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EVALUATION OF THE HYDROCARBON RESOURCE POTENTIAL PERTAINING TO CERTAIN ACREAGE INTEREST IN THE BEETALOO BASIN, ONSHORE AUSTRALIA AND MAKO TROUGH, ONSHORE HUNGARY.

Prepared for

FALCON OIL AND GAS LTD

1st January 2013

DISCLAIMER

The opinions and interpretations presented in this report represent our best technical interpretation of the data made available to us. However, due to the uncertainty inherent in the estimation of all sub-surface parameters, we cannot and do not guarantee the accuracy or correctness of any interpretation and we shall not, except in the case of gross or wilful negligence on our part, be liable or responsible for any loss, cost damages or expenses incurred or sustained by anyone resulting from any interpretation made by any of our officers, agents or employees.

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1 INTRODUCTION AND BACKGROUND

1.1 LICENCE OVERVIEW

This Report has been prepared as a Competent Persons Report ("CPR") by RPS for Falcon Oil & Gas Limited ("Falcon" or "the Company"). The Report is an independent evaluation of the potential hydrocarbon resource potential pertaining to certain acreage interests of Falcon in the Makó Trough, onshore Hungary and Beetaloo Basin, onshore Australia (together "the Properties"), as at 01 January 2013, in which Falcon has an interest as per Table 1.1 below.

Table 1.1 – Licence Status Summary

Licence Concessions (Country)	Interest (%)	Operator	Status	Area (km^2)	Expiry	Comments
Makó Trough Production Licence (Onshore Hungary)	100.0%	TXM Oil and Gas Ltd.	Production	994.6	21/05/2042	Periodic limited production. Development Unclarified for BCGA unconventional resources. Exploration potential in shallower Algyo Formation
Exploration Permit EP-76, (Northern Territory - Onshore Australia)	73.0%[1]	Hess Australia (Beetaloo) Pty Ltd.	Exploration	4,976.3	31/12/2013[2]	Under evaluation
Exploration Permit EP-98 (Northern Territory - Onshore Australia)	73.0%[1]	Hess Australia (Beetaloo) Pty Ltd.[3]	Exploration	11,412.1	31/12/2013[4]	Under evaluation
Exploration Permit EP-99 (Northern Territory - Onshore Australia)	73.0%[1]	Falcon Oil & Gas Australia Pty.	Exploration	2,587.2	31/12/2013	Under evaluation
Exploration Permit EP-117 (Northern Territory - Onshore Australia)	73.0%[1]	Hess Australia (Beetaloo) Pty Ltd.	Exploration	9218.3	31/12/2013	Under evaluation

[1] Falcon Oil & Gas Limited owns 73% of Falcon Oil & Gas Australia which holds a 100% interest in the licences. The remaining 24% is owned by Sweetpea Petroleum Pty. Ltd, which is a wholly owned Australian subsidiary of PetroHunter Energy Corp., and 3% interest by others

[2] See Falcon's press release 0n 14/09/2012.

[3] Note: Falcon Oil and Gas Australia Pty. retains operatorship in the Shenandoah-1 well and approximately 405 km^2 (100,000 acres) land around the Shenandoah-1 wellbore.

[4] See Falcon's press release 0n 14/09/2012.

The licence contracts are standard tax and royalty contracts. The Makó Trough licence requires a 12% royalty to be paid to the Government of Hungary on any production and Falcon has a further 5% royalty agreement with Prospect Resources Inc., the previous owners of the licence. For the Northern Territory permits, a royalty of 10% will be payable to the Northern Territory government on any future production. In addition, there is a 1% royalty to the indigenous native stakeholders to pay-back of costs, rising to 2% after payback unless production has gone into decline. The Company will also pay royalties amounting to 13% to certain third parties.

RPS Energy has assigned Contingent Resources – Development Unclarified and Prospective Resources to Falcon's Makó Trough licence interests; and Prospective Resources to the Beetaloo Basin licence interests. These are summarised in Section 2.

2 SUMMARY OF ASSETS

2.1 MAKO TROUGH - Hungary

RPS has assigned **Contingent Resources – Development Unclarified** to the BCGA discoveries in the Szolnok, Endrod, Basal Conglomerate and Synrift Formations; and, Prospective Resources to a number of identified leads and prospects located in the overlying Algyo Formation.

The total estimated range of Contingent Resources is given in Table 2.1-1 below. Table 2.1-2 gives an estimated range of Prospective Resources. In each case they are arithmetic aggregation of the Resources calculated by zone.

Table 2.1-1 – Contingent Resources Summary

	Gross			Net Entitlement		
	1C	**2C**	**3C**	**1C**	**2C**	**3C**
Szolnok (Gas – Tcf)	12.13	30.96	63.60	10.07	25.70	52.79
Lower Endrod (Gas – Tcf)	0.61	1.11	1.87	0.51	0.92	1.55
Basal Conglomerate (Gas – Tcf)	1.41	3.00	5.53	1.17	2.49	4.59
Synrift Sequence (Gas – Tcf)	0.08	0.19	0.42	0.07	0.16	0.35
Arithmetic Aggregation[1]	**14.24**	**35.27**	**71.41**	**11.82**	**29.27**	**59.27**
Probabilistic Aggregation	**16.85**	**35.78**	**68.46**	**13.99**	**29.70**	**56.82**
Upper Endrod (Oil – MMstb)	32.89	76.71	158.26	27.30	63.67	131.36

1: It is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Probabilistic Aggregation in the next row.

The volumes quoted above are classified as Contingent Resources – Development Unclarified. Oil and Gas have been discovered and may be present in large quantities but commercial flow-rates have yet to have be achieved (although Falcon does periodically produce oil and gas from certain wells). RPS currently estimates that there is a less than or equal to 25% chance that the Contingent Resources quoted above will be converted to Reserves.

Table 2.1-2 – Prospective Resources Summary

	Gross			Net Entitlement			GPoS
	Low Estimate	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**	
Besa (Gas – Bcf)	26.8	65.0	125.0	22.2	54.0	103.8	10%
Hod, SE (Gas – Bcf)	32.3	103.0	219.0	26.8	85.5	181.8	10%
Kiralyhegyes (Gas – Bcf)	3.7	12.1	26.0	3.1	10.0	21.6	10%
Kodmonosdulo (Gas – Bcf)	11.0	36.3	78.6	9.1	30.1	65.2	10%
Kovegy (Gas – Bcf)	2.0	6.7	14.5	1.7	5.6	12.0	10%
Kutvolgy (Gas – Bcf)	47.1	144.0	304.0	39.1	119.5	252.3	10%
Tompahat (Gas – Bcf)	39.8	135.0	296.0	33.0	112.1	245.7	10%
Urmos (Gas – Bcf)	6.2	15.0	29.0	5.1	12.5	24.1	10%
Arithmetic Aggregation[1]	**168.9**	**517.1**	**1092.1**	**140.2**	**429.2**	**906.4**	**<<1%**
Stochastic Aggregation[2]	**378.0**	**568.0**	**820.0**	**313.7**	**471.4**	**680.6**	**<<1%**
Stochastic Aggregation[3]	**8.0**	**64.0**	**251.0**	**6.6**	**53.1**	**208.3**	**57%**

1: It is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Probabilistic Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (56.2 Bcf Net) constitutes the true expectation of success.

2.2 BEETALOO BASIN – Northern Territory, Australia

Basin Resource Potential – Prospective Resources (Play level)

Using the parameters described in Section 5.5.9.1 and the Play Risks described in Section 5.5.9.2, RPS has calculated the Prospective Resource potential for the Beetaloo Basin at the Play level as shown in Tables 2.2-1 to 2.2-3.

Table 2.2-1 – Prospective Unconventional Oil Resources (Play level) Summary for Beetaloo Basin

Resource Play	Potentially In-place				Potentially Recoverable			
	P90	P50	P10		P90	P50	P10	Play risk
Unconventional Shale Oil (MMstb)								
Kyalla Upper	49,663	70,985	100,700		1,290	2,654	5,526	80%
Kyalla Lower	121,327	159,658	209,528		3,023	5,971	12,011	50%
Velkerri Middle	168,927	337,982	673,176		4,942	12,720	32,503	80%

Table 2.2-2 – Prospective Unconventional Gas Resources (Play level) Summary for Beetaloo Basin

Resource Play	Potentially In-place				Potentially Recoverable			
	P90	P50	P10		P90	P50	P10	Play risk
Unconventional Shale Gas (Tcf)								
Kyalla Lower	31.47	52.26	86.97		21.83	37.29	63.81	90%
Velkerri Middle	65.012	104.22	166.77		45.09	74.50	122.78	100%

Table 2.2-3 – Prospective BCGA Resources (Play level) Summary for Beetaloo Basin

Resource Play	Potentially In-place				Potentially Recoverable			
	P90	P50	P10		P90	P50	P10	Play risk
BCGA Gas (Tcf)								
Moroak Sst	1.36	8.26	51.24		0.95	5.90	36.72	50%
Bessie Creek Sst	35.22	62.31	107.03		24.58	44.31	78.48	50%

Prospective Resources – Areas centered around well penetrations (Prospect level)

RPS has assigned Prospective Resources (Prospect level) to three shale plays within the Beetaloo Basin, namely Unconventional Shale Oil in the Kyalla and Middle Velkerri Formations (above 1500m TVDSRD), and Unconventional Shale Gas in the lower most Kyalla and Middle Velkerri. No wells have yet proved the viability of the Moroak and Bessie Creek sandstones and these remain as Propsective Resource (Play level) potential (possibly BCGA in type) but no Prospective Resources (Prospect level) have been assigned at this time. The Prospective Resources (Prospect level) are shown in Tables 2.2-4 and 2.2-5.

Table 2.2-4 – Prospective Unconventional Oil Resources (Prospect level) Summary for Beetaloo Basin

	Gross				Net Attributable			
Prospect (WI=73%)	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	**GPoS**
Unconventional Oil (MMstb)								
Shenandoah – Upper Kyalla	17.5	62.7	223.0		9.71	34.79	123.72	40%
Elliot – Upper Kyalla	4.4	15.7	55.8		2.44	8.71	30.96	10%
Burdo – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%
Ronald – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%
Chanin – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%
Walton-McManus – Middle Velkerri	12.2	49.6	198.0		6.77	27.52	109.85	40%
Arithmetic Aggregation[1]	**48.5**	**177.5**	**649.3**		**26.91**	**98.48**	**360.23**	**<<1%**
Stochastic Aggregation[2]	**130.0**	**245.0**	**497.0**		**72.12**	**135.93**	**275.74**	**<<1%**
Stochastic Aggregation[3]	**14.2**	**69.4**	**253.0**		**7.88**	**38.50**	**140.36**	**73%**

1: Although commonly done, it is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Statistical Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (**62.14** MMstb Net) constitutes the true expectation of success.

Table 2.2-5 – Prospective Unconventional Gas Resources (Prospect level) Summary for Beetaloo Basin

Prospect (WI=73%)	Gross				Net Attributable			
	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	**Risk Factor**
Unconventional Gas (Bcf)								
Shenandoah – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	45%
Jamieson – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	45%
Elliot – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	11.25%
Shenandoah – Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	50%
Jamieson – Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	32%
Elliot –Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	12.5%
Arithmetic Aggregation[1]	**556.8**	**1740.0**	**5541.0**		**308.91**	**965.35**	**3074.15**	**<<1%**
Stochastic Aggregation[2]	**1400.0**	**2342.0**	**4015.0**		**776.72**	**1299.34**	**2227.52**	**<<1%**
Stochastic Aggregation[3]	**184.0**	**703.0**	**1878.0**		**102.08**	**390.02**	**1041.91**	**92%**

1: Although commonly done, it is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Statistical Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (**504.31** Bcf Net) constitutes the true expectation of success.

3 METHODOLOGY USED IN THIS REPORT

The evaluation presented in this report has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. RPS Energy is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property.

3.1 RESERVES AND RESOURCES CLASSIFICATION

All Reserves and Resources definitions and estimates, and also risk factors, shown in this report are based on the SPE/SPEE/AAPG/WPC Petroleum Resource Management System ("PRMS"). The key definitions of the PRMS are given in Appendix B.

In estimating Reserves and resources we have used standard petroleum engineering techniques. These techniques combine geological and production data with detailed information concerning fluid characteristics and reservoir pressure. RPS Energy has estimated the degree of uncertainty inherent in the measurements and interpretation of the data and has calculated a range of recoverable resources. RPS Energy has assumed that the working interest in the assets advised by Falcon is correct and RPS Energy has not investigated nor does it make any warranty as to the Falcon interest in these properties.

Hydrocarbon resource and reserve estimates are expressions of judgement based on knowledge, experience and industry practice and are restricted to the data made available. They are, therefore, imprecise and depend to some extent on interpretations, which may prove to be inaccurate. Estimates that were reasonable when made may change significantly when new information from additional exploration or appraisal activity becomes available.

3.2 RISK ASSESSMENT

For all prospects and appraisal assets estimates of the commercial chance of success for Contingent Resources, and estimates of geological chance of success for Prospective Resources, have been made. The former is called Chance of Development (CoD) and the latter Chance of Discovery (also CoD). To avoid confusion with acronyms we have used the term Geological Probability of Success (GPoS) in this document synonymously with Chance of Discovery.

3.2.1 Contingent Resources (Discovered Hydrocarbons)

The chance of success in this context means the estimated chance, or probability, that the volumes will be commercially extracted. A Contingent Resource includes both proved hydrocarbon accumulations for which there is currently no development plan or sales contract and proved hydrocarbon accumulations that are too small or are in reservoirs that are of insufficient quality to allow commercial flow rates and development at current prices. As a result, the estimation of the chance that the volumes will be commercially extracted may have to address both commercial (i.e. contractual or oil price considerations) and technical (i.e. technology to address low deliverability reservoirs) issues.

3.2.2 Prospective Resources (Exploration Prospects)

Unlike risk assessment for Contingent Resources, when dealing with undrilled prospects there is a more accepted industry approach to risk assessment for Prospective Resources. It is standard practice to assign a Geological Probability of Success (GPoS) which represents the likelihood of source rock, charge, reservoir, trap and seal combining to result in a present-day hydrocarbon accumulation. RPS assesses risk by considering both a play risk and a prospect risk. The chance of success for the play and prospect are multiplied together to give a Geological Probability of Success (GPoS). We consider three factors when assessing play risk: source, reservoir, seal and we consider four factors when assessing prospect risk: trap, seal, reservoir and charge. The result is the chance or probability of discovering hydrocarbon volumes within the range defined. As a check on the outcome of such exercises, RPS usually cross-checks the resulting GPoS against published benchmarks[1] that position the GPoS percentage relative to historical oil and gas play maturity.

Where the resources in question are unconventional (in particular "shale" plays and prospects), RPS has developed a methodology which is described in more detail in Section 5.5.9.2.

3.3 UNCERTAINTY ESTIMATION

The estimation of expected hydrocarbon volumes is an integral part of the evaluation process. It is normal practice to assign a range to the volume estimates because of the uncertainty over exactly how large the discovery or prospect will be. Estimating the range is normally undertaken in a probabilistic way (i.e. using Monte Carlo simulation), using a range for each input parameter to derive a range for the output volumes. Key contributing factors to the overall uncertainty are data uncertainty, interpretation uncertainty and model uncertainty.

Volumetric input parameters, gross rock volume (GRV), porosity, net-to-gross ratio (N:G), water saturation (Sw), fluid expansion factor (Bo or Bg) and recovery factor, are considered separately. RPS Energy has internal guidelines on the best practice in characterising appropriate input distributions for these parameters.

Systematic bias in volumetric assessment is a well-established phenomenon. There is a tendency to estimate parameters to a greater degree of precision than is warranted[2] and to bias pre-drill estimates to the high side[3]. Rose and Edwards observe the tendency towards assessing volumes in too narrow a range with overly large low-side and mean estimates. RPS Energy uses benchmarked P90/P10 ratios and known field size distributions to check the reasonableness of estimated volumes.

3.4 AUDIT METHOD

RPS Energy has performed the audit of Resources estimates in accordance with generally accepted petroleum engineering evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers ("SPE Audit Standards").

Our approach in this instance has been to review the technical interpretation of the geoscience and engineering data for reasonableness. Where necessary, RPS Energy has undertaken independent re-interpretation to produce a technically reasonable base case interpretation. We have then reviewed the range of uncertainty for each parameter around this base case which have been used to estimate a range of petroleum initially in place and recoverable for each field.

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[1] E.g. Otis, R.M. & Schneidermann, N. 1997. "A Process for Evaluating Exploration Prospects", AAPG Bulletin 81 (7) pp.1087-1109.

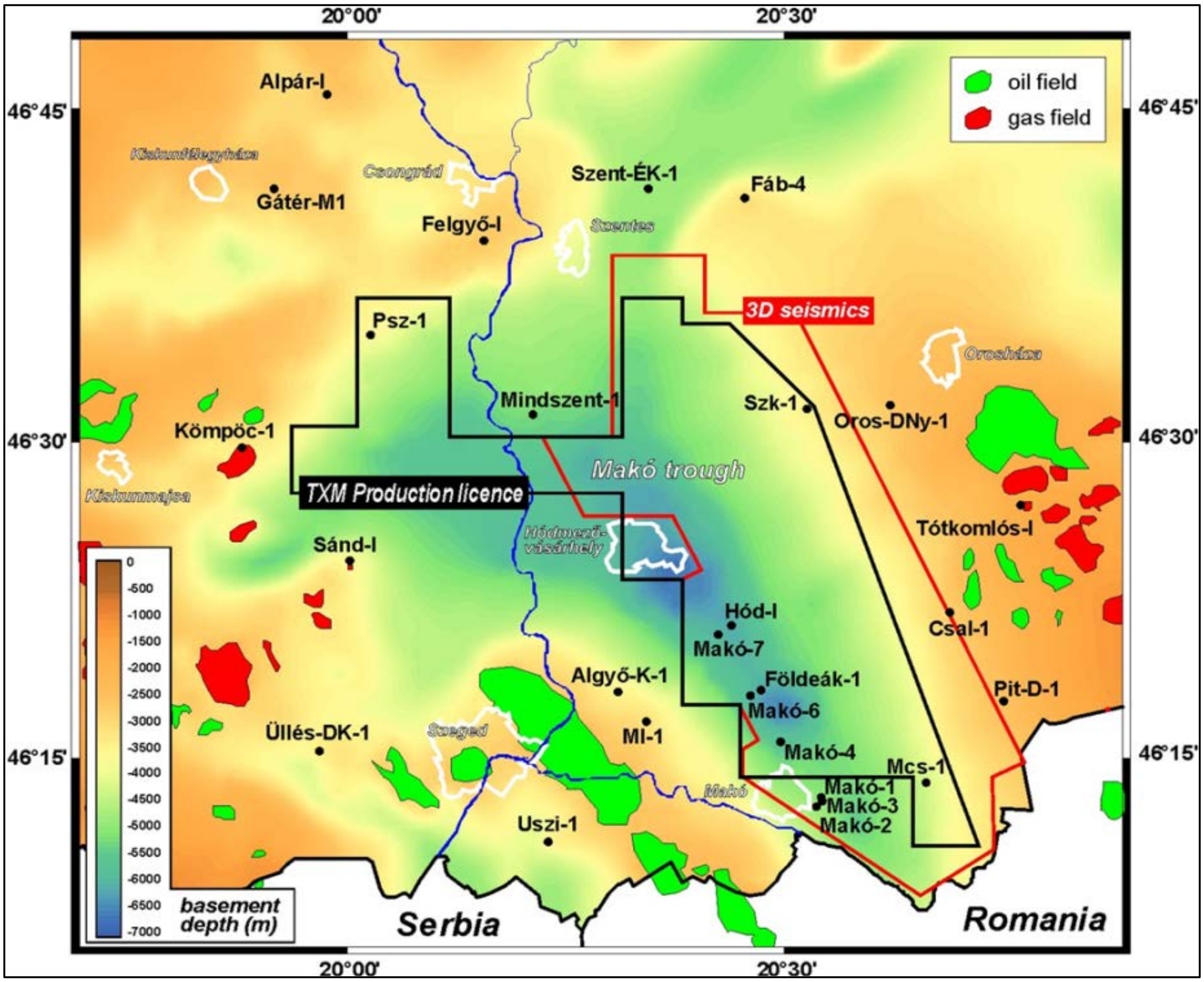
[2] Rose, P.R., 1987. Dealing with Risk and Uncertainty in Exploration: How Can We Improve? AAPG Bulletin, 71 (1), pp. 1-16.

[3] Rose, R.P. and Edwards, B., 2001. Could this prospect turn out to be a mediocre little one-well field? Abstract, AAPG Bulletin, 84(13)

4 MAKO TROUGH PRODUCTION LICENCE (Onshore Hungary)

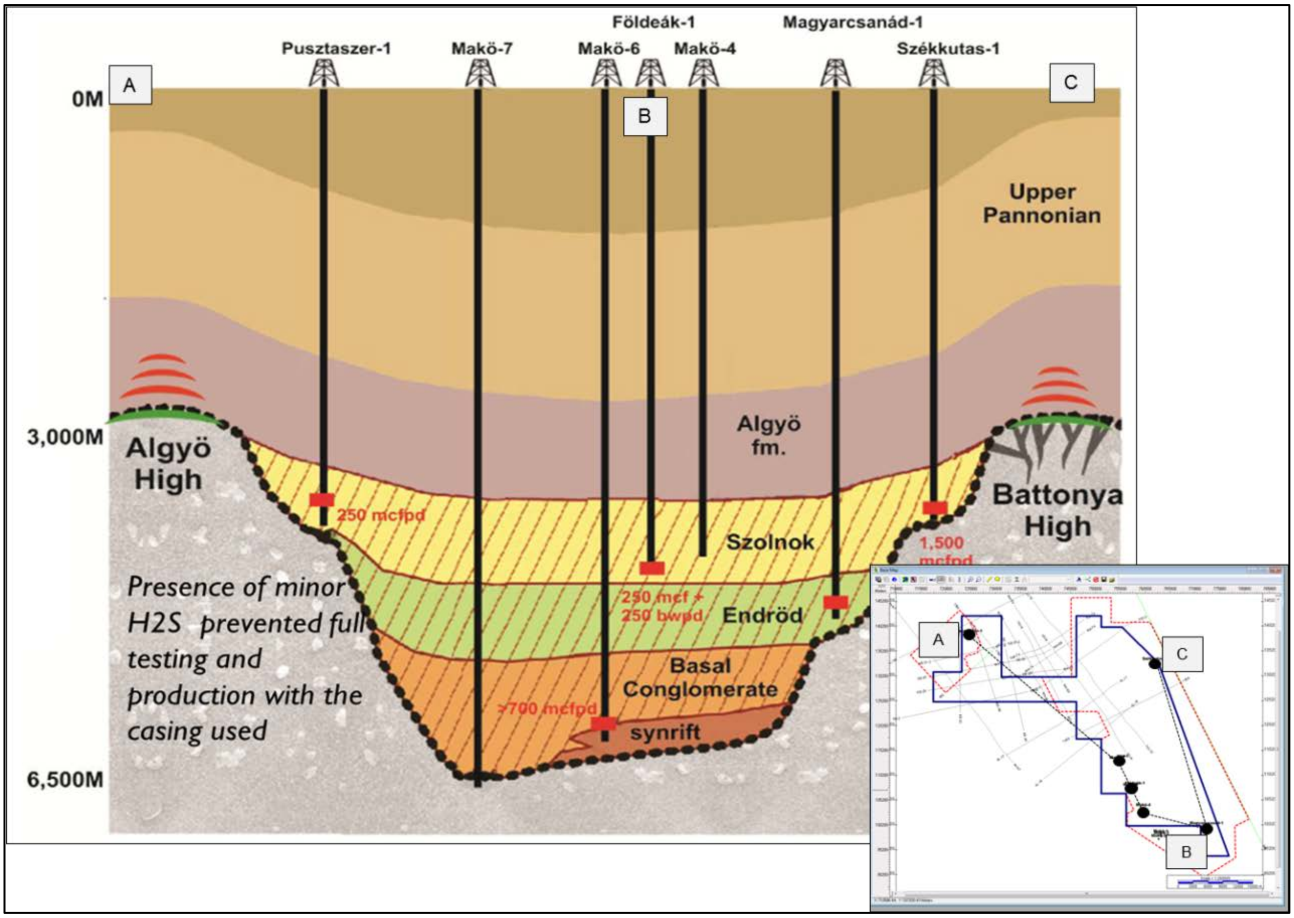
4.1 GEOLOGICAL OVERVIEW

The Makó Trough is a large structural sag or trough, which is located in southeastern Hungary near the Romanian border (see Figure 4.1-1). Hungary is an established oil and gas producing country and Falcons' licence is located some 5 km to the east of the largest field in Hungary, the Algyo field (2.5Tcf and 220 MMbo produced). The licence is transacted by existing gas pipeline infrastructure offering transport and access to local and other European markets.



Source: Falcon

Figure 4.1-1: Regional Location Map



Source: Falcon

Figure 4.1-2: Schematic Geological Section Across the Makó Trough

Figure 4.1-2 shows a schematic geological cross-section across the Makó Trough play. The play consists of a discovered Basin Centered Gas Accumulation ("BCGA") and several leads and prospects located within a conventional turbiditic sandstone play within the overlying Algyo Formation.

BCGA's are characterized by overpressured, gas-saturated, low-permeability reservoirs. In this case the principal potential reservoirs are divided into the Szolnok, Endrod, Basal Conglomerate and Synrift Formations. These formations are also the source rocks for the oil and gas fields found on structural highs which surround the Makó Trough depression.

The Algyo Formation is characterised as southeast prograding lacustrine slope deposits and are expected to vary between sandy slope aprons connected to shelf-margin deltas to turbidite systems fed by major channels. These stratigraphic intervals are distinctive on 3D seismic data as prograding clinoforms. Several leads and prospects have been identified within the toes of clinoforms or in slope detached positions within the fan sequences.

4.2 LICENCE STATUS AND WORK COMMITMENTS

The Makó Trough acreage interest is held 100% in the name of TXM Oil & Gas Limited, ("TXM") a wholly owned subsidiary of Falcon Oil and Gas Limited. Under the terms of the Production Licence, Falcon is obliged to pay a 12% royalty to the Government of Hungary on any production and has a further 5% royalty agreement with Prospect Resources Inc., the previous owners of the licence. TXM is the operator of the licence which covers 994.6 square kilometres (245,765 acres) following a 57.3% relinquishment as per the terms of the licence in "Tisza" exploration permit in September 2010 and the "Makó" exploration permit in November 2010.

Table 4.2-1 summarises the Makó Trough production licence status.

Table 4.2-1 – Licence Status Summary

Licence Concessions (Country)	Interest (%)	Operator	Status	Area (km^2)	Expiry	Comments
Makó Trough Production Licence **(Onshore Hungary)**	100.0%	TXM Oil and Gas Ltd.	Production	994.6	21/05/2042	Periodic limited production. Development Unclarified for BCGA unconventional resources. Exploration potential in shallower Algyo Formation

4.2.1 Required Minimum Work Program

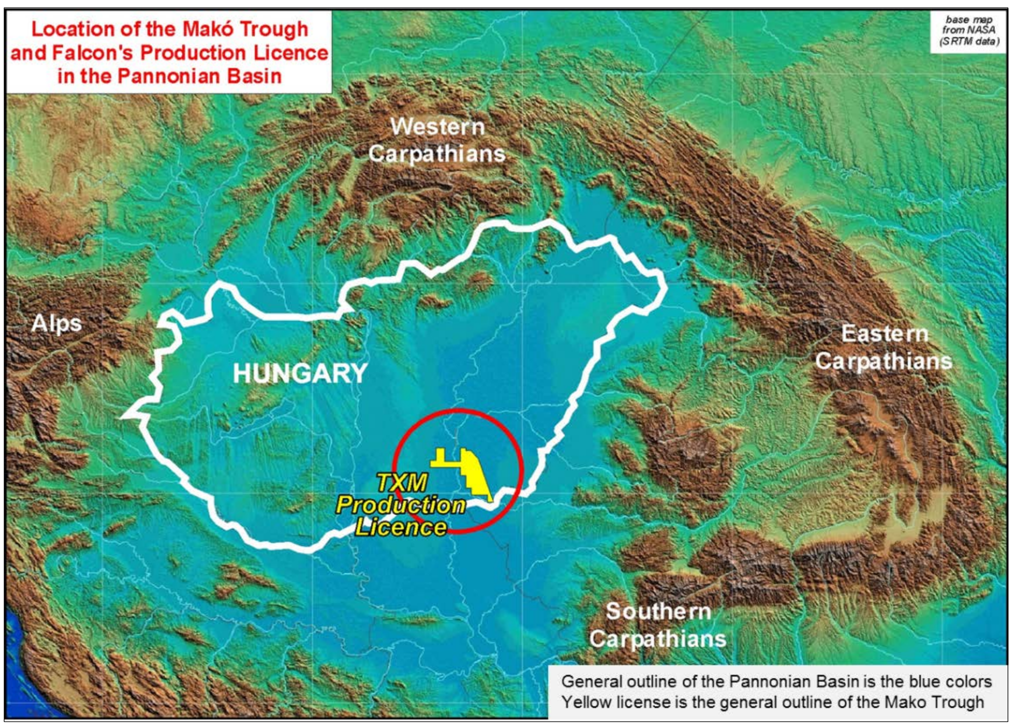
There are no remaining work commitments outstanding for the licence.

4.3 GEOLOGICAL SETTING AND PROSPECTIVTY

4.3.1 Tectonic Setting

The Makó Trough is a large structural sag or trough, which is located in southeastern Hungary near the Romanian border. The axis of the trough strikes in a NW-SE direction.

The greater Pannonian Basin encompasses most of Hungary (Figure 4.3.1). The Makó Trough is a large extensional feature lying within this basin.

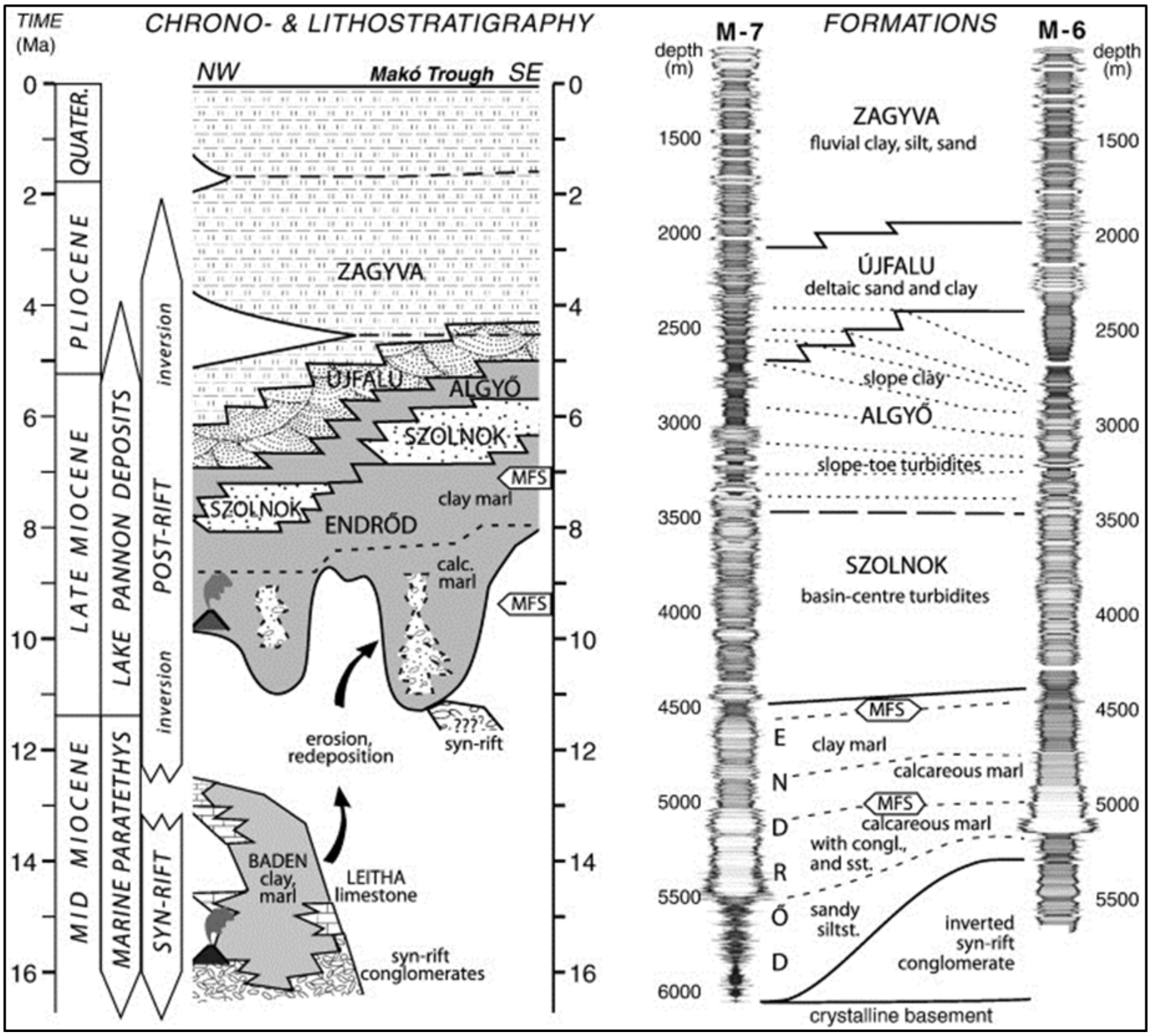


Source: Falcon

Figure 4.3-1: Location of the Pannonian Basin

The early Paleozoic and Mesozoic history of the area is complex and not completely constrained. In the Mesozoic compression caused by the northward movement of Africa and the Adriatic microplate initiated the closure of the Tethys Sea. During this process the smaller, Paratethys Sea formed with the deposition of marine sediments. In the Oligocene to early Miocene the seaway remained open despite continued northward African plate movement, compression, rotation, thrusting and folding.

In the Middle Miocene, rifting occurred due to the coeval extrusion of Alpine terranes and subduction roll-back and the large Pannonian Basin formed in central Europe (Figure 4.3-1). The greater Pannonian Basin is approximately 600 km from east to west and 500 km from north to south. Within this larger area, there are numerous sub-basins separated by horst blocks. The formation of these depressions was diachronous between the late Early Miocene and the early Late Miocene. One of these is the Makó Trough. It strikes northwest-southeast and is between the Algyo and Battonya basement highs. The connection to the Paratethys remained open during the deposition of the Synrift sediments (Figures 4.1-2 and 4.3-2).



Source: Falcon

Figure 4.3-2: Makó Trough Stratigraphic Chart

After the termination of the slab retreat, the soft collision of the extruded blocks with the East European Platform led to the build-up of the Carpathian orogen. This resulted in the isolation of the Pannonian Basin from the sea, the formation of Lake Pannon. The collision was accompanied by a short period of tectonic inversion and is marked by a widespread unconformity between the syn- and postrift deposits. It was followed by the phase of post-rift thermal subsidence and the formation and maintenance of deep basins with the deposition of the lacustrine and non-marine sediments of the Endrod, Szolnok, and Algyo formations. Due to the ongoing indentation of the Adriatic microplate and the cessation of the subduction beneath the contemporaneous Carpathians, the basin has been gradually inverted. The Pliocene and

Quaternary has had uplift along the basin edges and subsidence in the basin center. In the Makó Trough section of the Pannonian Basin there is currently in excess of 7,000 m of sediment.

The target zones are the entire accumulations of Szolnok and Endrod clastic sediments in the Makó Trough as well as the underlying Basal Conglomerate and Synrift Sequence (the BCGA dicoveries) and leads and prospects within the overlying Algyo formation.

4.3.1.1 Synrift Formation

The Synrift formation is poorly understood. In places it is composed of poorly sorted conglomerates interbedded with shales. The conglomerates are composed of metamorphic, granitic, quartz, and dolomite clasts. The deposition environment is also poorly known. It may have been deposited in alluvial fans into a fluvial or near shore environment.

4.3.1.2 Basal Conglomerates

These are also considered the lowermost part of the Endrod Formation. The Basal Conglomerate is dominantly black marls with a thin clast/matrix supporting a metamorphic and quartz conglomerate and sandstone intercalations. The coarse-grained sediments most probably have local source (neighboring basement highs) and their deposition is related to mass gravity flow processes. Upwards decreasing abundance of conglomeratic intercalations points to ongoing transgression of local shorelines.

4.3.1.3 Endrod

Deposition of the Endrod began with volcanic tuffs, limestones, and conglomerates. This was followed by alternating bands of sandstone, siltstone, and anoxic shales, and marls deposited in basin floor fans. The Endrod formation represents a transgressive phase of the basin fill. The formation is often subdivided into smaller units based on lithology. The changes in lithology correspond to major changes in deposition. The shales and marls are dark gray to brownish gray and the often grade into a siltstone/shale section with minor sandstone beds.

The Lower Endrod is generally a calcareous marl. The organic-rich calcareous marls contain brackish water microfossils indicating they were deposited in clear open lacustrine waters. The calcareous marls grade into very thin sandstones and siltstones. Condensed black marls reveal maximum flooding during the transgressive phase.

The Upper Endrod is composed mainly of a clayey marls and siltstones. They are characterized by upward decreasing carbonate and increasing silt content. A few centimeter scale very fine grained interbedded turbiditic sandstones are common. This reflects the gradual approach of the shelf-margin slope system. The uppermost 100 m of the Endrőd Marl is clay. The lack of silt and mass gravity flow deposits may indicate significant pause in sediment input.

4.3.1.4 Szolnok

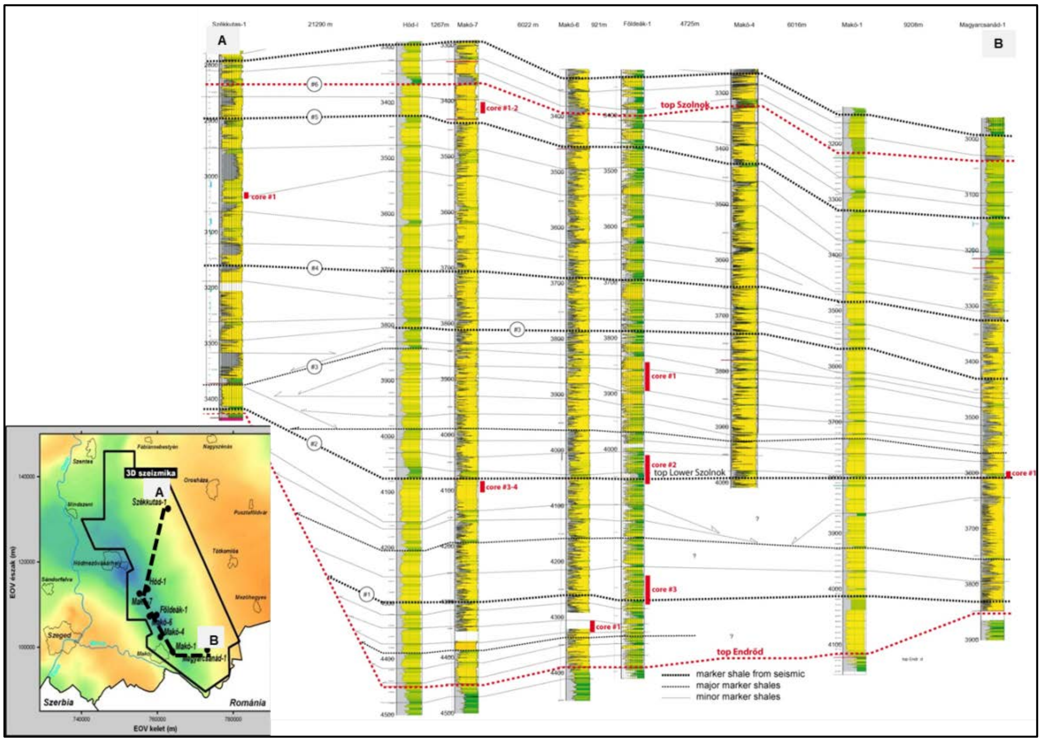
With the increased subsidence, came increased sedimentation. The Szolnok Formation has basal, deep water sediments of the turbidite deposition of the Pannonian Delta (Figure 4.3-3). The Szolnok in the center of the Makó Trough is composed of interbedded sandstone, siltstone and shale, which may be finely interbedded. Sandstones are light gray, hard, micaceous, very fine-grained, well sorted with calcareous cement and poor visual porosity. Siltstones are dark to medium gray, micaceous, occasionally fissile, splintery and sometimes sandy. Shales are brownish gray or light brownish gray, medium to hard and splintery. The entire sequence may be considered a series of shifting channel fans and lobes.

Four facies have been defined in the Szolnok:

1. Fully bioturbated clay, clayey siltstone,
2. Silty mudstones with mm-thick very fine sandstones to coarse siltstones,
3. Thin-bedded turbidites (mostly 5–10 cm thick, fine to very fine-grained sandstones) alternating with siltstones

4. Thick-bedded turbidites (0.3–2 m thick, fine- to medium-grained, commonly amalgamated sandstones) without any silt- or claystone.

These are alternating low density, low-volume suspension deposits and large volume high-density turbidity currents. The facies appear to be a typical turbiditic sequence with the silty mudstones deposited in between turbidite flows.



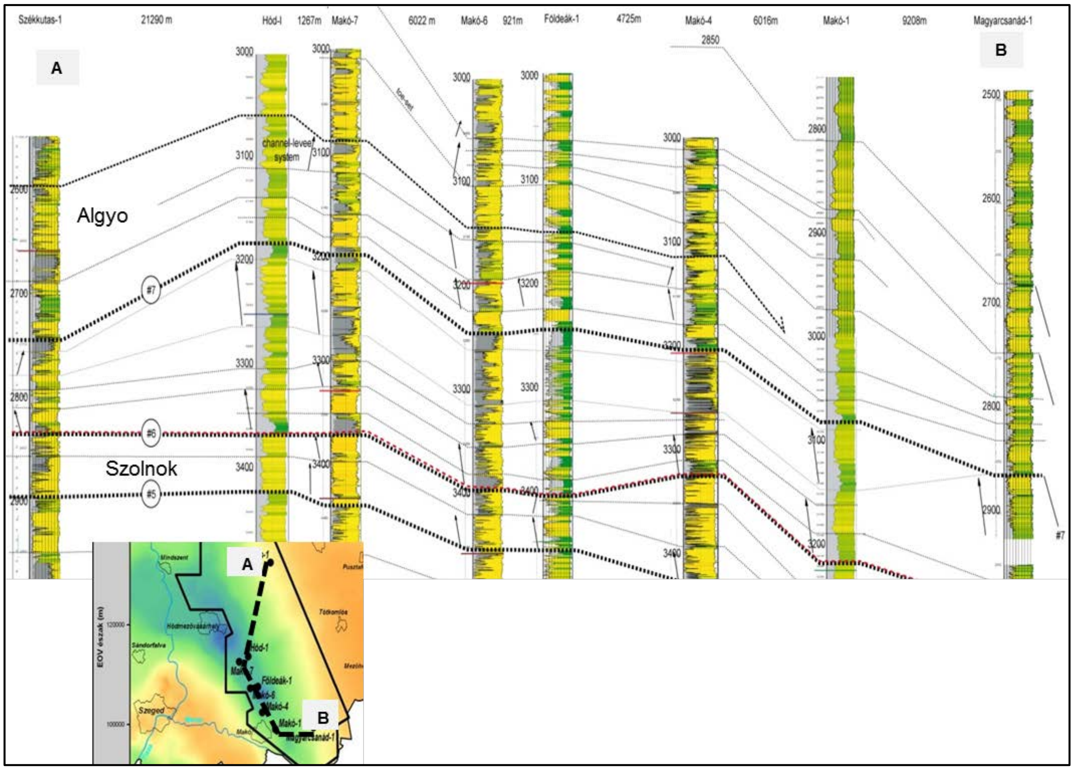
Source: Falcon

Figure 4.3-3: Szolnok Cross Section

The sand-dominated intervals are regarded as the center of the channels and fan lobe deposits while the thin-bedded sandstone association may be interpreted as overbank of distal fan deposits. Minor shales indicate fan/channel abandonment and quiet water deposition. Amalgamated channel and fan deposits occur and the sand bodies are stacked to form 50–150 m thick complexes, separated by major marker shales of 5–10 m thickness.

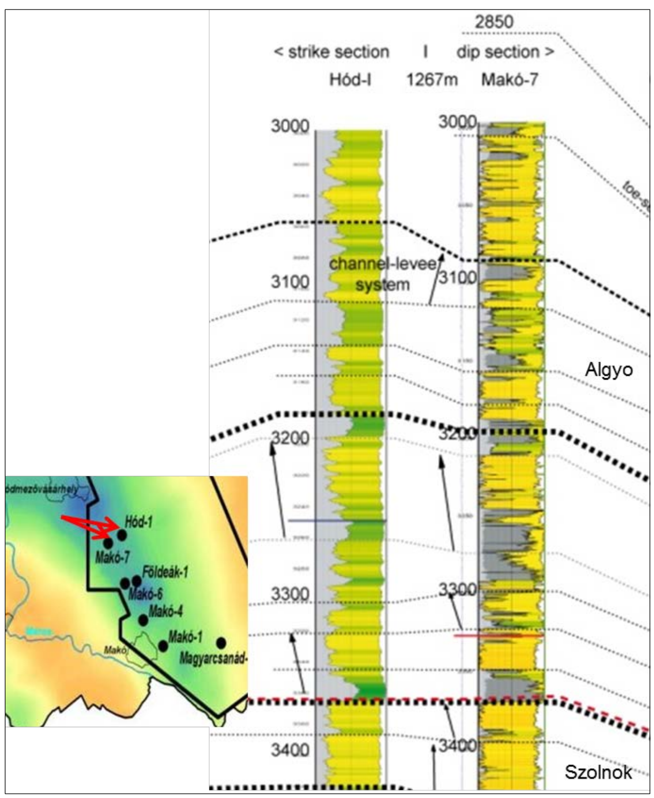
4.3.1.5 Algyo

The Algyo formation represents the slope deposits of the Pannonian Delta and is composed of prograding clinoforms. The Algyo is composed of dark gray siltstones, interbedded with thin to thicker sandstone beds (Figures 4.3-4 and 4.3-5). Thicker (20-50 m) coarsening upward sandstones separated by 5-10 m thick mudstone units are more abundant in the lower part of the formation. The clayey sediments represent the slope, while the sandy units were deposited from decelerating turbidity currents comprising channel-fed lobes near the slope-toe region.



Source: Falcon

Figure 4.3-4: Algyo Cross Section



Source: Falcon

Figure 4.3-5: Detailed Algyo Cross Section

Six wells were drilled and cased to test the Makó Trough BCGA during the years of 2006 and 2007. All of the wells confirmed the presence of BCGA in the Makó Trough but production characteristics were mixed.

In the most recent well, ExxonMobil's Foldeak-1 drilled and completed in 2009, a minor increase in background total gas readings was recorded while drilling the Algyo and Szolnok formations. After reaching total depth (TD), the Foldeak-1 completed and tested the Upper and Lower Szolnok. Each of the zones was perforated and fracture stimulated. Following the stimulation of each zone, the Foldeak-1 was production tested. The highest gas rate was recorded in the Lower Szolnok at 250 Mcfd and 370 bwpd. The upper Szolnok tested at a post-frac rate of 20 Mcfd. The well was plugged and abandoned following production testing of the Szolnok later in 2009. Figure 4.1-2 shows the seven well penetrations through the Makó Trough unconventional play with production test rates posted on each well.

The unconventional play is interpreted to exist within the Szolnok and Endrod formations from a depth of about 3,200 m (as encountered in the Makó-6 well) and to persist to the total depth of that well at 5,689 m (driller's depth), to include the underlying Basal Conglomerate and Synrift Sequence. This is based on an evaluation of available data for the deep section within the Makó Trough. The Algyo formation top for the exploration prospects is interpreted to be present at 2782 m in the ExxonMobil Foldeak-1 to a base of 3390 m in the Makó-4 well.

4.3.2 Overview Of Discoveries and Prospectivity

The initial wells (Szekkutas-1, Pusztaszer-1, Mako-4, Mako-6, Mako-7, Magyarcsanad-1 and Foldeak-1) have been drilled, cased and partially tested as of the Effective Date of this report. The Algyo was MDT tested in the Makó-4 and flowed water. The Szolnok tested burnable hydrocarbons, CO_2 and some H_2S in the Pusztaszer-1, Szekkutas-1 and Foldeak-1. The Makó-6, Magyarcsanad-1 and Szekkutas-1 tested burnable hydrocarbons in the Endrod and Basal Conglomerate. The Synrift flowed water in the Makó-6. The Magyarcsanad-1 produced some light oil and associated gas from the Endrod.

4.3.2.1 Pusztaszer-1

In late 2005, Falcon began its initial exploration drilling program with the Pusztaszer-1. The well was designed as a delineation well to test the northeastern extent of the Makó Trough. The well was drilled to a total vertical depth of 3,782 m and encountered Gneiss Basement, the Endrod and Szolnok formations. The Pusztaszer was then tested in the Basement and Szolnok formation following small fracture stimulation. The well tested approximately 200 Mcfd and 200 bwpd from the Szolnok formation.

4.3.2.2 Szekkutas-1

The next well to be drilled and tested in early 2006 was the Szekkutas-1. The well was designed to test the northwest extension of the Makó Trough and was drilled to a total depth of 3,585 m. The well encountered the Triassic Basement, Endrod and the Szolnok formations. The well tested 130 Mcfd and 549 bwpd from the Triassic Basement. The Endrod tested gas at an unstabilized rate of 1,577 Mcfd at 50 to 100 ppm hydrogen sulfide and 150 Mcfd at similar H_2S concentrations from the Szolnok. The presence of H_2S in these concentrations required Falcon to abort the test due to safety considerations.

4.3.2.3 Makó-6

The Makó-6 was drilled in 2006 to a total depth of 5,692 m and was the first deep test in the basin by Falcon. The well encountered the Synrift, Basal Conglomerate, Endrod and Szolnok formations. Petrophysical analysis of the log and core data indicated the possible presence of hydrocarbons in all formations, establishing a possible hydrocarbon column of 2 km. A test of the Synrift was attempted which proved tight. An interval at the base of the Basal Conglomerate was tested with initial rates of up to 700 Mcfd with associated H_2S of 400 ppm. The test was aborted when a suspected down-hole failure occurred.

4.3.2.4 Makó-7

The Makó-7, also drilled in 2006, was designed to be a second deep basin test. The well was drilled to a total depth of 6,085 m and encountered the Basal Conglomerate, Endrod and Szolnok formations. Petrophysical analysis indicates the possible presence of hydrocarbon in all formations encountered, but no testing has been accomplished to date. If the well tests hydrocarbons it may indicate the presence of a 2.5 km hydrocarbon column. The interval between 3370 and 3429 m MD shows density/neutron crossover, and increase in background total gas reading up to 2670 gas units. The well has produced/tested Basal Conglomerate gas intermittently between October 2011 and September 2012 (cumulative production of 1.5 MMcf) from the well, which has since been shut-in.

4.3.2.5 Magyarcsanad-1

The evaluation program continued in 2006 with the Magyarcsanad-1. This well was designed to test the southern end of the Makó Trough. The well was drilled to a total depth of 4,226 m and encountered the Endrod and Szolnok formations. The well tested oil and gas from the Endrod formation at unstabilized rates of 360 bopd and 1,100 Mcfd, declining to 65 bopd and 137 Mcfd without stimulation. The well has produced/tested gas and light oil intermittently from the Endrod between November 2009 and July 2012 (cumulative production of 2000 Mcf of gas and 850 Bbls of light oil).

This is very encouraging in that it establishes the presence of mobile high gravity oil in the Endrod formation. In addition, it indicates the Endrod in the area of the wellbore to be a naturally fractured reservoir capable of delivering hydrocarbon. If future analysis and testing establishes the Endrod to contain a pervasive natural fracture system, charged with hydrocarbon and capable of transmissibility of the hydrocarbon, this could significantly add to resources of the basin.

4.3.2.6 Makó-4

Makó-4, drilled in 2007, was designed to test the Szolnok formation in the southern portion of the basin. The well was drilled to a total depth of 4,011 m. An MDT test from 2368-3179 m yielded water. The well encountered low gas saturated sands in the Algyo Urmos lead and TD's in the Szolnok formation and is suspended pending completion of the current geologic and operational review.

4.3.2.7 Foldeak-1

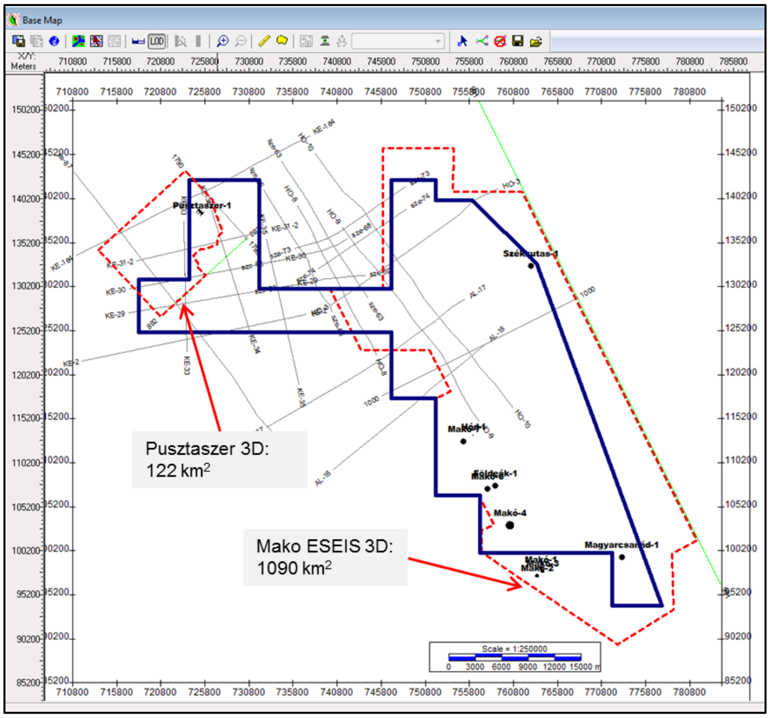
The ExxonMobil well was drilled in early 2009 to a total depth of 4,421 m in the top of the Endrod as a northeast offset to the Makó-6. After reaching total depth, the Foldeak #1 completed and tested the Upper and Lower Szolnok. Each of the zones was perforated and fracture stimulated. Following the stimulation of each zone, the Foldeak #1 was production tested. The Lower Szolnok was tested at 200 Mcfd on a 16/64"choke with a 300 ppm H_2S average concentration. This well confirms the distribution of gas in the deep basin from the shallower Szolnok test in the Szekkutas-1 on the eastern Makó Trough flank and the Pusztaszer-1 on the western flank. The well has since been suspended.

4.4 DATABASE

RPS was provided access to a comprehensive dataset including an interpreted SMT project, as well as well logs, well reports, deviation data, mudlogs, core data, well test and well completion reports.

4.4.1 Seismic Data

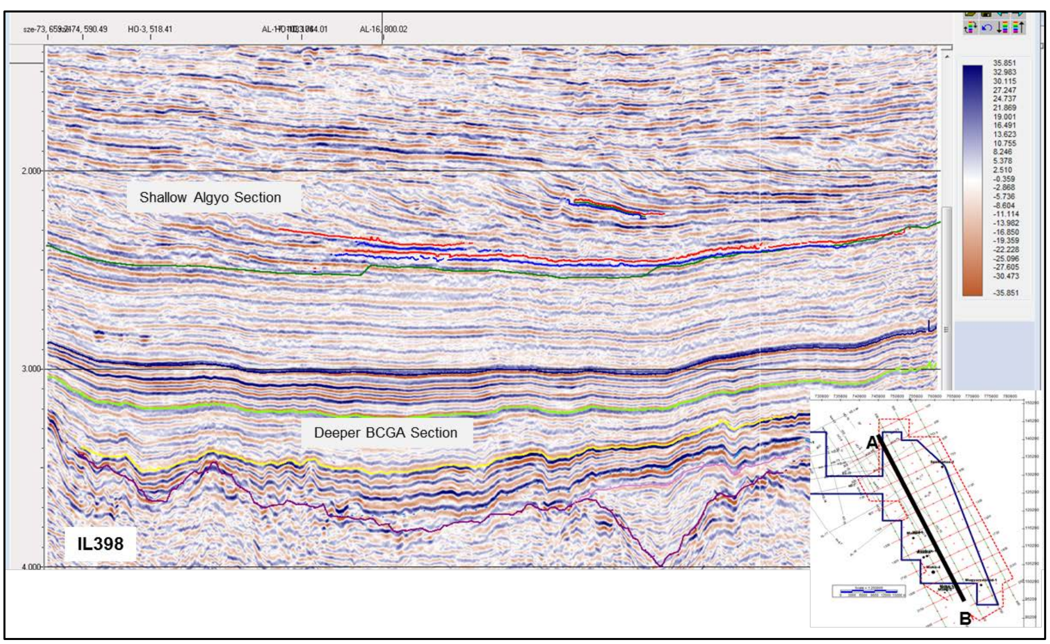
The SMT project included two 3D seismic surveys and older 2D data. Falcon also provided, in the SMT project, the well logs, well tops, horizons, key faults, grids and coonturs. Figure 4.4-1 shows the avaliable seismic data.



Source: Falcon

Figure 4.4-1: Makó Trough Seismic Data

The resources included in this report were covered by the Makó-ESEIS 3D. A number of seismic cubes were provided for the review including frequency, Hilbert, phase, and proprietary ESEIS processing attributes. Seismic data quality was fair to good and the time maps were completed on the 4thPrSTM processing. Figure 4.4-2 is a strike seismic line through the center of the Makó trough. The clinoforms of the shallower Algyo formation are well imaged, as is the deeper section.



Source: Falcon

Figure 4.4-2: Example of Seismic Data Quality

4.4.2 Well Data

RPS was provided access to a comprehensive dataset including an interpreted SMT project, as well as well logs, well reports, deviation data, mudlogs, core data, well test and well completion reports

4.4.3 Previous Reports

1. **"RESOURCE ESTIMATE , MAKO TROUGH, HUNGARY", Effective date August 15, 2006**. Scope of work: Preparation of report under the Canadian Oil & Gas Evaluation Handbook (COGEH) and Canadian securities instrument National Instrument 51-101 – Standards of Disclosure for Oil and Gas Issues (51-101) standards regarding the Client's Mining license in the Makó trough and Tisza license blocks in Hungary (each the Makó Mining License and Tisza License and together Licenses).
2. **"RESOURCE ESTIMATE , MAKO TROUGH, HUNGARY", Effective date March 31, 2008**. Scope of work: Preparation of report under the Canadian Oil & Gas Evaluation Handbook (COGEH) and Canadian securities instrument National Instrument 51-101 – Standards of Disclosure for Oil and Gas Issues (51-101) standards regarding the Client's Mining license in the Makó trough and Tisza license blocks in Hungary (each the Makó Mining License and Tisza License and together Licenses).
3. **"MAKÓ TROUGH GEOLOGICAL MODEL", January 7, 2009**. Main objective was to identify rock volumes having anomalous characteristics that might indicate prospectivity, using all available 3D data volumes. Nine (9) Petrel models containing data and geocellular models were developed and delivered as final products.

4.5 DISCOVERED BCGA AND ALGYO FORMATION LEADS AND PROSPECTS

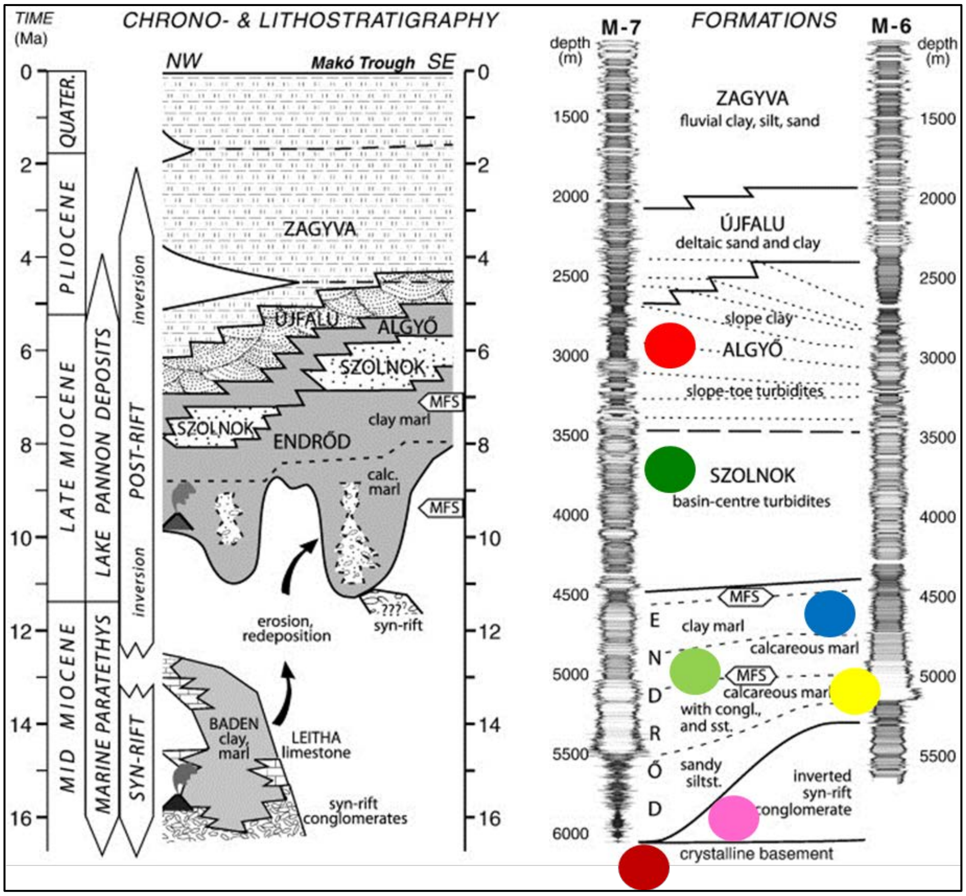
4.5.1 Overview

RPS evaluated several sources of information provided by Falcon (see Section 4.4) to assess the unconventional shale BCGA resource for the Szolnok, Endrod, Basal Conglomerate and Synrift Formations and the shallower conventional fan deposit leads and prospects for the Algyo Formation. The information used in the evaluation included seismic data and interpretation, depth maps, mudlogs, wireline logs, test data, and geochemical analysis.

4.5.2 Seismic Interpretation and Depth Maps

RPS has QC'd the seismic interpretation behind the current Falcon mapping of the Makó Trough and finds it to be broadly consistent with the underlying data. Since the BCGA is mapped as a resource play the seismic interpretation is used to confirm the general sequence stratigraphy and the presence or absence of the resource zones.

Figure 4.5-1 is a stratigraphic chart with the major formations and Figure 4.5-2 illustrates the seismic horizons interpreted by Falcon and reviewed by RPS.



Source: Falcon

Figure 4.5-1: Stratigraphic Chart with Seismic Horizons Annotated

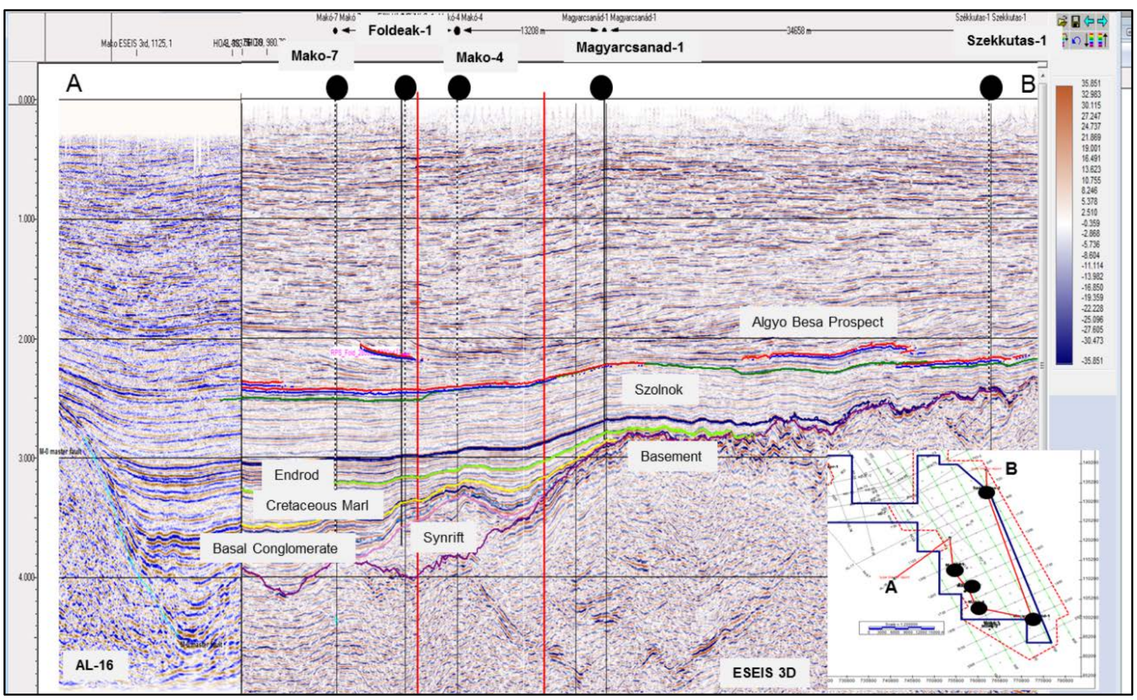
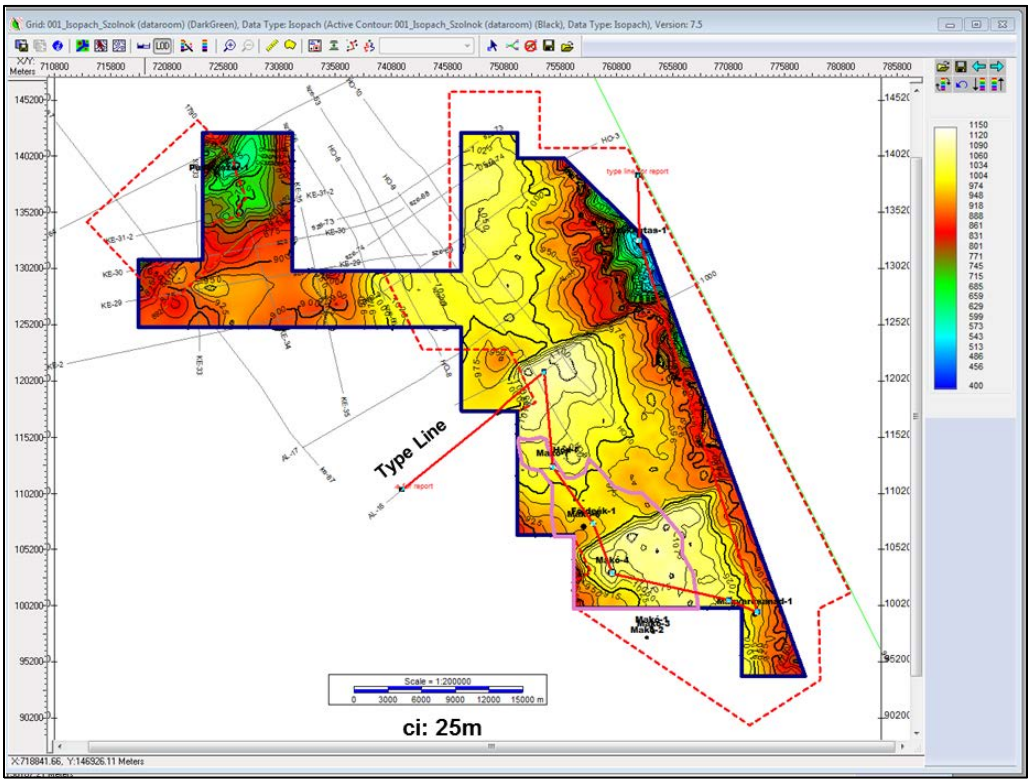


Figure 4.5-2: Type Seismic Line through the Key Wells

Falcon interpreted seven deeper horizons for use in the BCGA resource assessment:

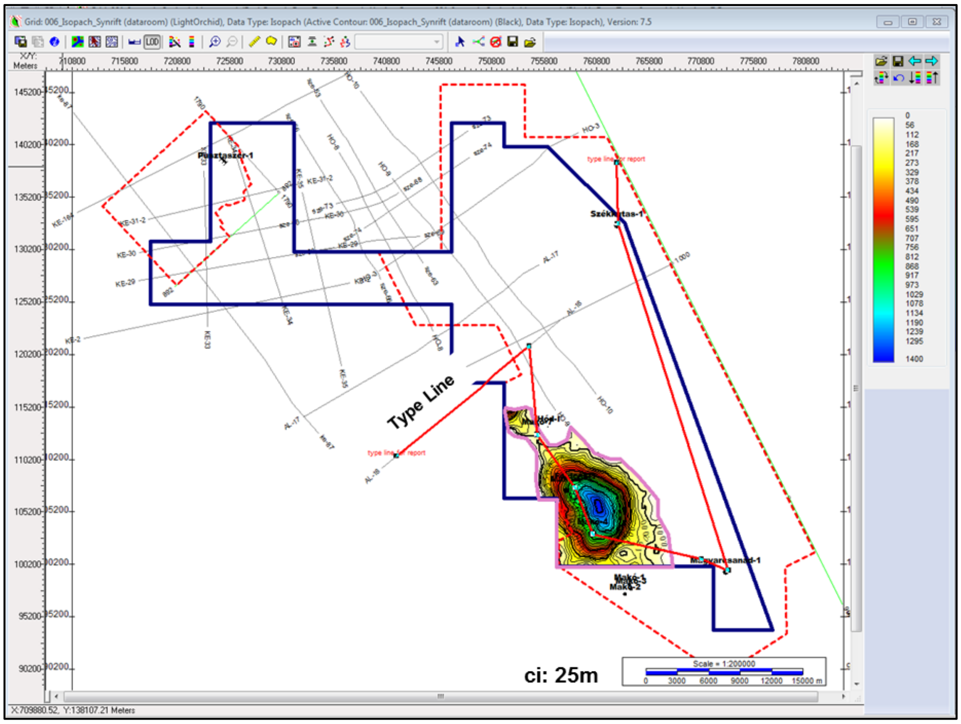
- Top Szolnok
- Top Endrod
- Top Calcareous marl
- Top Basal
- Top Synrift
- Top Basement

The gross rock volume used in the BCGA analysis was derived from the interval isopachs in SMT. The areas covered vary from the entire concession, Szolnok, to the areally restricted Synrift sequence. These gross rock volumes were placed into the Monte Carlo resource calculations. For example, Figure 4.5-3, the isopach for the Szolnok encompasses the entire Falcon concession and the gross rock volume used in the resource calculations is derived from the SMT volumetrics module in EarthPak™. Different from Szolnok, is the areally restricted Synrift sequence (see Figures 4.5-2 and 4.5-4). The resources for the BGCA for the synrift are found only in the south-western corner of the concession in the deepest part of the basin.



Source: Falcon

Figure 4.5-3: Szolnok Isopach used for Gross Rock Volume Calculations



Source: Falcon

Figure 4.5-4: Synrift Isopach used for Gross Rock Volume Calculations

For the conventional fan deposit sands in the Algyo, seismic amplitude anomalies are used to identify potential stratigraphically trapped sand-bodies. The prospects are identified by variations in calculated seismic attributes that have not yet been definitively calibrated to the well control. This lack of calibration is compounded by the fact that the seismic signal and seismic attributes are also impacted by constructive and destructive interference of the overlying and underlying turbidites and channels.

The time-to-depth conversion was reviewed and is considered correct. Depth conversion is not considered a key consideration for either play-type.

4.5.3 Well Test Information

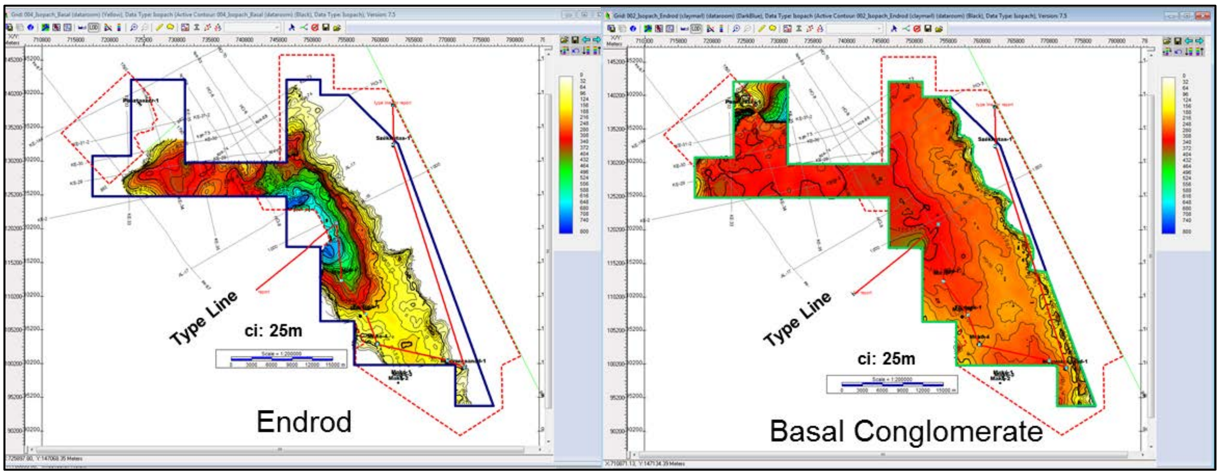
As described in Section 4.3.3, a number of well tests have been conducted within the BCGA play. All of the wells confirmed the presence of BCGA in the Makó Trough but the tests have yet to prove sustainable commercial flow rates of gas or oil, although Falcon does periodically produce oil and gas from certain wells.

4.5.4 BCGA Play

The exploration program in the Makó Trough is in the early-intermediate stages of evaluating the BCGA. BCGA plays are termed “unconventional” due to the low permeabilities that characterize such plays and the fact that thick, continuous, gas-charged sections are encountered across the play without the requirement for a conventional stratigraphic or structural trap. Due to the low permeability, commercially successful wells require the presence of a thick gas bearing section and successful implementation of hydraulic fracture treatments. Experience has shown that considerable experimentation is usually required to find the optimal completion technology. Given that even with successful completion technology, the productivity of low permeability gas wells is less than that of their conventional counterparts, the risks are primarily engineering and economic factors, rather than geological.

The deep drilling results to date have shown the presence of a thick sequence of hydrocarbon-bearing sediments. The presence of hydrocarbon is not in question, as drilling and testing results to date have confirmed its existence. The unknowns at present concern whether technology can be applied that will allow these hydrocarbon accumulations can be produced at commercial rates.

The gross rock volumes used in the four BGCA resource calculations were derived from the interval isopach maps. Figures 4.5-3 and 4.5-4 represent two of the four units in the BGCA resource assessment. The remaining two are the Endrod and Basal Conglomerate. As above, the gross rock volumes were calculated from the isopachs (Figure 4.5-5).



Source: Falcon

Figure 4.5-5: Endrod and Basal Conglomerate Isopachs used for Gross Rock Volume Calculations

4.5.5 Algyo Play

The shallow Algyo southeast prograding lacustrine slope deposits are expected to vary between sandy slope aprons connected to shelf-margin deltas to turbidite systems fed by major channels. The clinoforms prograded basinward from northwest to southeast over the Szolnok Formation. These stratigraphic intervals are distinctive on 3D seismic data as prograding clinoforms. The seismic characteristics of the amplitudes are variable. Eight (8) prospects have been considered in the newly defined Algyo play. Most prospects lie along the toes of the clinoforms or are in a slope detached position in the fan sequences. This new play is unproven and has risk in all play elements. The prospects are identified by variations in calculated seismic attributes that have not yet been definitively calibrated to the well control. This lack of calibration is compounded by the fact that the seismic signal and seismic attributes are also impacted by constructive and destructive interference of the overlying and underlying turbidites and channels.

Figure 4.5-6 shows the production license outline, key wells, and the Algyo prospect areas. One of the prospects, Urmos, has been penetrated by the Makó-4 well (See Section 4.3.3.6). This well encountered low gas saturated sands within the prospect outline at 3320-3367 m. There was no density/neutron gas cross-over, but an increase in background Total Gas readings up to 42 units recorded while drilling thus indicated low gas saturations. Another interval, 2368 m to 3179 m MD, had Total Gas readings for an up to 80 units, 38 units higher than the 3320-3367 m interval. The 3320 interval has no density/neutron cross-over and an MDT test yielded water. This indicates the Urmos prospect is likely water with low gas saturation. Thus, Makó-4 is illustrative of one of the risks with a new play, the inability to distinguish gas pay from low gas saturation. Sands in other wells penetrating the Algyo had inconsistent calibration of seismic attributes with gas pay.

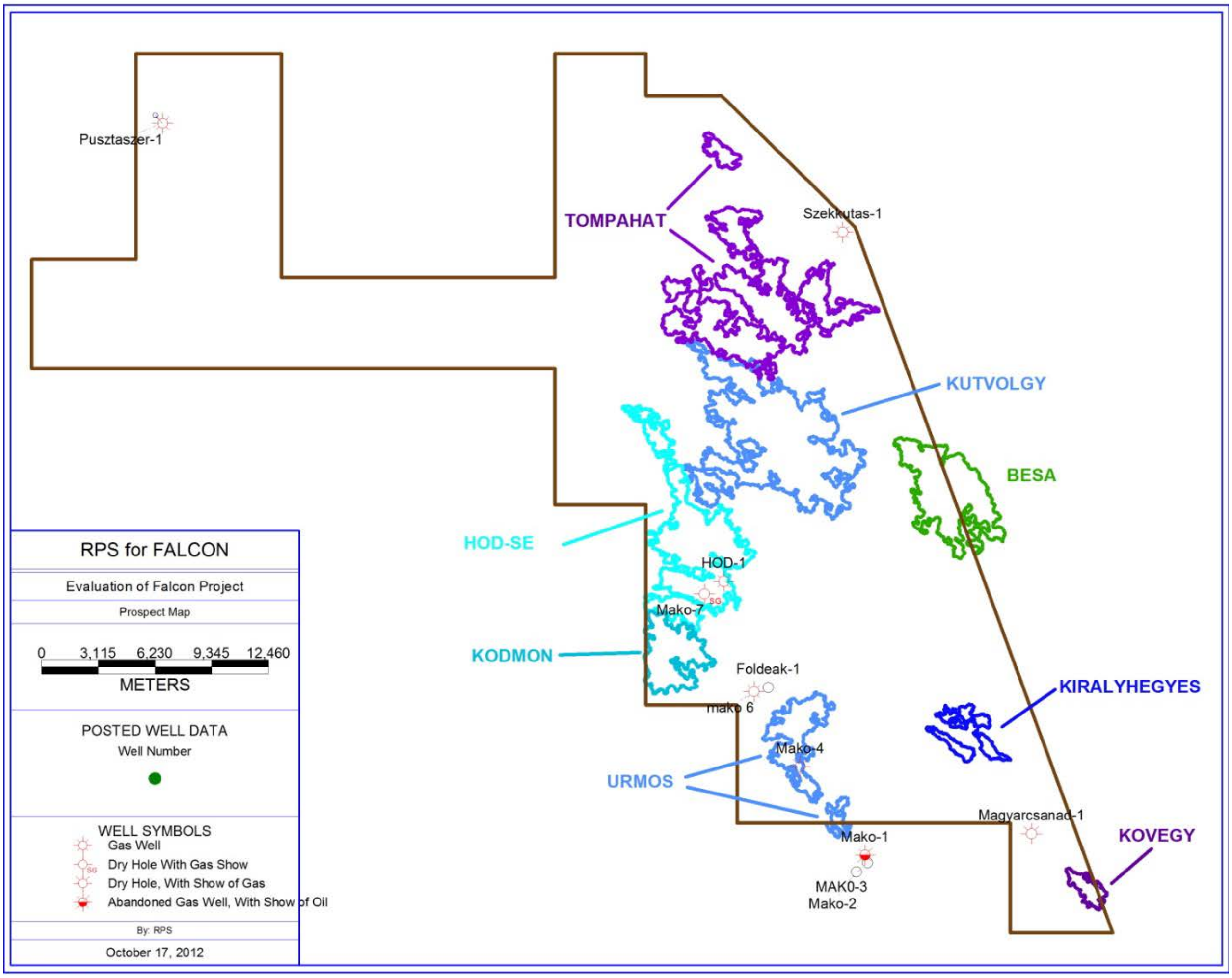


Figure 4.5-6: Algyo prospect location map

The traps are not structural, but are defined by the stratigraphic limits of the seismic attributes. Most of the Algyo anomalies are along the bases of the clinoforms. Figure 4.5-7 is a type seismic line across the Algyo Besa Prospect. The prograding clinoforms begin in the north and spread southward. Besa lies along the eastern edge of the concession and is located at the base of a clinoform. Figure 4.5-8 is an expanded view of Besa Prospect. The top of the Besa anomaly is the red horizon and the base is the blue horizon. The actual Besa prospect is the white zero crossing between the two horizons. Figure 4.5-9 is the same line from an inversion cube. The Besa anomaly is between the top and base seismic markers and is in bright red on the display. Figure 4.5-10 is the amplitude map from the inversion cube. The P10 is derived from the maximum extent of the blending of the seismic attributes and the P90 is from the areas with the strongest attribute strength.

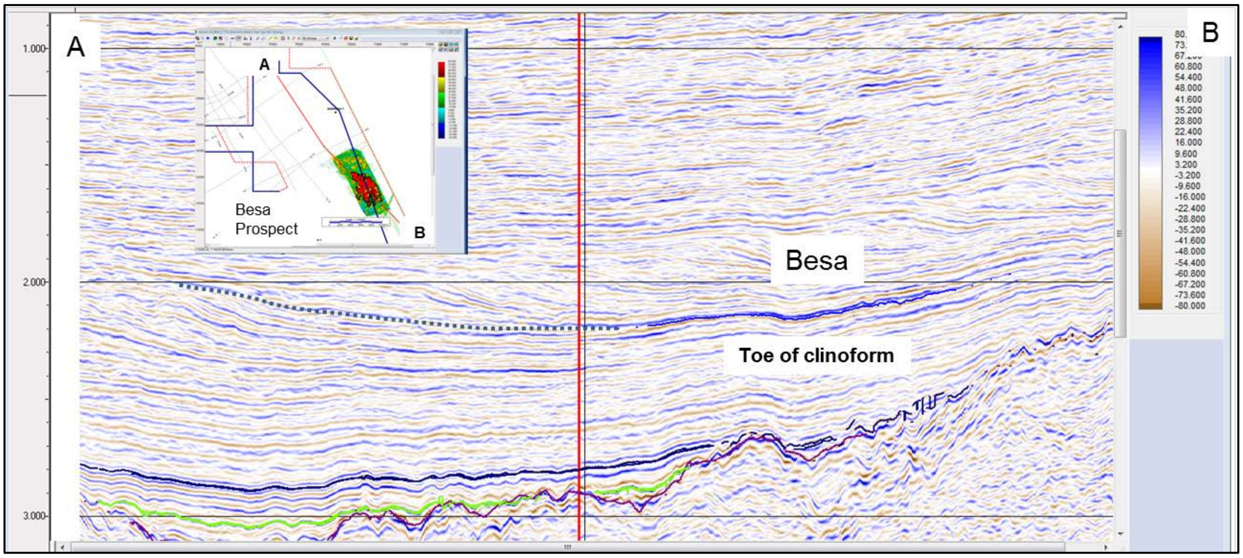


Figure 4.5-7: Besa Prospect Type Line

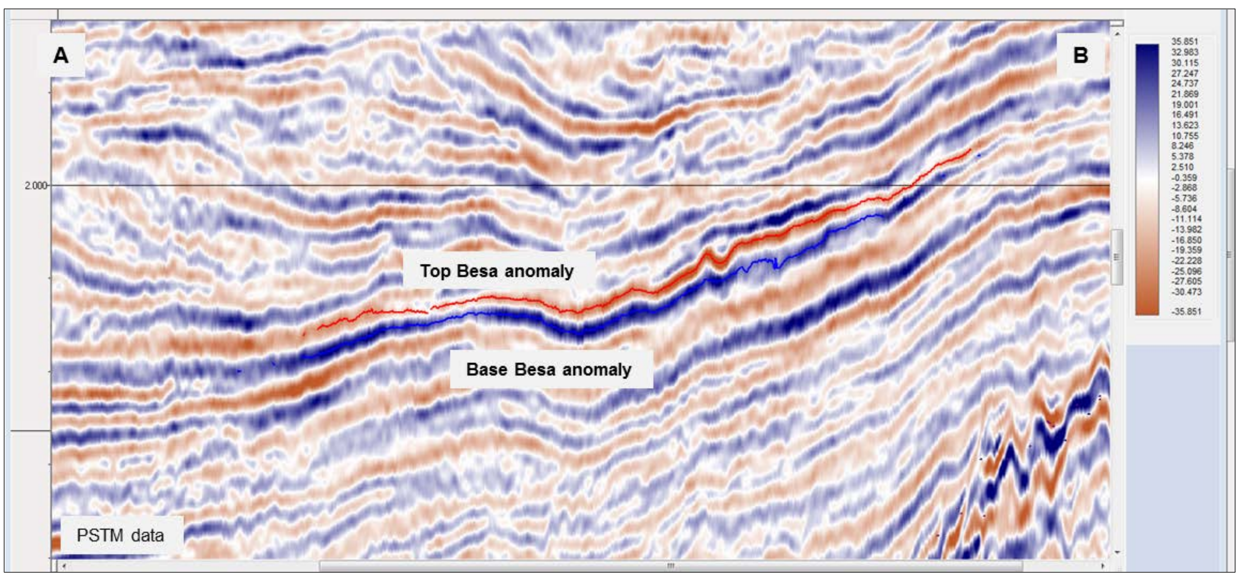


Figure 4.5-8: Besa Prospect: Detailed View on PSTM Seismic Data

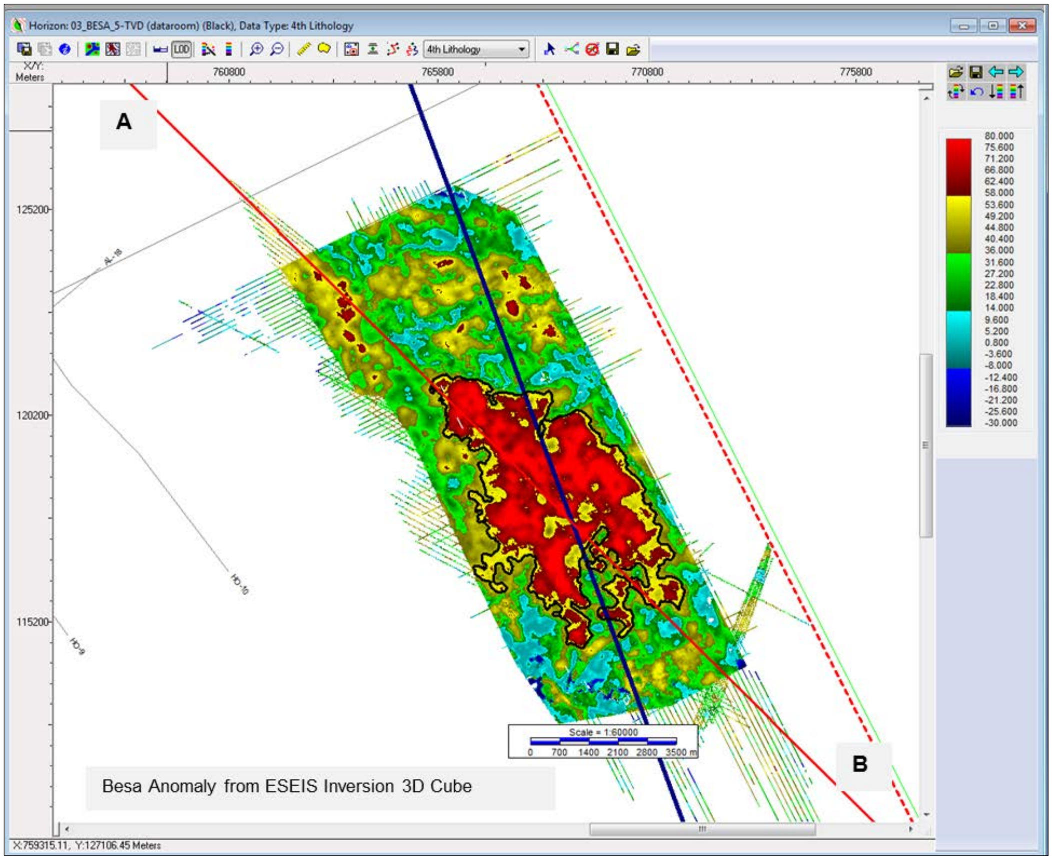


Figure 4.5-9: Besa Prospect ESEIS Inversion Map

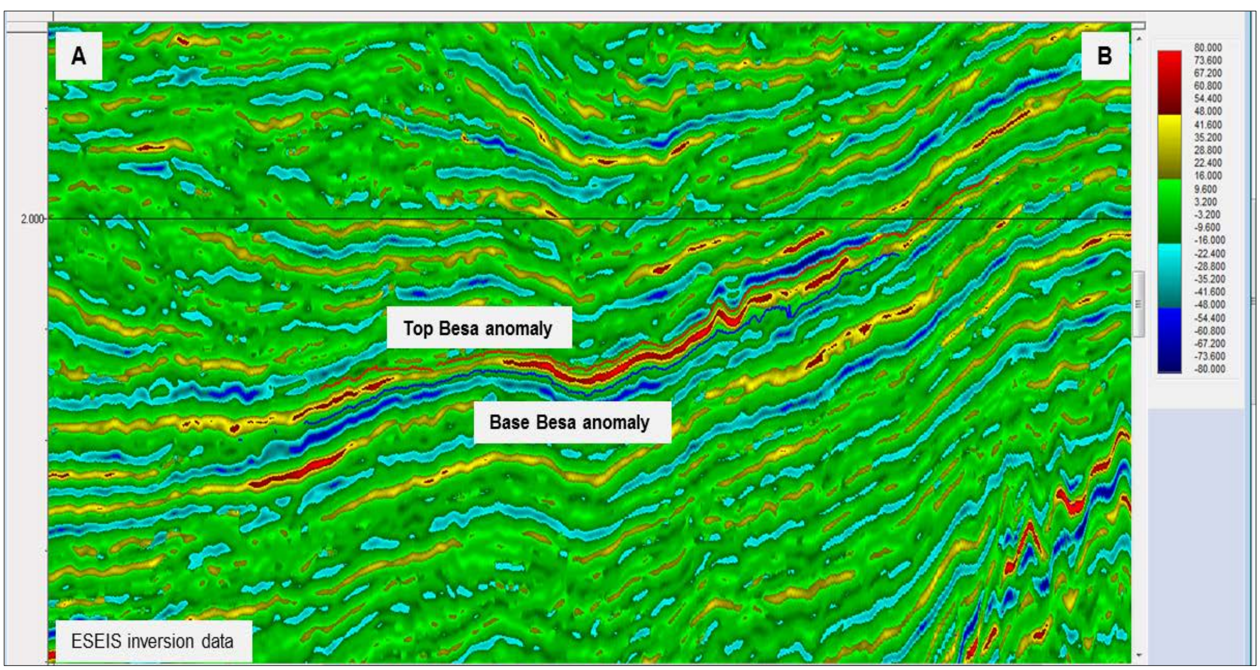


Figure 4.5-10: Besa Prospect Detailed View on ESEIS Inversion 3D Cube

The Algyo reservoir is composed of sands and shales. There is a good possibility of encountering sand and the reservoir presence risk is relatively low. The reservoir quality is fair as the risk of encountering good quality reservoir is low. The overall reservoir risk is low. Top seal is provided by the interbedded shales and seal risk is generally low.

The underlying Szolnok, Endrod, and Synrift formation are mature source rocks containing gas. The risk assigned to the presence of source is low. However, migration risk can be considerable and is somewhat dependent on vertical migration through the section or the presence of fractures connecting the Algyo clinoforms to the deeper source rocks.

4.5.6 Probabilistic Resource Estimates

The probabilistic Resource estimates were computed using the REP™ (Logicom E&P Ltd) software. This software allows for input of a variety of probability distributions for each uncertain parameter. The program then performs a large number of iterations randomly sampling each variable and honoring the dependencies that were input. The number of iterations was set at 100,000, which achieved the desired level of stability of the resulting answers. The results include a probability distribution for the output, sampled probability for the inputs, and sensitivity analysis showing which input parameters have the most effect on the uncertainty in each output parameter.

4.5.6.1 Input Parameters

The parameters required for this analysis consist of the inputs to the volumetric equation, and are described as follows, including a brief statement as to the source of information for each parameter in the BCGA discovered zones and Algyo leads and prospects.

Gross Rock Volume – For the BCGA reservoirs, the dependency between area and thickness in calculating gross rock volume from distributions is eliminated by starting with a gross rock volume estimate itself rather than area and thickness. Interpretation of new 3D seismic took place during 2009-2012, isopachs have been created by subtraction. For the present report, isopachs maps were provided by Falcon in a SMT™ project and gross rock volumes thus calculated, limiting the calculation to those volumes that are inside the License areas. (See Section 4.5.2)

The Algyo traps are not structural, but are defined by the stratigraphic limits based on mapping of seismic attributes (see Section 4.5.5). The P10 area is derived from the maximum extent of the blending of the seismic attributes and the P90 is from the areas with the strongest attribute strength. Thickness was determined by a petrophysical analsysis of the Algyo formation in the wells. The sand thickness in the key wells varied from 10 m to 20 m. Therefore, 10 m was used as the P90 and 20 m was used as the P10.

Porosity –For the BCGA reservoirs, these porosities were determined in a previous 2008 study by Falcon's petrophysicist D. Hoyer using Statmin, the statistical mineral analysis add-on module to Fugro-Jason's PowerLog™ that uses a probabilistic model to calculate the reservoir volumetric composition based on actual log responses and anticipated component log measurement endpoints. One such endpoint was the measured grain density from the core data. Adverse environmental effects required log measurement corrections and normalizations. The previously determined minimum porosity cut-off value of 6% was used to differentiate between reservoir and non-reservoir intervals. Using this value and a maximum clay volume cut-off of 40%, a net reservoir thickness for each well was determined. New core data measured in whole cores recovered from Upper and Lower Szolnok in well Foldeak-1 were used to adjust the porosity range in the probabilistic analysis of the recoverable resource estimated in the Szolnok interval. For the Algyo prospects, porosity was estimated by Falcon and considered reasonable by RPS.

Fluid Saturations – Estimations of the percentage of the rock pore volume that contain fluids, either water or hydrocarbons. This estimate, when calculated from logs, is highly dependent on knowledge of the resistivity or composition of the formation waters. For the BCGA reservoirs, the water saturations were determined in the previous 2008 study by Falcon's petrophysicist D. Hoyer using the Archie Water Saturation model within Fugro-Jason's PowerLog™ well log interpretation software.

The formation water resistivity value of 0.30 ohm-m at 75^{o} F was verified through SP deflection analysis and was temperature-corrected to the value corresponding to the interval temperature based on a temperature gradient established for the Makó Trough. The other selected values of the saturation parameters of tortuosity (a), cementation (m), and saturation (n), were 1.0, 1.8, and 2.0. In the Monte Carlo simulation model, gas saturation was modeled as a direct function of porosity. For the Algyo prospects, the water saturation was estimated by Falcon and considered reasonable by RPS.

Net-to-Gross Ratio – The fraction of the gross rock volume that is estimated to contain gas pay. For the BCGA reservoir, the net reservoir thickness was calculated using the 6% minimum porosity and 40% maximum clay volume was divided by the gross thickness for each interval under consideration to yield the net-to-gross ratio for each layer. For the Algyo prospects, the Net-to-Gross Ratio was estimated by Falcon and considered reasonable by RPS

Percent Productive – An estimate of what fraction of the total play will be productive. As noted above, even though gas saturation is ubiquitous, commercial productivity is not. Percent productive is a key unknown, and was estimated by performing an analysis of five BCGA plays in the Rocky Mountain area of the US and using these plays as analogies. For the Algyo prospects this parameter does not apply.

Formation Volume Factor – The factor that represents the amount of expansion of gas from reservoir to surface conditions. Estimation of formation volume factor is dependent on knowledge of temperature, pressure and gas compositional variations. For the BCGA reservoirs, data from the existing well penetrations was used in calculating these factors, and is consistent with the original estimate performed by RPS in 2006 and 2008. For the Algyo prospects, the Formation Volume Factor was estimated by Falcon and considered reasonable by RPS.

Recovery Factor – The fraction of the calculated in-place resources that is considered typically recoverable. Note that the amounts estimated represent potentially recoverable Resources, not Reserves. Since there is insufficient information at this point in time on the potential productivity of each zone, no meaningful economic analysis is possible. However, knowledge of the performance of U.S. BCGA wells does provide information on the typical recovery and drainage areas. Since drainage areas are typically small, a large number of wells are required to achieve the optimal recovery factor. Although insufficient data exists to accurately well performance, it is reasonable to assume that the recovery factor will be critically dependant on the number of wells it is commercially viable to drill i.e. very high recovery factors are theoretically possible drilling to a very high density. However, in reality, the actual density achieved will be the result of the balance between the cost of the wells and the relative deliverability. At present proven deliverability is low and improved performance (via large frac programs or other stimulation techniques) will be required to improve recovery.

Table 4.5.6-1 summarizes the BCGA unconventional parameters used in the probabilistic analysis and Table 4.5.6-2 summarizes the Algyo parameters used in the probabilistic analysis

Table 4.5.6-1 – Summary of the BCGA unconventional parameters used in the probabilistic analysis.

Szolnok	Units	Minimum	Most Likely	Maximum
Bulk Rock Volume	MM ac.ft	670.9	745.4	819.9
Net:Gross Ratio	ratio	0.052	0.302	0.430
Fraction Productive	dec.fr	0.050	0.400	0.700
Porosity	dec.fr	0.040	0.100	0.138
Gas Saturation	dec.fr	0.400	0.545	0.700
Fmn Vol Factor	vol/vol	273.224	298.503	316.456
Overall Recovery factor	dec.fr	0.650	0.700	0.750
Upper Endröd	Units	Minimum	Most Likely	Maximum
Bulk Rock Volume	MM ac.ft	179.0	198.8	218.7
Net:Gross Ratio	ratio	0.044	0.250	0.649
Fraction Productive	dec.fr	0.050	0.150	0.300
Porosity	dec.fr	0.060	0.070	0.097
Oil Saturation	dec.fr	0.400	0.585	0.650
Oil Shrinkage	MMstb	0.428	0.457	0.485
Overall Recovery factor	dec.fr	0.040	0.060	0.080
Lower Endröd	Units	Minimum	Most Likely	Maximum
Bulk Rock Volume	MM ac.ft	184.5	205.0	225.5
Net:Gross Ratio	ratio	0.066	0.130	0.178
Fraction Productive	dec.fr	0.050	0.150	0.300
Porosity	dec.fr	0.060	0.070	0.108
Gas Saturation	dec.fr	0.400	0.499	0.550
Fmn Vol Factor	vol/vol	327.869	332.226	336.700
Overall Recovery factor	dec.fr	0.450	0.500	0.550
Basal Conglomerate	Units	Minimum	Most Likely	Maximum
Bulk Rock Volume	MM ac.ft	132.0	146.6	161.3
Net:Gross Ratio	ratio	0.070	0.400	0.521
Fraction Productive	dec.fr	0.050	0.150	0.300
Porosity	dec.fr	0.060	0.075	0.089
Gas Saturation	dec.fr	0.400	0.545	0.850
Fmn Vol Factor	vol/vol	273.224	300.000	316.456
Overall Recovery factor	dec.fr	0.650	0.700	0.750
Synrift Sequence	Units	Minimum	Most Likely	Maximum
Bulk Rock Volume	MM ac.ft	37.0	41.1	45.3
Net:Gross Ratio	ratio	0.060	0.065	0.069
Fraction Productive	dec.fr	0.050	0.150	0.300
Porosity	dec.fr	0.060	0.075	0.095
Gas Saturation	dec.fr	0.400	0.523	0.750
Fmn Vol Factor	vol/vol	341.297	343.643	347.222
Overall Recovery factor	dec.fr	0.350	0.400	0.450

Table 4.5.6-2 – Summary of the Algyo parameters used in the probabilistic analysis

BESA	Units	Distribution	P90	P10
Area	km^2	Normal	5.855	18.44
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	215	235
Overall Recovery Factor	dec.fr	Single	0.6	0.8
HOD SE	**Units**	**Distribution**	**P90**	**P10**
Area	km^2	Normal	3.877	27.13
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	265	285
Overall Recovery Factor	dec.fr	Single	0.6	0.8
KIRALYHEGYES	**Units**	**Distribution**	**P90**	**P10**
Area	km^2	Normal	0.513	4.026
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	210	230
Overall Recovery Factor	dec.fr	Single	0.6	0.8
KODMONOSDULO	**Units**	**Distribution**	**P90**	**P10**
Area	km^2	Normal	1.094	9.88
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	265	285
Overall Recovery Factor	dec.fr	Single	0.6	0.8

KOVEGY	Units	Distribution	P90	P10
Area	km^2	Normal	0.247	2.199
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	215	235
Overall Recovery Factor	dec.fr	Single	0.6	0.8
KUTVOLGY	**Units**	**Distribution**	**P90**	**P10**
Area	km^2	Normal	6.832	41.18
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	265	285
Overall Recovery Factor	dec.fr	Single	0.6	0.8
TOMPAHAT	**Units**	**Distribution**	**P90**	**P10**
Area	km^2	Normal	3.39	36.63
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	210	230
Overall Recovery Factor	dec.fr	Single	0.6	0.8
URMOS	**Units**	**Distribution**	**P90**	**P10**
Area	km^2	Normal	1.1	3.5
Thickness	m	Normal	10	20
Shape Factor	%	Single	100	100
Degree of Fill	%	Single	100	100
Net:Gross Ratio	dec.fr	Single	1	1
Porosity	dec.fr	Normal	0.1075	0.1728
Water Saturation	dec.fr	Normal	0.4	0.6
Fmn Vol Factor	vol/vol	Normal	265	285
Overall Recovery Factor	dec.fr	Single	0.6	0.8

4.5.6.2 Risk and Uncertainty

As previously discussed, the BCGA in the deeper formations is discovered and therefore has a GPoS (see Section 3.2.2) of 100%. The elements impacting the remining commercial risks are discussed below and the calculated range of uncertainty, based on the geological uncertainties is discussed in Section 4.5.6.1 above.

For the Algyo leads and prospects, however, most are yet to be drilled and have an associated GPoS. The exploration of the Algyo stratigraphic leads and prospects is at an early stage and the calibration of seismic amplitude/attributes to the presence of high concentrations of hydrocarbons has yet to be proved. As an example the Makó-4 well, whilst reportedly drilled to target the underlying Szolnok, did drill through the edge of the Urmos lead as defined by the seismic amplitude/attribute mapping. The well did find low but variable saturations of gas at different depths which were not picked by density/neutron cross-over. The well is suspended awaiting testing (see Section 4.3.3.6).

There are many examples around the world where low concentrations of gas in water can lead to an apparent seismic "anomaly" and given the Makó-4 well results to date, this must be regarded as a risk to the seismically mapped stratigrapic traps currently proposed in the Algyo Formation. However, as discussed in Section 4.5.5, seismic response to fluid and thickness changes in reservoirs is a complex matter and insufficient calibration has been done to prove or disprove the potential at this point. In Section 4.5.5, RPS notes that reservoir presence and quality in the Algyo is considered relatively low risk and the Formation overlies known source rocks. Oil and gas has clearly migrated to surrounding fields, however, this migration path may rely on the basin edges rather than vertically into the prognosed fan deposits of the Algyo. The sands appear to be encased in shales (consistent with the seismic response noted regardless of fluid fill) making trap risk small. Therefore, many of the conventional risk elements that effect GPoS appear to be positive. Nonetheless, given the uncertainty on gas concentration, RPS has assigned a GPoS based on the maturity of this relatively recently recognised play and RPS assigns a risk between 1 in 12 (8.33%) to 1 in 8 to (12.5%) to the current likelihood of discovering a hydrocarbon accumulation in the Blue Creek concession. Otis and Schneidermann's 'Rule of Thumb' for Geological Risk Assessment[4] describes this range of risk as an appropriate level of risk for a new play in an emerging area. Accordingly, an average GPoS of 10% is assigned to the Algyo leads and prospects.

4.5.6.3 Summary of Resources

RPS has assigned **Contingent Resources – Development Unclarified** to the BCGA discoveries in the Szolnok, Endrod, Basal Conglomerate and Synrift Formations; and, Prospective Resources to a number of identified leads and prospects located the overlying Algyo Formation.

The total estimated range of Contingent Resources is given in Table 4.5.6-3 below. Table 4.5.6-4 gives an estimated range of Prospective Resources. In each case they are arithmetic aggregation of the Resources calculated by zone. **Actual recovery is likely to be less and may be substantially less or zero.**

Table 4.5.6-3 – Contingent Resources Summary

	Gross			Net Entitlement		
	1C	**2C**	**3C**	**1C**	**2C**	**3C**
Szolnok (Gas – Tcf)	12.13	30.96	63.60	10.07	25.70	52.79
Lower Endrod (Gas – Tcf)	0.61	1.11	1.87	0.51	0.92	1.55
Basal Conglomerate (Gas – Tcf)	1.41	3.00	5.53	1.17	2.49	4.59
Synrift Sequence (Gas – Tcf)	0.08	0.19	0.42	0.07	0.16	0.35
Arithmetic Aggregation[1]	**14.24**	**35.27**	**71.41**	**11.82**	**29.27**	**59.27**
Probabilistic Aggregation	**16.85**	**35.78**	**68.46**	**13.99**	**29.70**	**56.82**
Upper Endrod (Oil – MMstb)	32.89	76.71	158.26	27.30	63.67	131.36

1: It is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Probabilistic Aggregation in the next row.

[4] Otis, R.M. & Schneidermann, N. 1997. "A Process for Evaluating Exploration Prospects", AAPG Bulletin 81 (7) pp.1087-1109.

The volumes quoted above are classified as Contingent Resources – Development Unclarified. Oil and Gas have been discovered and may be present in large quantities but commercial flow-rates have yet to be achieved (although Falcon does periodically produce oil and gas from certain wells). In addition to the currently low flow-rates, several of the well-tests to date have demonstrated quantities of H_2S sufficient to cause shut-ins for safety reasons. This is not an insurmountable problem by any means but will add to capex and Opex considerations since the H_2S will need to be collected and treated in special separation towers and the resulting sulphur disposed of (though this can be a useful by-product in certain parts of the world).

As a result of the current commercial uncertainties, RPS currently estimates that there is a less than or equal to 25% chance that the Contingent Resources quoted above will be converted to Reserves based on the data available at this time.

Table 4.5.6-4 – Prospective Resources Summary

	Gross			Net Entitlement			GPoS
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	
Besa (Gas – Bcf)	26.8	65.0	125.0	22.2	54.0	103.8	10%
Hod, SE (Gas – Bcf)	32.3	103.0	219.0	26.8	85.5	181.8	10%
Kiralyhegyes (Gas – Bcf)	3.7	12.1	26.0	3.1	10.0	21.6	10%
Kodmonosdulo (Gas – Bcf)	11.0	36.3	78.6	9.1	30.1	65.2	10%
Kovegy (Gas – Bcf)	2.0	6.7	14.5	1.7	5.6	12.0	10%
Kutvolgy (Gas – Bcf)	47.1	144.0	304.0	39.1	119.5	252.3	10%
Tompahat (Gas – Bcf)	39.8	135.0	296.0	33.0	112.1	245.7	10%
Urmos (Gas – Bcf)	6.2	15.0	29.0	5.1	12.5	24.1	10%
Arithmetic Aggregation[1]	**168.9**	**517.1**	**1092.1**	**140.2**	**429.2**	**906.4**	**<<1%**
Stochastic Aggregation[2]	**378.0**	**568.0**	**820.0**	**313.7**	**471.4**	**680.6**	**<<1%**
Stochastic Aggregation[3]	**8.0**	**64.0**	**251.0**	**6.6**	**53.1**	**208.3**	**57%**

1: It is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Probabilistic Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

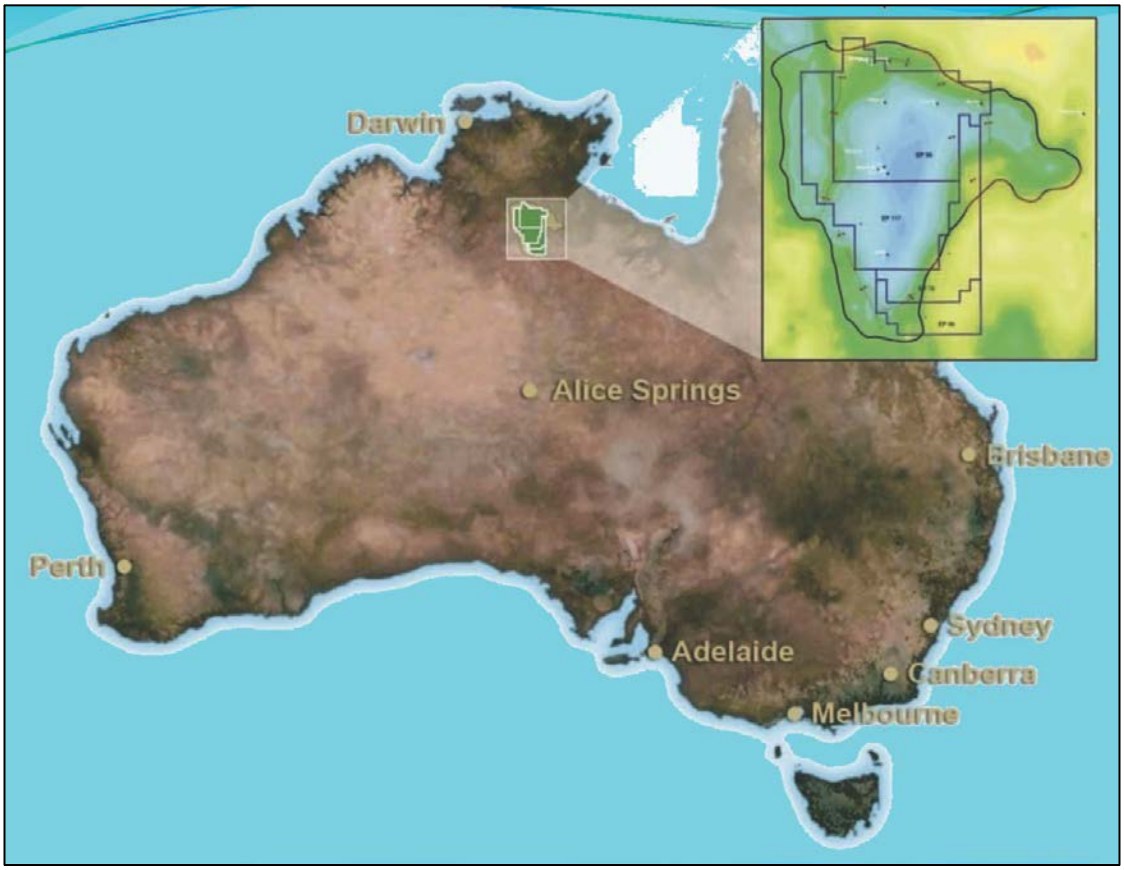
2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (56.2 Bcf Net) constitutes the true expectation of success.

5 BEETALOO EXPLORATION PERMITS (Northern Territory, Australia)

5.1 GEOLOGICAL OVERVIEW

The EP-76, -98, -99 and -117 Beetaloo Exploration Permits (also known as Beetaloo Blocks) are located in the Beataloo Basin of the greater McArthur Basin in the Northern Territory, Australia (see Figure 5-1).



Source: Silverman

Figure 5-1: Regional Location Map

The Beetaloo Basin is a Proterozoic and Cambrian age tight oil and gas basin described by Silverman as a “crustal downwarp” and a separate depocenter within the greater McArthur Basin. The Beetaloo Basin represents one of the few remaining sparsely explored - 11 exploration wells in approximately 28,000 km^2 (7 million acres) - onshore exploration basins of the world located in a “western country” with political, legal and regulatory system stability. Figure 5-2 shows the Beetaloo Exploration Permits in relation to the Northern territory pipeline infrastructure.

Figure 5-3 shows a typical depth structure map and stratigraphic column. The historical wells are shown on the map and likely source and reservoir rocks within the stratigraphic column. Oil is thought to be likely within the Upper to Lower Kyalla Formation with gas likely to be the dominant phase in the lowest most Kyalla and the underlying Velkerri Shale and Moroak and Bessie Creek low porosity/permeability sandstones (“Tight Gas Sandstones”).

Beetaloo Basin (as defined by gravity, 2D seismic and previous wells) has undergone mild tectonism and is bounded on the north by the Walton High, on the northeast by the Arnold Arch, to the west by the Daly-Waters Arch and to the south by the Helen Springs High. Sediments are up to 3000 m thick in the basin center. Conventional tight sandstone reservoirs, pervasive tight sandstone gas in the basin center as well as unconventional shale source oil and gas have been identified in the basin from approximately 600 to 2500 m depth. Erosional thinning has occurred on the Walton High and Arnold Arch structural highs resulting in unconformities. No metamorphism has been reported for these sediments.

The stratigraphic section shown in Figure 5-3 demonstrates fluvial, deltaic and shallow marine deposition and at times a “starved basin” condition was present and is represented by organic rich source rock deposition of the Kyalla and Middle Velkerri formation shales. Organic matter in these formations consist primarily of bacteria, cyanobacteria and algae. Source rock of Proterozoic age are not common but have generated significant economic volumes of oil and gas in Eastern Siberia and Oman.

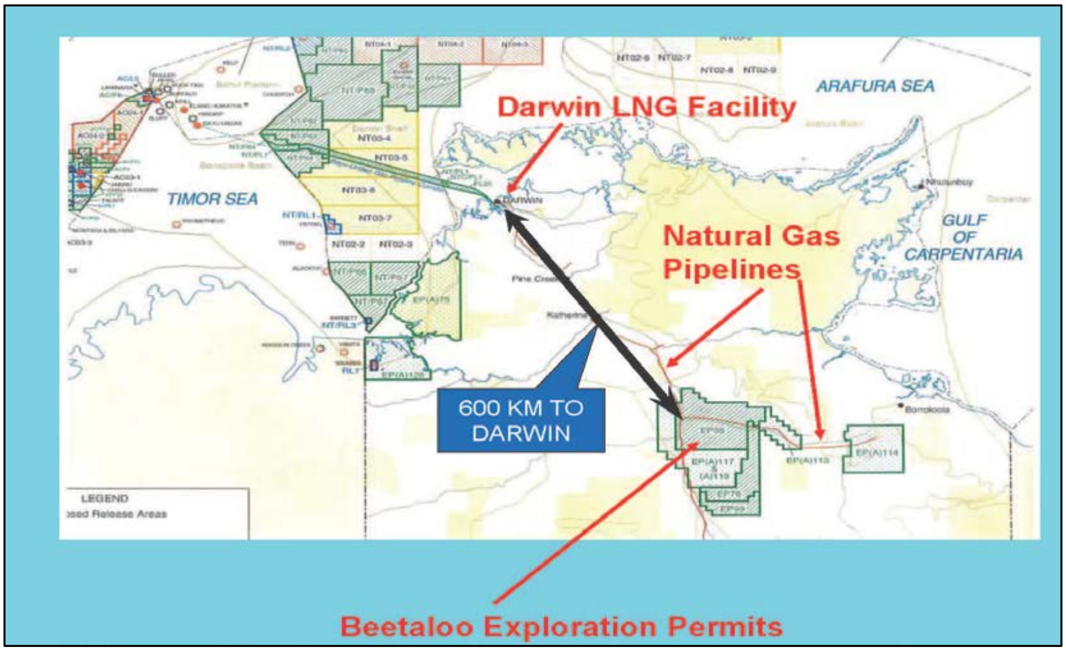
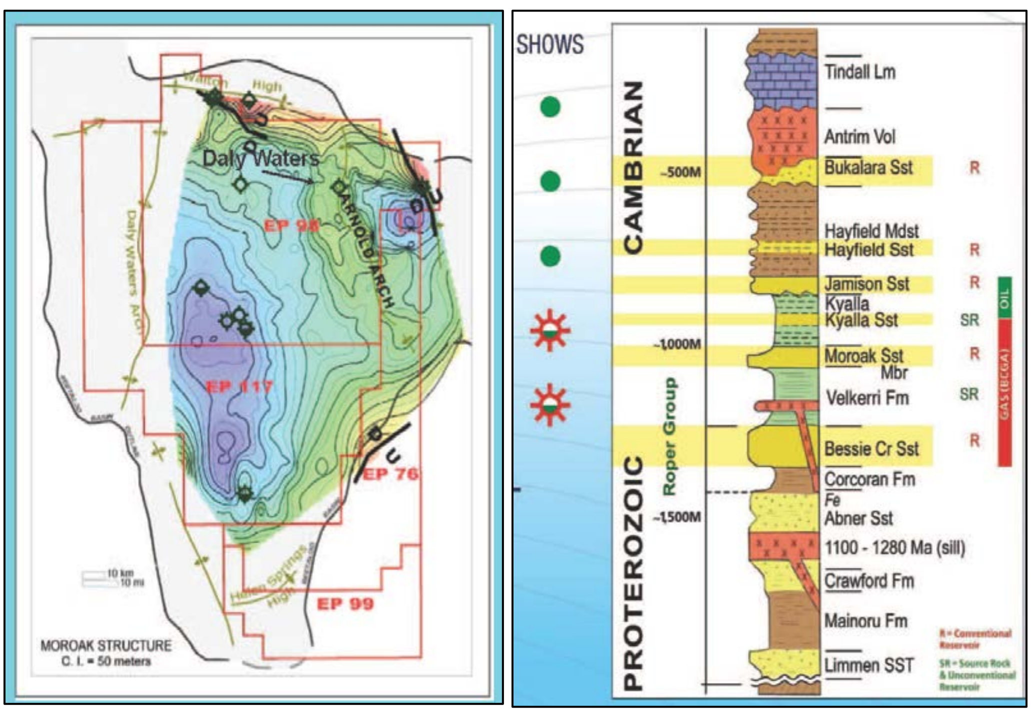


Figure 5-2: Beetaloo Basin Regional Facilities and Exploration Permits showing existing field areas



Source: Silverman

Figure 5-3: Beetaloo Moroak Sandstone Depth Structure and Stratigraphic Column

5.2 LICENCE STATUS AND WORK COMMITMENTS

The EP-76, EP-98, EP-99 and EP-117 Exploration Permits in the Beetaloo Basin (comprising 28,193 square kilometres or 6,966,860 acres) covering the majority of the Beetaloo Basin and basin margin highs (see Figure 5-3).

The subject acreage interests are held 100 per cent. in the name of Falcon Oil and Gas Australia Pty. Ltd., ("Falcon Australia"), which is an Australian incorporated oil and gas exploration company. Falcon has a 73 per cent. interest in Falcon Australia. Sweetpea Petroleum Pty. Ltd, which is a wholly owned Australian subsidiary of PetroHunter Energy Corp, owns 24 per cent and others the remaining 3 per cent interest in Falcon Australia. In accordance with local regulations, all Falcon Australia's acreage interests are subject to certain royalties payable to the Government of the Northern Territory, the Australian native stakeholders (Traditional owners), and the other third parties as detailed below. Falcon Australia is the operator of Exploration Permit EP 99 and Hess Australia (Beetaloo) Pty Ltd. is the operator of Exploration Permits EP 76, 98 and 117. Falcon Australia Pty. retained operatorship in the Shenandoah-1 well and aprrroximately 405 km^2 (100,000 acres) land around the Shenandoah-1 wellbore in EP98.

- NT Government – 10% royalty on production revenues.
- Native Stakeholders – 1% royalty on production revenues form first production until Falcon Australia has recovered its costs and 2% thereafter unless the production has gone into decline, in which case, the royalty will return or remain at 1%.
- Other third parties – 13% royalty on production revenues.

The Minister for Mines and Energy, Northern Territory (NT), is responsible for the administration of the Petroleum Act which regulates hydrocarbon exploration. The Department of Mines and Energy administers the legislation and is responsible for overseeing the activities of Permit holders including the meeting of work commitments. The Northern Territory Government issues Exploration Permits under the Petroleum Act for a period of five years. In each year the minimum work commitments to be achieved by the titleholder are specified by the Department of Mines and Energy. These requirements can be reviewed and adjusted in light of changing circumstances. The Government has the power to suspend permits where the titleholder demonstrates a sufficiently strong case and has done so on a number of occasions for the Beetaloo Basin permits. These changes are formalised in a Determination by the Director of Energy, Department of Mines and Energy.

On June 17, 2011 the Director of Energy, Department of Resources ("DoR" - predecessor to Department of Mines and Energy), advised Falcon of approvals to vary the work programs for EP-76, EP-98 and EP-117 to undertake seismic work with Hess as the operator. On August 27, 2012 the Director of Energy advised Falcon of his approval to vary the work program for EP-99 by deferring the completion of the proposed seismic program for 12 months to December 31, 2013. The commitments for the permits held by Falcon have all been met for previous years. All the permits are in good standing and can be renewed.

Table 5.2-1 sumarizes the status of each of the four EPs.

Table 5.2-1 – Summary of Beetaloo Basin Exploration Permit status

Licence Concessions (Country)	Interest (%)	Operator	Status	Area (km^2)	Expiry	Comments
Exploration Permit EP-76, (Northern Territory - Onshore Australia)	73.0%[1]	Hess Australia (Beetaloo) Pty Ltd.	Exploration	4,976.3	31/12/2013[2]	Under evaluation
Exploration Permit EP-98 (Northern Territory - Onshore Australia)	73.0%[1]	Hess Australia (Beetaloo) Pty Ltd.[3]	Exploration	11,412.1	31/12/2013[4]	Under evaluation
Exploration Permit EP-99 (Northern Territory - Onshore Australia)	73.0%[1]	Falcon Oil & Gas Australia Pty.	Exploration	2,587.2	31/12/2013	Under evaluation
Exploration Permit EP-117 (Northern Territory - Onshore Australia)	73.0%[1]	Hess Australia (Beetaloo) Pty Ltd.	Exploration	9218.3	31/12/2013	Under evaluation

[1] Falcon Oil & Gas Limited owns 73% of Falcon Oil & Gas Australia which holds a 100% interest in the licences. The remaining 24% is owned by Sweetpea Petroleum Pty. Ltd, which is a wholly owned Australian subsidiary of PetroHunter Energy Corp., and 3% interest by others

[2] See Falcon's press release 0n 14/09/2012.

[3] Note: Falcon Oil and Gas Australia Pty. retains operatorship in the Shenandoah-1 well and approximately 405 km^2 (100,000 acres) land around the Shenandoah-1 wellbore.

[4] See Falcon's press release 0n 14/09/2012.

5.2.1 Required Minimum Work Program

Tables 5.2-1, 5.2-2, 5.2-3 and 5.2-4 summarize the required minimum work program for each of the 4 licences.

Table 5.2-1 – Summary of Licence Status and Minimum Work Commitments for EP-76

Permit Name	Licence Period	Start	End	Minimum Work Requirements	Status and Cost
EP-76	Phase 4	01-Jan-09	31-Dec-10	- G&G studies - Reservoir assessment	**AUS$ 200,000** Completed
EP-76	Phase 5	01-Jan-11	31-Dec-13	- Collect and analyse 485 km 2D seismic data	**AUS$ 3,500,000** 327 km 2D seismic data collected by Dec-2012. Program not yet completed.

Table 5.2-2 – Summary of Licence Status and Minimum Work Commitments for EP-98

Permit Name	Licence Period	Start	End	Minimum Work Requirements	Status and Cost
EP-98	Phase 4	01-Jan-09	31-Dec-10	- Complete Shenandoah-1 well	Well completion suspended with approval of DoR
EP-98	Phase 5	01-Jan-11	31-Dec-13	- Complete and test Shenandoah-1 well - Collect and analyse 1,945 km 2D seismic data	**AUS$ 11,000,000** Falcon Australia completed the Shenandoah-1 well in Nov-2012 at a total cost of AUS$ 14 million **AUS$ 14,000,000** 1,852 km 2D seismic data collected by Dec-2012. Program not yet completed.

Table 5.2-2 – Summary of Licence Status and Minimum Work Commitments for EP99

Permit Name	Licence Period	Start	End	Minimum Work Requirements	Status and Cost
EP-99	Phase 4	01-Jan-10	31-Dec-11	- G&G studies - Geophysical re-evaluation	**AUS$ 100,000** Completed
EP-99	Phase 5	01-Jan-12	31-Dec-13	- Collect and analyse 150 km 2D seismic data	**AUS$ 1,500,000** Seismic data collection on schedule for first half of 2013

Table 5.2-2 – Summary of Licence Status and Minimum Work Commitments for EP-117

Permit Name	Licence Period	Start	End	Minimum Work Requirements	Status and Cost
EP-117	Phase 4	01-Jan-10	31-Dec-11	- Collect and analyse 280 km 2D seismic data	**AUS$ 2,000,000** Seismic program not completed because of regulatory delays and weather. Extended into Phase 5
EP-117	Phase 5	01-Jan-12	31-Dec-13	- Collect and analyse 890 km 2D seismic data	**AUS$ 6,400,000** 1,311 km 2D seismic data collected by Dec-2012. Program not yet completed.

5.3 GEOLOGICAL SETTING AND PROSPECTIVTY

5.3.1 Tectonic Setting

Central Australia is divided into separate and distinct basins, most of which, including the Beetaloo basin, have a Proterozoic origin. The 8.8 million acre Beetaloo Basin is a rift basin resting on Archean crust that formed during the Pre-Cambrian approximately 1.4 billion years ago. The Beetaloo Basin is considered a sub-basin of the larger McArthur Basin (Figure 5.3-1).

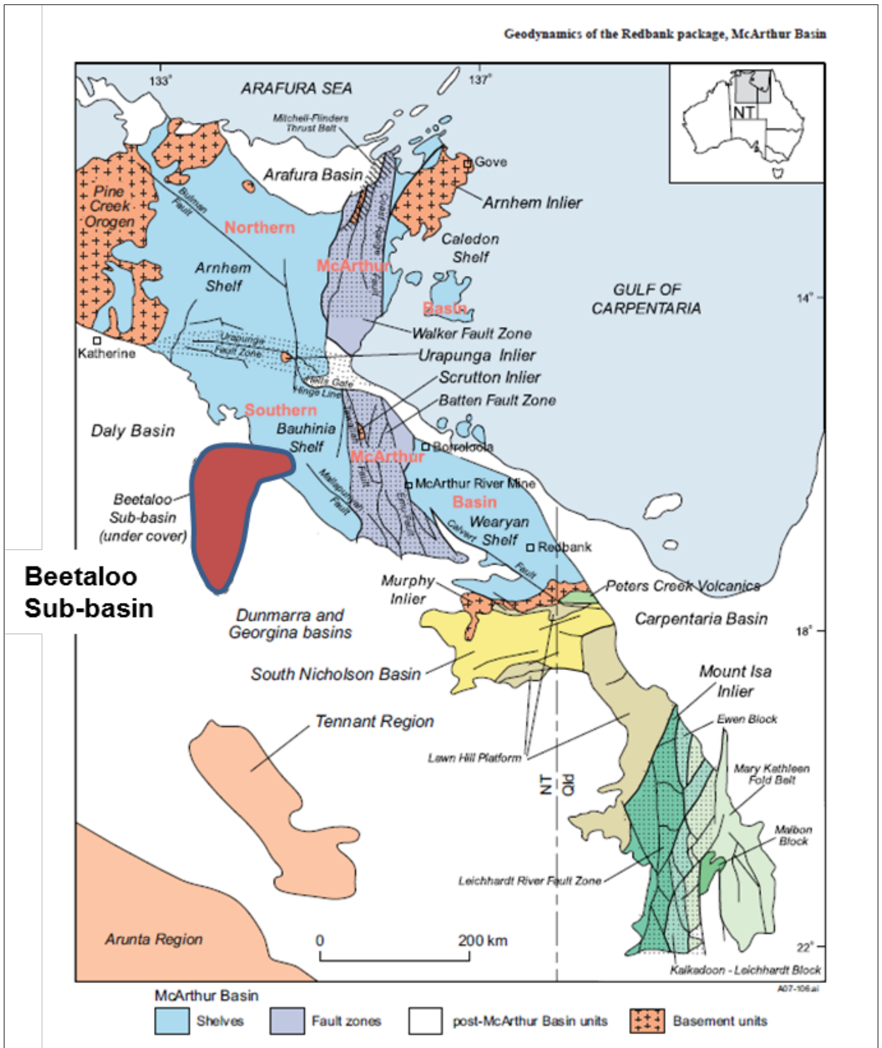


Figure 2. Principal tectonic elements and geological divisions of the McArthur Basin–Mount Isa Inlier region, northern Australia, including basement terranes. Modified after Plumb *et al* (1980, 1990), Pietsch *et al* (1991) and Rawlings *et al* (1997).

Source: Rawlings

Figure 5.3-1: Beetaloo Basin Tectonic Setting

There is some evidence of compression or transpression on the seismic data. The Beetaloo Basin appears to have undergone mild tectonism resulting in a set of northwest-southeast trending faults and two sub-basins separated by an intervening high. Although there is in excess of 3 km (perhaps as much as 10 km) of sediment in the center of the basin visible on the seismic data, the oldest sediments show no significant metamorphism. It is bounded on the north by the Walton High (Figure 5.3-2), and to the south by the Helen Springs High. It is less well defined on the east and west, but the Daly Waters Arch and Arnold Arch can be observed cutting through the basin. One result of this is the erosion of much of the section in the northern wells that are located on the Walton High. The deeper of the two sub-basins lies in the west beneath the Shenandoah-1 well

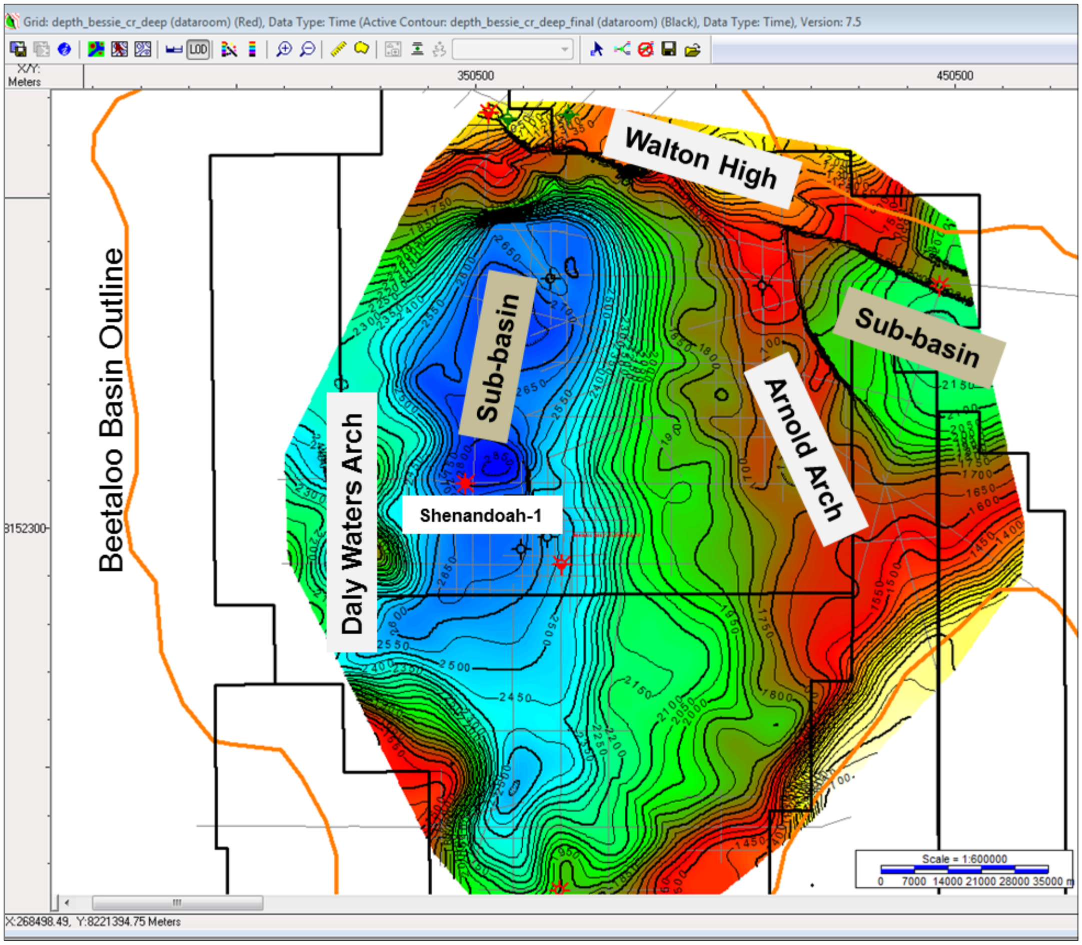


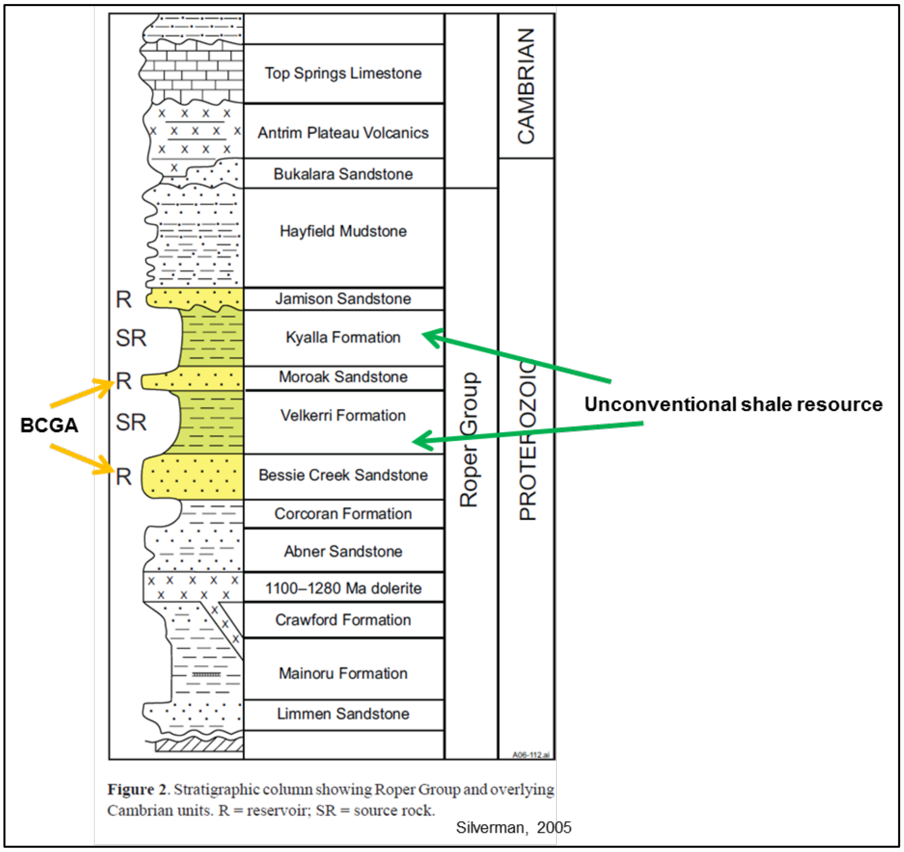
Figure 5.3-2: Beetaloo Principal Tectonic Elements on Bessie Creek Depth Map

5.3.2 Resource Stratigraphy

There is a shallow veneer of Paleozoic and recent sediments overlying a sequence of unmetamorphosed sedimentary rocks. The stratigraphy is in the Beetaloo basin is illustrated on Figures 5.3-3 and 5.3-4. All of the formations reviewed in this report are part of the Proterozoic Roper Group that extends across both the Beetaloo and McArthur basins. The Roper Group is generally a shallow marine sequence composed of shales and sands. It contains both petroleum source rocks and reservoir sands.

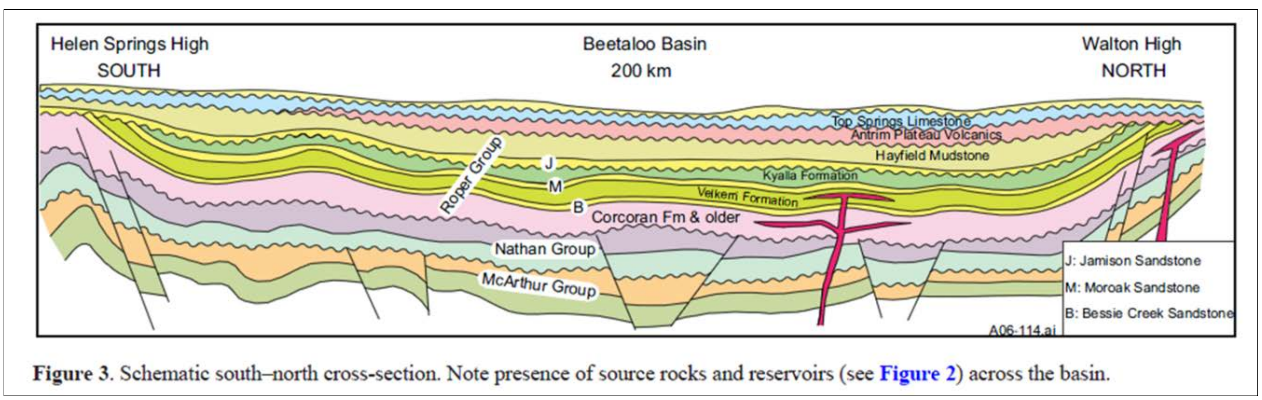
The Moroak Sandstone is situated between the Kyalla and Velkerri source rocks. It is a regional coarsening-upward quartz sandstone with anhydrite and silica cement. The Bessie Creek Sandstone is a fine-to-medium grained sandstone deposited and may have the best reservoir parameter in the Roper Group.

This Mesoproterozoic intercratonic basin is one of the oldest basins in the world known to contain live oil and hydrocarbons. The preservation of the oils is attributed to the mild tectonic activity experienced by the basin over the last 1.4 Ga.



Source: Silverman, 2005

Figure 5.3-3: Stratigraphic Column



Source: Silverman, 2005

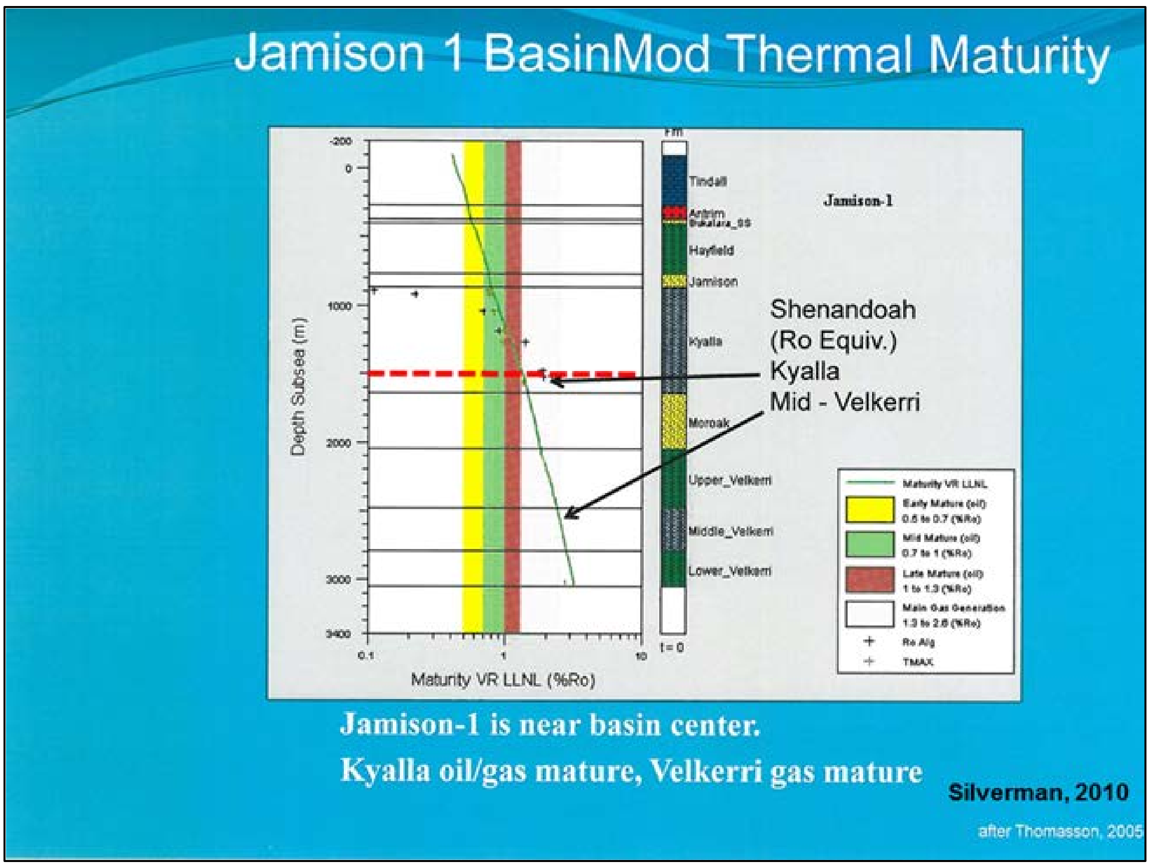
Figure 5.3-4: Schematic North-South Cross Section

The Kyalla and Velkerri formations are the two source rocks evaluated in this report and the Moroak and Bessie Creek Formations are considered to have BCGA (basin centered gas accumulation) potential.

Both source rock units are composed of primarily Type II kerogen. The Kyalla formation is a deep water unit with the highest organic content just above the underlying Moroak sandstone. The organic-rich Velkerri is the best source rock in the Beetaloo Basin and has the highest generation potential in the middle of the formation (Middle Velkerri). It was deposited in anoxic conditions, probably on the deep shelf. Both exhibit oil and gas shows in cores and mud logs. Geochemical analysis indicates that both the Kyalla and Velkerri source rocks are mature.

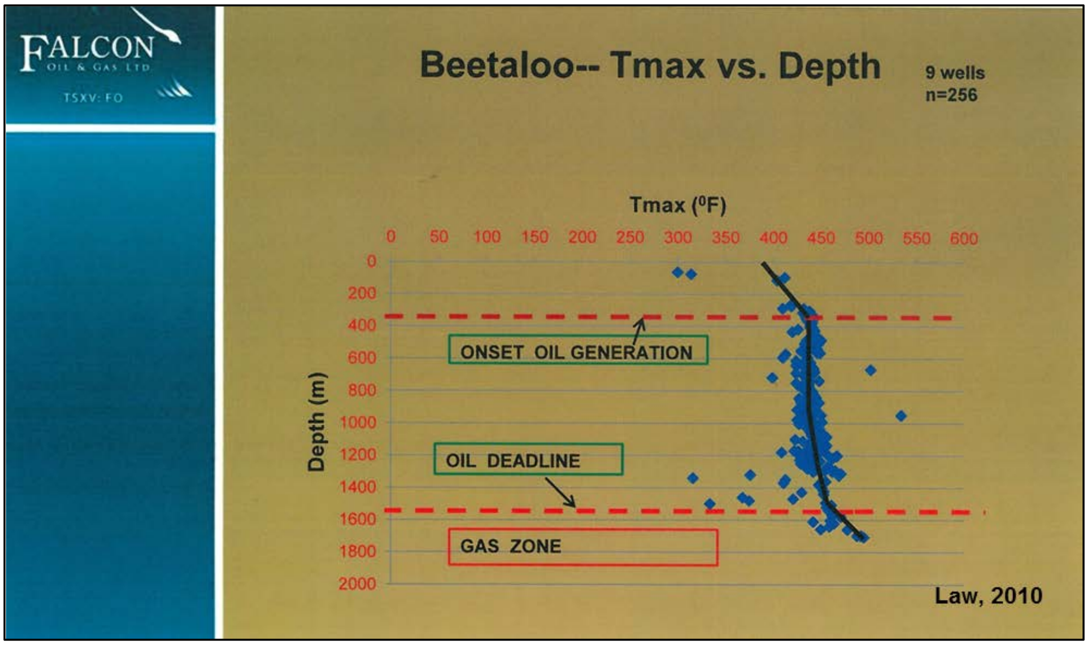
Although these formations are Proterozoic in age and there is some uncertainty in the maturation data and modelling, the Kyalla and Velkerri have had a relatively shallow burial history and subsequent uplift. Maturation modelling has been discussed by Silverman (2005), Law (2010), and Dutkiewicz (2005). Additional work was done by Thomasson Partners (2005) in a proprietary report that has been discussed, but was not available to RPS for review. The maximum burial depth and maturation may have occured shortly after the deposition of the Moroak sandstone (Dutkiewicz) with uplift shortly thereafter. This has preserved much of the section in the oil window and the deeper parts of the basin still remain in the gas generating window. Results indicate that the shales are mature to over-mature in the center of the basin and in the oil window along the shallower basin edges.

According to the 2010 Ryder Scott report and modelling completed by Law and Thomasson Partners, the source rocks are mature for oil above 1500 m TVD seismic and for gas below 1500 m. Both Figures 5.3-5 and 5.3-6 illustrate data from basin modelling of geochemical analyses and alganite Ro values. They indicate that the sediments may be mature for oil generation below 300-500 m TVDss and for gas generation below 1400 m to 1700 m. The report follows the convention used in the 2010 Ryder Scott report of the 1500 m TVD seismic contour as the boundary between the oil generation area and the gas generation area. The 1500m depth contour on the maps was used to distinguish the potential oil shale resources form the potential gas shale resources.



Source: Silverman, 2010

Figure 5.3-5: Jamison-1 BasinMod thermal Maturity



Source: Law

Figure 5-3.6: Beetaloo: Tmax vs. Depth

5.3.3 Overview Of Discoveries and Prospectivity

The Beetaloo Basin is relatively under-explored and has shale oil, shale gas and BCGA potential. The formations under evuation are the Upper Kyalla, Lower Kyalla and Middle Velkerri for shale oil and gas and the Moroak and Bessie Creek for BCGA. There are no existing fields in the basin, but the Shenandoah -1 has produced gas and condensate from the Middle Velkerri and gas from the Lower Kyalla on test. There are also numerous mudlog and core oil and gas shows throughout the basin in the prospective formations.

The drilling and suspension of the Shenandoah-1 wells at a 1555 m TD (vertical) occurred in 2007. The well was deepened to 2714 m TD in August 2009 as a vertical well and renamed as Shenandoah-1A. The Shenandoah-1A was a twin to an older Balmain-1 well which had significant oil and gas shows. Falcon re-entered the Shenandoah-1A on September 14, 2011, ran casing and tested the well. Five short-term production tests, including fracture treatments and conventional perforation tests were run in the deep section to test the potential of the Lower Kyalla shale, Moroak Sandstone and the Middle Velkerri shale formations. Summary of the well test is presented below.

Middle Velkerri

Test #1 (2529-2548 m MD): Interpreted to be a shale/siltstone rock with average TOC of approximately 2 wt%. Testing equipment was not properly suited for unconventional well testing and could not properly handle the high water rates in conjunction with low gas rates. There was enough gas to burn the flare without the pilot being on. Gas rate was insufficient to measure. Increasing CO_2 content ranged from 3% to 6%. Condensate with an API gravity of 43 degrees was collected in the mud pit. Modeling of the data and fracture treatment results indicated a very low permeability (0.000074 mD).

Test#2 (2481-2598.5 m MD): Interpreted to be a low porosity sands with shale laminations. Little to no TOC identified. Early flow initial gas rates were as high as 84 Mscf with 3,200 bbls of water per day. After performing a post-frac DFIT, the well flowed unasssisted with measureable rates of over 2,000 bbl/d water and ~60 Mscfd gas. Modeling of the data and fracture treatment results indicated a very low permeability (0.006 mD).

Moroak Sandstone

Test#3 (1837-1910 m MD): Interpreted to be a very low porosity sands with shale laminations. There is a subtle mud gas increase over this interval. The well did not flow as a result of very low permeability. Modeling of the data and fracture treatment results indicate a permeability of 0.000913 mD)

Test#4 (1728-1780 m MD): Interpreted to be a massive fluvial sandstone. There were modest mud gas shows over this interval. However, the test failed to flow any detectable gas. Modeling of the data and fracture treatment results indicated a very low permeability (0.0829 mD).

Lower Kyalla

Test#5 (1631-1649 m MD): Interpreted to be composed of shale/siltstone and sandstone layers with TOC of 2 wt%. Mudlog gas shows over this interval reaching 11% TGas. Burnable gas was observed. Modeling of the data and fracture treatment results indicated a very low permeability (0.002190 mD)

The well was plugged and abandoned on November 7, 2011.

Petrophysical evaluations done by Falcon and Darrell Hoyer (see Appendix C, Figure C-19 indicate pay in Upper and Lower Kyalla, Moroak Sandstone and Middle Velkerri formations.

Figure 5.3-7 shows the prospective shale oil resource areas for the Upper Kyalla, Lower Kyalla and the Middle Velkerri. Much of the basin has unconventional shale oil potential. Figure 5.3-8 has the Lower Kyalla and Middle Velkerri unconventional shale gas potential outlined. The shale gas areas are confined to the center of the basin. Figure 5.3-9 has the BCGA outlines for the Moroak and Bessie Creek. In accordance with the model, they are limited to the center of the basin where the source rocks are in the gas window.

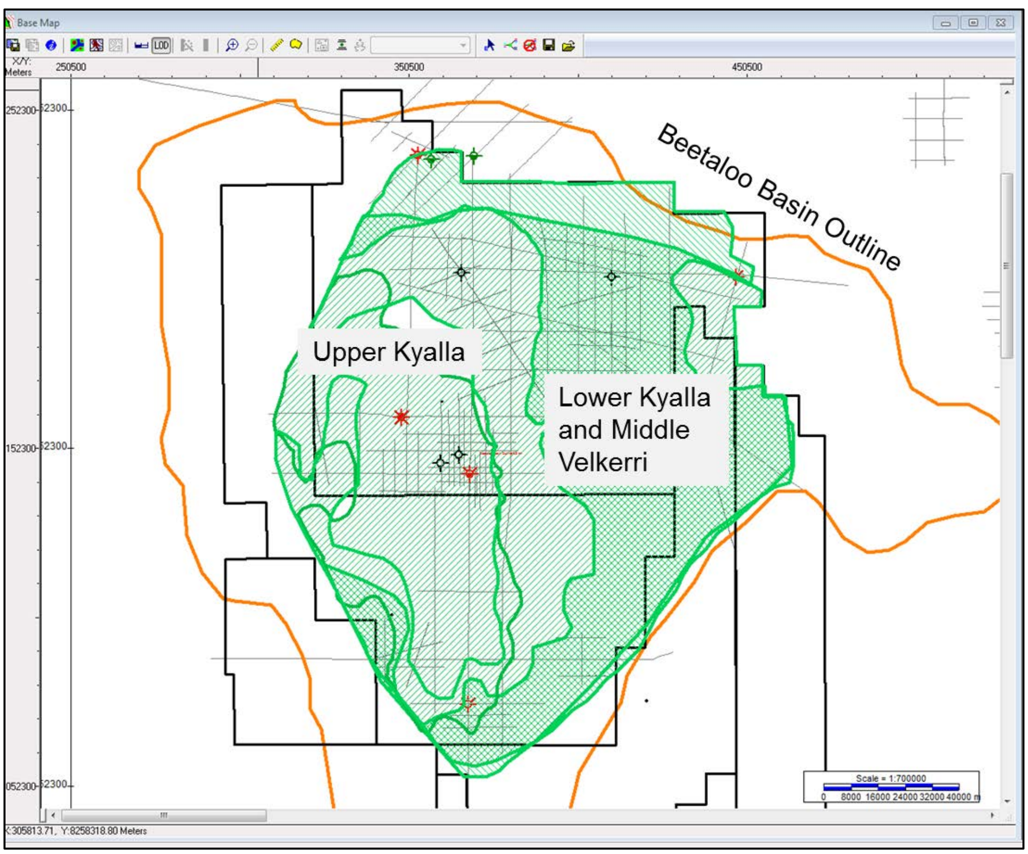


Figure 5.3-7: Potentially Prospective Upper Kyalla, Lower Kyalla, and Middle Velkerri Shale Oil Areas

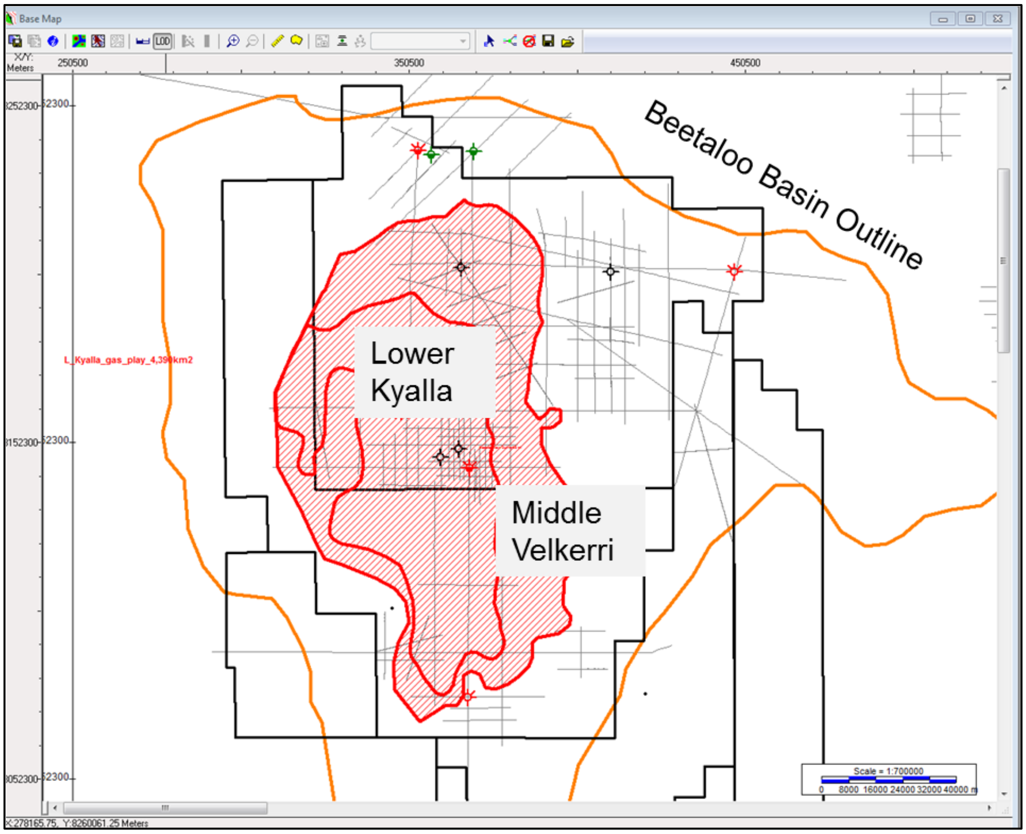


Figure 5.3-8: Potentially Prospective Lower Kyalla and Middle Velkerri Gas Areas

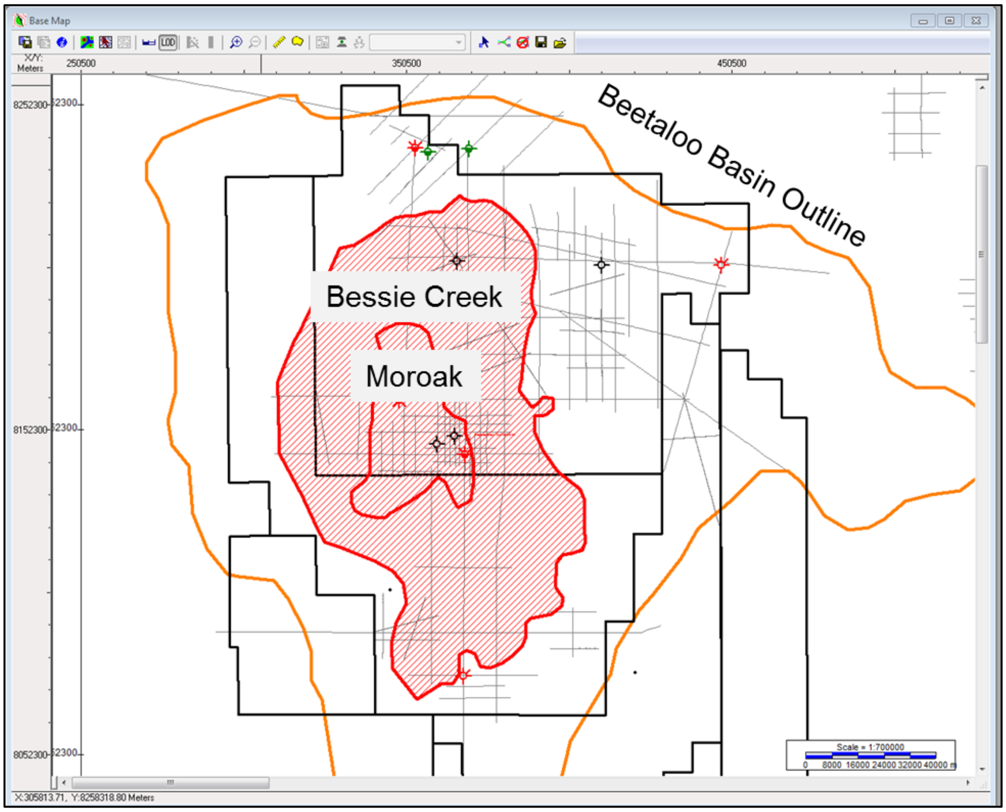


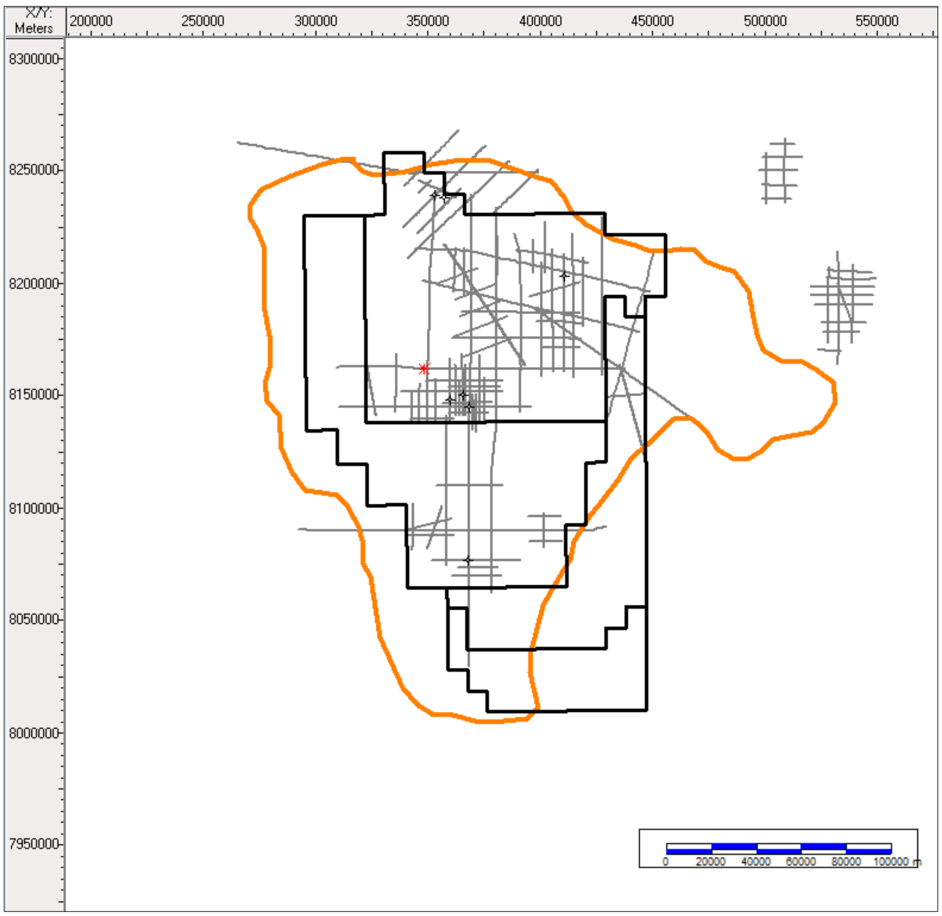
Figure 5.3-9: Potentially Prospective Moroak and Bessie Creek BCGA Areas

5.4 DATABASE

RPS was provided access to a comprehensive dataset including an interpreted SMT project, as well as well logs, well reports, deviation data, mudlogs, core data, well test and well completion reports.

5.4.1 Seismic Data

RPS was were provided with access to a SMT Kingdom™ project containing various vintages of 2D seismic data. The prospective area is covered by 2D seismic data. The seismic data and interpretation was loaded into an SMT project and provide to RPS for review. Approximately 2000 line km was acquired between 1984 and 1988 and 1988 and 1992 (Figure 5.4-1). As part of their farm-in agreement, Hess acquired 700 line km of 2D sesimic in 2006 and an additional 3,490 line km of new seismic data in 2011-2012 which is still in processing (Figure 5.4-2). Falcon Australia will collect an additional 150 km 2D seismic data in the EP99 permit in 2013. Under the terms of the current potential farm-in agreement, Hess has until 30 June 2013 to elect to undertake a five (5) well program in return for a 62.5% interest in the agreement area. Falcon will be carried though these five wells.

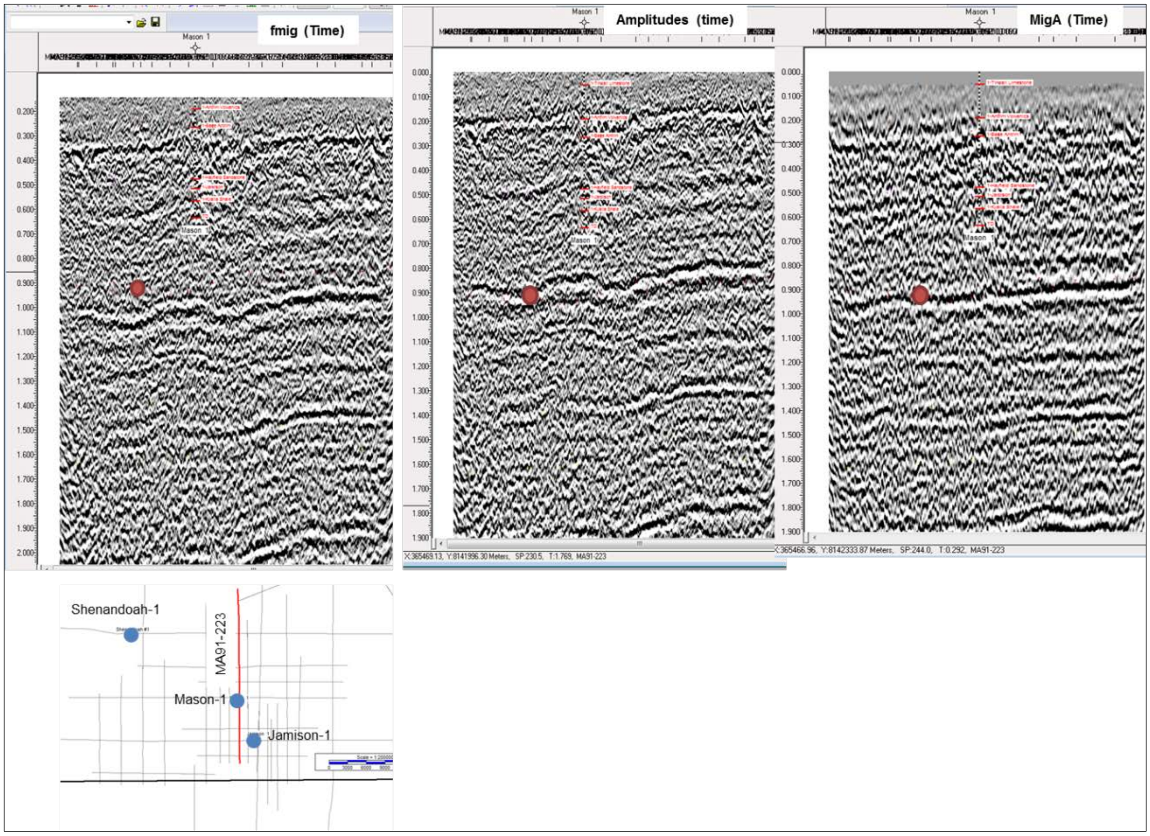


Source: Falcon

Figure 5.4-1: Existing 2D Seismic Data before Hess 2011-12 Seismic Acquisition

Seismic data quality is poor to fair. There are significant velocity issues resulting from a shallow karsted limestone (Tindall Formation), variable unconsolidated surface sediments, and the effects of volcanics (Antrim) injected into the near subsurface. Much of the seismic data is processed using different algorithms with the different statics and replacement velocities resulting in 2D time misties.

Multiple processing efforts have occurred and most of the data has been reprocessed several times. The effects of the different surface statics and shallow velocities can be observed in Figure 5.4-2.



Source: Falcon

Figure 5.4-2: Seismic Processing Issues

The three different sets of processing parameters are shown for Line MA91-223. The brown dot is located at the same X, Y, Z position on all three lines. The changes in these line versions clearly show the impact of the karsted carbonate surface topography, the shallow intrusions and dykes, and the different static corrections and replacement velocities. These issues result in a high degree of uncertainty in prospect mapping. However, the general basin configuration and general depth to the major sequence boundaries are broadly recognisable and the resulting interpretation and maps can be used for basin-wide unconventional analysis.

In 2007, 1000 line km of seismic were reprocessed with varying and unpredictable results. In some areas, the processing improved, but in others, the near surface problems limited the success of the results. Additional reprocessing in 2008 showed some improvement, but the velocity and statics problems remained. In 2009, approximately 2700 line km of the data were again reprocessed with some success. It is hoped that the new acquisition will include improvements in the source acquisition parameters, spacing, coupling of the geophones, and processing and will deliver a more consistent and usable dataset.

Working with the Falcon geoscientists, RPS is satisfied that the seismic interpretation has been carried out in an appropriate manner, incorporating all available geological information including well data.

5.4.2 Well Data

Data made available to RPS include CPI (Computer Processed Interpretation) in LAS (Log Ascii Standard) format for wells Altree-2, Balmain-1, Burdo-1, Chanin-1, Elliot-1, Jamison-1, Mason-1, McManus-1, Ronald-1, Shenandoah-1, Shortland-1 and Walton-1. Also, composite logs in PDF (Portable Document File) format. Digital mud log data was made available for all wells.

Available core data for the offset wells Altree-2, Balmain-1, Broadmere-1, Burdo-1, Chanin-1, Elliot-1, Jamison-1, Mason-1, McManus-1, Ronald-1, Sever-1, Walton-2, include Porosity, Permeability, grain density, Water Saturation, Oil Saturation and TOC.

Petrophysical evaluations had been previously made by Falcon and Darrell Hoyer, (Falcon's independent petrophysical consultant) and RPS concluded that previous petrophysical work was reasonable.

Well completion report for the Shenandoah-1 includes Diagnostic Fracture Injection Test (DFIT) results on 5 zones. The report also includes results of fracture stimulation treatments pumped in 3 of the 5 zones.

5.4.3 Previous Reports

Two previous reports were made available to RPS. These include but are not limited to:

- "Falcon Oil & Gas Ltd. Evaluation of the Hydrocarbon Resource Potential Pertaining to Certain Acreage Interest in the Beetaloo Basin, Northern Territory, Australia, as of July 1, 2009. By Ryder Scott Company".
- "Falcon Oil & Gas Ltd. Evaluation of the Unconventional Oil Resource Potential Pertaining to Certain Acreage Interest in the Beetaloo Basin, Northern Territory, Australia. As of May 1, 2010. By Ryder Scott Company".

5.5 BEETALOO BASIN UNCONVENTIONAL AND TIGHT GAS RESOURCES

5.5.1 Overview

RPS evaluated several sources of information provided by Falcon to assess the unconventional shale resource for the Upper Kyalla, the Lower Kyalla, and Middle Velkerri formations and BCGA potential for the Moroak and Bessie Creek sandstone in the Beetaloo Basin. The information used in the evaluation included seismic data and interpretation, depth maps, mudlogs, wireline logs, test data, and geochemical analysis.

5.5.2 Seismic Interpretation and Depth Maps

RPS has QC'd the seismic interpretation behind the current Falcon mapping of the Beetaloo Basin and finds it to be consistent with the underlying data. It is clear that much care has been taken to incorporate all the available geological information from both wells and surface geology.

RPS believes that the mapping, whilst subject to a large range of uncertainty as a result of the sparse, poor quality 2D seismic is a reasonable representation of the potential structures at this time.

Figure 5.5-1 is a stratigraphic chart with the major formations and Figure 5.5-2 illustrates the seismic horizons interpreted by Falcon and reviewed by RPS.

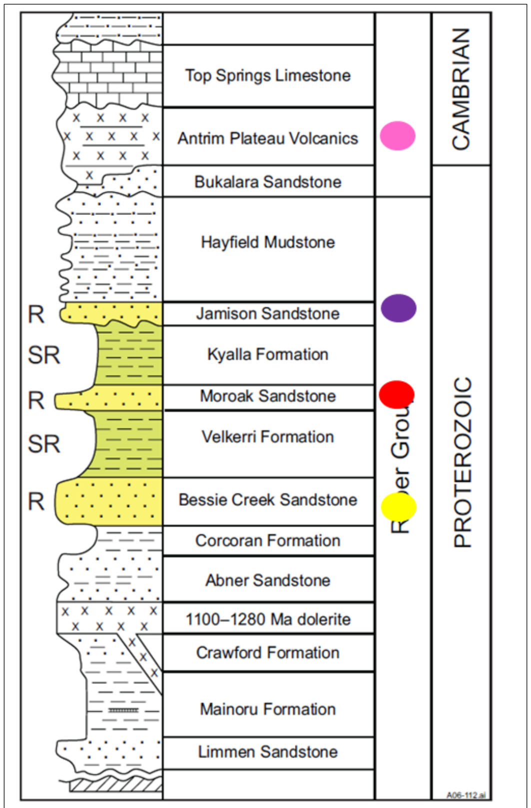


Figure 2. Stratigraphic column showing Roper Group and overlying Cambrian units. R = reservoir; SR = source rock.

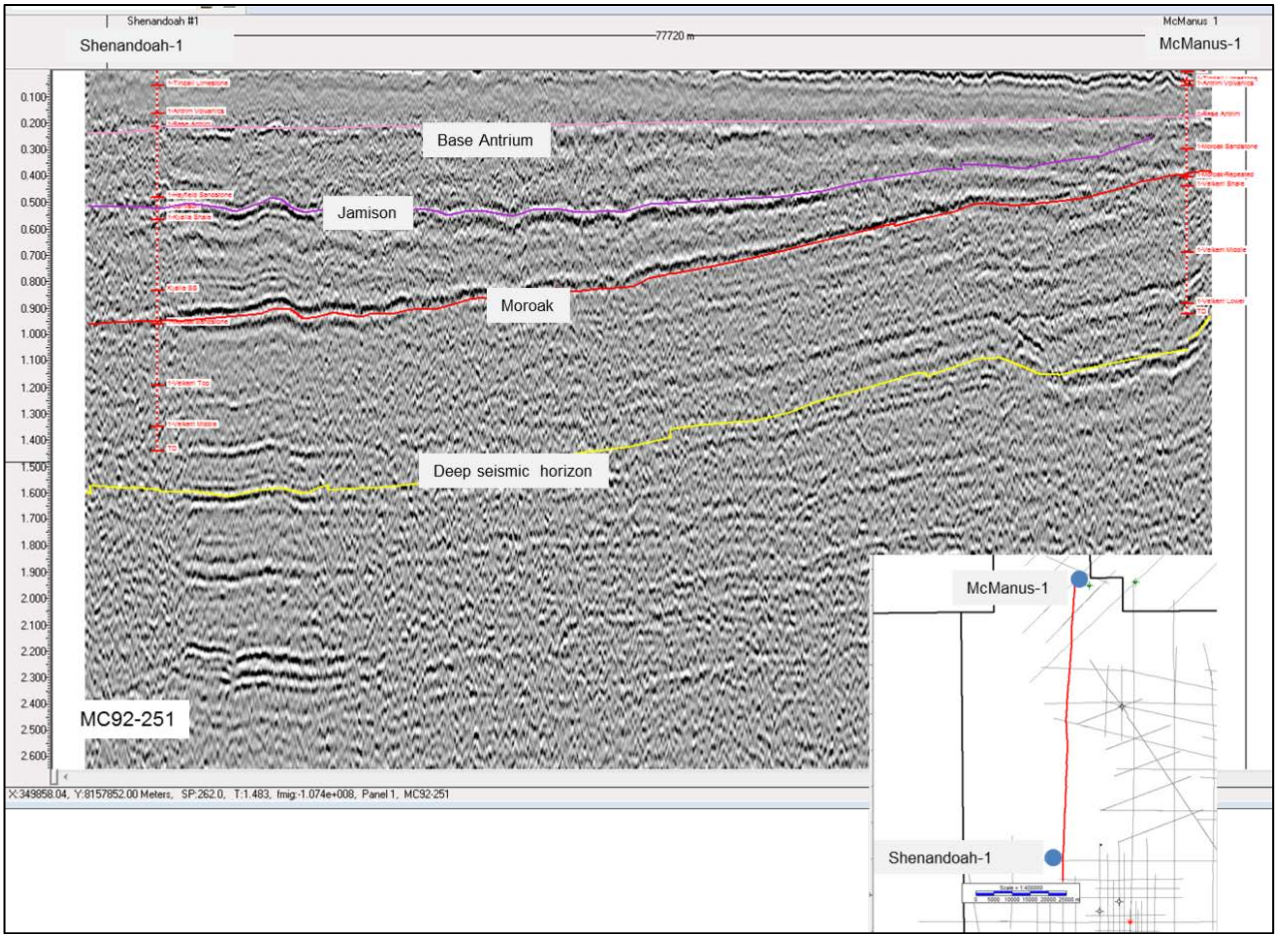
Source: Silverman

Figure 5.5-1: Stratigraphic Chart with Seismic Horizons Annotated

The four horizons interpreted were:

- Antrim and/or Base of Antrim
- Jamison Sandstone
- Moroak Sandstone
- Deep seismic horizon

These are represented by the strongest, most continuous reflectors on the seismic data. The Moroak and Jamison sandstones are good consistent seismic markers across the area and are the most widely interpreted. A synthetic generated in the Jamison well was tied to the seismic data to confirm the Jamison, Moroak, and Base Antrim volcanic seismic markers. The seismic interpretation and mapping is generally good and was accepted for use in the resource assessment.



Source: Falcon

Figure 5.5-2: Type Seismic Line

Depth grids were provided to RPS for use in the assessment. The depth maps are in TVD Seismic which is 200 m above mean sea level. The depth maps were tied to the well control except along the northern basin margin where both the well log correlations are uncertain and the seismic data is very poor quality.

The depth conversion was confirmed by generating time grids from the seismic interpretation and calculating average velocity grids from the time and depth maps. The Jamison and Moroak interpretation, mapping, and depth conversion appear to be reasonable.

The depth maps used in the resource assessment include:

- Upper Kyalla shale
- Lower Kyalla shale
- Moroak sandstone
- Middle Velkerri shale
- Bessie Creek sandstone

The Upper Kyalla depth map was derived from the Jamison interpretation and depth mapping. The Upper Kyalla is 75 - 90 m below the Jamison. The Jamison depth map was downward continued 80 m to generate the Upper Kyalla map. The Lower Kyalla depth map was generated from the Moroak depth map. The most prospective shaly part of the Lower Kyalla lies just above the Moroak sandstone and the Lower Kyalla depth map was upward continued 20 m to this shaly unit.

There are limited Middle Velkerri penetrations, Shenandoah-1 in the center of the basin and the Walton-2, Altree-2 and McManus-1 on the shallow northern basin edge. The Middle Velkerri does not have a strong, continuous seismic event and the Middle Velkerri depth map was generated from the Moroak depth map.

There are limited Middle Velkerri penetrations, Shenandoah-1 in the center of the basin and the Walton-2, Altree-2 and McManus-1 on the shallow northern basin edge. The Moroak depth map was downward continued to match the Middle Velkerri in the Shenandoah-1 well.

The Bessie Creek is reached in the Walton-2 and Altree-2. The Bessie Creek depth map was tied to the well control along the northern edge of the basin and downward continued to give a depth estimate to the Bessie Creek.

5.5.3 Well Test Information

Fourteen wells have penetrated the Beetaloo Basin from as shallow as 777m in the Balmain-1 to as deep as 2714m in the Shenandoah-1. All of the wells with the exception of the Shenandoah-1 were drilled to capture data and were not flow tested. The Shenandoah-1 was re-entered in September 2011 with the objective to complete and fracture stimulate unconventional zones in the vertical well to determine the hydrocarbon productivity potential in the Basin as well as fracture design parameters. High rates of production were not expected because the objective was a Diagnostic Fracture Injection Test (DFIT). The DFIT provided much needed hydraulic fracturing design parameters that will be helpful in optimizing future hydraulic frac designs.

Diagnostic Fracture Injection Tests were performed in five (5) stages in the Shenandoah-1. Stage 1 was in the Middle Velkerri LB sand and Stage 2 was in the Middle Velkerri B sand. Stages 3 and 4 were in the Moroak sandstone and Stage 5 was in the Lower Kyalla sand. Stages 1 and 2 were stimulated with 40/70 mesh proppant as well as Stage 5. Stages 3 and 4 were not stimulated with proppant due to extremely low porosity and permeability. See Table 5.4.1 provides a summary of perforation and stimulation data for the Shenandoah-1.

Summary of the well test is presented below.

Middle Velkerri

Test #1 (2529-2548 m MD): Interpreted to be a shale/siltstone rock with average TOC of approximately 2 wt%. Testing equipment was not properly suited for unconventional well testing and could not properly handle the high water rates in conjunction with low gas rates. There was enough gas to burn the flare without the pilot being on. Gas rate was insufficient to measure. Increasing CO_2 content ranged from 3% to 6%. Condensate with an API gravity of 43 degrees was collected in the mud pit. Modeling of the data and fracture treatment results indicated a very low permeability (0.000074 mD).

Test#2 (2481-2598.5 m MD): Interpreted to be a low porosity sands with shale laminations. Little to no TOC identified. Early flow initial gas rates were as high as 84 Mscf with 3,200 bbls of water per day. After performing a post-frac DFIT, the well flowed unasssisted with measureable rates of over 2,000 bbl/d water and ~60 Mscfd gas. Modeling of the data and fracture treatment results indicated a very low permeability (0.006 mD).

Moroak Sandstone

Test#3 (1837-1910 m MD): Interpreted to be a very low porosity sands with shale laminations. There is a subtle mud gas increase over this interval. The well did not flow as a result of very low permeability. Modeling of the data and fracture treatment results indicate a permeability of 0.000913 mD)

Test#4 (1728-1780 m MD): Interpreted to be a massive fluvial sandstone. There were modest mud gas shows over this interval. However, the test failed to flow any detectable gas. Modeling of the data and fracture treatment results indicated a very low permeability (0.0829 mD).

Lower Kyalla

Test#5 (1631-1649 m MD): Interpreted to be composed of shale/siltstone and sandstone layers with TOC of 2 wt%. Mudlog gas shows over this interval reaching 11% TGas. Burnable gas was observed. Modeling of the data and fracture treatment results indicated a very low permeability (0.002190 mD)

The well was plugged and abandoned on November 7, 2011.

Table 5.5-1 - Summary of Perforation and Stimulation data for the Shanandoah-1 Well

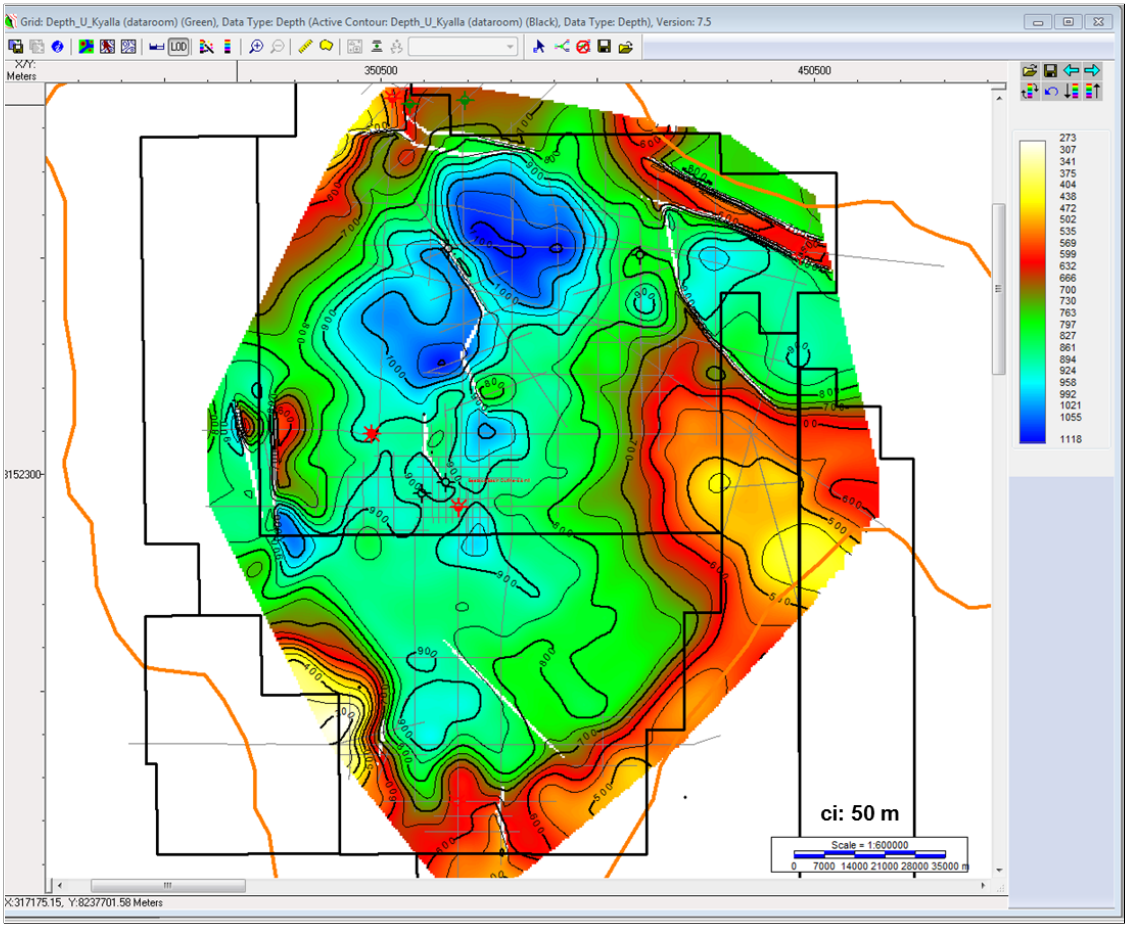
PERFORATION / STIMULATION SUMMARY

	Wireline Perforations (meter MDRT)					DFIT		Stimulation Treatment		
	Top	Base	Interval	Type	Density	Water	HCL%	Total Fluid	Silica Sand	Silica Sand
	(m)	(m)	(m)	SDP	(shots/m)	(bbls)	(bbls)	(bbls)	100 mesh	40/70 mesh
Stage 1	2547	2548	1	3/3/8"	20	212	36 @15%	6,654	52,912 lbs	148,815 lbs
	2529	2530	1	3/3/8"	20					
CIBP 1	2522									
Stage 2	2497.5	2498.5	1	3/3/8"	20	320	47 @15%	7,575	76,061 lbs	125,666 lbs
	2481	2482	1	3/3/8"	20					
CIBP 2	1952									
Stage 3	1900	1910	10	2 3/4"	10	12.6	32 @13.5%	44.6	N.A.	N.A.
	1860	1870	10	2 3/4"	10					
	1850	1860	10	2 3/4"	10					
	1837	1843	6	2 3/4"	10					
CIBP 3	1815									
Stage 4	1774	1780	6	2 7/8"	10	No DFIT	28.2 @15%	135.2	N.A.	N.A.
	1755	1760	5	2 3/4"	5					
	1745	1755	10	2 7/8"	10					
	1728	1740	12	2 7/8"	10					
CIBP 4	1660									
Stage 5	1648	1649	1	3/3/8"	20	No DFIT	32 @15%	7,866	69,447 lbs	158,736 lbs
	1641	1642	1	3/3/8"	20					
	1631	1632	1	3/3/8"	20					
CIBP 5	1610									
CIBP 6	1575									

5.5.4 Upper Kyalla Formation

Shale plays have a wide range of TOC (Total Organic Carbon) and HI (Hydrogen Index) values. However, the better shale gas/oil plays have current average TOC values in excess of 2.0% and HI values above 400 mg/g (Jarvie). The best shale plays have TOC values above 3.0% and HI values in excess of 500 mg/g.

The Upper Kyalla depth map (Figure 5.5-3) shows the central syncline of the Beetaloo basin and the basin edges.



Source: Falcon

Figure 5.5-3: Upper Kyalla Depth Structure Map

The geochemical analysis of the northern wells did not show reasonable TOC or HI values, even though the section is in the oil window and should be at or below the peak oil generation. The Chanin-1 (average 0.47% TOC and HI of 243 mg/m) , Ronald-1 (average 0.61%TOC and HI of 274 mg/m), and Burdo-1 (average 0.66% TOC and 192 mg/m HI) all had TOC values <2.0% and HI values <400 mg/m. The source rock characteristics of the Elliot-1 and Jamison-1 were better. The Upper Kyalla interval in the Ellliott-1 is from 664 m to 1140 m MD. One interval, 1064 m to 1141 m, had the best shale potential. The best source rock samples were sent for source rock analysis (Appendix 5 of the well report) and the results indicate an average TOC of 1.88% and average HI of 235 mg/m. In Jamison-1 the Upper Kyalla is from 965 m to 1485 m MD. As with the Elliot-1, the darkest and finest-grained samples (Appendix 4 of the well report) were sent for geochemical analysis and yielded the best results from 1012 m to 1043 m MD with an average TOC of 2.16% and HI of 410 mg/m.

Since the source rock characteristics of the Upper Kyalla are so varied, it may be that paleo-topography and distance from the basin edges controlled the amount of and later preservation of the organic matter. The thickest and deepest part of the Upper Kyalla away from the sediment influx from the basin boundary should have had the most anoxic and reducing environment with the best source rock resource potential. Figure 5.5-4 is an isopach map with the geochemical results annotated. It confirms that the deeper part of the Beetaloo basin in Upper Kyalla time has the greatest potential for the development of shale resources, with much less potential outside the basin center.

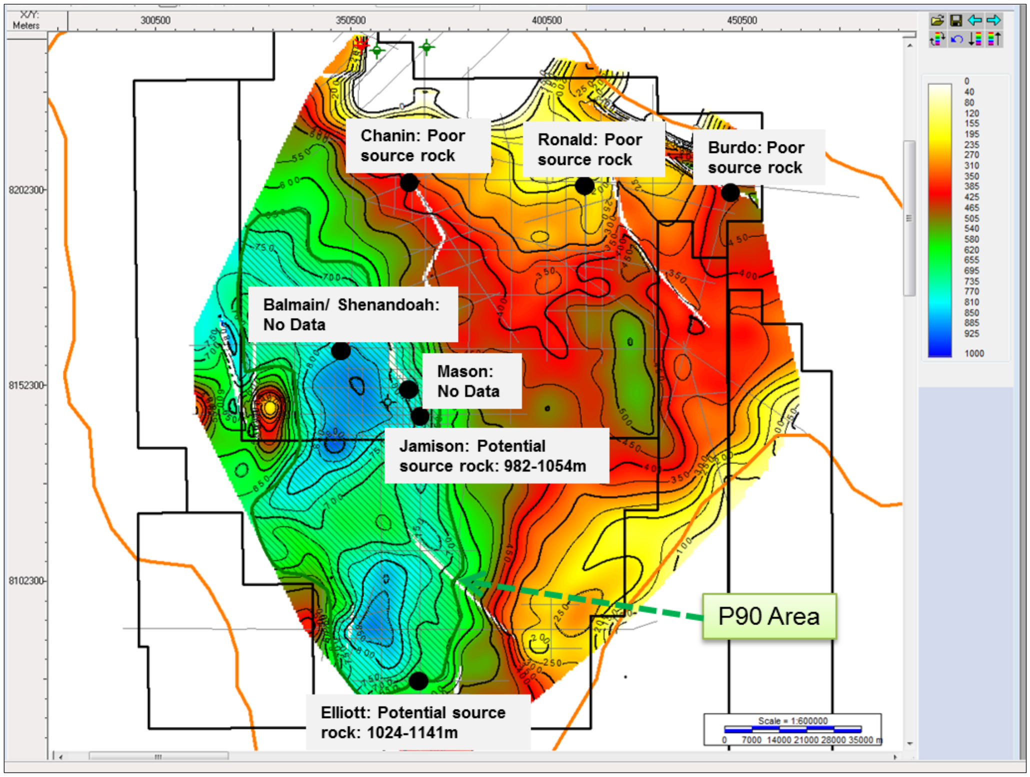


Figure 5.5-4: Upper Kyalla Isopach Map with Geochemical Analysis and P10 Area

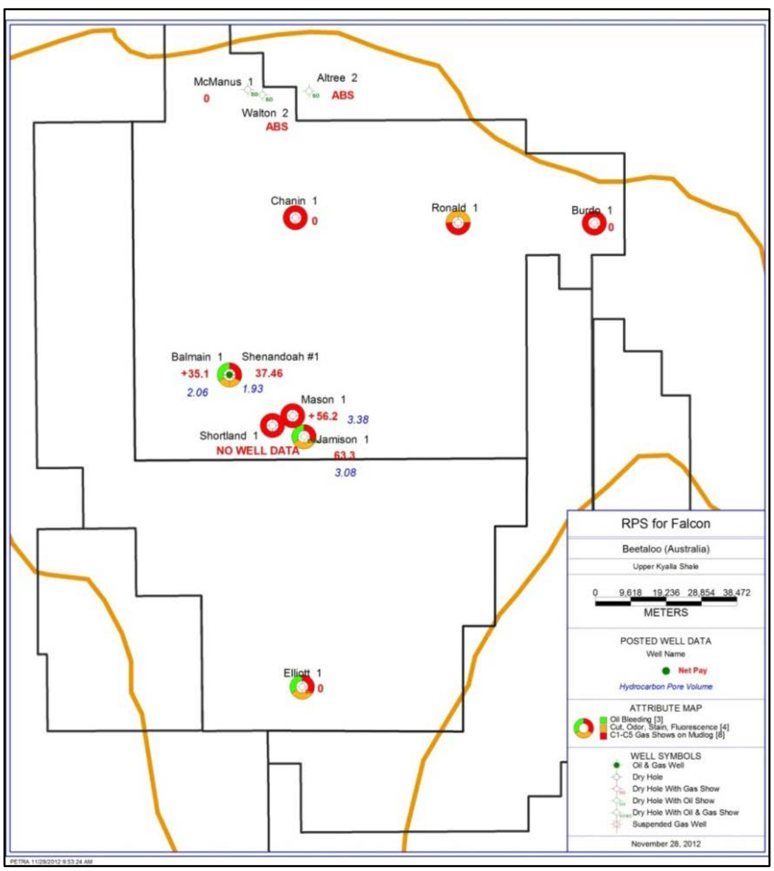


Figure 5.5-5: Upper Kyalla Show Map

Figure 5.5-5 is a map with the mudlog, test, show and calculated net pay annotated. While there are mudlog shows in the Chanin-1, Ronald-1 and Burdo-1, there is no calculated net shale resource pay. Also, the Elliot-1, along the southern edge of the basin center, did not have any calculated net pay. All of the wells in the center, thickest, most distal part of the basin had 35 m to 63 m of net pay (red numbers in Figure 5.5-5).

Therefore, the isopach was used to define both the Upper Kyalla shale P10 and P90 areas. The P90 includes the Shenandoah, Balmain, Mason and Jamison wells with calculated oil pay and covers 4421 km^2 (1,092,504 ac.). As the Elliot-1 had marginal geochemical characteristics and no calculated oil pay, but is reported to have had some oil in a well test and the P10 area (Figure 5.5-6) was extended to include this well and is 5576 km^2 (1,377,987 ac.).

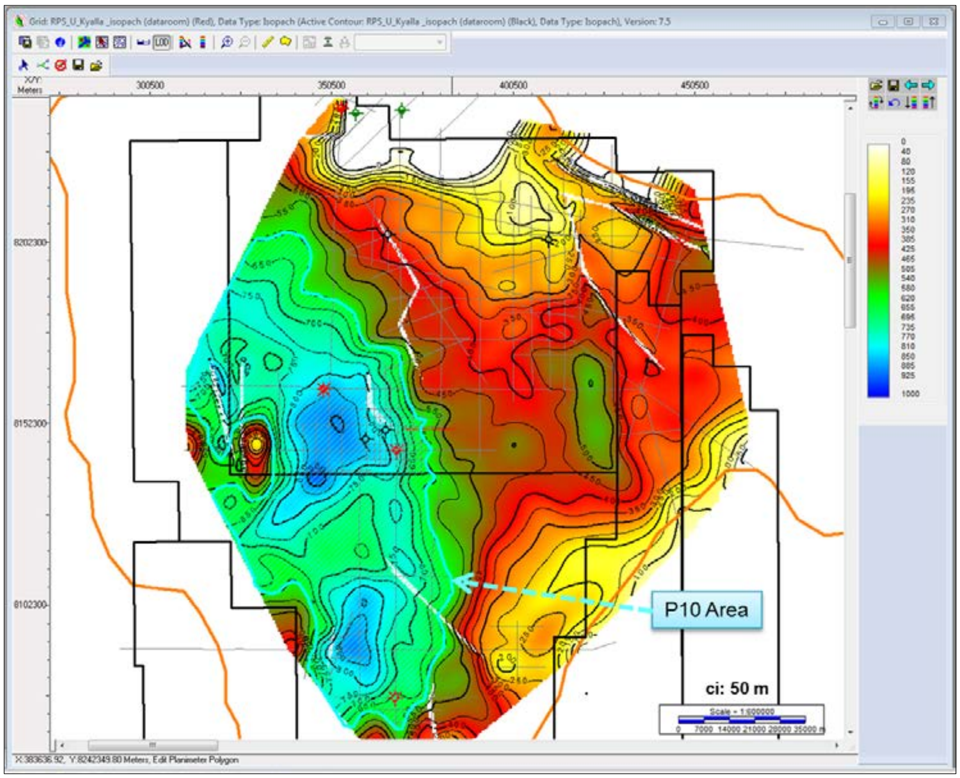
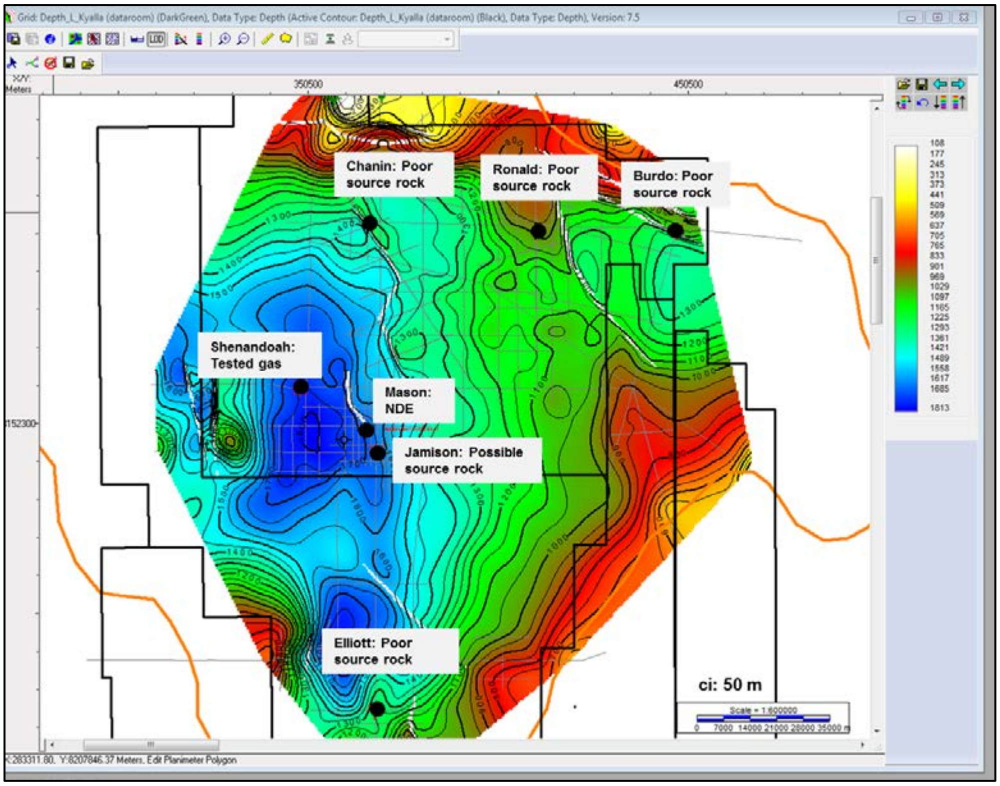


Figure 5.5-6: Upper Kyalla Isopach with P10 Area

5.5.5 Lower Kyalla Formation

The Lower Kyalla (Figure 5.5-7) reaches depths greater than 1500 m (see Section 5.3.2). Therefore, it is sub-divided into a gas resource play (<1500 m TVDSRD) and an oil resource play (>1500 m TVDSRD). As with the Upper Kyalla, the Lower Kyalla is eroded along the northern boundary of the basin in the McManus-1, Altree-2, and Walton-2 and may also be eroded along the high areas to the west and east.

There is limited TOC and HI data for the Lower Kyalla (Figure 5.5-7). The Burdo-1 has an average 0.82% TOC and 185 mg/m HI. The Chanin-1 has an average 1.0% TOC and 108 mg/m HI. The Ronald-1 average is 0.63% TOC and 120 mg/m HI. The Elliot-1, which is still in the oil window, has an average TOC of 1.18% with no values above 1.55% and an average HI of 136 mg/m. As these wells are in the oil window and not over mature, the source rock characteristics imply this may be a poor quality oil resource play. In the center of the basin, the Shenandoah-1 (gas window) tested gas from the Lower Kyalla. The Jamison-1 (gas window) had the best shale resource potential, 1492 m to TD, with an average TOC of 2.29% and numerous values over 2%. The average HI is low, 66 mg/m, but Jamison is in the gas window, most of the generation could have occurred earlier when in the oil window, the shale is now depleted in hydrogen, and is no longer able to generate hydrocarbons. The high remaining TOC values imply that this may have been an excellent source rock in the past and may have retained the gas it has generated.



Source: Falcon

Figure 5.5-7: Lower Kyalla Depth Structure Map

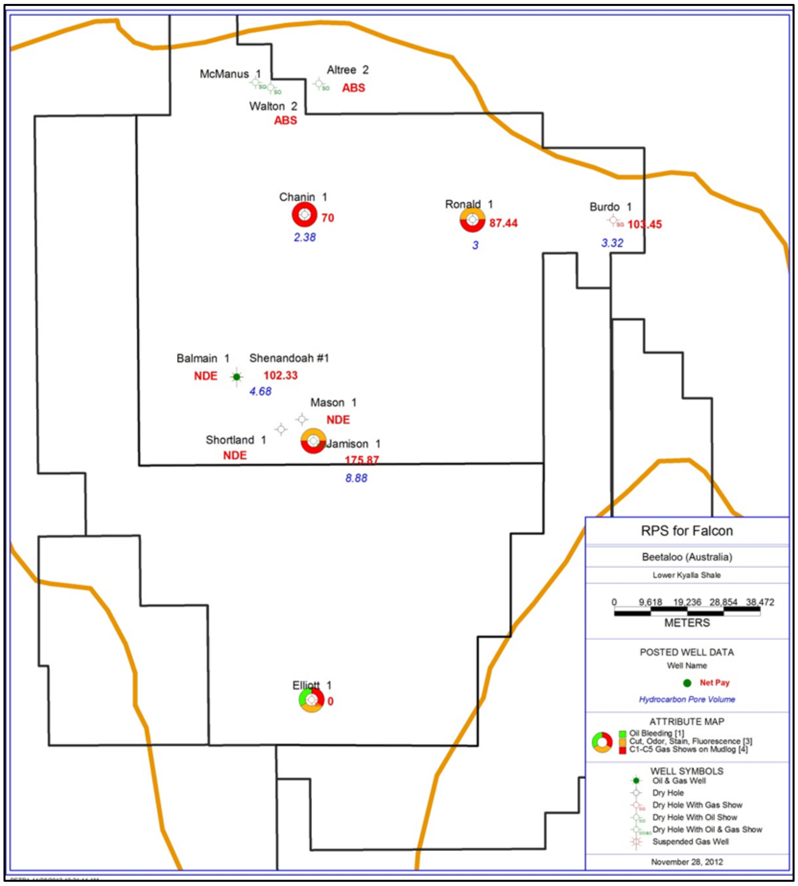
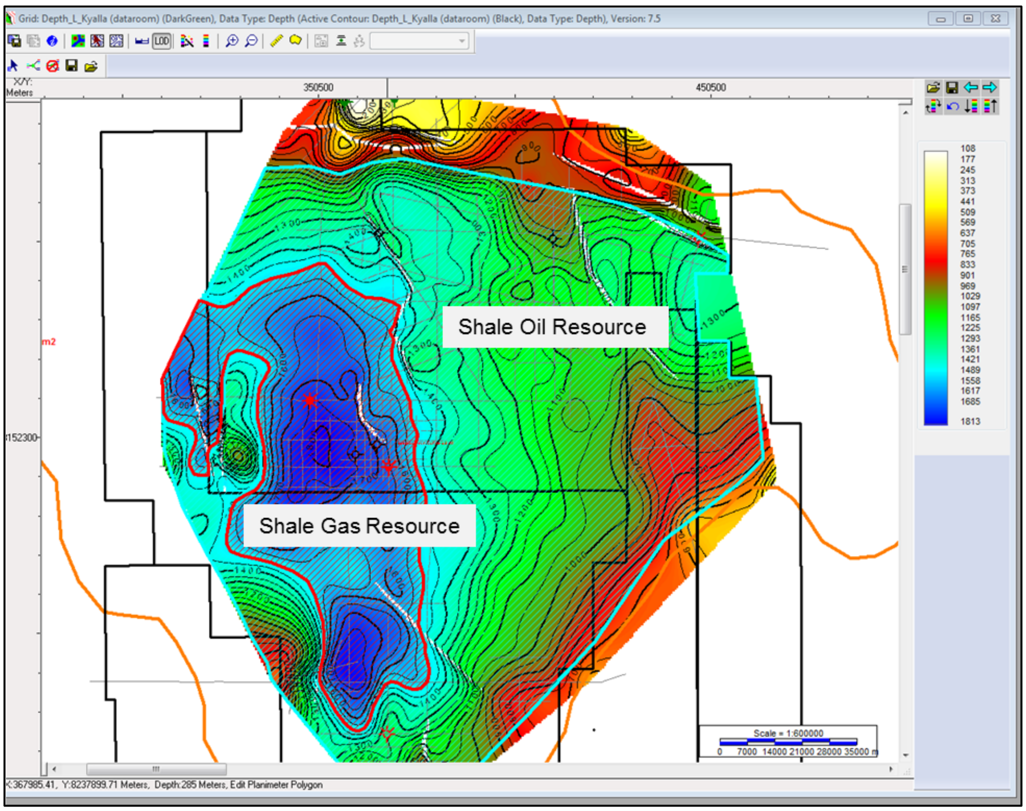


Figure 5.5-8: Lower Kyalla Show Map

Although the TOC and HI values were low, the wells had oil or gas shows (Figure 5.5-8), staining, fluorescence, and/or other indications of hydrocarbons. The Lower Kyalla had calculated net pay in all the wells except Elliot-1. The calculated net pay (red numbers in Figure 5.5-9) ranged from 70 m in the Chanin-1 to 175 m in the Jamison-1. Although the geochemical TOC and HI data indicates poor potential for Lower Kyalla shale resources, the net pay counts are good and the entire basin was included in the resource calculations.

The P10 shale oil area (Figure 5.5-9) encompasses the entire basin above the 1500 m line. This area (cyan outline) is 12,694 km^2 (3,136,820 ac.). The shale gas area (red outline) located in the deepest part of the basin, has a P10 area of 4382 km^2 or 1,082,942 ac. surrounding the Jamison-1 and Shenandoah-1. The P90 area for the Lower Kyalla oil resource was set at 70% of the P10 area i.e. 8,885 km^2 (2,195,776 ac.) The P90 for the Lower Kyalla gas resource was also set at 70% of the P10 area or 3068 km^2 (758,063 ac.).

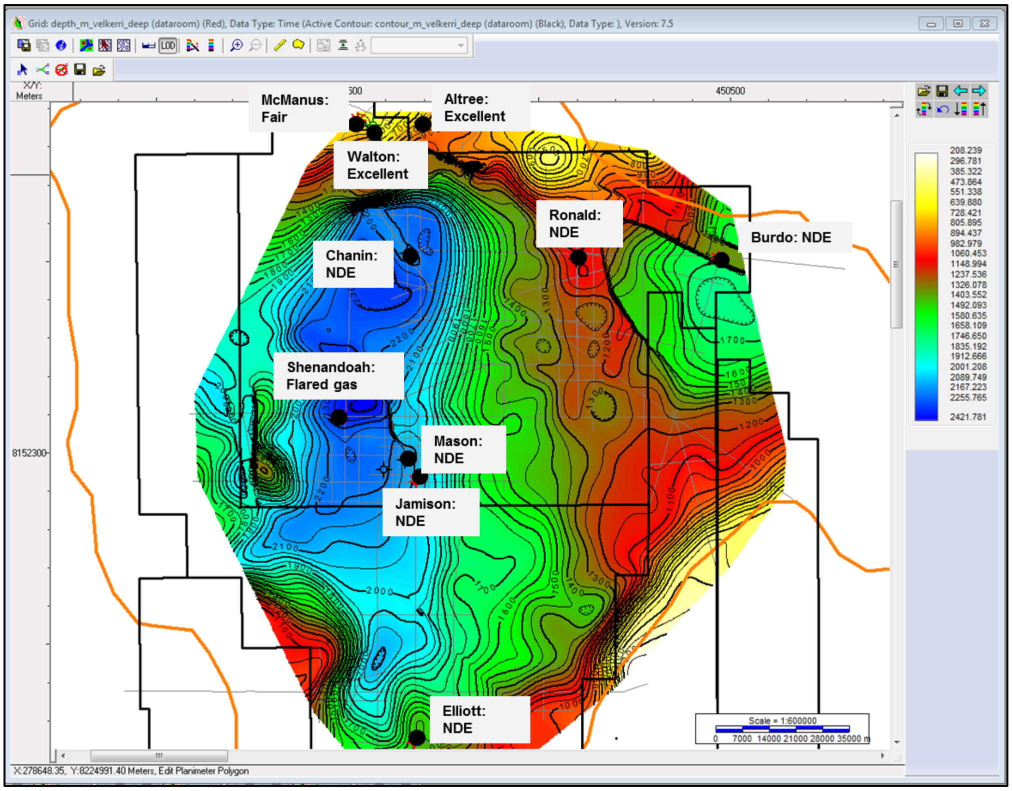


Source: Falcon

Figure 5.5-9: Lower Kyalla Depth Structure Map with P10 Gas and Oil Areas

5.5.6 Middle Velkerri Formation

The Middle Velkerri (Figure 5.5-10) is not penetrated in most of the wells. The only wells with Velkerri are the three wells along the basin edge, McManus-1, Altree-2, and Walton-2 and the Shenandoah-1 in the center of the basin. The Middle Velkerri appears to have excellent source rock characteristics and meets the criteria for a shale resource play. Biomarker data implies that the source rock is composed primarily of of prokaryotic cyanobacteria (Dutkiewicz). The Altree-2 is in the oil window and has excellent TOC (average 3.8%) and HI values (ranges from 200-460 mg/m). The McManus-1 has an average TOC of 2.32% and an HI range of <100 to 330 mg/m. The good oil shale in the McManus appears to be laminated with high TOC/HI values from 1130-1160 m, 1220-1280 m, 1360-1440 m and 1540-1550 m. Photomicrographs show that solid bitumen and oil-bearing inclusions in the McManus-1 are found in microfractures (Dutkiewicz, Figure 5). In the Walton-2, the Upper Velkerri has excellent source rock characteristics with TOC with most of the values are >3% TOC and >400 mg/m HI. According the Dutkiewicz, analysis of key wells in the Beetaloo and adjacent McArthur Basin indicates that a large portion of the generated hydrocarbons appear to remain in the Velkerri formation.



Source: Falcon

Figure 5.5-10: Middle Velkerri Depth Structure Map with Geochemical Analysis

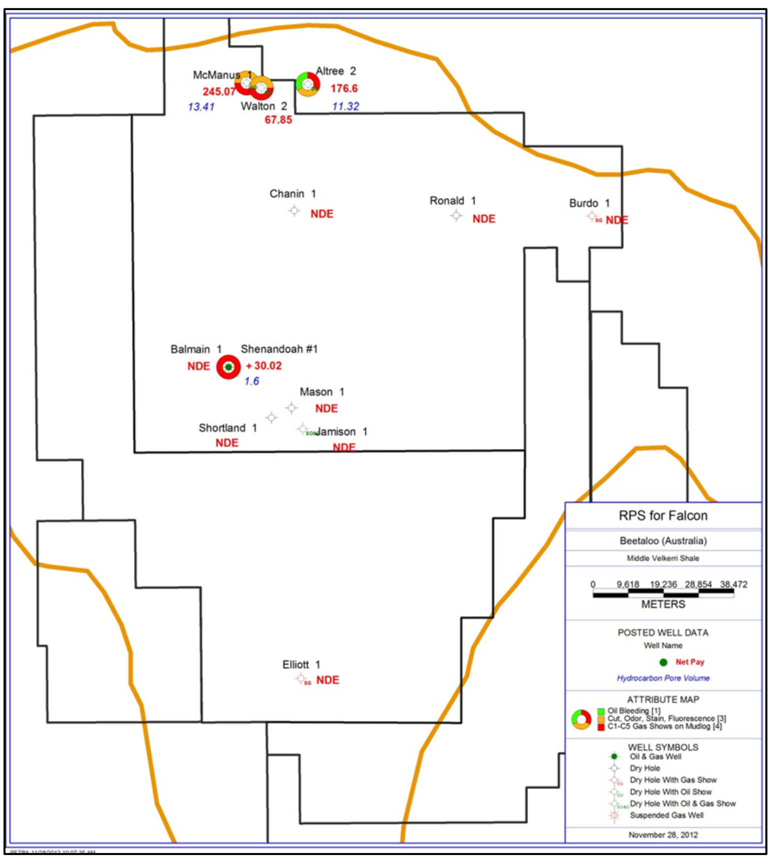
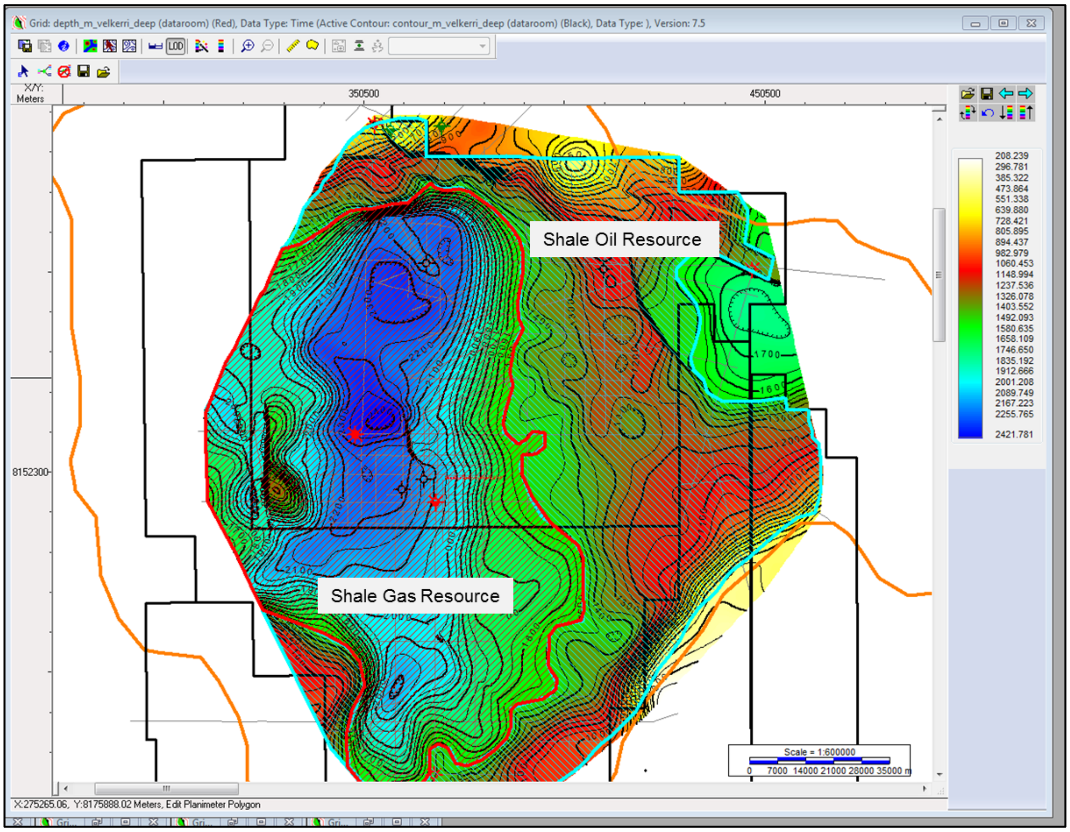


Figure 5.5-11: Middle Velkerri Show Map

On Figure 5.5-11 is the oil show information, the net pay (red numbers) and hydrocarbon pore volume data (blue numbers). The calculated net pay ranged from >30 m in the Shenandoah-1 well to 245 m in the McManus-1. The wells also had oil or gas shows, staining, fluorescence and/or other indications of hydrocarbons.

The P10 oil area (Figure 5.5-12) includes the Middle Velkerri from the 1500m gas/oil line to the edge of the block or 8,978 km^2 (2,218,598 ac.). The P10 for the gas window is 9,302 km^2 or 2,298,607 ac. The P90 areas are 70% of the P10 areas or 6284 km^2 for oil and 6511 km^2 for gas.



Source: Falcon

Figure 5.5-12: Middle Velkerri Depth Map with P10 Oil and Gas Areas

5.5.7 Moroak Formation

The Moroak Sandstone is a proposed BCGA (basin centered gas accumulation) play. Seven wells in the basin (Figure 5.5-13) did not have hydrocarbons, had no pay, and were wet (McManus-1, Walton-2, Altree-2, Chanin-1, Ronald-1, Burdo-1 and Elliot-1). The Jamison may have 1 m of pay. There was a significant amount of net pay in the Shenandoah-1, 144 m.

The Shenandoah-1 tested the Moroak sandstone (2 stages). Middle Moroak Deltaic interval 1837-1910 mMD, very low porosity and permeability with shale laminations, subtle log gas increase. After perforation test the well did not flow. Moroak Fluvial Sandstone interval 1728-1780 mMD, with indications of natural fractures from the STAR image log (Well completion report), modest mud log gas shows. After perforation test and Nitrogen circulation the well did not flow.Moroak was not fracked.

As petrophysical analysis indicated that most of the wells do not have any net pay, the P10 area was (Figure 5.5-14) set to exclude the wet wells, include the Shenandoah-1, and honor the possible 1 m of net pay in the Jamison well. This gave a P10 area of 1,372 km^2 or 339,071 ac. The P90 area is 70% of the P10 or 960 km^2.

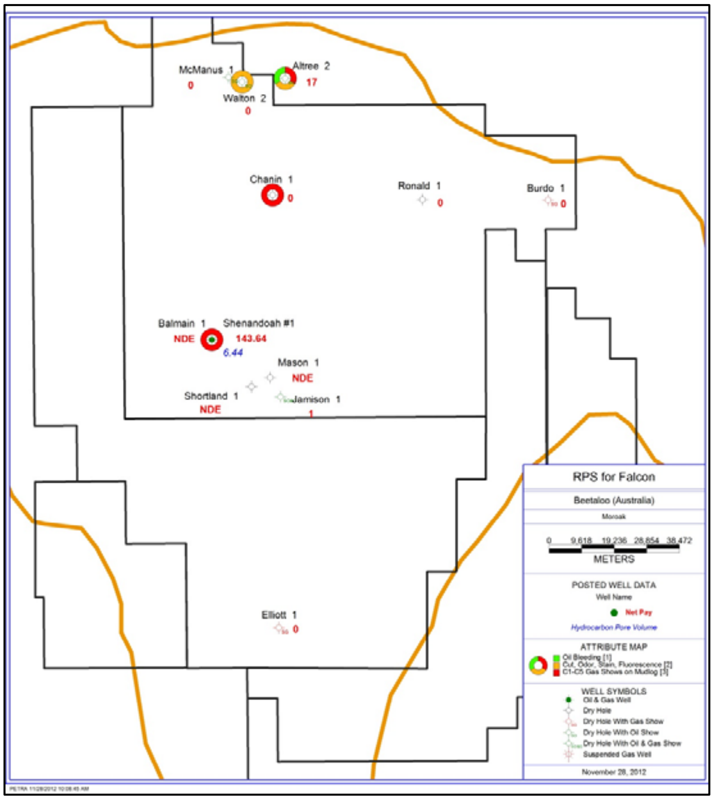


Figure 5.5-13: Moroak Show Map

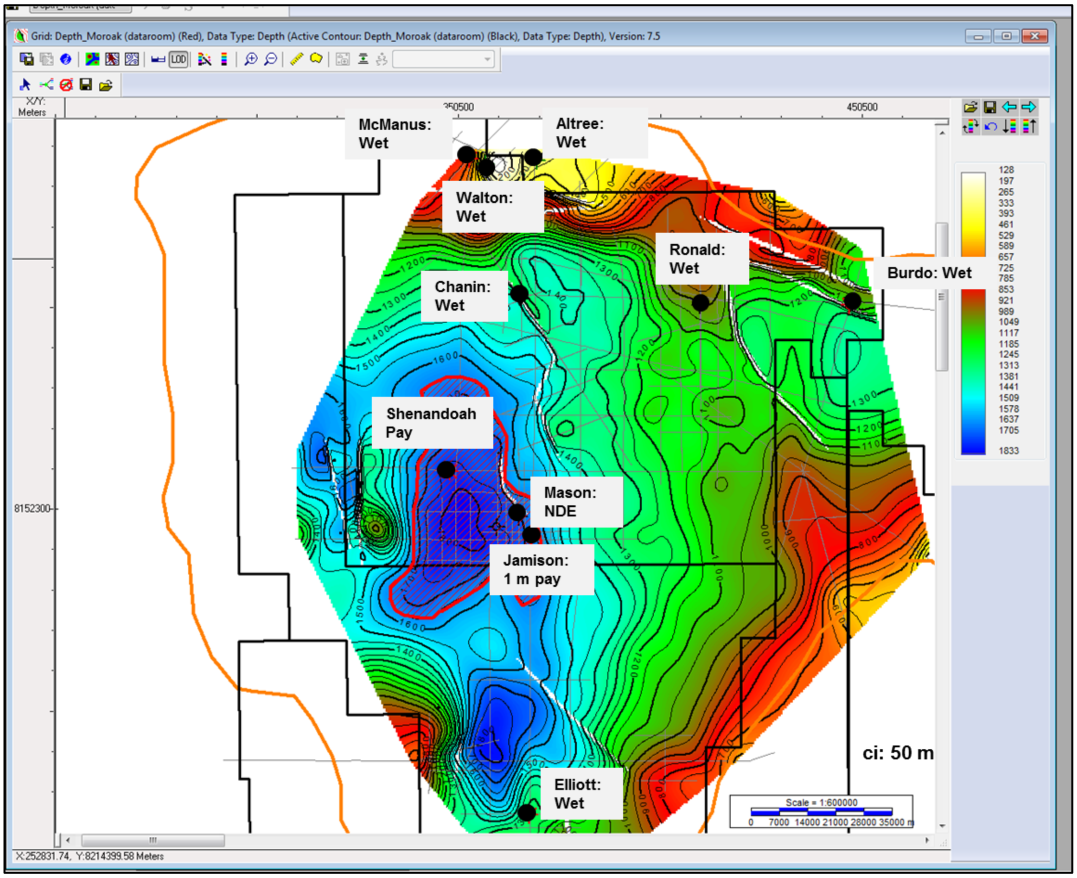


Figure 5.5-14: Moroak Depth Structure Map with BCGA Area

5.5.8 Bessie Creek Formation

The Bessie Creek is a deep sandstone unit penetrated only along the basin edge in the Altree-2 and Walton-2. Figure 5.5-15 has the show information for the Bessie Creek sandstone. Of the two wells penetrating the formation, the Walton-2 was wet, but the Altree-2 calculated 42 m of oil pay. These wells are on the flank of the basin leaving the center of the basin for a potential BCGA. As the BCGA may occur where the Middle Velkerri source rock in in the gas window, the P10 area (Figure 5.5-16) is coincident with the Middle Velkerri gas generation window and is 9,302 km^2 (2,298,607 ac.). The P90 is 70% of the P10 area or 6511 km^2.

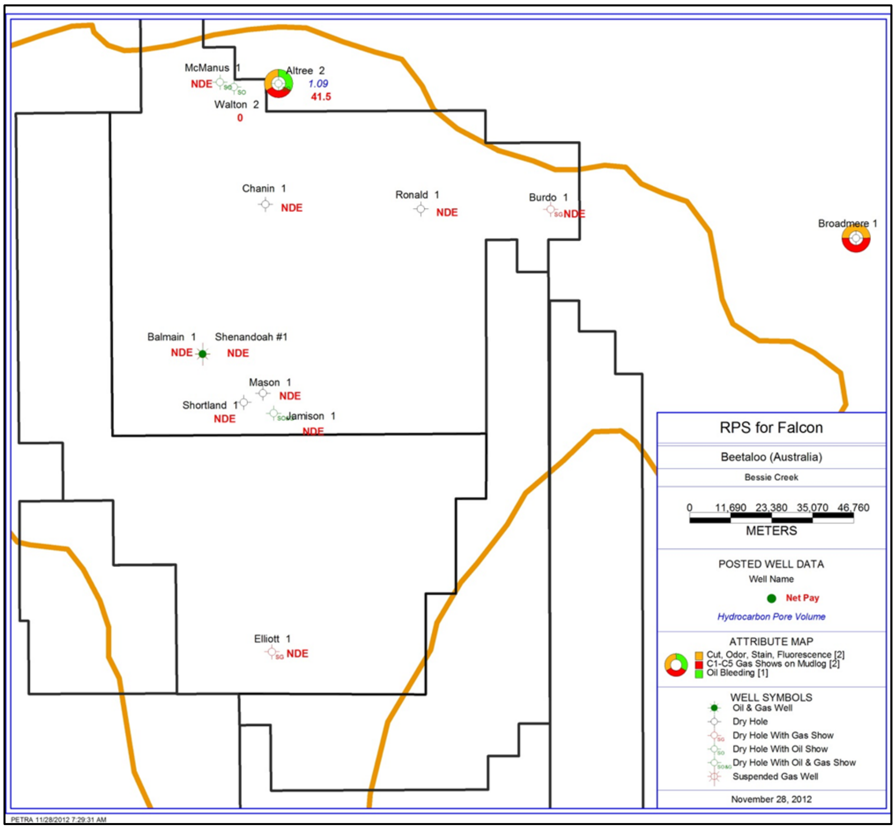


Figure 5.5-15: Bessie Creek Show Map

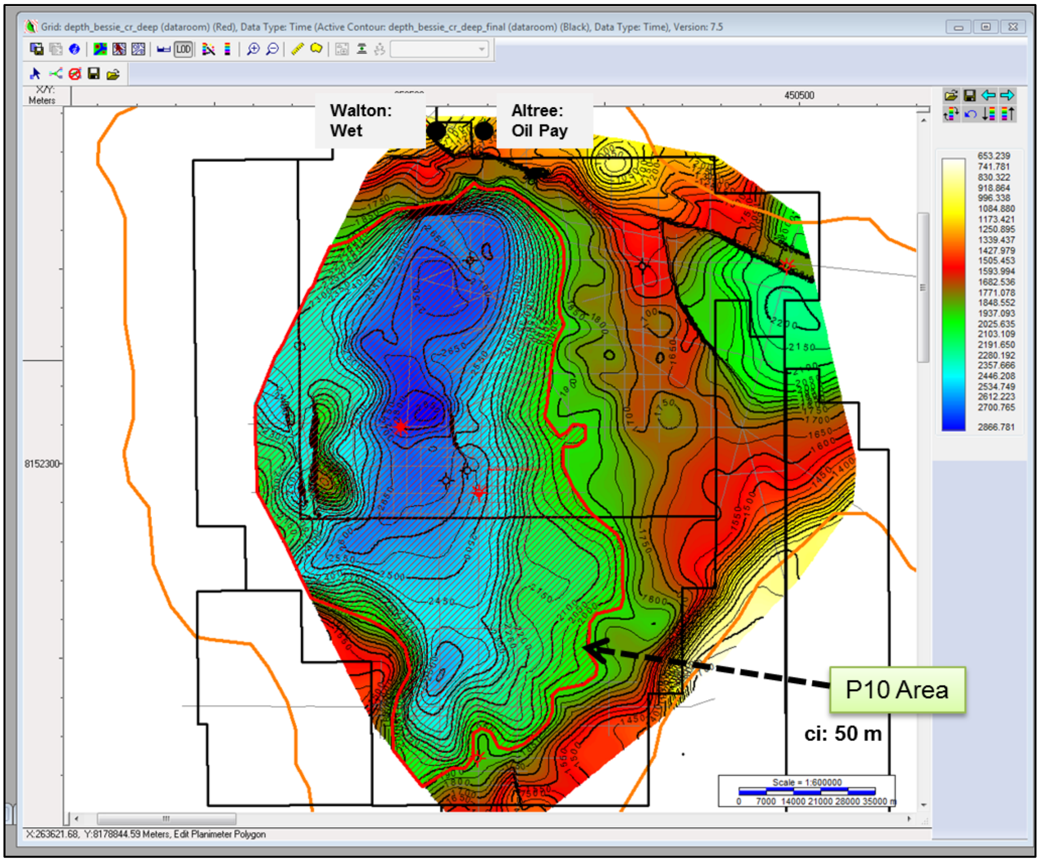


Figure 5.5-16: Bessie Creek Depth Structure Map with BCGA Area

5.5.9 Probabilistic Resource Estimates

Potentially recoverable Resources were estimated for five intervals; three in the unconventional shale for the Upper Kyalla, the Lower Kyalla (partitioned into oil and gas windows), and Middle Velkerri formations (also partitioned into the oil and gas window) and two with BCGA potential in the Moroak and Bessie Creek sandstone in the Beetaloo Basin:

- Kyalla Upper Oil
- Kyalla Lower Oil
- Velkerri Middle Oil
- Kyalla Lower Gas
- Velkerri Middle Gas
- Moroak Sandstone Gas
- Bessie Creek Sandstone Gas

The probabilistic Resource estimates were computed using the REP™ (Logicom E&P Ltd) software. This software allows for input of a variety of probability distributions for each uncertain parameter. The program then performs a large number of iterations randomly sampling each variable and honoring the dependencies that were input. The number of iterations was set at 100,000, which achieved the desired level of stability of the resulting answers. The results include a probability distribution for the output, sampled probability for the inputs, and sensitivity analysis showing which input parameters have the most effect on the uncertainty in each output parameter.

Once the Resource potential of each interval had been calculated for the basin, each interval was reviewed on a well by well basis to determine which wells might be assigned a more representative area to define the currently identified leads and prospects for the purposes of determining Prospective Resources at this stage of the basin's exploration.

Section 5.5.9.2 discusses the risking of each play (the resource potential for each interval and maturity window) and the further risking for each identified 'prospect' within the various intervals as currently sampled by the existing wells. As exploration (and subsequent appraisal) continues, RPS expects the number of prospects (or 'sweetspots') to increase and become better defined and prioritised.

5.5.9.1 Resource Potential Input Parameters for the Beetaloo Basin

The parameters required for the probabilistic analysis of the Resource potential of the Beetaloo Basin are summarized in Tables 5.5.9.1-1, 5.5.9.1-2 and 5.5.9.1-3 shown below.

Table 5.5.9.1-1 - Input parameters for Kyalla Upper & Lower and Velkerri Middle shales

Kyalla Upper Oil	**Units**	**P90**	**P50**	**P10**
Area	acres	1,092,505	1,226,971	1,377,987
Thickness	m	35.05	47.24	63.40
Shape Factor	%	100	100	100
Porosity	%	8.3	8.97	9.7
Sw	%	34.60	39.20	44.40
FVF	rb/stb	1.01	1.13	1.26
GOR	scf/bbl	201	281	402
Oil Rec Fact	%	2.00	3.74	7.00
Kyalla Lower Oil	**Units**	**P90**	**P50**	**P10**
Area	acres	2,195,776	2,624,453	3,136,820
Thickness	m	70.00	85.10	103.00
Shape Factor	%	100	100	100
Porosity	%	6.6	6.7	6.8
Sw	%	49.7	50.6	51.5
FVF	rb/stb	1.10	1.18	1.26
GOR	scf/bbl	201	281	402
Oil Rec Fact	%	2.00	3.74	7.00
Velkerri Middle Oil	**Units**	**P90**	**P50**	**P10**
Area	acres	1,553,019	1,856,212	2,218,598
Thickness	m	67.8	129	245
Shape Factor	%	100	100	100
Porosity	%	8.8	10.2	11.8
Sw	%	37.2	38.8	40.4
FVF	rb/stb	1.01	1.13	1.26
GOR	scf/bbl	201	281	402
Oil Rec Fact	%	2.00	3.74	7.00

Table 5.5.9.1-2 - Input parameters for Kyalla Lower and Velkerri Middle Shales

Kyalla Lower Gas	**Units**	**P90**	**P50**	**P10**
Area	acres	758,063	906,056	1,082,942
Thickness	m	31.09	40.84	53.64
Shape Factor	%	100	100	100
Porosity	%	7.60	8.36	9.20
Sw	%	40.10	42.40	44.90
FVF	vol/vol	140	205	300
Gas Rec Fact	%	60.00	71.40	85.00
Velkerri Middle Gas	**Units**	**P90**	**P50**	**P10**
Area	acre	1,609,026	1,923,153	2,298,607
Thickness	m	25	29.6	35
Shape Factor	%	100	100	100
Porosity	%	8.8	10.2	11.8
Sw	%	37.2	38.8	40.4
FVF	vol/vol	140	205	300
Gas Rec Fact	%	60.00	71.40	85.00

Table 5.5.9.1-3 - Input parameters for Moroak and Bessie Creek Sandstones

Moroak SS Gas	Units	P90	P50	P10
Area	acres	237,350	283,687	339,071
Thickness	m	4.2	24.7	144
Shape Factor	%	100	100	100
Porosity	%	5.5	6.63	8
Sw	%	37.2	38.8	40.4
FVF	vol/vol	140	205	300
Gas Rec Fact	%	60.00	71.40	85.00
Bessie Creek SS Gas	**Units**	**P90**	**P50**	**P10**
Area	acres	1,609,026	1,923,153	2,298,607
Thickness	m	36.4	41.1	46.5
Shape Factor	%	100	100	100
Porosity	%	5.06	6.26	7.75
Sw	%	46	55.9	67.9
FVF	vol/vol	140	205	300
Gas Rec Fact	%	60.00	71.40	85.00

5.5.9.2 Risk and Uncertainty

Resource plays, particularly "shale" plays, are notoriously difficult to assign an appropriate level of risk in terms of assessing the likelihood of making a successful discovery (i.e flowing potentially commercial quantities of hydrocarbons to surface under test) within what is usually a regionally extensive (hundreds of thousands to millions of acres) layer of variable quality but generally low porosity, low permeability rock with internal hydrocarbon generation potential. Such discoveries and subsequent developments almost always occur in areas where many necessary components (i.e various geochemical, formation continuity and mechanical properties) all occur in the same place, usually a relatively restricted area or areas compared to the resource play, known as “Sweet Spots”. These “Sweet Spots” are the equivalent to the more tradtional ‘trap’ areas (or Prospects) associated with conventional hydrocarbon accumulations.

RPS’ methodology is similar to that used for conventional reservoirs (see Section 3.2.2) in that the risk is divided into a Play risk and an individual Prospect risk. However, the component parameters that make up the Play and Prospect risk have been adapted to capture the main elements that make up a working unconventional hydrocarbon play and prospects therein.

Play Risk

Three main components are considered in assessing the risk of a shale play, namely:

Basin – characteristics likely to promote the deposition of areally extensive clastic sequences under relatively stable conditions over periods of ‘geological time’ (hundreds of thousands to millions of years) such that the predicted shale sequence is present at a suitable depth and laterally continuous.

Burial history – evidence of sufficient burial characteristics (depth, thickness of over-burden, temperature gradient etc) likely to have resulted in hydrocarbon generation within organic rich source rocks.

Organic content – evidence that sufficient organic content exists to promote hydrocarbon generation. This can be assigned as likely from core sample measurements where established minima (see Jarvie, 2012) are exceeded by some degree or proved up by test data (preferably from within, but not necessarily limited to, the generating shale itself).

“Sweet Spot” or Prospect Risk

Individual “Sweet Spots” or prospects are risked based on three main component groupings:

Geochemical – the specific area in question (sampled by a well or wells) must demonstrate the correct kerogen type, acceptable TOC and hydrocarbon indices (HI), and thermal maturity. Each of these parameters are considered based on the well data and assigned a risk. The lowest chance of success from the three is passed through to the prospect risk matrix.

Mechanical – the specific area in question must have certain mechanical properties that will likely promote effective fracturing (necessary to create permeability near the well-bore and allow hydrocarbons to be produced). Such properties include brittleness, natural fractures, clay content, over-pressure and present-day stress regimes. The lowest chance of success from the three properties is passed to the prospect risk matrix.

Continuity – the specific area in question must favourably located such that the Geochemical and Mechanical parameters and shale thickness are likely to extend for sufficiently long distances from the well(s) to make the prospect large enough to drill a significant number of relative low EUR wells such that production will be commercially viable. Evidence that the seismic interpretation and depth conversion correctly define the “Sweet Spot”. Evidence such as position withn the basin structure and isopach mapping is considered and risked accordingly.

For each identified potential prospect (where rock has already been sampled by a well and possibly tested but at low rates over a short unsustained period or from an adjacent zone rather than the “shale” itself), the play risk and prospect risk are combined such that the product of the two becomes the individual prospect risk or geological probability of success (“GPoS”) as recognised by PRMS.

For the Beetaloo Basin, RPS has identified the following prospects based on the wells drilled to date:

- Upper Kyalla – The Elliot prospect and the Shenandoah prospect; both prognosed as potentially oil prospects.
- Lower Kyalla – The Burdo, Roanld and Chanin prospects in the oil window and the Shenandoah, Jamison and Elliot prospects in the gas window.
- Middle Velkerri – The Walton-McManus prospect in the oil window and the Shenandoah, Jamison and Elliot prospects in the gas window.

The Moroak and Bessie Creek tight sand plays are risked as basin centered gas accumulation (BCGA) plays but have no identified prospects at this time.

Tables 5.5.9.2-1 and 5.5.9.2-2 below show the Play and Prospect Risk derivation for the formations and prospects.

Table 5.5.9.2-1 – Play Risk Summary for Beetaloo Shales

Zone	Phase	Basin	Burial History	Organic Content	Play Risk	Comments
Upper Kyalla	Oil	100%	100%	80%	80%	No test from Upper Kyalla. Variable TOC/HI observed in wells.
Lower Kyalla	Oil	100%	100%	50%	50%	No test from Lower Kyalla and no insitu samples. Some shows.
	Gas	100%	100%	90%	90%	Gas tested in adjacent clayey-siltstone. Reasonable TOC/HI in most wells.
Middle Velkerri	Oil	100%	100%	80%	80%	No test from Middle Velkerri. Reasonable TOC/HI in one well at far north of basin area.
	Gas	100%	100%	100%	100%	Gas tested from Middle Velkerri.

Table 5.5.9.2-2 – Prospect Risk Summary for Beetaloo Shales

Prospect	Zone / Phase	Geochem	Mech.	Cont.	Prospect Risk	Play Risk	GPoS	Comments
Shenandoah (incl Jamison)	Upper Kyalla / Oil	100%	50%	100%	50%	80%	**40%**	No data on Mech. for all prospects below
Elliot		50%	50%	50%	12.5%		**10%**	Poor well up-dip of potentially good loc.
Burdo	Lower Kyalla / Oil	25%	50%	100%	12.5%	50%	**6.25%**	No TOCs etc in well
Ronald		25%	50%	100%	12.5%		**6.25%**	No TOCs etc in well
Chanin		25%	50%	100%	12.5%		**6.25%**	No TOCs etc in well
Shenandoah	Lower Kyalla / Gas	100%	50%	100%	50%	90%	**45%**	Reasonable TOCs etc
Jamison		100%	50%	100%	50%		**45%**	Reasonable TOCs etc
Elliot		50%	50%	50%	12.5%		**11.25%**	Poor well up-dip of potentially good loc.
Walton-McManus	Middle Velkerri / Oil	100%	50%	100%	50%	80%	**40%**	Reasonable TOCs etc
Shenandoah	Middle Velkerri / Gas	100%	50%	100%	50%	100%	**50%**	Reasonable TOCs etc
Jamison		80%	50%	80%	32%		**32%**	No data in M.V. but other zones good
Elliot		50%	50%	50%	12.5%		**12.5%**	Poor well up-dip of potentially good loc.

The Moroak and Bessie Creek sandstones are potential BCGA plays and have been risked using the more conventional approach of Source, Reservoir and Seal. Source and seal are more or less assured as they are inter-bedded with the Lower Kyalla and Middle Velkerri shales which have been assigned very high probabilities of being a working source rock for gas (see Table 5.5.9.1) and will also likely act as a seal relative to the sandstone porosity. The main remaining play risk is reservoir effectiveness since frac'ing is likely to be required and is untested. A natural flow test was attempted in the Moroak in the Shenandoah-1 well and was a failure. The presence of effective reservoir (even allowing for potential frac'ing success) is therefore no better than 50% which becomes the play risk for these potential BCGAs.

5.5.9.3 Summary of Resources

Basin Resource Potential – Prospective Resources (Play level)

Using the parameters described in Section 5.5.9.1 and the Play Risks described in Section 5.5.9.2, RPS has calculated the Prospective Resource potential for the Beetaloo Basin at the Play level as shown in Tables 5.5.9.3-1 to 5.5.9.3-3.

Table 5.5.9.3-1 – Prospective Shale Oil Resources (Play level) Summary for Beetaloo Basin

Resource Play	Potentially In-place				Potentially Recoverable			
	P90	P50	P10		Low Estimate	Best Estimate	High Estimate	**Play risk**
Unconventional Shale Oil (MMstb)								
Kyalla Upper	49,663	70,985	100,700		1,290	2,654	5,526	80%
Kyalla Lower	121,327	159,658	209,528		3,023	5,971	12,011	50%
Velkerri Middle	168,927	337,982	673,176		4,942	12,720	32,503	80%

Table 5.5.9.3-2 – Prospective Shale Gas Resources (Play level) Summary for Beetaloo Basin

Resource Play	Potentially In-place				Potentially Recoverable			
	P90	P50	P10		Low Estimate	Best Estimate	High Estimate	**Play risk**
Unconventional Shale Gas (Tcf)								
Kyalla Lower	31.47	52.26	86.97		21.83	37.29	63.81	90%
Velkerri Middle	65.012	104.22	166.77		45.09	74.50	122.78	100%

Table 5.5.9.3-3 – Prospective BCGA Resources (Play level) Summary for Beetaloo Basin

Resource Play	Potentially In-place				Potentially Recoverable			
	P90	P50	P10		Low Estimate	Best Estimate	High Estimate	**Play risk**
BCGA Gas (Tcf)								
Moroak Sst	1.36	8.26	51.24		0.95	5.90	36.72	50%
Bessie Creek Sst	35.22	62.31	107.03		24.58	44.31	78.48	50%

Prospective Resources – Areas centered around well penetrations (Prospect level)

RPS has assigned Prospective Resources (Prospect level) to three shale plays within the Beetaloo Basin, namely Unconventional Shale Oil in the Kyalla and Middle Velkerri Formations (above 1500m TVDSRD), and Unconventional Shale Gas in the lower most Kyalla and Middle Velkerri. No wells have yet proved the viability of the Moroak and Bessie Creek sandstones and these remain as Propsective Resource (Play level) potential (possibly BCGA in type) but no Prospective Resources (Prospect level) have been assigned at this time.

To calculate the potential volumes associated with the prospects, the same reservoir parameter ranges as were used for the regional Resource potential calculations (Section 5.5.9.1) with the exception of the area assigned to each prospect. As described above, each prospect is currently based on a single well with the exception of Upper Kyalla "Shenendoah" prospect which has been amalgamated with the three relatively close wells which all exhibit encouraging indications of potential prospectivity.

RPS has estimated, based on experience in similar types of play (mainly in the United States), an average Sweet Spot area of 10,240 acres (based on step-out increments of 640-1280 acres). To get a meaningful range of uncertainty, RPS has adopted a P90 area of 2560 acres and a P10 of 20,480 acres which gives an acceptable ratio between P10 and P90 for the stage of exploration that the Beetaloo Basin is at. This range is used for each prospect (single well data points) except the Upper Kyalla "Shenandoah" prospect as described above. This prospect is assessed as potentially having an area of 10,240 acres (P90) to 81,920 acres (P10). These areas were substituted into the REP™ runs prepared earlier for the Resource potential calculations and re-run to derive the potentially recoverable volumes of hydrocarbon associated with each prospect.

The total estimated range of Prospective Resources by play type is given in Tables 5.5.9.3-1 to 5.5.9.3-2 below. The Gross Prospective Resources are those allocated to each prospect on a 100% WI basis and the Net Attributable is the volume adjusted for WI and Royalties which would be attributable to Falcon in the event of success. The Prospective Resources are aggregated using RPS' standard presentation to show the statistically correct range of outcomes assuming all prospects are successfully discovered or assuming at least one prospect is successful taking into account the range of outcomes between the prospects and the appropriate chance of success (GPoS). It should be noted that it will take a number of wells to confirm the volume ranges quoted.

Table 5.5.9.3-1 – Prospective Shale Oil Resources (Prospect level) Summary for Beetaloo Basin

	Gross				**Net Attributable**			
Prospect (WI=73%)	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	**GPoS**
Unconventional Oil (MMstb)								
Shenandoah – Upper Kyalla	17.5	62.7	223.0		9.71	34.79	123.72	40%
Elliot – Upper Kyalla	4.4	15.7	55.8		2.44	8.71	30.96	10%
Burdo – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%
Ronald – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%
Chanin – Lower Kyalla	4.8	16.5	57.5		2.66	9.15	31.90	6.25%
Walton-McManus – Middle Velkerri	12.2	49.6	198.0		6.77	27.52	109.85	40%
Arithmetic Aggregation[1]	**48.5**	**177.5**	**649.3**		**26.91**	**98.48**	**360.23**	**<<1%**
Stochastic Aggregation[2]	**130.0**	**245.0**	**497.0**		**72.12**	**135.93**	**275.74**	**<<1%**
Stochastic Aggregation[3]	**14.2**	**69.4**	**253.0**		**7.88**	**38.50**	**140.36**	**73%**

1: Although commonly done, it is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Statistical Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (**62.14** MMstb Net) constitutes the true expectation of success.

Table 5.5.9.3-2 – Prospective Shale Gas Resources (Prospect level) Summary for Beetaloo Basin

Prospect (WI=73%)	**Gross**				**Net Attributable**			
	Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate	**Risk Factor**
Unconventional Gas (Bcf)								
Shenandoah – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	45%
Jamison – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	45%
Elliot – Lower Kyalla	95.1	299.0	958.0		52.76	165.89	531.50	11.25%
Shenandoah – Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	50%
Jamison – Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	32%
Elliot –Middle Velkerri	90.5	281.0	889.0		50.21	155.90	493.22	12.5%
Arithmetic Aggregation[1]	**556.8**	**1740.0**	**5541.0**		**308.91**	**965.35**	**3074.15**	**<<1%**
Stochastic Aggregation[2]	**1400.0**	**2342.0**	**4015.0**		**776.72**	**1299.34**	**2227.52**	**<<1%**
Stochastic Aggregation[3]	**184.0**	**703.0**	**1878.0**		**102.08**	**390.02**	**1041.91**	**92%**

1: Although commonly done, it is statistically incorrect to arithmetically sum probabilistic estimates of P90, P50 and P10. To do so tends to under-estimate the true P90 and over-estimate the true P10 of the combined distribution as seen when compared to the Statistical Aggregation in the next row. This is exacerbated by the introduction of GPoS into the statistical aggregation (see below).

2: Statistical Aggregation assuming that all prospects are successful. The probability of this occurring is the product of each individual risk (GPoS) and is therefore very small.

3: Statistical Aggregation assuming at least one prospect is successful. This total takes into account all possible successful outcomes and the mean value for the resultant distribution (**504.31** Bcf Net) constitutes the true expectation of success.

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APPENDIX A - GLOSSARY OF TERMS AND ABBREVIATIONS

API	American Petroleum Institute
AUS$	Austrailian Dollar
B	Billion
bbl(s)	Barrels
bbls/d	barrels per day
Bcm	billion cubic metres
B_g	gas formation volume factor
B_o	oil formation volume factor
BTU	British Thermal Unit
Bscf	billions of standard cubic feet
Bwpd	barrels of water per day
CO_2	Carbon dioxide
DST	Drill stem test
EMV	Expected Monetary Value
EP	Exploration Permit
ft	Feet
ftSS	depth in feet below sea level
GDT	Gas Down To
GIP	Gas in Place
GIIP	Gas Initially in Place
GOR	gas/oil ratio
GRV	gross rock volume
GWC	gas water contact
H_2S	Hydrogen sulphide
HI	hydrogen index
IRR	internal rate of return
KB	Kelly Bushing
k	permeability
Km	Kilometres
Km^2	square kilometres
M	Thousand
MM	Million
M$	thousand US dollars
MM$	million US dollars
MD	measured depth
MDT	Modular (formation) dynamic tester
mD	permeability in millidarcies

m^3	cubic metres
m^3/d	cubic metres per day
MMscf/d	millions of standard cubic feet per day
m/s	metres per second
Msec	Milliseconds
NDE	No Deep Enough
NTG	net to gross ratio
NPV	Net Present Value
OWC	oil water contact
Petroleum	deposits of oil and/or gas
Phi	porosity fraction
PVT	pressure volume temperature
RFT	repeat formation tester
RKB	relative to kelly bushing
SCAL	Special Core Analysis
scf	standard cubic feet measured at 14.7 pounds per square inch and 60° F
sscf/d	standard cubic feet per day
sscf/stb	standard cubic feet per stock tank barrel
Sm^3	standard cubic metres
S_o	oil saturation
Stb	stock tank barrels measured at 14.7 pounds per square inch and 60° F
Stb/d	stock tank barrels per day
STOIIP	stock tank oil initially in place
S_w	water saturation
$	United States Dollars
Tcf	trillion cubic feet
TVDSRD	True vertical depth relative to seismic reference datum
TVDSS	true vertical depth (sub-sea)
TVT	true vertical thickness
TWT	two-way time
US$	United States Dollar
V_{sh}	shale volume
ϕ	porosity
μ	viscosity

APPENDIX B - SPE/WPC/AAPG/SPEE RESERVE/RESOURCE DEFINITIONS

The following is extracted from the SPE/WPC/AAPG/SPEE PRMS 2007 using the section numbering and spelling from PRMS.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulphide and sulphur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure B.1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

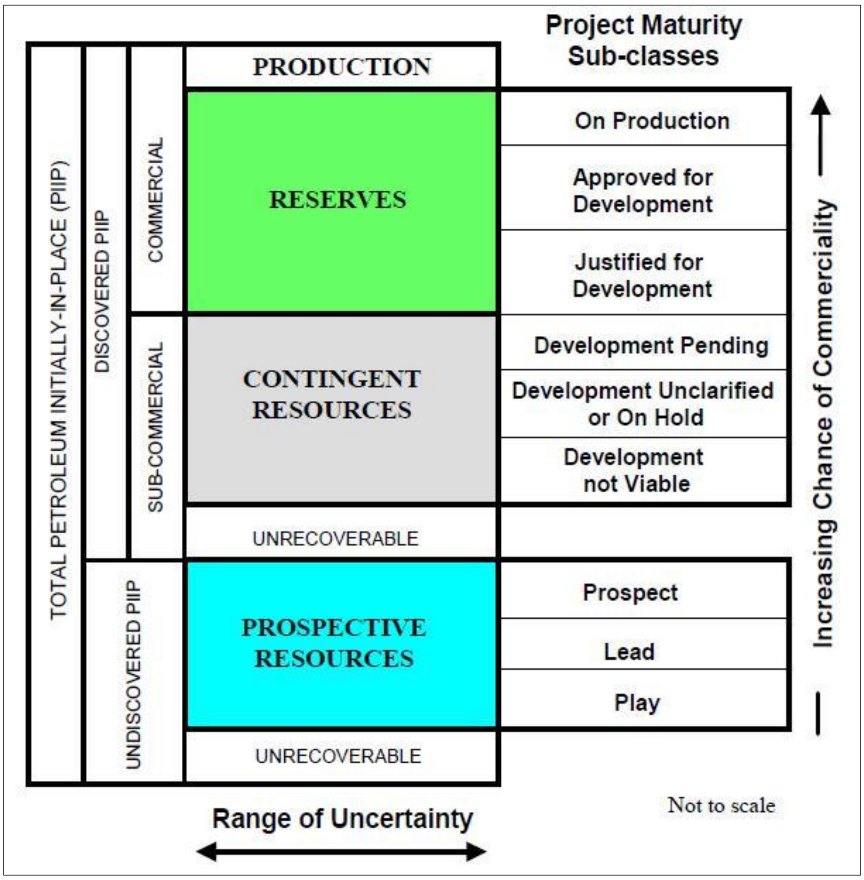


Figure B.1: Resources Classification Framework

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality, that is, the chance that the project that will be developed and reach commercial producing status.

A further option for classification purposes is to subdivide Contingent Resource projects on the basis of economic status, into Marginal or Submarginal Contingent Resources. In addition, PRMS indicates that, where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is "undetermined." As with the classification options for Reserves that are based on reserves status, this is an optional subdivision that may be used alone or in combination with project maturity subclasses. Broadly speaking, one might expect the following approximate relationships between the two optional approaches:

<table>
<tr><th>Project Maturity Subclass</th><th>Additional Sub-Classification</th><th>Economic Status</th></tr>
<tr><td>Development Pending</td><td>Pending</td><td rowspan="2">Marginal Contingent Resources</td></tr>
<tr><td rowspan="2">Development Unclarified or On Hold</td><td>On Hold</td></tr>
<tr><td>Unclarified</td><td>Undetermined</td></tr>
<tr><td>Development Not Viable</td><td>Not Viable</td><td>Sub-marginal Contingent Resources</td></tr>
</table>

The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage.

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure A1-2) that may be described as follows:

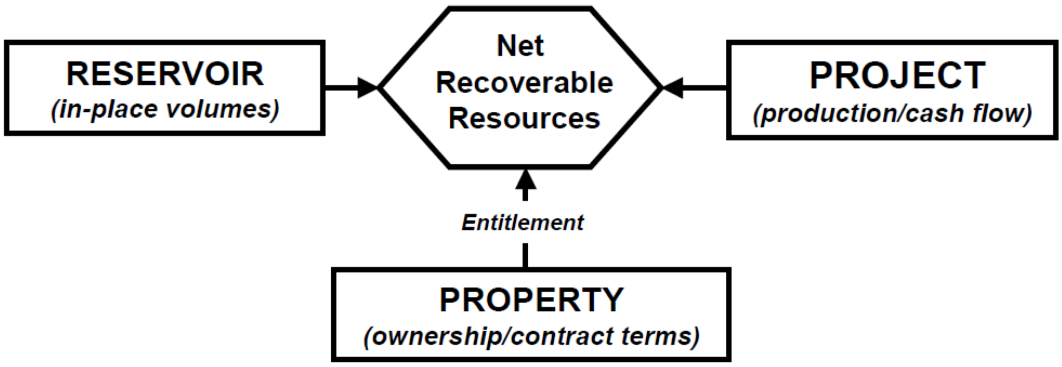


Figure B.2: Resources Evaluation Data Sources

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.
- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities. "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer. The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project.

APPENDIX C – COMPUTER PROCESSED INTERPRETATIONS (CPI)

Figure C-1
Well ALTREE-2 – Velkerri Middle, CPI

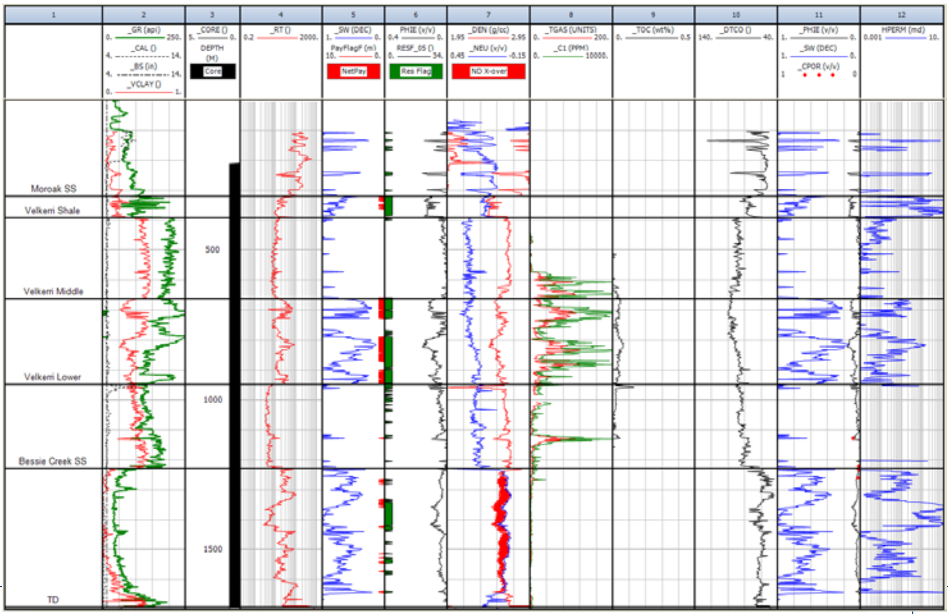


Figure C-2
Well ALTREE-2 – Velkerri Middle Summation

Petrophysical Zone Averages Report

Well : ALTREE 2
Date : 11/16/2012 10:15:10 AM

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Moroak SS	320.00	392.00	72.00	67.48	0.937	0.116	0.798	0.174	7.81	1.58
2	Velkerri Shale	392.00	662.00	270.00	11.48	0.043	0.060	0.846	0.411	0.69	0.11
3	Velkerri Middle	662.00	948.00	286.00	221.23	0.774	0.094	0.429	0.319	20.75	11.86
4	Velkerri Lower	948.00	1229.00	281.00	60.35	0.215	0.063	0.920	0.374	3.80	0.31
5	Bessie Creek SS	1229.00	1693.00	464.00	139.29	0.300	0.067	0.819	0.018	9.35	1.69
	All Zones	320.00	1693.00	1373.00	499.84	0.364	0.085	0.634	0.224	42.41	15.54

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Moroak SS	320.00	392.00	72.00	16.88	0.234	0.122	0.650	0.155	2.05	0.72
2	Velkerri Shale	392.00	662.00	270.00	1.37	0.005	0.070	0.638	0.342	0.10	0.03
3	Velkerri Middle	662.00	948.00	286.00	176.63	0.618	0.102	0.372	0.299	18.02	11.32
4	Velkerri Lower	948.00	1229.00	281.00	4.12	0.015	0.091	0.564	0.267	0.37	0.16
5	Bessie Creek SS	1229.00	1693.00	464.00	41.45	0.089	0.061	0.568	0.022	2.52	1.09
	All Zones	320.00	1693.00	1373.00	240.45	0.175	0.096	0.422	0.241	23.07	13.33

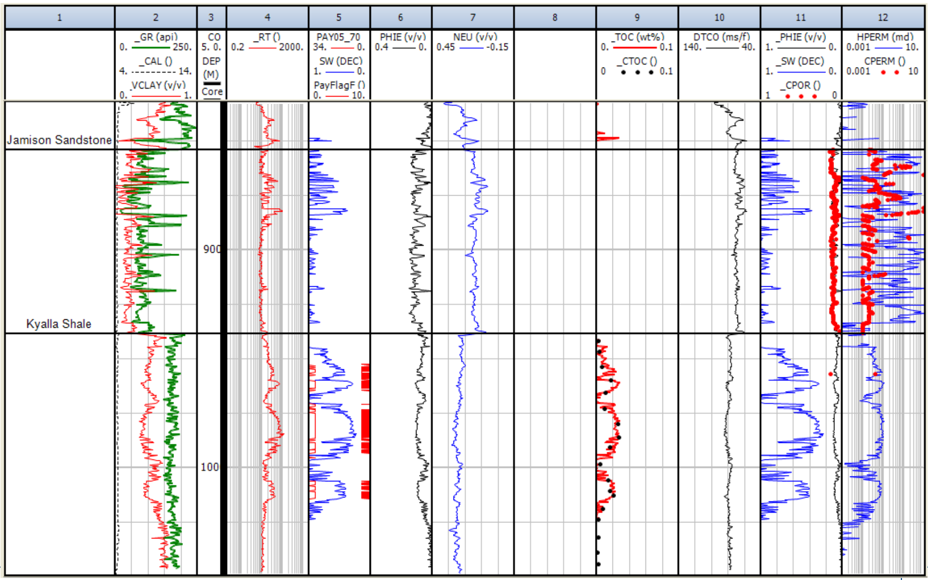
Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Moroak SS	320.00	392.00	0	>= 0.05		<= 0.5
2	Velkerri Shale	392.00	662.00	0	>= 0.05		<= 0.5
3	Velkerri Middle	662.00	948.00	0	>= 0.05		<= 0.5
4	Velkerri Lower	948.00	1229.00	0	>= 0.05		<= 0.5
5	Bessie Creek SS	1229.00	1693.00	0	>= 0.05		<= 0.5
	Pay						
1	Moroak SS	320.00	392.00	0	>= 0.05	<= 0.7	<= 0.5
2	Velkerri Shale	392.00	662.00	0	>= 0.05	<= 0.7	<= 0.5
3	Velkerri Middle	662.00	948.00	0	>= 0.05	<= 0.7	<= 0.5
4	Velkerri Lower	948.00	1229.00	0	>= 0.05	<= 0.7	<= 0.5
5	Bessie Creek SS	1229.00	1693.00	0	>= 0.05	<= 0.7	<= 0.5

Depth Units : m

RPS

Figure C-2
Well BALMAIN-1 – Jamison SS & Kyalla Shale, CPI



RPS

Figure C-4
Well BALMAIN-1 – Kyalla Shale Summation

Petrophysical Zone Averages Report

Well : BALMAIN 1
Date : 11/03/2012 21:26:02

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale	938.50	1050.00	111.16	$$68.94	0.620	0.083	0.537	0.397	5.72	2.65
	All Zones	938.50	1050.00	111.15	$$68.94	0.620	0.083	0.537	0.397	5.72	2.65

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale	938.50	1050.00	111.16	$$35.05	0.315	0.097	0.391	0.357	3.39	2.06
	All Zones	938.50	1050.00	111.15	$$35.05	0.315	0.097	0.391	0.357	3.39	2.06

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla Shale	938.50	1050.00	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla Shale	938.50	1050.00	0	>= 0.05	<= 0.55	<= 0.5

Depth Units : m
$$ indicates missing or null data in the zone.

Figure C-5
Well BURDO-1 – Kyalla SS and Kyalla Shale Lower CPI

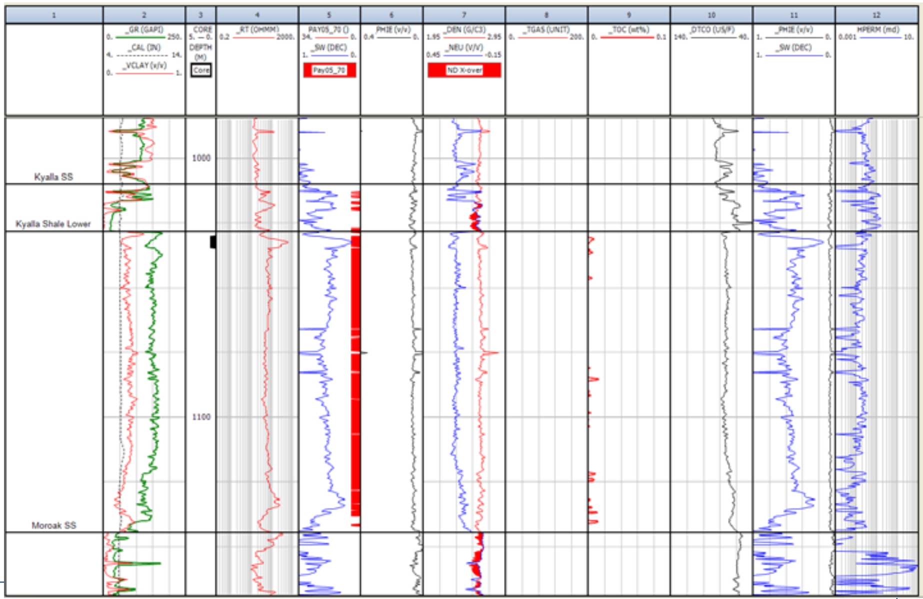


Figure C-6
Well BURDO-1 – Kyalla SS and Kyalla Shale Lower Summation

Petrophysical Zone Averages Report

Well : BURDO 1
Date : 11/3/2012 9:08:05 AM

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla SS	1010.10	1028.30	18.20	15.25	0.838	0.070	0.663	0.117	1.07	0.36
2	Kyalla Shale Lower	1028.30	1144.60	116.30	110.35	0.949	0.066	0.531	0.298	7.27	3.41
	All Zones	1010.10	1144.60	134.50	125.60	0.934	0.066	0.548	0.276	8.33	3.77

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla SS	1010.10	1028.30	18.20	8.35	0.459	0.068	0.539	0.158	0.57	0.26
2	Kyalla Shale Lower	1028.30	1144.60	116.30	103.45	0.890	0.066	0.515	0.295	6.85	3.32
	All Zones	1010.10	1144.60	134.50	111.80	0.831	0.066	0.517	0.285	7.43	3.58

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla SS	1010.10	1028.30	0	>= 0.05		<= 0.5
2	Kyalla Shale Lower	1028.30	1144.60	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla SS	1010.10	1028.30	0	>= 0.05	<= 0.7	<= 0.5
2	Kyalla Shale Lower	1028.30	1144.60	0	>= 0.05	<= 0.7	<= 0.5

Depth Units : m

Figure C-7
Well CHANIN-1 – Kyalla Shale Lower SS CPI

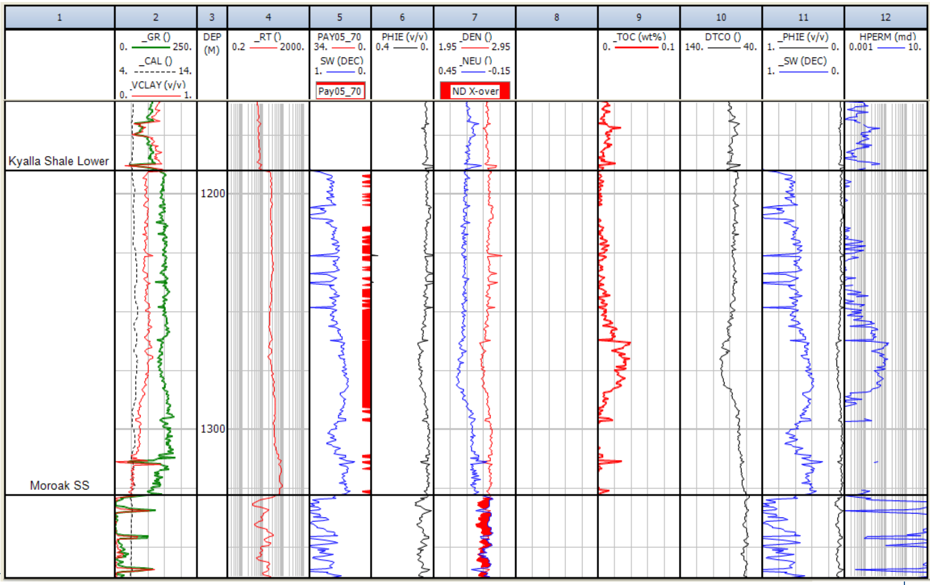


Figure C-8
Well CHANIN-1 – Kyalla Shale Lower Summation

Petrophysical Zone Averages Report

Well : CHANIN 1
Date : 11/03/2012 09:56:55

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale Lower	1190.00	1328.00	138.00	70.00	0.507	0.068	0.497	0.363	4.74	2.38
	All Zones	1190.00	1328.00	138.00	70.00	0.507	0.068	0.497	0.363	4.74	2.38

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale Lower	1190.00	1328.00	138.00	70.00	0.507	0.068	0.497	0.363	4.74	2.38
	All Zones	1190.00	1328.00	138.00	70.00	0.507	0.068	0.497	0.363	4.74	2.38

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla Shale Lower	1190.00	1328.00	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla Shale Lower	1190.00	1328.00	0	>= 0.05	<= 0.7	<= 0.5

Depth Units : m

Figure C-9
Well ELLIOT-1 – Kyalla Shale Lower SS CPI

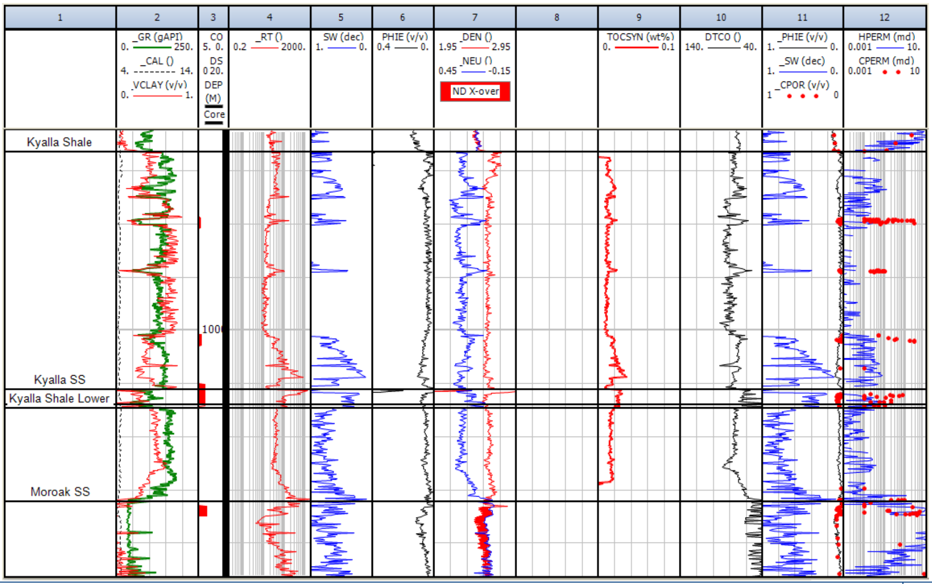


Figure C-10
Well JAMISON-1 – Kyalla Shale and Kyalla SS CPI

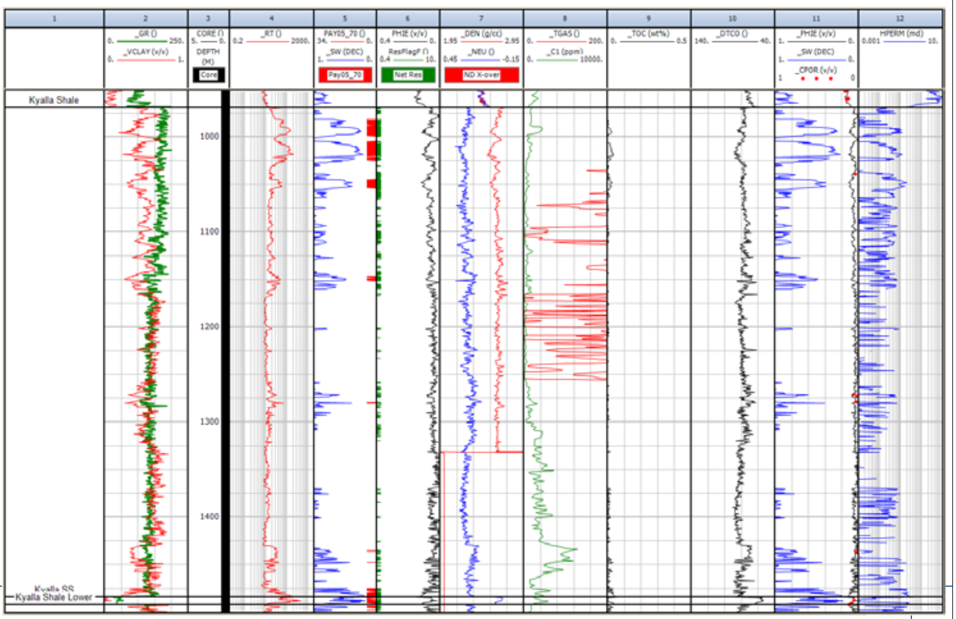


Figure C-11
Well JAMISON-1 – Kyalla Shale Lower CPI

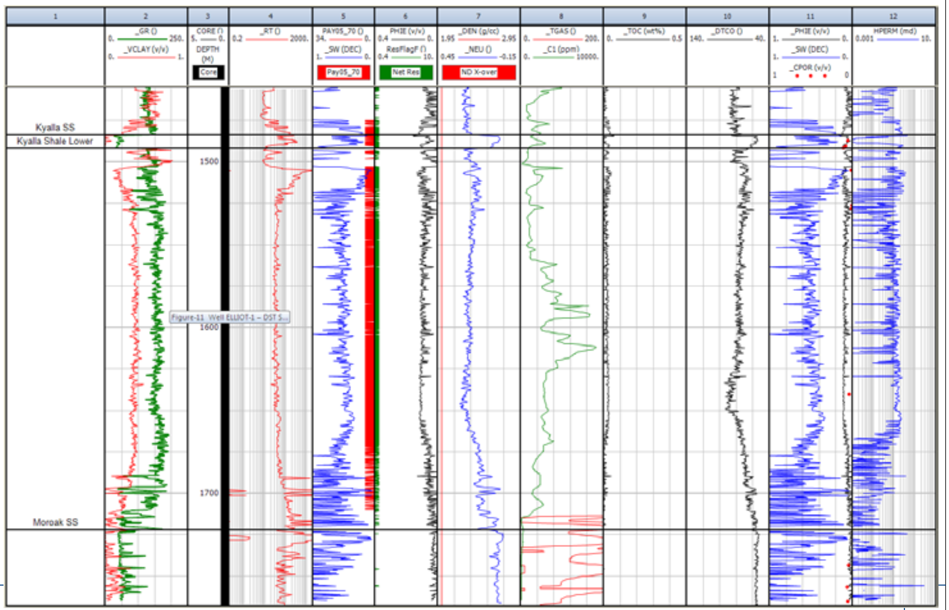


Figure C-12
Well JAMISON-1 – Kyalla Summation

Petrophysical Zone Averages Report

Well : JAMISON 1
Date : 11/15/2012 16:16:43

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale	968.90	1483.90	515.00	150.48	0.292	0.075	0.675	0.391	11.35	3.69
2	Kyalla SS	1483.90	1492.10	8.20	6.80	0.829	0.087	0.484	0.012	0.59	0.31
3	Kyalla Shale Lower	1492.10	1722.00	229.90	182.12	0.792	0.091	0.457	0.329	16.49	8.96
4	Moroak SS	1722.00	1769.00	47.00	$$0.76	0.016	0.055	0.432	0.002	0.04	0.02
	All Zones	968.90	1769.00	800.10	$$340.16	0.425	0.084	0.544	0.349	28.48	12.98

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale	968.90	1483.90	515.00	63.30	0.123	0.088	0.444	0.344	5.54	3.08
2	Kyalla SS	1483.90	1492.10	8.20	5.12	0.625	0.085	0.360	0.011	0.44	0.28
3	Kyalla Shale Lower	1492.10	1722.00	229.90	175.87	0.765	0.092	0.449	0.327	16.13	8.88
4	Moroak SS	1722.00	1769.00	47.00	$$0.76	0.016	0.055	0.432	0.002	0.04	0.02
	All Zones	968.90	1769.00	800.10	$$245.06	0.306	0.090	0.446	0.324	22.14	12.26

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla Shale	968.90	1483.90	0	>= 0.05		<= 0.5
2	Kyalla SS	1483.90	1492.10	0	>= 0.05		<= 0.5
3	Kyalla Shale Lower	1492.10	1722.00	0	>= 0.05		<= 0.5
4	Moroak SS	1722.00	1769.00	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla Shale	968.90	1483.90	0	>= 0.05	<= 0.7	<= 0.5
2	Kyalla SS	1483.90	1492.10	0	>= 0.05	<= 0.7	<= 0.5
3	Kyalla Shale Lower	1492.10	1722.00	0	>= 0.05	<= 0.7	<= 0.5
4	Moroak SS	1722.00	1769.00	0	>= 0.05	<= 0.7	<= 0.5

Depth Units : m
$$ indicates missing or null data in the zone.

Figure C-13
Well MASON-1 – Kyalla Shale CPI

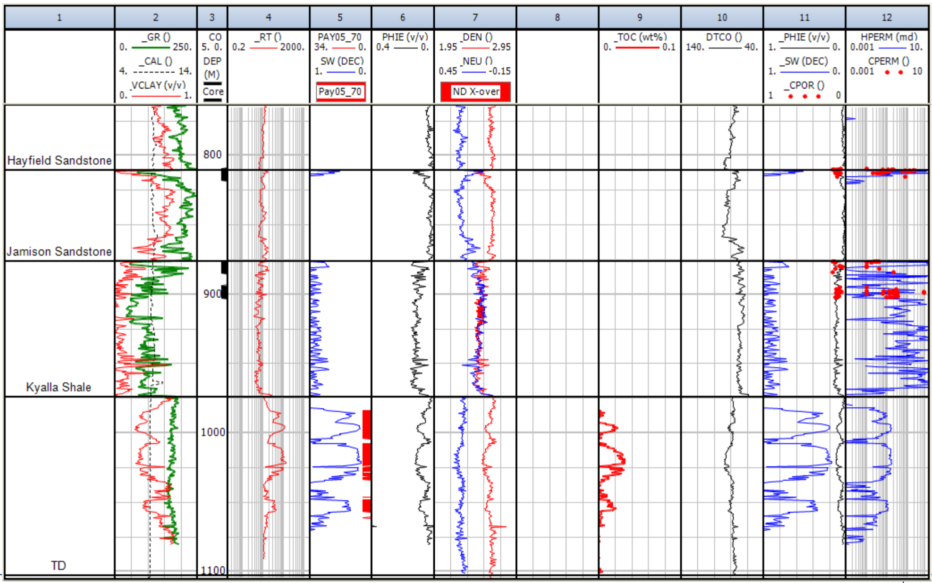


Figure C-14
Well MASON-1 – Kyalla Shale Summation

Petrophysical Zone Averages Report

Well : MASON 1
Date : 11/03/2012 15:23:03

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale	974.00	1103.00	129.00	$$59.74	0.463	0.090	0.360	0.355	5.37	3.44
	All Zones	974.00	1103.00	129.00	$$59.74	0.463	0.090	0.360	0.355	5.37	3.44

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale	974.00	1103.00	129.00	$$56.24	0.436	0.092	0.346	0.348	5.17	3.38
	All Zones	974.00	1103.00	129.00	$$56.24	0.436	0.092	0.346	0.348	5.17	3.38

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla Shale	974.00	1103.00	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla Shale	974.00	1103.00	0	>= 0.05	<= 0.7	<= 0.5

Depth Units : m
$$ indicates missing or null data in the zone.

Figure C-15
Well MCMANUS-1 – Kyalla Shale CPI

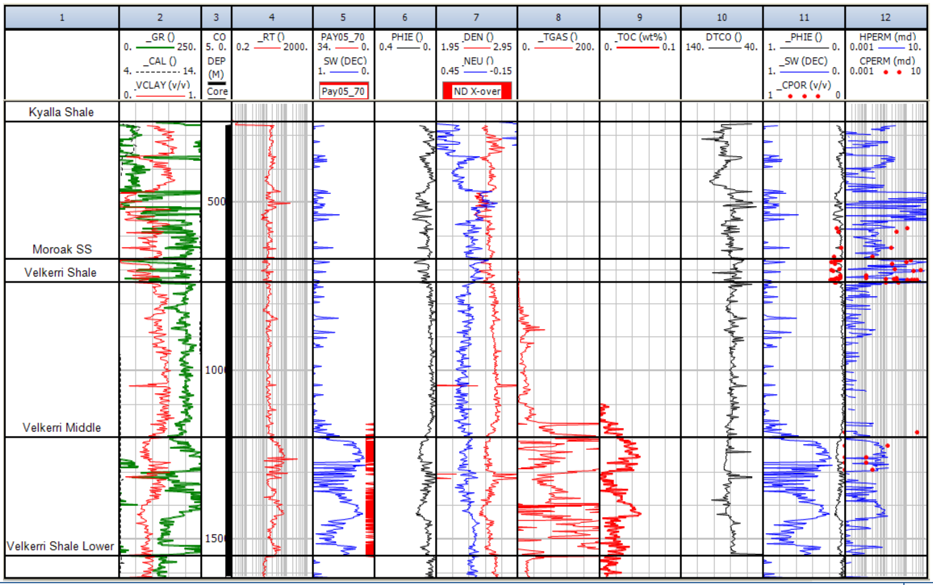


Figure C-16
Well MCMANUS-1 – Kyalla Shale Summation

Petrophysical Zone Averages Report

Well : MCMANUS 1
Date : 11/03/2012 18:50:00

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Velkerri Middle	1199.00	1550.00	351.00	268.54	0.765	0.085	0.399	0.336	22.81	13.72
	All Zones	1199.00	1550.00	351.00	268.54	0.765	0.085	0.399	0.336	22.81	13.72

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Velkerri Middle	1199.00	1550.00	351.00	245.08	0.698	0.088	0.375	0.331	21.44	13.41
	All Zones	1199.00	1550.00	351.00	245.07	0.698	0.088	0.375	0.331	21.44	13.41

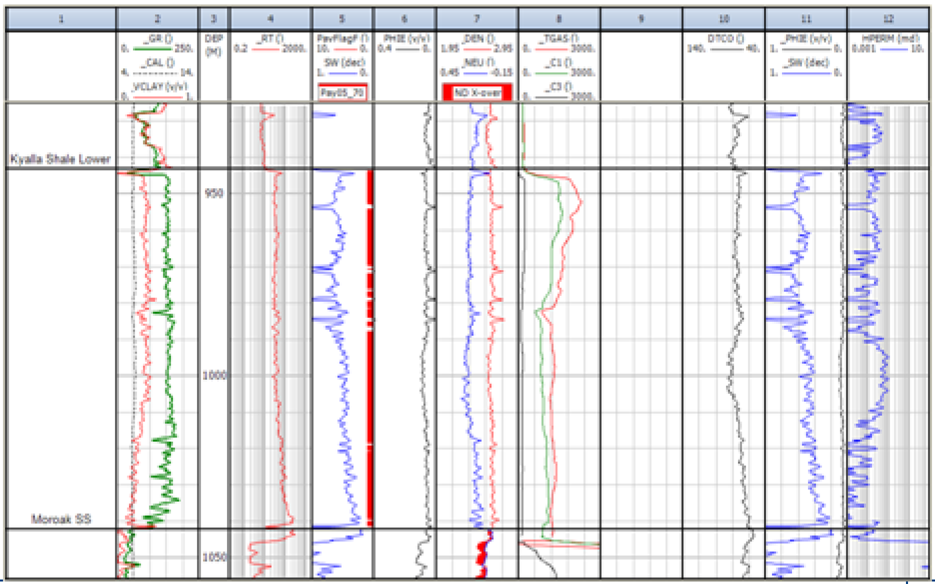
Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Velkerri Middle	1199.00	1550.00	0	>= 0.05		<= 0.5
	Pay						
1	Velkerri Middle	1199.00	1550.00	0	>= 0.05	<= 0.7	<= 0.5

Depth Units : m

RPS

Figure C-17
Well RONALD-1 – Kyalla Shale Lower CPI



RPS

Figure C-18
Well RONALD-1 – Kyalla Shale Lower Summation

Petrophysical Zone Averages Report

Well : RONALD 1
Date : 11/03/2012 19:34:21

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale Lower	943.20	1042.00	98.80	90.64	0.917	0.068	0.505	0.304	6.16	3.05
	All Zones	943.20	1042.00	98.80	90.64	0.917	0.068	0.505	0.304	6.16	3.05

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale Lower	943.20	1042.00	98.80	87.44	0.885	0.068	0.498	0.301	5.99	3.00
	All Zones	943.20	1042.00	98.80	87.44	0.885	0.068	0.498	0.301	5.99	3.00

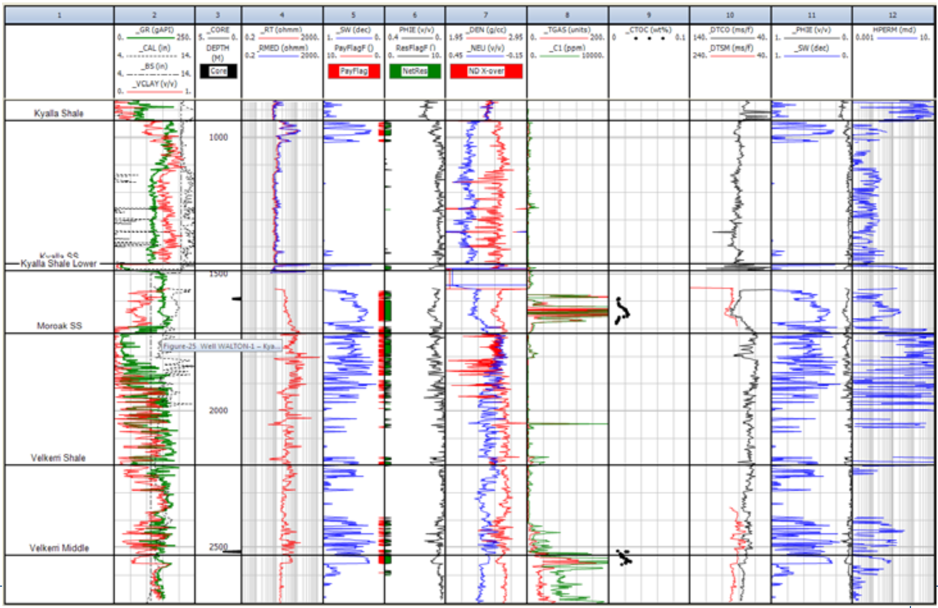
Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla Shale Lower	943.20	1042.00	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla Shale Lower	943.20	1042.00	0	>= 0.05	<= 0.7	<= 0.5

Depth Units : m

RPS

Figure C-19
Well SHENANDOAH-1 – CPI



RPS

Figure C-20
Well RONALD-1 – SHENANDOAH-1 Summation

Petrophysical Zone Averages Report

Well : SHENANDOAH 1
Date : 11/16/2012 9:14:17 AM

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale	938.00	1464.00	526.00	50.57	0.096	0.080	0.501	0.426	4.02	2.01
2	Kyalla SS	1464.00	1487.40	23.40	$$12.98	0.555	0.083	0.954	0.069	1.08	0.05
3	Kyalla Shale Lower	1487.40	1718.00	230.60	$$102.94	0.446	0.076	0.405	0.267	7.87	4.68
4	Moroak SS	1718.00	2200.00	482.00	186.16	0.386	0.079	0.532	0.057	14.68	6.87
5	Velkerri Shale	2200.00	2529.00	329.00	58.37	0.177	0.069	0.344	0.238	4.01	2.63
6	Velkerri Middle	2529.00	2714.00	185.00	$$33.99	0.184	0.074	0.345	0.296	2.53	1.65
	All Zones	938.00	2714.00	1776.00	$$445.01	0.251	0.077	0.476	0.190	34.19	17.90

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Kyalla Shale	938.00	1464.00	526.00	37.46	0.071	0.083	0.383	0.414	3.12	1.93
2	Kyalla SS	1464.00	1487.40	23.40	$$0.64	0.027	0.078	0.304	0.023	0.05	0.03
3	Kyalla Shale Lower	1487.40	1718.00	230.60	$$102.33	0.444	0.076	0.401	0.267	7.81	4.68
4	Moroak SS	1718.00	2200.00	482.00	143.64	0.298	0.080	0.442	0.041	11.55	6.44
5	Velkerri Shale	2200.00	2529.00	329.00	57.91	0.176	0.069	0.341	0.237	3.99	2.63
6	Velkerri Middle	2529.00	2714.00	185.00	$$30.02	0.162	0.077	0.308	0.271	2.32	1.60
	All Zones	938.00	2714.00	1776.00	$$372.01	0.209	0.078	0.400	0.190	28.84	17.31

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Kyalla Shale	938.00	1464.00	0	>= 0.05		<= 0.5
2	Kyalla SS	1464.00	1487.40	0	>= 0.05		<= 0.5
3	Kyalla Shale Lower	1487.40	1718.00	0	>= 0.05		<= 0.5
4	Moroak SS	1718.00	2200.00	0	>= 0.05		<= 0.5
5	Velkerri Shale	2200.00	2529.00	0	>= 0.05		<= 0.5
6	Velkerri Middle	2529.00	2714.00	0	>= 0.05		<= 0.5
	Pay						
1	Kyalla Shale	938.00	1464.00	0	>= 0.05	<= 0.7	<= 0.5
2	Kyalla SS	1464.00	1487.40	0	>= 0.05	<= 0.7	<= 0.5
3	Kyalla Shale Lower	1487.40	1718.00	0	>= 0.05	<= 0.7	<= 0.5
4	Moroak SS	1718.00	2200.00	0	>= 0.05	<= 0.7	<= 0.5
5	Velkerri Shale	2200.00	2529.00	0	>= 0.05	<= 0.7	<= 0.5
6	Velkerri Middle	2529.00	2714.00	0	>= 0.05	<= 0.7	<= 0.5

Depth Units : m
$$ indicates missing or null data in the zone.

Figure C-21
Well WALTON-1 – Kyalla Shale CPI

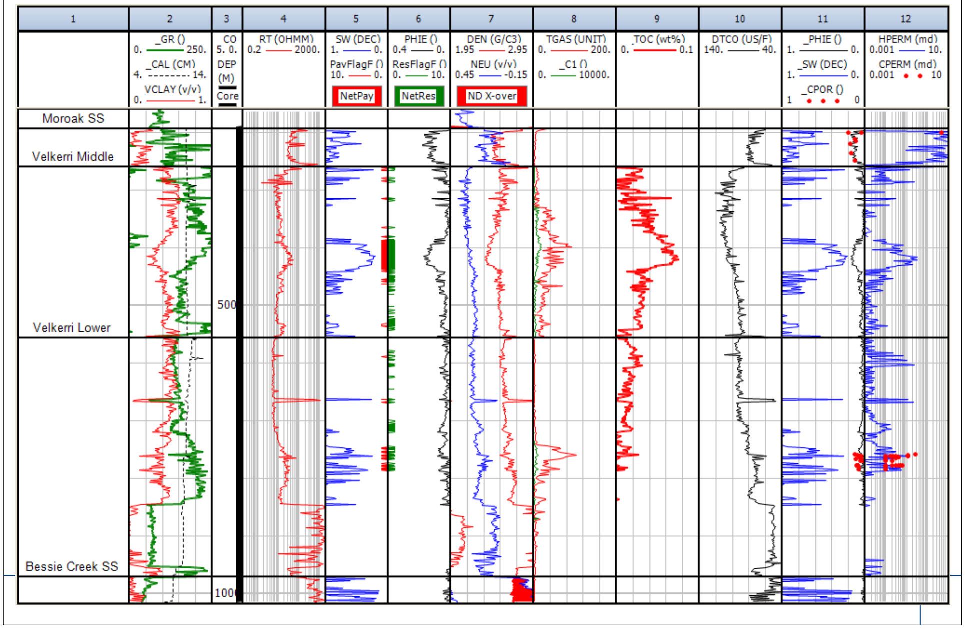


Figure C-22
Well WALTON-2 – Summation

Petrophysical Zone Averages Report

Well : WALTON 2
Date : 11/16/2012 11:54:34

Reservoir Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Velkerri Middle	260.00	556.00	296.00	98.10	0.331	0.103	0.503	0.359	10.13	5.04
2	Velkerri Lower	556.00	971.00	415.00	54.55	0.131	0.069	0.746	0.317	3.77	0.96
3	Bessie Creek SS	971.00	1033.00	46.95	$$0.40	0.009	0.061	0.104	0.053	0.02	0.02
	All Zones	260.00	1033.00	757.95	$$153.05	0.202	0.091	0.568	0.343	13.93	6.02

Pay Summary

Zn #	Zone Name	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl Ari	Phi*H	PhiSo*H
1	Velkerri Middle	260.00	556.00	296.00	67.85	0.229	0.118	0.404	0.344	8.01	4.78
2	Velkerri Lower	556.00	971.00	415.00	22.15	0.053	0.075	0.489	0.258	1.66	0.85
3	Bessie Creek SS	971.00	1033.00	46.95	$$0.40	0.009	0.061	0.104	0.053	0.02	0.02
	All Zones	260.00	1033.00	757.95	$$90.40	0.119	0.107	0.418	0.321	9.70	5.65

Cutoffs Used

Zn #	Zone Name	Top	Bottom	Min. Height	Phi _PHIE	Sw _SW	Vcl _VCLAY
	Reservoir						
1	Velkerri Middle	260.00	556.00	0	>= 0.05		<= 0.5
2	Velkerri Lower	556.00	971.00	0	>= 0.05		<= 0.5
3	Bessie Creek SS	971.00	1033.00	0	>= 0.05		<= 0.5
	Pay						
1	Velkerri Middle	260.00	556.00	0	>= 0.05	<= 0.7	<= 0.5
2	Velkerri Lower	556.00	971.00	0	>= 0.05	<= 0.7	<= 0.5
3	Bessie Creek SS	971.00	1033.00	0	>= 0.05	<= 0.7	<= 0.5

Depth Units : m
$$ indicates missing or null data in the zone.

APPENDIX D – RPS INPUT PARAMETERS FOR VOLUMETRICS

Beetaloo - RPS Input parameters for volumetrics

	Area (acres)			PAY	PHIE	SW	SoPHIEH	Comments
	P10	P50	P90	(m)	(v/v)	(v/v)	(m)	
Kyalla Upper (Oil)	1,377,987		1,092,505					650 m isopach contour to estimate P90. P10 to 600 m isopach contour to include Elliott Potential
Balmain-1				35.05	0.097	0.391	2.06	Partial penetration. Mayority of the Pay included
Jamison-1				63.3	0.088	0.444	3.08	
Mason-1				56.4	0.092	0.346	3.38	Partial penetration. Mayority of the Pay included
Shenandoah-1				37.46	0.083	0.383	1.93	
				48.05	**0.09**	**0.391**	**2.61**	
Kyalla Lower (Oil)	3,136,820		2,195,775					P90 1500 meter contourn shalower (CHECK). P90 = P10*0.7
Chenin-1				70	0.068	0.497	2.38	
Burdo-1				103.45	0.066	0.515	3.32	
Ronald-1				87.44	0.068	0.498	3	
				86.96333	**0.067333**	**0.503333**	**2.9**	
Velkerri Middle (Oil)	2,218,598		1,553,019					P90 = P10*0.7. Excludes area outside concession boundary
Altree-2				176.63	0.102	0.372	11.32	PAY concentrated in three bodies
McManus-1				245.08	0.088	0.375	13.41	PAY concentrated
Walton-2				67.85	0.118	0.404	4.78	PAY concentrated in lower half interval
				163.1867	**0.102667**	**0.383667**	**9.836667**	
Kyalla Lower (Gas)	1,082,942		758,063					P90 = P10*0.7
Jamison-1				175.8	0.092	0.449	8.88	
Shenandoah-1				102.33	0.076	0.401	4.68	PAY concentrated in lower 2/3
				139.065	**0.084**	**0.425**	**6.78**	
Velkerri Middle (Gas)	2,298,607		1,609,026					P90 = 800m isopach contour
Shenandoah-1				30.02	0.077	0.308	1.6	Partial penetration. PAY concentrated in top of the Velkerri Lower
				30.02	**0.077**	**0.308**	**1.6**	
Moroak SS (Tight Gas)	339,071		237,350					P90 = Jamison-1 and take 70%
Shenandoah-1				143.64	0.08	0.442	6.44	Tested 1728-1780m, 1837-1870m. No stimulated, no flow. Very low permeability.
Jamison-1				0				Partial penetration.
Chanin-1				0		High		High Sw
				143.64	**0.08**	**0.442**	**6.44**	
Bessie Creek SS (Tight Gas)	2,298,607		1,609,026					P90 = P10*0.7. P10 same as the Velkerri Middle
Altree-2				41.45	0.061	0.568	1.09	PAY concentrated mostly in the middle of the interval.In the oil window. No gas penetration
Walton-2				0				Partial penetration. PAY not observed. Very low porosity and permeability
				41.45	**0.061**	**0.568**	**1.09**	

Only wells with Pay observed are included in this table

APPENDIX E – QUALIFICATIONS

Andy Kirchin is the Executive Vice President in charge of RPS' Houston upstream consulting services. RPS has brought Andy over to Houston to help grow the U.S. consulting business and help facilitate an effective exchange of skill-sets between RPS' various international offices. Before moving to the U.S. Andy was the operational director in charge of RPS' City of London office which provides integrated geoscience, engineering and commercial analysis of oil and gas properties internationally. He has more than 25 years of industry experience and, as one of the Principal consultants at RPS Energy, Andy has conducted numerous Expert roles both in Unitisation / Redetermination disputes and in the Valuations / Certification area providing technical advice and Competent Person Reporting to the City of London, both on AIM and full LSE. Andy has worked on projects in most of the world's hydrocarbon provinces on both conventional and unconventional plays. He is a geophysicist by background but has a broad experience in dealing with the techno-commercial aspects of upstream sector.