to the south occupies approximately 29,000 acres. The Sproule report of March 3, 2009 (1), noted that multiple leases may have been terminated under the Methane Energy Corporation bankruptcy proceedings. However, these are not the leases that Curzon owns.

An Oregon law firm was engaged by Curzon to provide an opinion on the legal title and ownership of the 2004 Lease and the Coos County lease. We have reviewed that legal opinion and note that the leases are held by Coos Bay a subsidiary of Curzon, that the leases are active and that the lease payments due under the leases have been made. The main terms and duration of the Rayonier and Coos Bay leases are set out in the following table:

Lease	Concession Type	Acreage	Commencement Date	Expiration Date	Curzon Interest	Comment
Rayonier	Methane gas	16,000	May, 7 2004	May 7, 2020[1]	100%	N/A
Coos County	Methane gas	29,000	Mar 7, 2017	Mar 6, 2020[2]	100%	N/A

[1]*And as long thereafter as oil and gas, or either of them, is produced in commercial quantities from the leased land or land pooled therewith.*

[2]*And so long thereafter as leased substances, or any of them, are produced in paying quantities from the leased land or from land pooled with the leased land, or drilling operations are continued as provided in the lease.*

Curzon envisions developing this acreage in three phases. Phase I (proof of concept) involves re-entering the 5 existing wells and returning them to production followed by the drilling and completion of 2 new wells with delivery of first gas scheduled for Q2 of 2018. Dependent on positive results from Phase I and raising additional capital, Phase II (initial development) will commence a year after Phase I begins and entails drilling and completion of 58 additional wells at the rate of 3 wells per month. First gas from Phase II is anticipated in Q2 of 2018 and all 58 wells should be on production by 4Q 2019. Dependent on positive results from Phase II and raising additional capital, Phase III (large scale development) would entail an additional 400 new wells. A drilling schedule for this final phase has not yet been developed. Dividing total leased acreage of 45,370 acres by the 465 wells planned for full field development gives a nominal spacing of 100 acres per well.

A 12 inch diameter regional pipeline (Coos County Gas Pipeline) operated by Northwest Natural Pipeline runs through the property in a north-south direction. This regional pipeline connects with the 4,000 mile long Northwest Pipeline Network operated by Williams and services 6 Western states with a maximum capacity of 115 bcf/mon (3.8 bcfd). Discussions between Curzon and NW Natural have resulted in an informal, non-binding letter of intent being issued by NW Natural to purchase CBM produced by the Coos Bay project. Curzon has installed their gathering lines up to a connection point on the Coos County Gas Pipeline identified by NW Natural during a site visit. Interconnection with this pipeline will be negotiated between Curzon and Coos County following successful completion of the Placing. Curzon has already laid 4 miles of pipeline running from the 5 wells to within 15 meters of the identified connection point.

The regional pipeline is owned by Coos County and managed by Northwest Natural. The Group has been in discussions with both Northwest and Coos County about connecting to the regional pipeline. Both are willing for the Group to connect to the pipeline. The Group will need to negotiate the final contract to connect to the pipeline with Northwest Natural which it intends to do as soon as possible after Admission. Northwest Natural engineers have selected the connection point where the produced gas will enter the pipeline on site (15 meters from the pipeline). The underground gathering system that connects the five current wells is installed to that location. In Phase I a compressor will be delivered and the gathering system will connect to the compressor. The gas will then be sent from the compressor into the pipeline through the final 15 meters of pipe that will be installed in Phase I. The cost for the compressor and the connection to the pipeline are estimated at $150,000. We estimate connection to the pipeline will take approximately 6 weeks commencing on Admission. Curzon is currently in talks with Northwest Natural and Coos County to work out the details of the sales agreement. In a letter to Coos Bay dated 18 November 2016, Northwest Natural expressed its willingness to purchase CBM gas from Coos Bay at a market-related price if the CBM gas meets its quality standards and as long as the CBM development is done in accordance with all legal, regulatory and environmental requirements. The Group expects the sales agreement with Northwest Natural to be finalized during the period between the Admission date and the anticipated connection date to the pipeline. There will be a limitation on quantity which would relate to NW Natural's gas sales in Coos County. Northwest Natural will also require the expected carbon footprint of the Coos Bay CBM operations to be comparable to the best practices employed for conventional natural gas production, gathering, processing and transportation which the Group is confident it can meet.

Coal deposits almost always require some dewatering before commercial gas production is achieved and individual wells can produce substantial water volumes throughout their life. Consequently, water disposal costs can play an important role in coalbed methane project economics. Water produced from the Coos Bay coals is relatively fresh, typical of coal waters. The company has obtained a permit to dispose of all produced water from this project in sloughs on the property, NPDES #102935. The produced water from each well will be piped to a gathering station at the Slough and released. Grants Pass Water Lab has tested the produced water and it is in compliance with the guidelines of the permit. The water will be filtered through a wetlands filter at the gathering station and monitored for compliance and reporting. The cost of the permit is $3,500 per year. Well tests showed 85 bbl of water per day per well. The permit is for 2,400 bbl of water per day which covers up to 28 wells. Additional discharge permits can be applied for as well count increases. Alternatively, water disposal wells may be drilled in addition to or in lieu of new permits.

Geology of Coos Bay coals

The Curzon Energy Coos Bay CBM prospect lies in the Coos Bay basin, a complex basin with numerous folds and faults. The basin contains a thick section of coal bearing sediments and this project targets the Eocene age Upper and Lower Coaledo coals. A stratigraphic column is presented in Figure 3 and a S-N cross section through the subject acreage is shown in Figure 4. Both Upper and Lower Coaledo coals occur as numerous thin beds typically less than 10 feet thick across an interval of several hundred feet resulting in a reservoir with small net-to-gross ratios. The coal beds are structurally complex with some dips up to 65 degrees. Accurate calculation of coal volumes and hence, original gas in place, often required dividing distances by the cosine of the dip angle (Sproule (1)).

The Lower Coaledo section consists of more than twenty coal seams varying in depth from outcrop to -8,000 ft SS with the deepest coals located in the northwest portion of the acreage (Figure 5). An isopach map of Lower Coaledo total net coal thickness (fig 6) shows two maxima, both with approximately 60 to 70 feet of net coal, lie in the west central and northeast areas. The pay cut-off used to define net coal was not reported.

The Upper Coaledo coals are absent across roughly half the subject acreage. Where present, the Upper Coaledo section hosts a dozen or more seams varying in depth from surface to -4,000 ft SS with deepest coals occurring in the northwest portion of the acreage (Figure 7). An isopach map of total coal thickness (Figure 8) shows the thickest coals, approximately 34 feet of net coal, lie in the extreme southern portion of the project.

The pay cut-off used to define net coal was not reported.

Coals in this prospect were reported by Sproule (1) as being subbituminous in rank but the basis was not reported. No proximate or ultimate analyses of the subject coals were available for this report.

Estimates of original gas in place

Original gas in place volumes for the Upper and Lower Coaledo coals were calculated volumetrically by Sproule (1) assuming the coal matrix was fully saturated with gas and the coal cleats (fractures) were fully saturated with water. Under these assumptions, original gas in place in a coal deposit is the product of area, net coal thickness, mean coal density, and coalbed gas content.

The Sproule calculations covered a large portion of the Coos Bay Basin, approximately 143,000 acres, on a section by section basis. The gas in place volume calculations were spot checked and appeared reasonable, allowing estimation of original gas in place for the subject acreage by summing the Sproule volumes for the Coos Bay Project acreage (Figure 2).

Sproule utilized a density of 1.75 gm/cm3 in their calculations, which is reasonable, however many current studies utilize a density cut-off 2.0 gm/cm3. The impact of pay cut-off on gas in place could not be assessed for this project as no density logs or other density data were available.

Sproule calculated coalbed gas contents using Langmuir sorption isotherm constants and assuming a normally pressured coal deposit with a gradient of 0.433 psi/ft. To capture uncertainty in the isotherm data, Sproule employed three Langmuir isotherms (Table 2, Figure 10) in their work.

Table 2. Sproule Langmuir isotherm constants

Langmuir constant	Low	Mid	High
VL, scf/ton	140.0	224.3	312.0
pL, psia	727.4	727.4	727.4

The Sproule report (1) notes pressure data from two injection/falloff tests in the Westport area and a build-up test in the Radio Hill area suggest a gradient of 0.4 psi/ft but did not specify which coals were tested. Original gas in place volumes calculated by Sproule assumed a normally pressured coal deposit with a gradient of 0.433 psi/ft. In contrast, injection/falloff tests (IFOT's) performed by Coal Gas Technology (6) in the Westport 09-21-26-13 well in the Lower Coaledo coals indicated all tested seams were underpressured. This well was drilled on the structural high located in the central portion of the acreage shown in Figure 5.

A stratigraphic column of the Lower Coaledo coals is included as Figure 9. The seven IFOT's, summarized in Table 3, had an average pressure gradient of 0.33 psi/ft.

Table 3. MEC Westport 09-21-26-13 Pressure Falloff Tests Summary (6)

Seam ID	Mid perf depth, ft TVD	net thickness, ft	Perm md	Skin	Pressure, psia	Pressure gradient, psi/ft
R	1,850	4.0	24	-5.2	506	0.27
R (retest)	1,850	4.0	29	-5.1	Na	Na

7A & 7B	1,754	5.0	11	-4.4	525	0.30
#2	1,355	10.0	2.3	-1.6	502	0.37
A & B	1,205	5.0	15.8	0.4	476	0.39
C	1,118	7.0	0.9	-3.6	365	0.33
D,E,F, & G	992	21.5	0.4	-3.1	336	0.34
						Average = 0.33

The Coal Gas Technology report (6) noted that these pressure gradients were consistent with those observed in the Westport 16-16-26-13 well (located in the adjacent section to the north) and the Beaver Hill #2 well (located approximately 5 miles to the southwest). Using Langmuir isotherm constants and depths given in the Sproule report (1) coupled with this lower pressure gradient, coalbed gas contents were calculated and compared with those of the Sproule report. Although the pressure decreased by roughly one-third (0.433/0.33 = 1.31), gas contents of the Lower Coaledo coals were reduced by a factor of 0.907 and gas contents of the Upper Coaledo coals were reduced by a factor of 0.856. Gas content drops were more modest than the reservoir pressure decrease as the coals are sufficiently deep enough that associated reservoir pressures gave gas contents which fall on the plateaus of the isotherms shown in Figure 10. Both of the Sproule low and mid OGIP estimates were reduced to reflect the 0.33 pressure gradient while the Sproule high OGIP volume was utilized for this study.

Shallow, immature coals such as the Coaledo coals can hold both thermogenic and biogenic methane. The amount of thermogenic methane depends on burial history while biogenic methane is controlled by meteoric water moving thru the coal deposit. Thermogenic gas resources generally vary smoothly over a deposit as compared to biogenic gas resources which can be highly variable over short distances. In coal deposits with blended thermogenic and biogenic gas, such as the Coaledo coals, the gas resource can be highly variable both areally and stratigraphically, ranging from virtually barren to fully saturated coals. Coals which hold less gas than their physical maximum are described as undersaturated. Undersaturated coals can be economically challenging to exploit as they often require long dewatering times before gas production commences. Exploitation of these Coaledo coals could require expensive, long term dewatering operations prior to generating any income from gas sales. Although the production tests reviewed below indicate nearly saturated coals, these represent limited tests of the Lower Coaled coals in a small area and undersaturation remains a significant risk for this project. Inspection of the Upper and Lower Coaledo structure maps (figs 7 and 5, respectively) show a good fraction of the coals lie in synclines with one limb open to outcrop, perhaps allowing gas to escape over geologic time. To account for this risk the pressure corrected Low OGIP volume was multiplied by an undersaturation factor of 0.5. While this factor is admittedly subjective, it is believed reasonable based on current information. Low, mid, and high estimates of original gas in place are shown in Table 4 below.

Table 4. Coos Bay Project CBM – Original Gas in Place Estimates, bcf

	Low	Mid	High
Upper Coaledo	20.6	66.2	101.5
Lower Coaledo	181.3	579.4	888.5
Total	201.9	645.5	989.9

The 5 existing wells and 2 locations for Phase I of this project all lie on a structural high (Fig. 11) approximately 1 mile wide and 6 miles long oriented in a northeast-southwest direction. Net thickness of the Lower Coaledo coals in this area ranges from 40 to 70 feet and represents some of the thickest coals in the subject acreage. Assuming 100 acre well spacing, an average coal density of 1.75 gm/cm3 (Sproule (1)), and 56.5 feet of net coal (CGT (6)) in conjunction with the low, mid estimate, and high sorption isotherms of Sproule (1) gives the volumetric original gas in place volumes for a Phase I well of 504 mmcf, 808 mmcf, and 1,124 mmcf, respectively.

The remainder of the structural high will be developed as Phase II of this project and the mid type well is thought to be a reasonable analog for Phase II wells. Areas of low gas resource most likely occur on the periphery of the coal deposits and structurally shallow coals.

Production tests & type curves

Five wells located in Sections 15, 16, 21, and 22 of T21S-R13W and completed in the Lower Coaledo coals were production tested from August 27 to September 15, 2008. No rate or pressure data were available for this evaluation but anecdotal reports indicate the wells were each producing roughly 100 mcfd of gas and 100 bpd of water throughout the 19 day test period. These reported gas and water flowrates are in fair agreement with those calculated from Darcy’s Law using the permeability, net thickness, and pressure (6 md, 56.5 ft, and 488 psia, respectively) determined by the Coal Gas Technology injection/falloff tests (6) in one of the wells. The calculations assumed a wellbore skin factor of -2 (typical of coal well stimulations) and a gas relative permeability of 0.1 (typical of native coal deposits).

Previous MHA scoping simulations (9) indicated recoveries for wells in the Phase I and Phase II areas ranging from 300 to 900 mmcf were reasonable. Curzon assumed low, mid, and high estimated ultimate recoveries (EUR’s) of 300 mmcf, 500 mmcf, and 750 mmcf, respectively, for Phase I wells (10). The Westport 1-21 well was production tested in April and June of 2012. Gas rate climbed steadily throughout these tests from an initial rate of 55 mcfd to a rate of 68 mcfd. Test data is included in this report as Figure 16. It should be noted that this well had not been cleaned out or any other remedial work performed after the long shut-in. For comparison, the initial rate used for type wells is 50 mcf/d for low case and 100 mcg for base and high side mcfd. Also noted in the 2012 Gas Volume production tests (Figure 16) was a reading of 16.6% Nitrogen. As gas composition analyses were not performed as part of those tests, we see this reading as not representative of the original gas-in-place composition. The source of this nitrogen fraction has not been confirmed although Curzon management has provided MHA with documentation that highlights that, as a result of a number of nitrogen fracs undertaken in 2006, material volumes of nitrogen were pumped into all the Coos Bay wells by the operator at that time.

Dividing these low, mid, and high EUR’s by their respective OGIP volumes calculated with information in Tables 2 and 3 above gives low, mid, and high recovery factors of 59%, 62%, and 67%, respectively. For comparison, coalbed methane recovery factors generally range from 50% to 90%.

Combining production test results and estimated ultimate recoveries from the MHA simulations, Curzon has developed low, mid, and high gas production type curves based on the typical Powder River Basin (PRB) coal well signature. Coals of the Powder River Basin, located in northeastern Wyoming, are shallow, young, thermally immature coal deposits, making them reasonable analogs for the Coos Bay coals. PRB coal wells typically show inclining gas production for several months, before plateauing for several more months then falling on an exponential decline. Coos Bay Project type curves (Figures 12 and 13) were assumed to follow this behavior. Coos Bay coals typically have a higher gas content than PRB coals, which may translate into similar, and possibly higher, per well recoverable volumes. Although type curves were not based on any coal well signatures from Horseshoe Canyon, located in western Canada, it is worth noting that Coos Bay coals are also similar to HC coals in terms of having similar lower permeability, limited quantities of movable water and the presence of larger numbers of thinner coal seams. In addition, as Coos Bay coals typically have a higher gas content than HC coals, Coos Bay coals may deliver similar, and possibly higher, per well recoverable volumes.

Water production type curves developed by Westport (10) and shown in Figure 14, bracket reported initial water production rates and show an exponential decline behavior often seen in shallow coalbed methane wells. Cumulative water production volumes for the low, mid, and high type curves are 1,117 mstb, 1,907 mstb, and 2,495 mstb, respectively. Assuming an 100 acre drainage area, a net coal thickness of 56.5 feet, a porosity of 10% (Bustin and Clarkson, 11), and an initial water saturation of 100%, the volumetric original water in place is 3,405 mstb. Thus, the low, mid, and high type curve cumulative water volumes represent recoveries of 33%, 56%, and 73% of original water in place.

Single well economics

Single well economics were run for the low, mid, and high gas and water type curves coupled with the assumptions shown in Table 5 (10).

Table 5. Economic inputs (10)	
WI, %	100
NRI, %	87.5
Capex, k$	350
Fixed Opex, $/mon	500
Variable Opex – Gas, $/mcf	0.50
Variable Opex – Water, $/bbl	0.10
Shrink, %	6
Tax rate, %	6.0

Natural gas trades in this area at a premium compared to NYMEX Henry Hub pricing. At Henry Hub prices of 2 to 3 $/mmbtu, the historic differential is roughly 2 $/mcf (8). This evaluation utilized the June 13, 2016 NYMEX Henry Hub forecast (Table 6) with this differential applied.

Table 6. NYMEX Henry Hub June 13, 2016 price forecast	
Year	$/mmbtu
2016	2.825
2017	3.114
2018	3.041

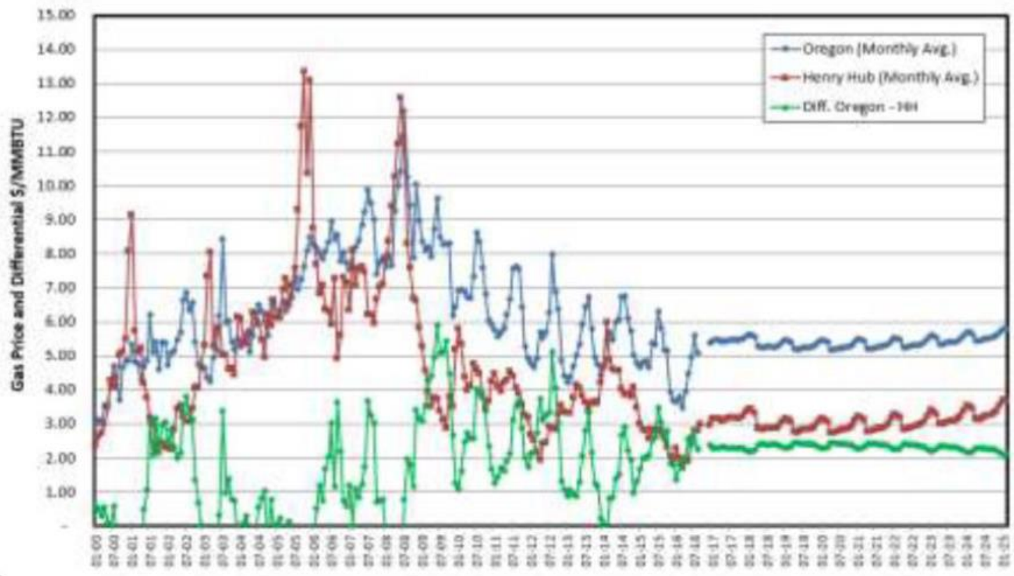
2019	3.023
2020	3.092
2021	3.232
2022	3.390
2023	3.557
2024 & beyond	3.735

The 15 year net gas recoveries associated with the three type curves varied by a factor of 2.2, ranging from 240.5 mmcf to 533.2 mmcf (Table 7). Net present values at a discount rate of 10% (PV10's) increased by a factor of 4 between the low and high type curves, 181.5 k$ to 578.9 k$, while the internal rates of return (IRR's) changed by a factor of 2.1 from low to high type curve, 22.6 % to 47.8%. The more productive high type curve well achieved payout in 2.6 years, about two-thirds of the 4.2 year payout of the low type curve well.

Table 7. Single well economics summary – 15 year well life							
Type Curve	Net gas, mmcf	Net Revenue, k$	Net Opex, k$	Taxes, k$	PV10, k$	IRR,%	Payout, yrs
Low	240.5	1,213.8	320.0	72.8	181.5	22.6	4.2
Mid	392.9	1,988.5	512.0	119.3	493.2	40.1	3.1
High	533.2	2,717.5	657.3	163.0	758.9	47.8	2.6

Breakeven NYMEX Henry Hub gas price for a single well with the mid type curve was calculated to be 1.006 $/mmbtu (2.89 $/mcf wellhead price).

The following table shows the comparison between Oregon City Gate prices vs Henry Hub:



Source: U.S. Energy Information Administration

Phase I and Phase II economics

Curzon envisions developing this acreage in three phases. Phase I (proof of concept) involves reentering and cleaning out the 5 existing wells, returning them to production, drilling and completion of 2 additional wells (Figure 15) at the rate of 2 wells per month, installing related infrastructure, connecting to the Coos County regional pipeline, with first gas from these new wells expected in 4Q 2017. Dependent on positive results from Phase I and raising additional capital, Phase II (initial development) is scheduled to commence a year after Phase I begins. This phase covers drilling and completion of 58 additional wells at the rate of 3 wells per month with first gas in 2Q 2018. Dependent on positive results from Phase II and raising additional capital, Phase III (large scale development) would entail an additional 400 new wells. A drilling schedule for this final phase has not yet been developed. Dividing total leased acreage of 45,370 acres by the 465 wells planned for full field development gives a nominal spacing of 100 acres per well.

Phase I economics were run under the same assumptions as were the single well economics with three changes. Gas and water production for all wells was modeled with the mid type curve. Capital required to return the 5 existing wells to production was assumed to be 104 k$. Total Capex for Phase I was estimated to be 1.2mm$ to cover (a) connection of the 5 existing wells to the pipeline – 500k$ and (b) drilling and connecting 2 further wells – 640k$. The wellhead gas price was assumed to be the current local price of 5.50 $/mcf (8), equivalent to a NYMEX Henry Hub price of 3.646 $/mmbtu. Operating expenses include general and administrative expenses, lease and permits, operational payroll, professional fees, overheads, field operating expenses and transportation costs. Economics for the Phase II package of 58 wells utilized the same mid type curve and wellhead gas price. Forecast net gas volume and the associated economics for both Phase I and II are summarized in Table 8 below. Operating expenses and capital costs were based on information provided by Curzon and used in its business plan. All economics assumed the same 6% tax rate as was used for single well economics.

Table 8. Phase I & II economics summary – 15-year project life

	Net gas, bcf	Net Revenue, mm$	Cap Ex, mm$	Net Opex, mm$	Taxes, mm$	PV10, mm$	IRR,%	Payout, yrs
Phase I	2.75	15.1	1.2	3.6	0.9	5.5	112%	1.6
Phase II	22.42	123.3	21.5	28.4	7.4	29.1	46%	4.6
Phase I + II	25.17	138.4	22.7	32.0	8.3	34.6	N/A	N/A

Contingent and Prospective Resources

The presence of gas in the Lower Coaledo coals has been demonstrated but commercial production has not yet been attained, allowing these gas volumes to be classified as Contingent Resources (12, 13). Contingent Resource volumes shown in Table 9 were calculated by multiplying the original gas in place volumes shown in Table 4 by the single well recovery factor of 59% and a chance of commerciality of 80%.

As specified in PRMS (12, 13), the chance of commerciality reflects the risk of commercial development of a given project. Commercial risk may be considered to have three components: Technical, Economic, and Regulatory. The company faces substantial Technical risk as the unavailability or high cost of drilling rigs, equipment, supplies, personnel, and field services could adversely affect the company's development schedule and budget. In addition, exploitation of coalbed methane resources may present challenges which even experienced, knowledgeable geoscience and engineering professionals may be unable to overcome. Economic risk associated with this project is considerable and may result in lower than anticipated revenues for reasons beyond the company's control. Regulatory risk for the Coos Bay project, similar to all U.S. oil and gas projects, is substantial and expected to increase with time. Local, state, and Federal regulations pertaining to oil and gas production are frequently revised or reinterpreted. Company efforts to comply with new or revised regulations could have an adverse impact on the company's operations.

While the 80% chance of commerciality assigned here is admittedly subjective it is believed to be reasonable as Curzon has the benefit of the previous operator's experience and has secured a water disposal permit, NPDES #102935, which will substantially reduce the high water disposal costs which plagued the previous operator. Pilot well completions are adequate but not yet optimal, development wells will be economic if projected well capital costs and operating expenses can be realized, and the regulatory climate in this area continues to be generally supportive of oil and gas operations.

Table 9. Coos Bay Project CBM – Lower Coaledo coals – Contingent Resources, bcf		
1C	2C	3C
85.6	273.5	419.4

The Upper Coaledo coals appear to exist across a portion of the subject acreage but the presence of hydrocarbons has not been tested, allowing classification of any undiscovered coalbed methane gas volumes as prospective resources. Following PRMS guidelines (12, 13), a chance of discovery assigned here, 90%, is based on analogy with the Lower Coaledo coals.

Prospective resources were estimated similar to contingent resource with the additional multiplication of the change of discovery. The resulting prospective resources are presented in Table 10.

Table 10. Coos Bay Project CBM – Upper Coaledo coals – Prospective Resources, bcf		
Low	Mid	High
8.77	28.1	43.1

Statement of Risk

The accuracy of resource, reserve and economic evaluations is always subject to uncertainty. The magnitude of this uncertainty is generally proportional to the quantity and quality of data available for analysis. As a project or well matures and new information becomes available, revisions may be required which may either increase or decrease the previous resource and reserve assignments. Sometimes these revisions may result not only in a significant change to the resources, reserves, and value assigned to a property, but also may impact the total company resource, reserve, and economic status. The resources, reserves, and forecasts contained in this report were based upon a technical analysis of the available data using accepted engineering principles (PRMS, 2007 and 2011). However, they must be accepted with the understanding that further information and future reservoir performance subsequent to the date of the estimate may justify their revision. It is MHA's opinion that the estimated resources and reserves and other information as specified in this report are reasonable, and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles (PRMS, 2007 and 2011). Notwithstanding the aforementioned opinion, MHA makes no warranties concerning the data and interpretations of such data. In no event shall MHA be liable for any special or consequential damages arising from Curzon Energy's use of MHA's interpretation, reports, or services produced as a result of its work for Coos Bay (or any of its predecessors).

Neither MHA, nor any of our employees have any interest in the subject properties and neither the employment to do this work, nor the compensation, is contingent on our estimates of reserves for the properties in this report.

This report was prepared for the exclusive use of Curzon Energy PLC and will not be released by MHA to any other parties without Curzon's written permission. The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices.

Qualifications

MHA Petroleum Consultants LLC is an independent oil and gas consulting firm specializing in petroleum reservoir evaluations and economic analysis. The work in this Competent Person's Report was completed by Dr. John Seidle, Vice President, with 35 years of experience in unconventional gas and oil reservoir engineering in domestic and international plays. A Registered Professional Engineer in Colorado, Oklahoma, and Wyoming, he is a member of SPE, AAPG, and SPEE. He is the author or co-author of 29 technical papers, the author of "Fundamentals of Coalbed Methane Reservoir Engineering", and editor of SPEE Monograph 4 "Estimating Ultimate Recovery of Developed Wells in Low-Permeability Reservoirs". He received a PhD in Mechanical Engineering from the University of Colorado.

It has been a pleasure preparing this report for Curzon Energy PLC. If you have any questions or wish to discuss something in more detail, please feel free to contact me.

Sincerely,

John P. Seidle

Glossary

1C	Low estimate of Contingent Resources (PRMS)
2C	Best estimate of Contingent Resources (PRMS)
3C	High estimate of Contingent Resources (PRMS)
BTU	British Thermal Unit
bcf	billions of standard cubic feet
CBM	Coalbed methane
IRR	Internal rate of return
K$	Thousands of U.S. dollars
mcf	Thousands of standard cubic feet
mmcf	Millions of standard cubic feet
MM$	Millions of U.S. dollars
OGIP	Original Gas in Place
PRMS	Petroleum Resources Management System
PV10	Net present value at a discount rate of 10%/yr

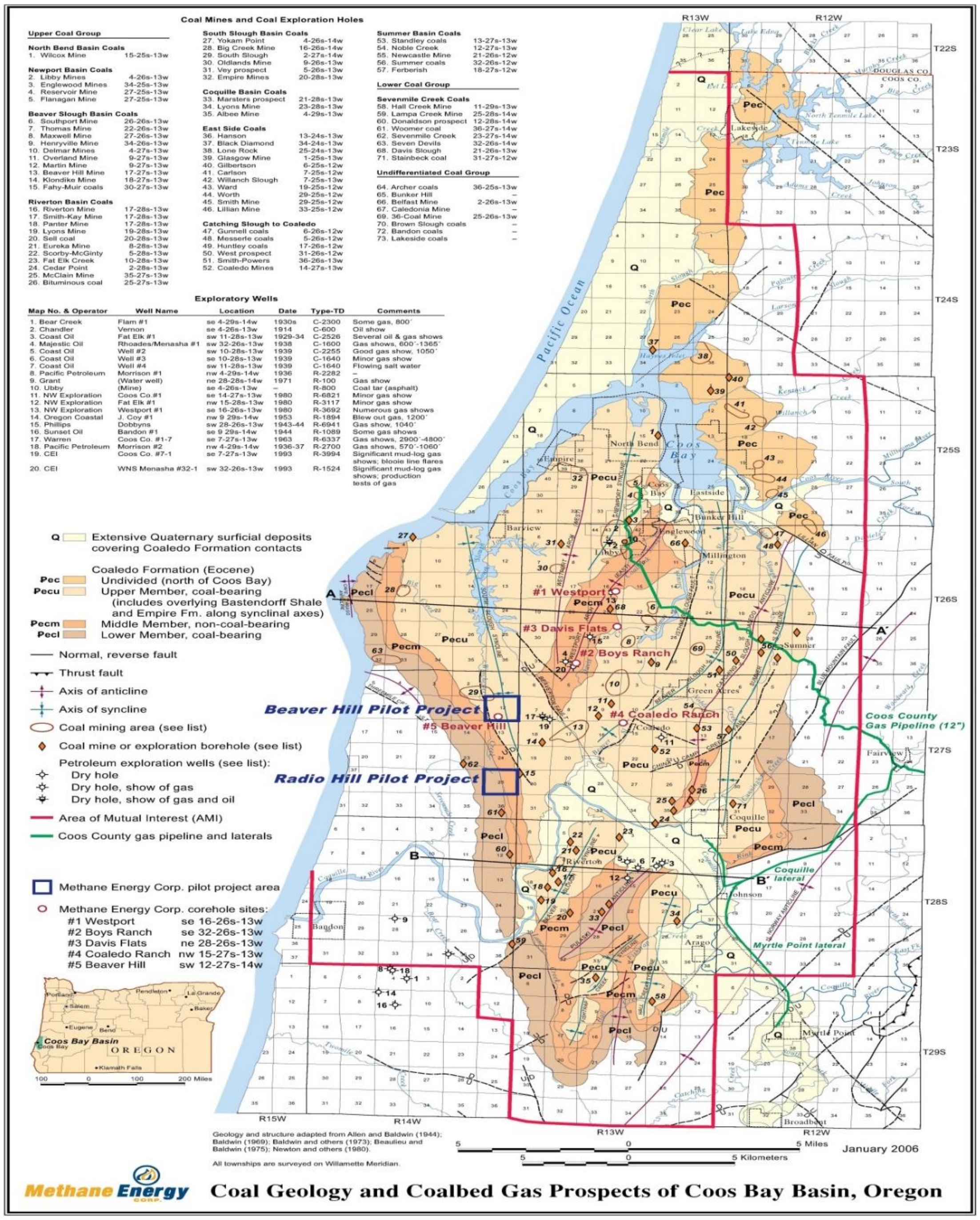


Figure 1 – Coos Bay Project location map

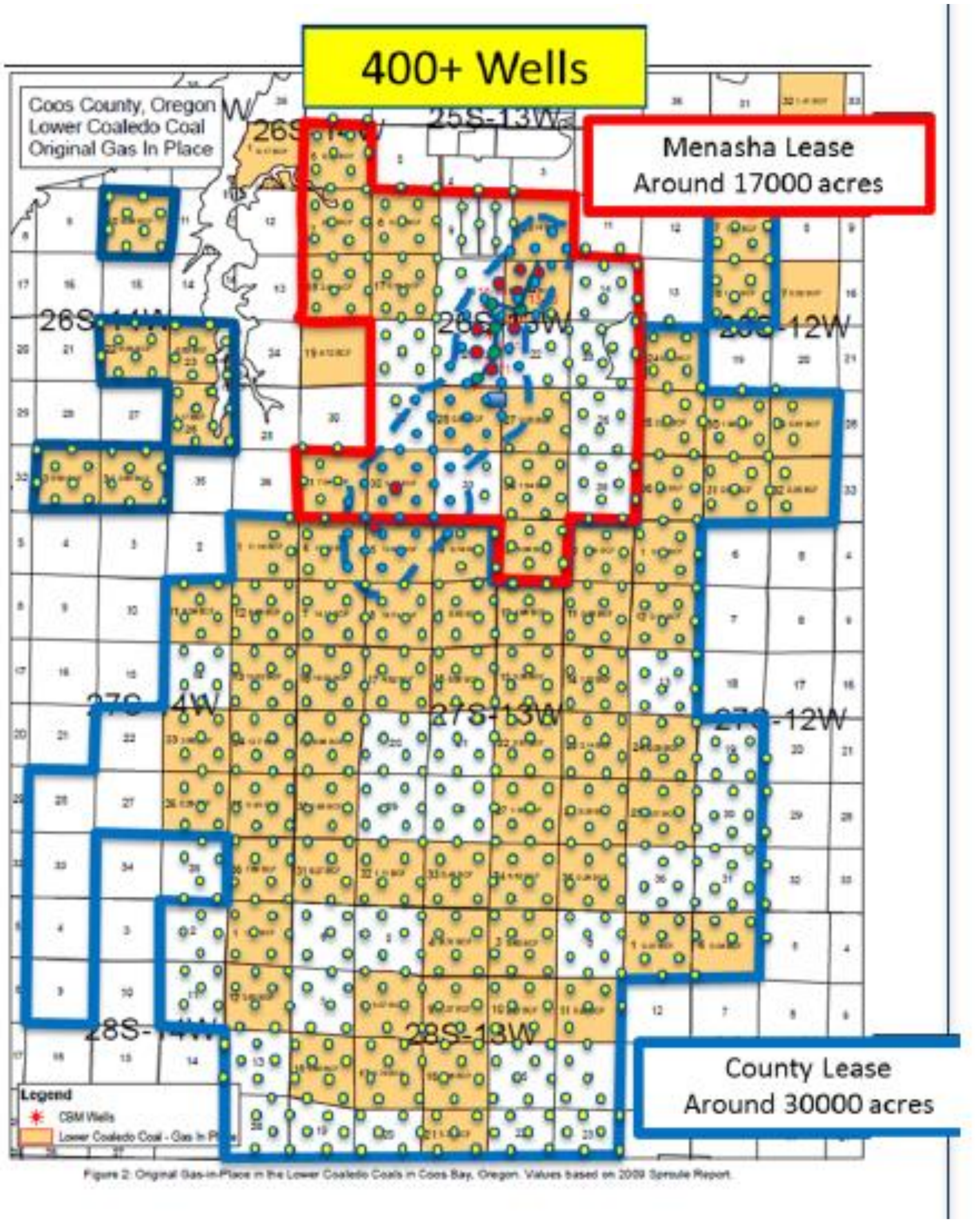


Figure 2 - Coos Bay Project acreage map

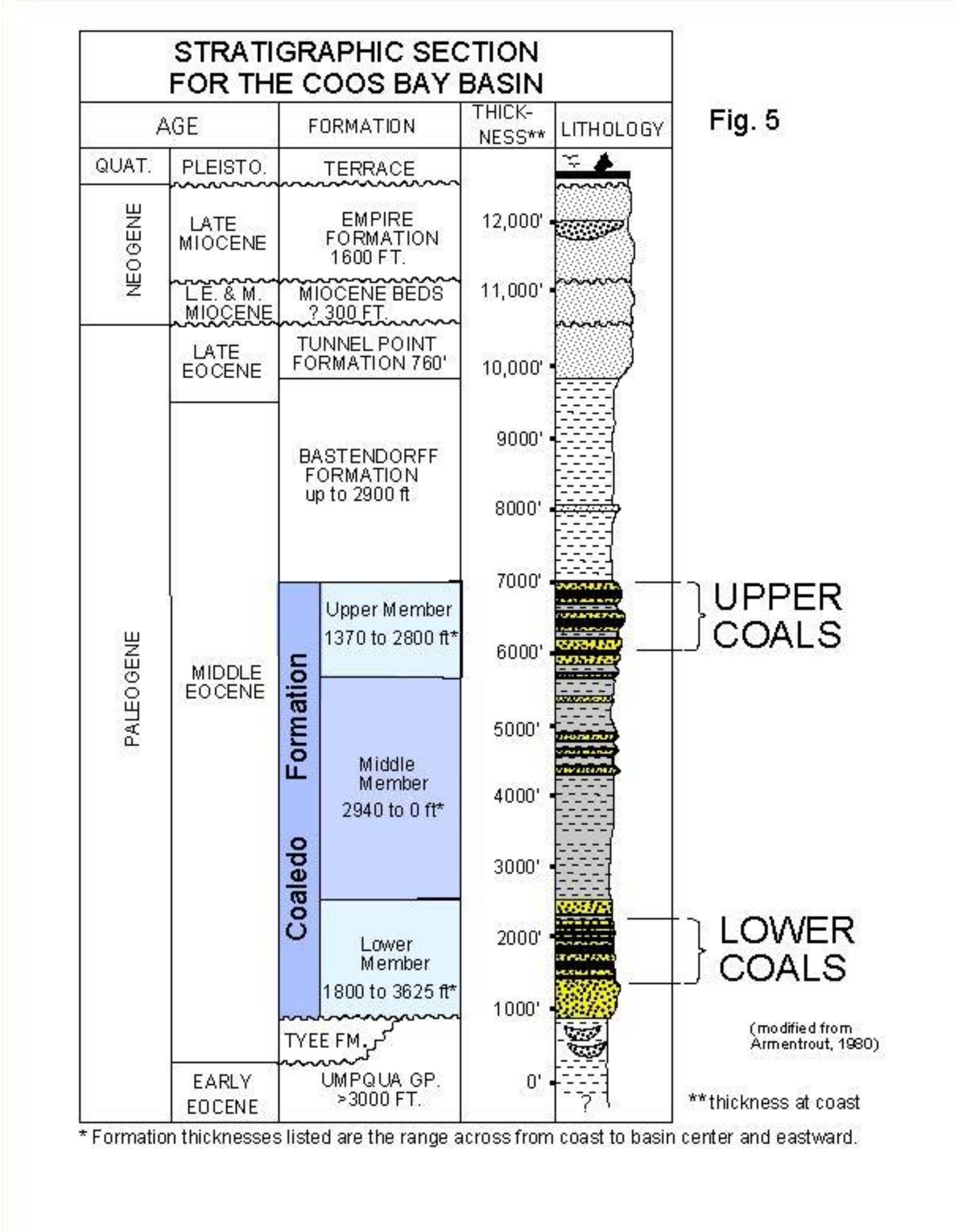


Figure 3 – Coos Bay Basin stratigraphic column

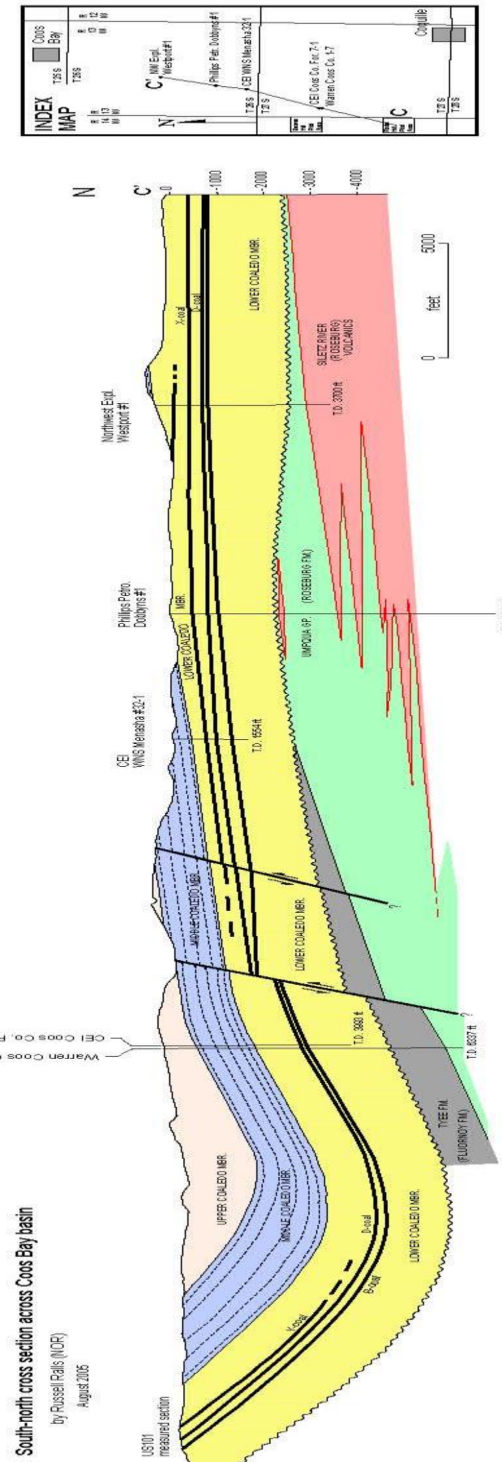


Figure 4 – N-S schematic cross-section

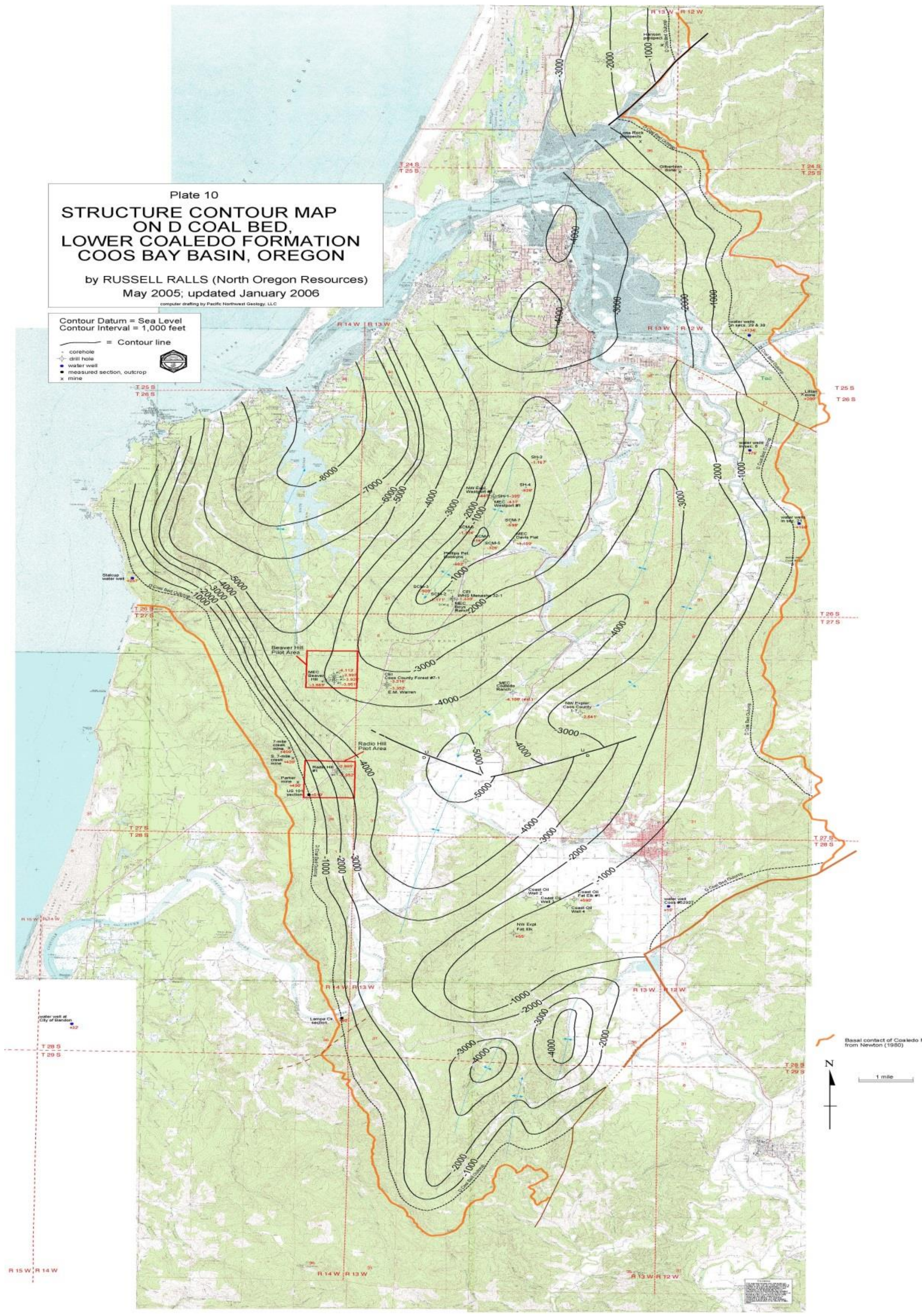


Figure 5 - Lower Coaledo structure map

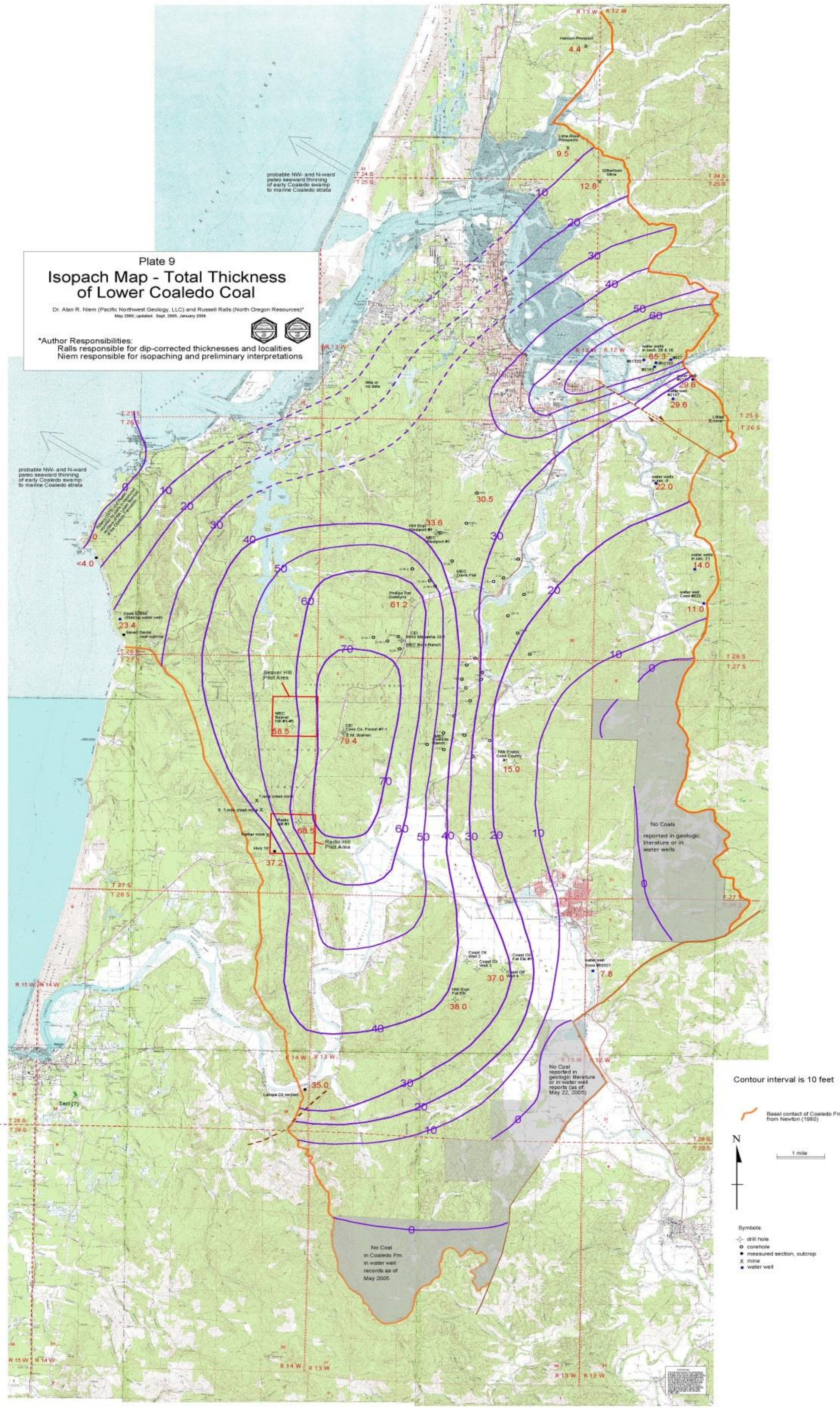


Figure 6 – Lower Coaledo isopach map

Figure 7 – Upper Coaledo structure map

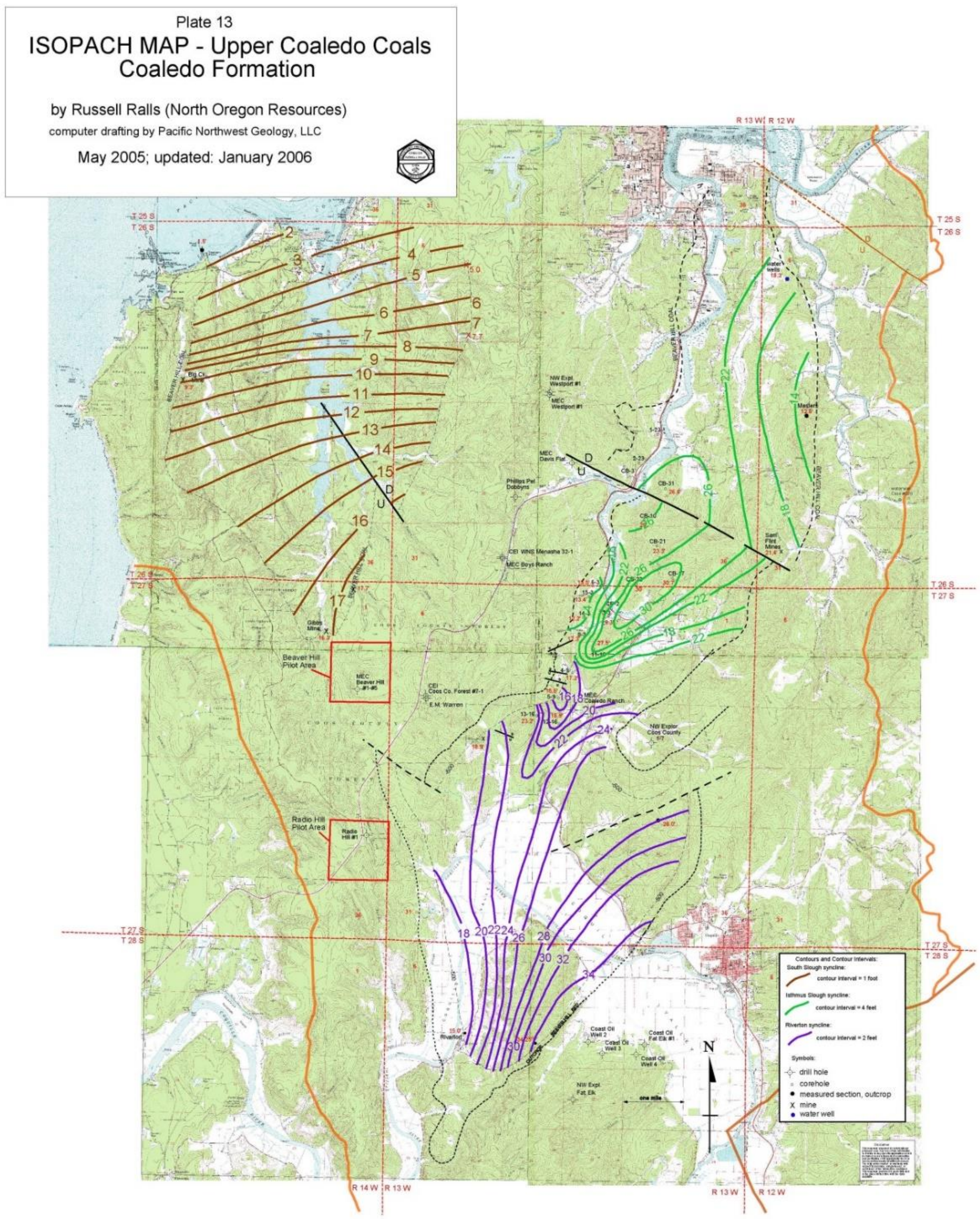


Figure 8 – Upper Coaledo isopach map

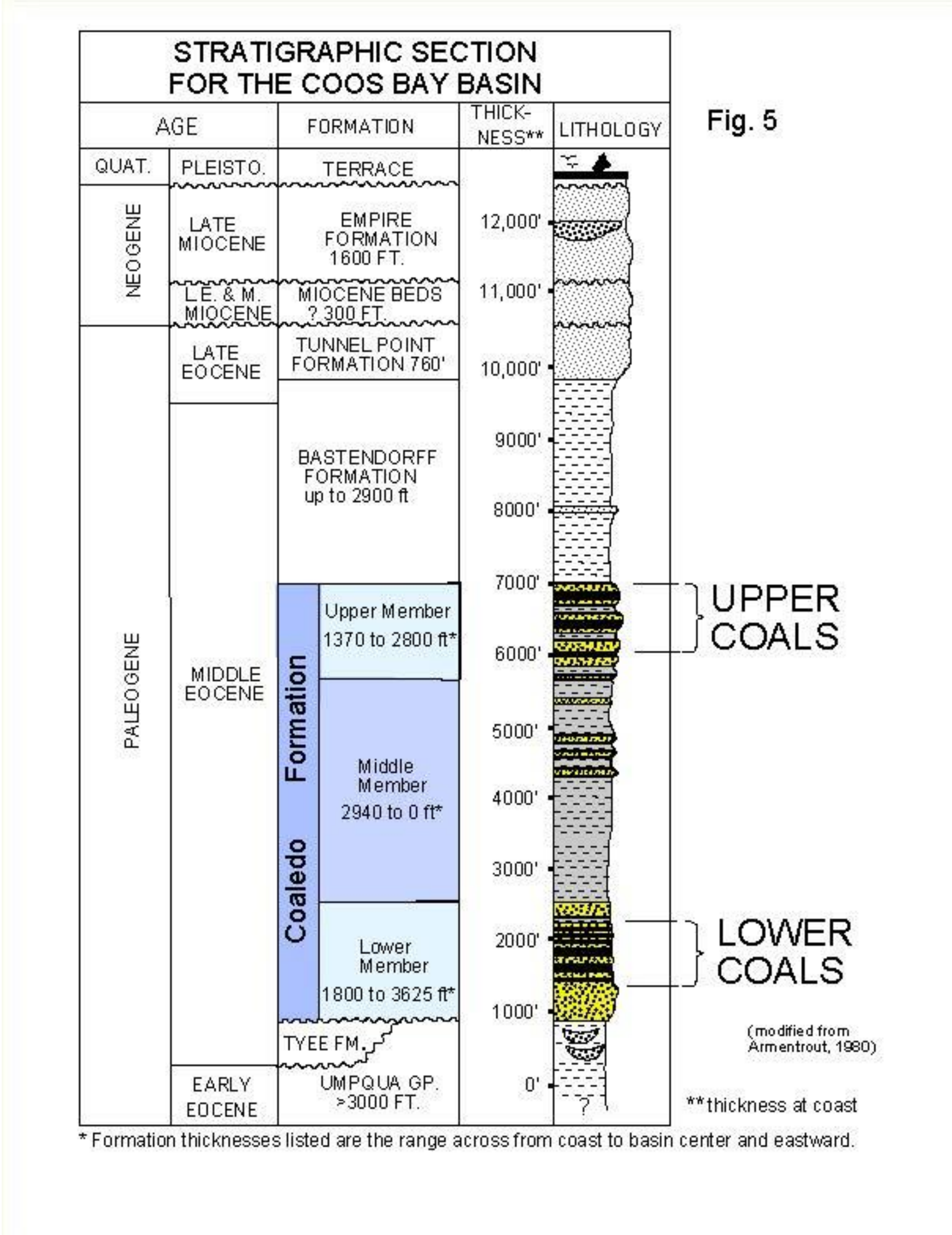


Figure 9 – Lower Coaledo stratigraphic column

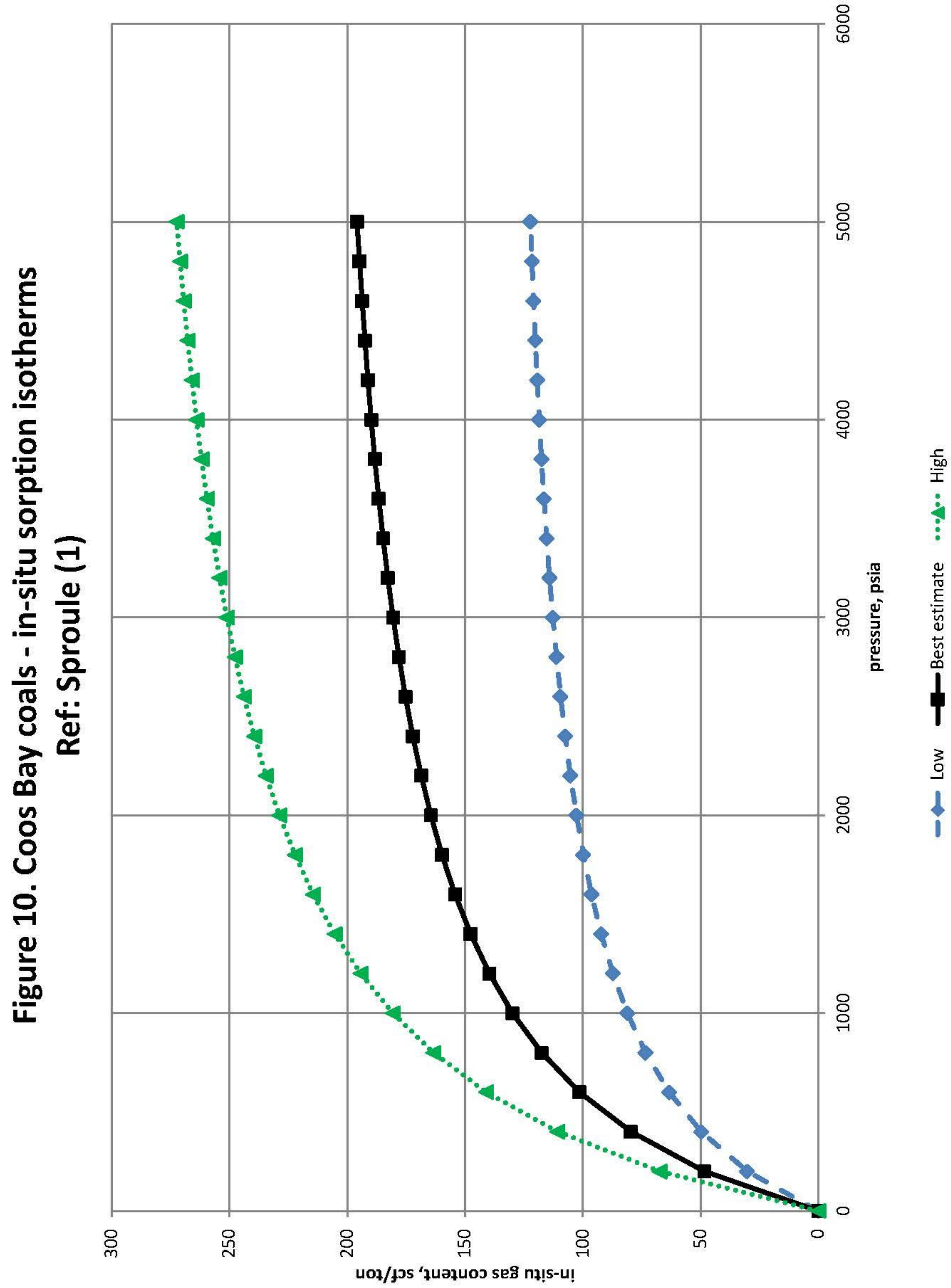


Figure 10 – Sproule sorption isotherms

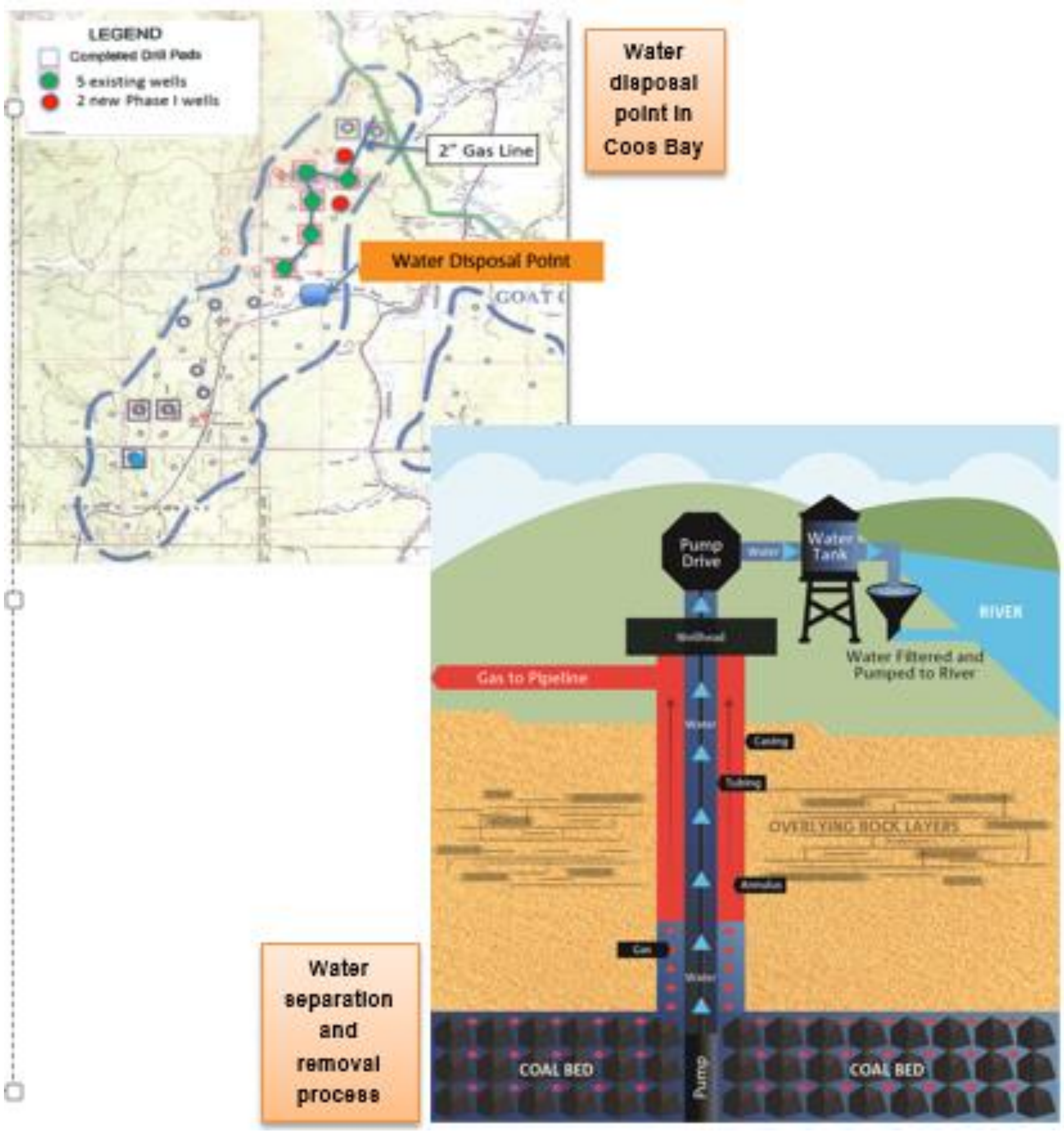


Figure 11 – Phase I well locations

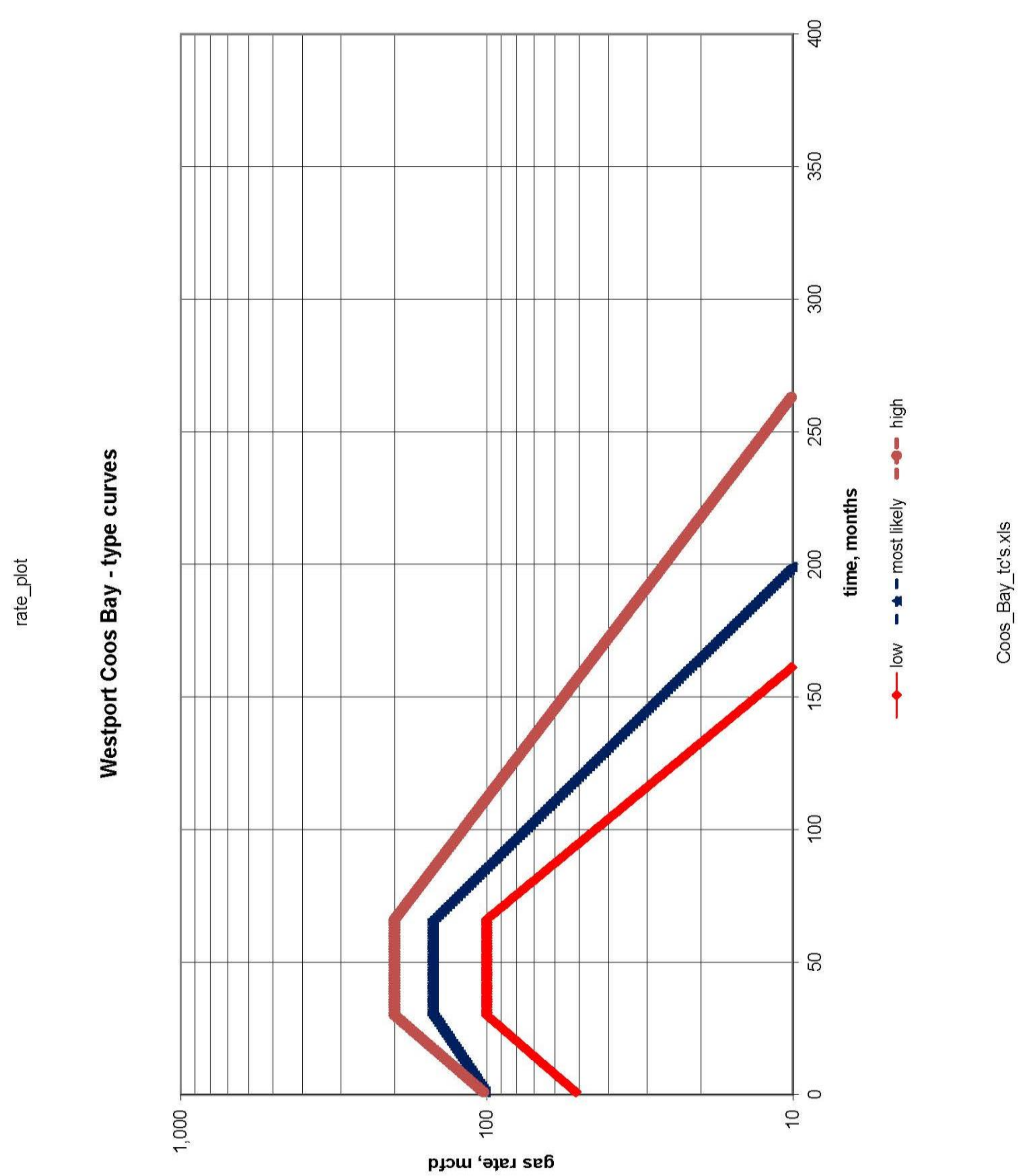


Figure 12 – Coos Bay Project gas type curves

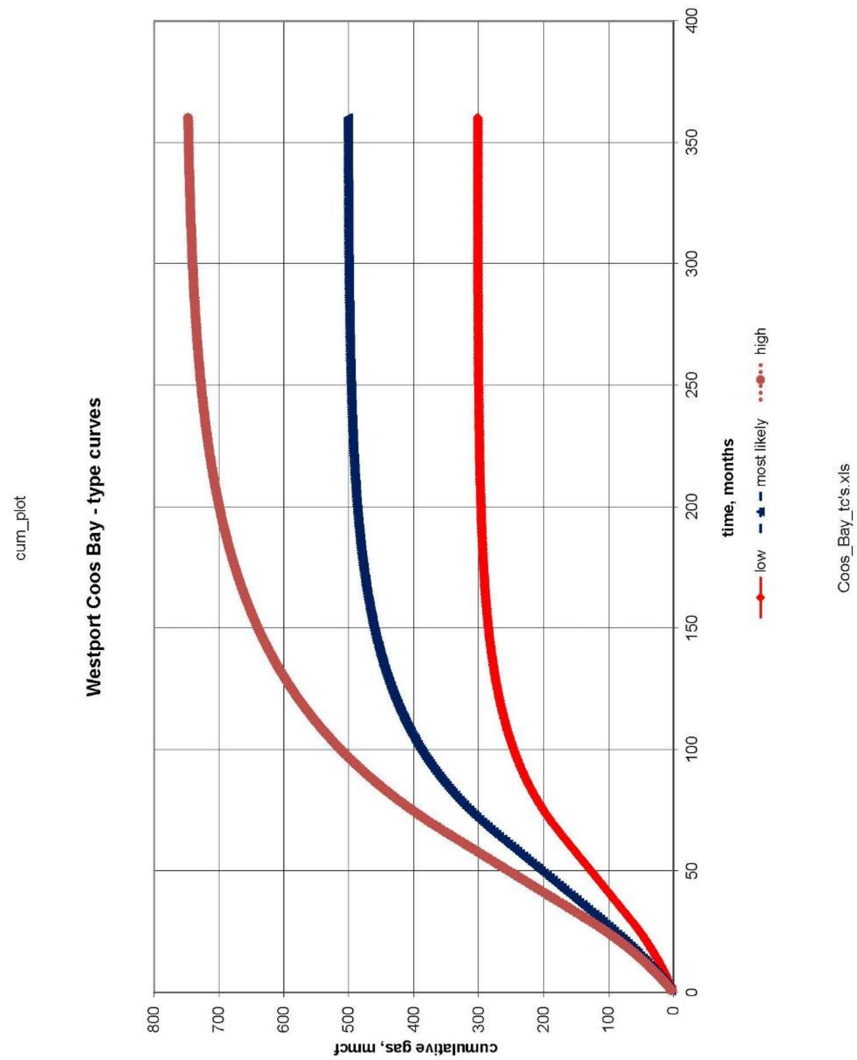


Figure 13 – Coos Bay Project gas type curves – cumulatives

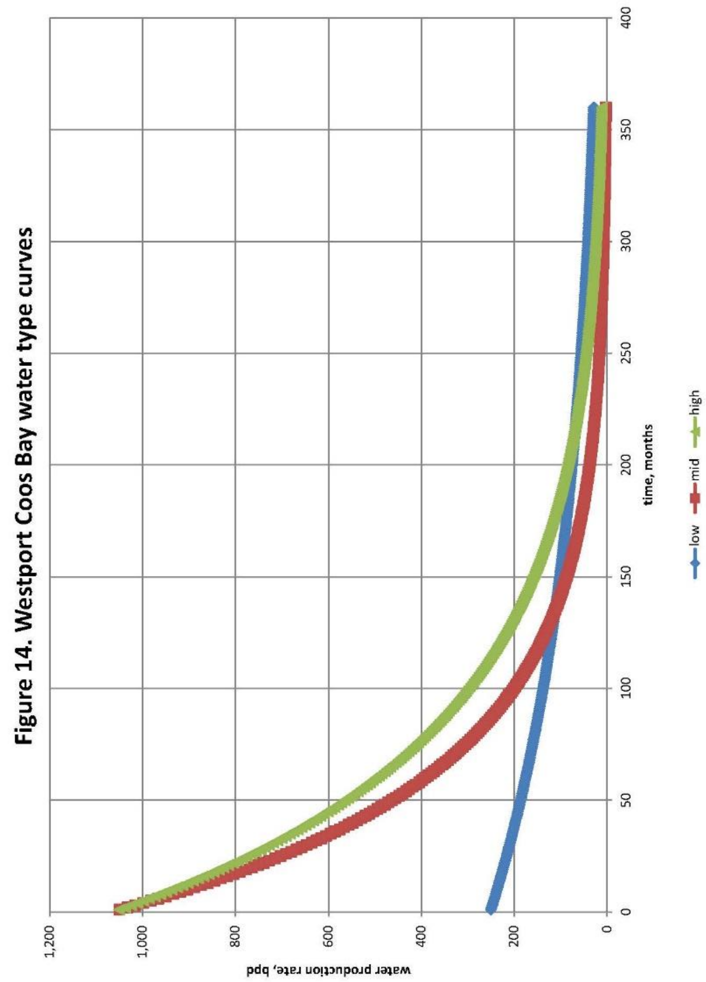


Figure 14 – Coos Bay Project water type curves

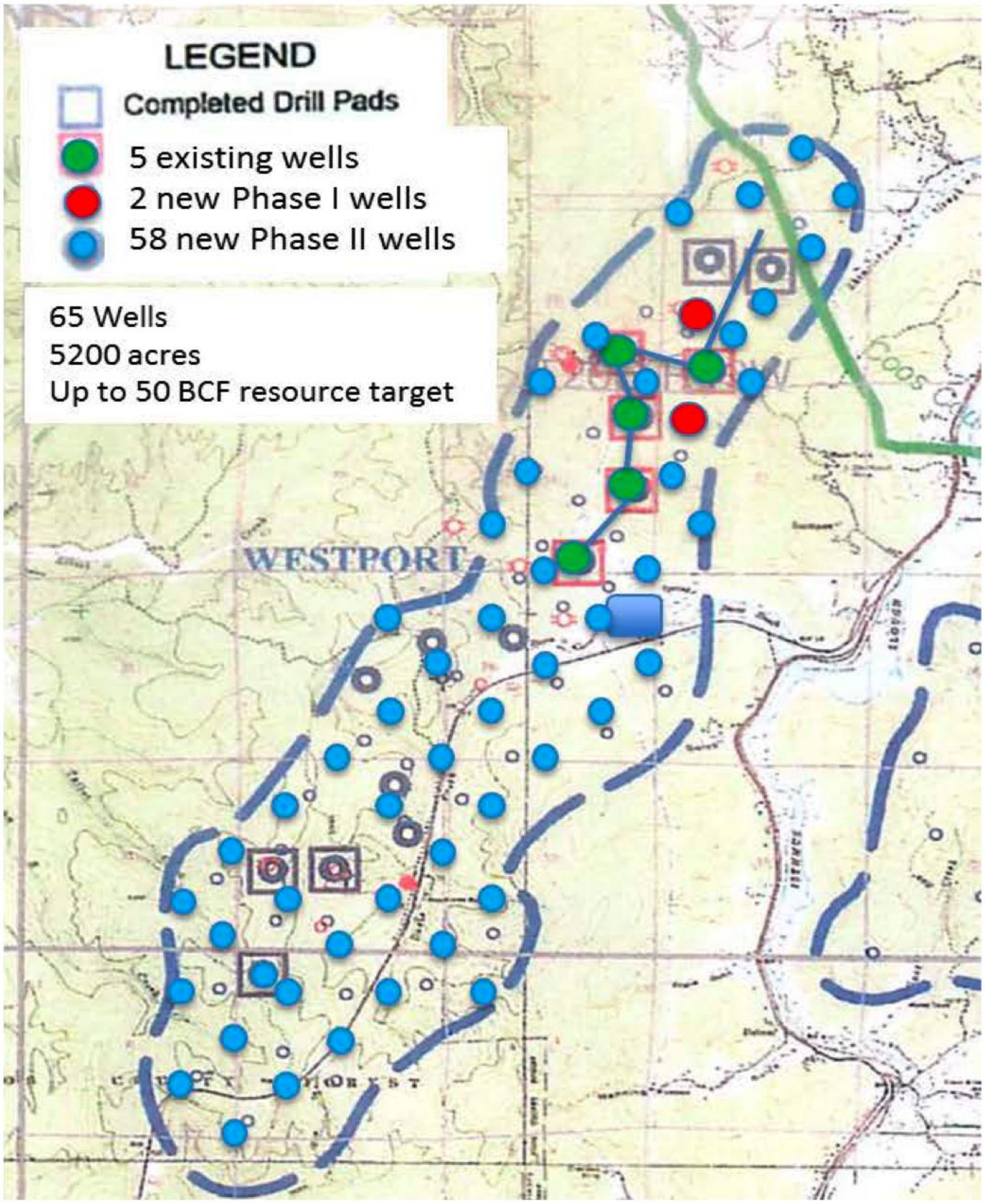


Figure 15 – Phases I & II well locations

Alamo Precision Services, Inc.

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140 Heimer, Suite 735
San Antonio, Texas 78232
(210)490-4527

P.O.Box 700530
San Antonio, Texas 78270-0530
Fax (210)490-8869

Gas Volume Statement
April, 2012

16-MAY-2012

Arch Energy

Meter #: 3573
Station ID: 1-21 26-13
WESTPORT 1-21

,

Pressure Base	14.7	Static Range	500	Sample Date	01-APR-12	Ethane	0.022	I-Pentane	0.000
Temperature Base	60	Differential	100	Carbon Dioxide	0.021	Propane	0.000	N-Pentane	0.000
Atmospheric Press	14.70	Temp Range	150	Nitrogen	16.661	I-Butane	0.000	N-Hexane	0.000
Super Comp Type	S	PSI Code	G	Methane	83.296	N-Butane	0.000	Hexane+	0.000
Tap Type & Loc	F D	Rotation	16						
Elev & Latitude	300 29	Tube Size	2.067						
C1= Fb*Ftb*Fpb*MC		C2= Fr*Fa*Fl*Y							

LEGEND: A= Analysis Changed D= Diff Changed E= Estimate Code
I= Init Delivery S= Static Changed T= Tube Changed

-DATE- ON	OFF	SPEC GRAV	ORIF	FLOWING DIFF	PRES	TEMP	HRS	COUNTS INTG	PRES	TIME	FACTORS C1	C2	Fg	Ftf	Fpv	L G	BTU SAT	BTU DRY	MCF
04/06	04/19	0.6239	0.500	1.01	375	59	94.4	134	7790	281	708.7	1.0021	1.266	1.0010	1.0214		0.8298	0.8434	123
04/19	05/02	0.6239	0.500	9.99	151	75	339.1	862	3313	883	810.0	1.0012	1.266	0.9859	1.0077		0.8298	0.8434	879
							433.5												1,002

	AVG BTU	MMBTU
Sat	0.8298	831
Dry	0.8436	846
Act	0.8436	846

Figure 16

Alamo Precision Services, Inc.

"Meeting your measurement needs since 1986"

140 Heimer, Suite 735
San Antonio, Texas 78232
(210)490-4527

P.O.Box 700530
San Antonio, Texas 78270-0530
Fax (210)490-8869

Gas Volume Statement
June, 2012

20-JUL-2012

Arch Energy
93575 Lookout Lane #2
Coos Bay, OR 97420

Meter #: 3573
Station ID: 1-21 26-13
WESTPORT 1-21

Pressure Base	14.7	Static Range	500	Sample Date	01-APR-12	Ethane	0.022	I-Pentane	0.000
Temperature Base	60	Differential	100	Carbon Dioxide	0.021	Propane	0.000	N-Pentane	0.000
Atmospheric Press	14.70	Temp Range	150	Nitrogen	16.661	I-Butane	0.000	N-Hexane	0.000
Super Comp Type	S	PSI Code	G	Methane	83.296	N-Butane	0.000	Hexane+	0.000
Tap Type & Loc	F D	Rotation	16						
Elev & Latitude	300 29	Tube Size	2.067						
C1= Fb*Ftb*Fpb*MC		C2= Fr*Fa*Fl*Y							

LEGEND: A= Analysis Changed D= Diff Changed E= Estimate Code
I= Init Delivery S= Static Changed T= Tube Changed

-DATE-		SPEC		--- FLOWING ---				- COUNTS -			--------- FACTORS --------					L	BTU	BTU	
ON	OFF	GRAV	ORIF	DIFF	PRES	TEMP	HRS	INTG	PRES	TIME	C1	C2	Fg	Ftf	Fpv	G	SAT	DRY	MCF
06/02	06/17	0.6239	0.500	9.11	176	78	360.6	940	3820	939	810.0	1.0012	1.266	0.9831	1.0088		0.8298	0.8436	957
06/17	07/03	0.6239	0.500	8.07	229	73	377.9	1047	4872	984	810.0	1.0009	1.266	0.9877	1.0118		0.8298	0.8436	1,074
							738.4												2,031

	AVG BTU	MMBTU
Sat	0.8298	1,685
Dry	0.8436	1,713
Act	0.8436	1,713

Figure 17