PUBLIC VERSION

Estimated CSG Production by Small Producers in QGC Production Area

QGC
A BG Group Business

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The following document was prepared by RLMS

On behalf of QGC

RLMS (Resource and Land Management Services) is an independent consultancy established in 1990, focusing on the energy, transport, communications and exploration sectors Australia wide. RLMS specialises in tenure management, land negotiation and acquisition, route corridor selection, environmental approvals, mapping, and gas market analysis.

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1. EXECUTIVE SUMMARY

QGC, a BG Group business, commissioned RLMS to provide estimates of potential natural gas production by small independent gas producers and petroleum tenements holders in an area close to QGC's upstream interests and its proposed gas transmission pipeline to the planned Queensland Curtis LNG plant on Curtis Island near Gladstone.

The area of interest was defined as that within 100 km of QGC's existing and planned upstream operations and the route of the proposed gas pipeline linking the gas production facilities with Curtis Island. The small independent gas producers have been defined as those not aligned with any of the proposed LNG projects being considered for the Gladstone Region.

Only six companies, five ASX listed [Blue Energy Limited, Bow Energy Limited, Icon Energy limited, Molopo Australia Limited and Rawson Resources Limited] and Anglo Coal Australia Limited, the Australian subsidiary of a large overseas resources group meet the above criteria. All of these companies are, or potential, CSG producers. Other than for Bow Energy's Gunyah Prospect, all of the petroleum tenements are more than 50 km from QGC's area of interest and all are closer to existing gas handling and transmission infrastructure such as the Roma to Brisbane Pipeline [RBP] and the Queensland Gas Pipeline [QGP]. Future production of sales gas by these companies is more likely to use the existing gas infrastructure rather than the proposed QGC gas pipeline as they are closer and operate at a slightly lower pressure than that planned for the proposed QGC pipeline.

The Gunyah Prospect of Bow Energy is waiting the finalization of Native Title agreements before the tenement is awarded by the Queensland Government. The Gunyah Prospect area in the southern part of the Dawson Valley has been sparsely explored for CSG. It is considered to host similar Bandanna Coals that are the source of CSG in the operating Dawson Valley Gas Fields. Although the Gunyah Prospect area is only 25 km from the proposed QGC pipeline route, the terrain between is rugged making a pipeline connection difficult. It is considered that should marketable gas reserves be established in the Gunyah Block, it is more likely to be connected to the existing, and lower pressure, QGP system which is some 40 km to the north. This connection distance will be reduced to 15 km should the Timmy Gas Field be developed by Molopo before Gunyah is sanctioned for commercial development.

Based on the location of the small independent gas producers relative to existing gas treating and gas transmission pipeline infrastructure in the Surat and southern Bowen Basins where connection and incremental expansion can be undertaken at relatively low cost and the proposed route of the QGC pipeline, it is highly unlikely that any of the small independent gas producers would consider utilizing the higher cost, high pressure QGC pipeline to transport natural gas to supply Central Queensland gas markets.

QGC will treat gas at its upstream processing facilities to a narrow gas specification which is required by the LNG Plant on Curtis Island. The QGC pipeline would unlikely to be used by small independent gas producers as the gas treatment costs to meet the required specifications for the Queensland Curtis LNG Plant would be an additional cost which would not be required for gas transportation in the RBP or QGP.

2. INTRODUCTION

QGC has commissioned RLMS to provide it with estimates of potential natural gas production by small independent producers and tenement holders in an area close to QGC's interests. These include QGC operated gas fields and tenements, other tenements in which QGC has a commercial interest, the proposed QGC natural gas pipeline from the Company's Surat Basin operations to Gladstone and the Queensland Curtis LNG site on Curtis Island. Natural gas in this study includes both coal seam gas [CSG] and gas recovered from conventional petroleum reservoirs though the latter is insignificant in the QGC area of interest.

The current and potential independent gas producers are those companies that do not have an interest in any of the proposed liquefied natural gas [LNG] being considered for establishment in, or around, the Gladstone environs including Curtis Island. The LNG proposals under consideration for establishment in the Gladstone Region are summarized in Table 1.

Table 1

CSG Based LNG Proposals at Gladstone

Proposal	Proponent	LNG train capacity [MMtpa]	No of trains	Ultimate project capacity [MMtpa]	Ultimate gas requirement PJ/yr	Initial start-up date
Gladstone LNG	Arrow LNG Limited	1.5	2	3.0	195	2012
Queensland Curtis LNG	BG Group	3.7	4	15.0	975	2014
Australia Pacific LNG	Origin ConocoPhillips	3.7-4.0	4	16.0	1,040	2014
GLNG	Santos PETRONAS	3.7-4.0	3	12.0	780	2014
Shell Australia LNG	Shell	4.0	4	16.0	1,040	2015

QGC's preferred option for the operation of the Queensland Curtis LNG Project natural gas pipeline is to apply to the National Competition Council [NCC] for QGC to be authorized to operate the proposed pipeline as an unregulated pipeline without the need for third party access for at least 15 years.

To assist QGC in its applications to the NCC, it has commissioned studies to determine the amounts of natural gas small independent gas producers are likely to be producing over a 15 year period [to approximately 2030] and which might need to be transported to markets in the Gladstone-Central Queensland Region and how the proposed QGC pipeline operating regime might materially affect competition. This particular study is focusing on the small independent gas producers, providing estimates of their likely gas production, costs of production and necessary infrastructure to access the Gladstone and other Central Queensland markets to 2030.

3. THE STUDY AREA

The areas of QGC interest for this investigation include those considered within economic reach of QGC's present and proposed upstream production areas, the proposed natural gas pipeline linking the Company's gas production areas with Gladstone and within proximity to the projected Queensland Curtis LNG facility on Curtis Island.

As part of the initial assessment of independent companies meeting this criteria, those groups within a 100 km distance from QGC's existing and proposed gas fields and proposed high pressure gas transmission pipeline and related collection system from near Tara to Curtis Island have been assessed.

The QGC area of interest basically encompasses the southern part of the Bowen Basin and most of the Surat Basin, east of Roma, in southern Queensland.

4. SMALL INDEPENDENT GAS COMPANIES

The companies that meet the criteria as small independent gas explorers and producers are companies without any interests in the five LNG proposals in the Gladstone Region. They include both public companies listed on the Australian Securities Exchange [ASX] as well as non Australian listed public and private companies.

The ASX listed companies with interests in tenements within the 100 km distance of the QGC interest zone include:

- A J Lucas Limited
- Blue Energy Limited
- Bow Energy Limited
- Icon Energy Limited
- Molopo Australia Limited
- Rawson Resources Limited
- Victoria Petroleum NL
- WestSide Corporation Limited

With regard to the above listed companies, the interests of A J Lucas Limited, Victoria Petroleum NL and WestSide Corporation Limited in tenements in the Bowen and Surat Basins within the QGC area of interest are all in association or joint venture with QGC.

AJ Lucas has a 15% interest in the Woleebee Creek Project [ATP 651P] with QGC, the operator holding the remaining 85%. In the case of Victoria Petroleum, it has a 20% interest in PL 171 and a 30% interest in the adjacent ATP 574P. The balance of the interest in these tenements is held by QGC, which is the operator for both. In the Dawson Valley, WestSide, with a 50% interest, is the operator of the Paranui Project [ATP 769P]. QGC holds the remaining 50%.

Details of any agreements between QGC and its partners in these tenements have not been made public, so no conclusions can be made as to whether QGC has marketing, pre-emptive or other agreements regarding any gas produced in the future from these tenements. For the purposes of this study, it is assumed that any gas produced from these tenements will be treated as fully available to QGC.

Details of each of the other above mentioned ASX listed small independent gas companies are included as Appendices A to E. Each Appendix covers name, structure, shareholders, names of Directors and key management, financials, tenements, reserve and resource data, location to gas infrastructure and potential connection costs, production and gas assets, markets and contracts, technical and gas quality issues and assessment of potential gas reserves.

Non ASX listed companies with CSG and/or conventional petroleum interests in the area under consideration include:

- Anglo Coal Australia Pty Ltd
- Clark Energy Pty Ltd
- Pangaea Resources Pty Ltd

Non ASX companies are not required to publically disclose information on their structures, operations and reserves, hence limited information of these groups is available. Brief details on these groups are given later in this report.

5. NATURAL GAS

The terms of reference for the study specifically refer to CSG. While this is the dominant natural gas resource in the Bowen and Surat Basins, there are small reserves and some ongoing production of conventional petroleum from the Denison Trough in the Bowen Basin and from the Surat Basin. The Denison Trough conventional gas fields are operated by Origin Energy on behalf of the Origin /Santos Joint Venture. The productive conventional gas fields in the Surat Basin are mostly over 100 km from the study area with only the edge of Mosaic Oil's Churchie gas field being within the 100 km zone. The raw gas from Churchie is processed in the Wallumbilla LPG plant operated by Santos.

In this analysis, conventional natural gas, as produced by Mosaic Oil NL in its areas south of Wallumbilla and directly connected to the Wallumbilla Gas Hub has been mentioned because of the potential importance of the Company's Silver Springs Gas Fields, where approximately 100 PJ of sales gas has been recovered over the last 30 years, to provide potential gas storage as part of a ramp up management portfolio for gas for the start up of LNG processing trains.

6. GAS RESERVES AND RESOURCES

In this study, the definitions used for reserves and resources are those outlined under the Petroleum Resources Management System [PRMS] by the Society of Petroleum Engineers [SPE], as revised in 2007. A summary of the PRMS System is included as Appendix F.

The reserves are specified in SI energy units such as the Peta Joule [PJ]. One PJ equals 10^{15}J. Some companies still report natural gas reserves and resources in volumetric or ft^3 [cubic feet] units. These have been converted in this document to energy units with a conversion of 1Bcf [10^9 ft^3] equal to 1.045 PJ.

7. COMMENT ON SPECIFIC INDEPENDENT CSG PARTICIPANTS

Details of each of the ASX listed independent CSG participants are included in Appendices A to E. However a summary and discussion of the reserve and resource position of each company is given in the following section together with comment on the necessary infrastructure required to connect any future gas supply to the QGC or other gas transmission pipeline systems such as the Queensland Gas Pipeline [QGP] and the Roma [Wallumbilla] to Brisbane Gas Pipeline [RBP].

7.1 Blue Energy Limited

Blue Energy Limited is a Brisbane based, Australian Securities Exchange listed company, with ASX Code: BUL. Its primary business is in the exploration, appraisal, development and commercial production of oil and gas. Blue's primary focus is on CSG in the Bowen, Surat, Galilee and Maryborough Basins.

In the area within 100 km of the proposed QGC pipeline, Blue Energy has one tenement area located in the eastern part of the Surat Basin. ATP's 818P and 896P are centred around Oakey, Pittsworth and Millmerran to the west of Toowoomba and east of Dalby and Arrow's Tipton West and Meenawarra Blocks. The Blue Energy acreage is approximately 50 km from QGC's most southerly tenements in the Surat Basin, viz PL's 274, 275 and 279. The RBP passes through both ATP 818P and ATP 896P. Both tenements are held 100% by Blue Energy.

Blue Energy is currently undertaking a five well coring program within ATP 896P targeting both the Juandah and the Taroom Coal Measures. The wells are being drilled to a planned depth of between 500m and 600m with three wells drilled to date. In addition to taking cores for further analysis and desorption tests, the wells are being fully logged while the coal intervals are undergoing permeability testing. No test results, other than well total depth details, of the drilling program have been released.

ATP 896P covers an area of 1,141 km^2 .The Company has reported an estimated gas in place resource [GIP] of 3,435 PJ. The northern blocks of ATP 818P, which are contiguous with ATP 896P, cover an area of 812 km^2 and are reported to have an estimated gas in place of 2,436 PJ. Assuming through further appraisal and development of the tenements that the recoverable gas is from 15% to 30% of the GIP resource, Blue Energy has potential recoverable CSG reserves of between 880 PJ and 1,760 PJ. This level of reserves will sustain gas production of between 44 PJ and 88 PJ per year over 20 years.

The 15% to 30% estimate of potential recoverable gas from initial gas in place estimates is an accepted industry norm. As on going exploration and appraisal of a CSG prospect occurs, the level of confidence in estimating the percentage of gas in place that can be converted to reserves improves.

The RBP passes through ATP's 818P and 896P. The Blocks are located over 100 km from the Berwyndale South gas processing hub, 95 km from a proposed gas processing facility in PL 261 and over 50 km from the nearest QGC tenement [PL 279]. It is unlikely that Blue Energy would supply gas to other than to the South East Queensland gas market via the RBP. However if it was to be connected in the future to gas gathering system in PL 261, a 95 km, 450 mm pipeline capable of carrying up to 90 PJ of gas per year would be required to interconnect Blue Energy's eastern Surat gas production into the QGC pipeline network. The estimated cost of this pipeline, to operate at 10.2 MPa, is $77 million. The estimated pipeline tariff could be expected to be in the $0.20 to $0.25 per GJ range.

The estimated cost of connecting CSG production from Blue Energy's ATP's 818P and 896P to the RBP, which traverses these tenements, is $3.25 million. This cost is primarily that of valves, metering, over-pressure and other safety equipment and control and telecommunication systems.

More detailed information on Blue Energy Limited is given in Appendix A.

7.2 Bow Energy Limited

Bow Energy Limited is a public company with ASX Code: BOW. It is a Brisbane based explorer for, and developer of, oil and gas. Its current focus is on CSG with prospective developments in the Bowen and Surat Basins.

The principal focus of Bow Energy is on its Comet Block [ATP 1025P] and Norwich Block [ATP 1031P] in the Bowen Basin and the Don Juan Project [ATP's 771P and

593P] based on the Walloon Coals of the Surat Basin. Subject to finalization of Native Title issues, Bow is expected to commence exploration in the Gunyah Prospect [ATP 1053P], the only tenement held by Bow Energy in the QGC area of interest.

The Comet Block near Blackwater is more than 100 km from the proposed QGC pipeline and any QGC held tenements. Any natural gas produced from the Comet Block for marketing in the Gladstone Region is likely to be transported by a dedicated pipeline or via a 125 km lateral to the QGP. The Comet Block [100% Bow] has been reported by Bow to have an estimated CSG resource of 10,900 PJ as gas in place.

The Norwich Block [100% Bow] is further north and will be dependent on the proposed Central Queensland Gas Pipeline to market natural gas into the Gladstone Region. The reported estimated CSG resource in the Norwich Block is 5,800 PJ as gas in place.

The Company has established CSG pilot operations at its Don Juan Project in ATP 771P to the west of QGC's Lacerta project area in ATP 795P. Bow has a 55% interest in Don Juan and it is the operator. The eastern boundary of Don Juan is just on 100 km west of the proposed QGC pipeline and 15 km west of the QGP, the logical means of transporting gas from Don Juan to Gladstone. Current certified reserves at Don Juan are 101 PJ as 2P with 3P reserves of 197 PJ. Early estimates by the Company reported a gas in place resource of 1,070 PJ

The only tenement held by Bow Energy close to the proposed QGC gas pipeline is the Gunyah Block [ATP 1053P] of 388 km^2 which is in the Bowen Basin. It is located in the southern part of the Dawson Valley to the west of Cracow. While the QGC pipeline route passes 25 km to the east of ATP 1053P, any lateral linking the Gunyah Block to the pipeline would have to traverse very rugged country including the Auburn Range.

The Gunyah Block has been offered to Bow Energy by the Queensland Government with the awarding of the title subject to finalization of a Native Title Agreement. This is expected in early 2010. Until title is granted, Bow is unable to undertake any exploration work over the Block. However from drilling in adjacent tenements, it is likely that the Block contains Permian Coals of the Bandanna Formation with a net thickness of the order of 20m and gas contents of approximately $8m^3$ per tonne of coal on a dry, ash free basis [daf]. Permeabilities are anticipated to be low. The estimated CSG resource in the Gunyah Block is 970 PJ as gas in place.

On the basis that up to 30% of the GIP resource could be recovered as deliverable gas, Gunyah could potentially sustain a gas supply of up to 15 PJ per year over a 20 year period.

Until drilling is undertaken in the Gunyah Block, the optimum well completion techniques are unknown. However based on the experience of wells drilled in nearby tenements and that it is likely that the Bandanna Coals in the Gunyah Block have a similar regional geological setting to those in the rest of the Dawson Valley, surface to in-seam wells are likely to be needed to achieve acceptable well productivity. This is expected at add approximately $0.50 per GJ to the costs of CSG production compared with the use of vertical, under-reamed wells typically used in the Surat Basin.

The Gunyah Block is a southern extension of the Dawson Valley gas fields and to the immediate south of the Anglo Coal Pty Ltd–Molopo Australia Limited Timmy Prospect [ATP 602P]. While any gas produced at Gunyah could use the proposed QGC pipeline, a most likely alternative would be for it to connect into the existing Dawson

Valley network of gas processing plants and pipelines, which are integrated with the QGP, as a means of supplying gas to Gladstone. The Gunyah Block will require a new lateral of approximately 40 km though if the Timmy Gas Field in ATP 602P is developed first by Anglo Coal-Molopo Joint Venture, only about 15 km of new gas pipeline will be needed. As the QGP and all the associated gas infrastructure in the Dawson Valley operates on between 7MPa and 8 MPa system, there are cost advantages using this facility over having to build to a higher pressure to meet the proposed QGC pipeline system requirements.

To supply 15 PJ per annum [41 TJ per day] from the Gunyah Block to the proposed QGC gas pipeline, a 25 km lateral of a notional 250 mm diameter would be required. Also associated gas treatment, compression and metering equipment is needed. The estimated capital cost of this lateral, over very rough terrain, is $12.5 million. Pig retrieval, metering and connection costs are likely to add a further $3.0 million. A pipeline tariff for this lateral could be expected to be in the $0.15 to $0.20 per GJ range.

For Bow Energy to connect to the existing Dawson Valley system, approximately 40 km of 250 mm pipe will be required costing an estimated $19.5 million. However if Molopo brings the adjacent Timmy Project to the north of the Gunyah Prospect into production before Bow, only 15 km of lateral will be required at an estimated cost of $8.25 Million.

More detailed information on Bow Energy is included at Appendix B

7.3 Icon Energy Limited

Icon Energy Limited, a Gold Coast petroleum exploration company is listed on the ASX with Code: ICN. Icon is focusing its exploration, appraisal and development activities on its Surat Basin Lydia Prospect in ATP 626P.

ATP 626P of approximately 2,250 km^2 is located in the southern part of the Surat Basin. The northern boundary of the tenement is approximately 75 km south of QGC's most southerly tenement [PL 262]. The closest gas infrastructure is the RBP with the Lydia CSG pilot area 115 km from Dalby.

Icon has established a five well CSG pilot in the 300 km^2 Lydia Project area with a further four wells planned to be drilled. The Stanwell Corporation is farming-in to the Lydia Project through a $36 million program to earn 50% of the Lydia Project. Icon is retaining a 100% interest in the balance of ATP 626P. As part of the agreement with Stanwell, Icon will be able to deliver 225 PJ of gas over 15 years after proving up 340 PJ of 2P gas reserves. Stanwell propose to use the gas for power generation. It is understood that Stanwell has the option to increase the quantity of gas it takes from Icon. Currently Icon has 373 PJ of contingent gas resource [2C] at Lydia.

The contingent gas resource in ATP 626P, including the Lydia Project area, is 1,150 PJ as a 2C resource and 1,773 PJ in the 3C resource category. The Company has reported that ATP 626P has an estimated 6,115 PJ as gas in place. Icon is planning to drill up to a further 20 wells in 2010 in the tenement outside of the Lydia Project area to establish 2P reserves. Until the results of the projected drilling program in ATP 626P outside of the Lydia Project area are known, it is not possible to provide any reliable estimates of the potential gas resource in the tenement. However based on the currently announced 2C resource figures, in which the Lydia Project area contains approximately one third of the total 2C resource in the tenement, the estimated gas in place in ATP 626P outside of the Lydia Project area is of the order of 4,000 PJ. Again assuming an up to 30% of gas in place may be recoverable as sales gas, this would give Icon the ability to market up to 1,200 PJ or a maximum of 60 PJ per year over 20 years.

While the early production of CSG from Lydia will be taken by Stanwell Corporation, Icon is pursuing gas markets in its own right. The closest existing gas infrastructure is the RBP, approximately 110 km to the north. The route of the proposed Queensland Hunter Gas Pipeline passes 75 km to the west of ATP 626P.

Icon is unlikely to pursue gas markets in Central Queensland having regard to the location of ATP 626P and the Lydia Project being over 110 km south of the RBP. The Company's focus is marketing gas to south east Queensland as possibly to southern markets via the proposed Wallumbilla to Newcastle pipeline or a dedicated pipeline to some proposed gas fuelled power projects in the northern part of New South Wales. Icon is most unlikely to need to connect into the proposed QGC gas pipeline. However, should it be decided in the future to connect into the QGC system, a lateral of approximately 75 km of 350 mm notional diameter and costing an estimated $48 million would be required to deliver up to 60 PJ per year. The estimated pipeline tariff would be $0.15 to $0.20 per GJ.

The estimated cost of Icon Energy connecting into the RBP gas transmission pipeline system for 110 km of 350 mm pipe is $71.0 million.

Details of Icon Energy Limited are provided in Appendix C

7.4 Molopo Australia Limited

Molopo Australia Limited, soon to be renamed Molopo Energy Limited, is a Melbourne based publicly listed oil and gas exploration group with the ASX Code: MPO.

Molopo's principal gas interests in Queensland are in CSG exploration, development and production in the Dawson Valley which hosts Permian Bandanna Coals within the Bowen Basin. The Company has a 50% interest in each of the Mungi CSG Project [PL 94-Northern Section], Harcourt/Bindaree [ATP 564P/PLA 210] and the Timmy Project [ATP 602P]. The other interests in these tenures are Anglo Coal [Moura] Limited [25.5% and operator] and Mitsui Moura Investments Pty Ltd [24.5%].

The Mungi CSG Gas Field is near Moura and west of Anglo's Dawson Valley coal mines. Gross gas production at Mungi in 2008-2009 was 0.7 PJ though production is now ramping up as three new surface to in-seam laterals with a total of 15 lateral sections having 9,200m lined horizontal exposure to the coals. Two new horizontal multi seam surface to in-seam wells with a total exposure to coal of 16,000m in 15 horizontal sections are being drilled. These wells should see production ramp up to 6 TJ per day [2.2 PJ per year]. The new wells have been sole funded by Molopo.

Mungi covers an area of 110 km^2 with current 2P reserves of 60 PJ and 3P reserves of 152 PJ. The Molopo funded drilling program is targeting 2P reserves of 550 PJ and 3P reserves of 700 PJ gross for the field to be established by 2012. Currently the estimated resource at Mungi is 1,500 PJ as gas in place.

ATP 564P/PLA 210, the Harcourt Project is to the immediate north of Mungi. Harcourt South, the main area of interest covers an area of 178 km^2 and has 2P reserves of CSG of 37 PJ while the 3P reserves are currently certified at 318 PJ. The joint venturers are finalizing arrangements to target 850 PJ of 2P reserves and 1,200 of 3P reserves by 2012. Current estimates of the CSG resource are 2,500 PJ as gas in place.

To the South of PL 94 is the Timmy Project with an area of 71 km^2 in ATP 602P which covers a total area of 310 km^2. The target reserves are 550 PJ of 2P and 850 PJ of 3P.The estimated CSG resource in the title block is 2,300 PJ. Timmy is within 50 km of the proposed QGC pipeline.

Anglo Coal has advised the market that CSG production from its leases in the Dawson Valley is not core business and that it would consider offers for its CSG assets. To date, Anglo has not reported any negotiations with potential investors though it is known it engaged financial investors to provide a valuation of its CSG assets. Molopo has a first right of refusal over those assets that Molopo has in joint venture with Anglo [PL 94 N, ATP 564P and ATP 602P].

Currently Molopo and Anglo have extensive gas infrastructure in the Dawson Valley including two gas treatment facilities, compressor stations and two gas pipelines connecting to the QGP at Moura. Gas from the Dawson Valley is used as feedstock in the Dyno Nobel ammonium nitrate plant at Moura, in a cotton gin as well as being supplied to markets in Gladstone and Rockhampton.

Molopo is investigating the establishment of power generating plant near Moura. Initially it is looking at installing 30 MW but envisages expansion over time to up to 200 MW.

All the gas treating and transmission facilities in the Dawson Valley have a maximum design operating pressure of 10 MPa though the system operates in the 7 MPa to 8 MPa range. Increased production of gas by Molopo and Anglo is expected to be processed through the existing facilities with augmentation as necessary. The existing facilities are approximately 80 km from the proposed QGC pipeline with the current connection to the QGP being approximately 25 km. Because of the distances and the technical and cost s involved in upgrading the Dawson Valley system to make it compatible with QGC proposed pipeline, gas produced by Molopo and Anglo aimed for the Central Queensland gas market is almost certain to utilize the existing Dawson Valley gas infrastructure and the QGP.

Molopo's capital costs of marketing additional gas from Mungi and Harcourt will involve augmentation of the company's existing facilities once they are capacity limited. Bringing the Timmy Project into production will require the construction of a 25 km 300 mm lateral capable of transporting up to 30 PJ per year to the existing Dawson Valley facilities.

A more detailed outline of Molopo Australia Limited is given at Appendix D.

7.5 Rawson Resources Limited

Rawson Resources Limited [ASX: RAW] is a small Sydney based oil and gas explorer. The Company has two ATP's in the southern part of the Surat Basin south of the RBP.

The northern section of ATP 893P is between 50 km and 100 km from the proposed QGC pipeline. Part of Rawson's other tenement [ATP 901P] is just within the 100 km of the QGC pipeline route.

Rawson Resources with its farm-in partners Hardie Energy Pty Ltd and Energetica Pty Ltd have undertaken limited exploration over the blocks which are on the western edge of the Taroom Trough where the Walloon Coals dip steeply. Because the depth of the coals [> 1,000 m] in these areas is deeper than generally considered suitable for the economic recovery of CSG, the planned exploration for the area will also investigate shallower [400 m-500 m] Cretaceous Coals known to exist in the area. The suitability of these coals, which are not as mature as the Jurassic Walloon Coals, for CSG recovery has yet to be tested.

Rawson Resources has not announced any estimates for a gas in place resource.

Because of its location, any prospective gas production from ATP's 893P and 901P would connect to either the RBP or the proposed Queensland Hunter Gas Pipeline. Connection to the RBP would require the construction of approximately 100 km of lateral. For a 200 mm pipeline, the estimated cost of this lateral is $86 million.

A more detailed outline of Rawson Resources is attached as Appendix E.

8. NON ASX LISTED CSG EXPLORERS/PRODUCERS

The areas held by Clark Energy Pty Ltd and Pangaea Resources Pty Ltd are in the Southern Surat Basin, south of the RBP and close to the Taroom Trough. Both company's title areas are considered to be more prospective for conventional petroleum due to the depths of any likely Walloon Coals. Some shallower Cretaceous Coals may occur within the acreage but no drilling has been undertaken to evaluate this resource.

Anglo Coal [Moura] Limited, a subsidiary of Anglo Coal Australia Pty Ltd, along with its partner Mitsui Moura Investments Pty Ltd recovers CSG from its coal leases in the Dawson Valley, south of Moura township. Anglo has a 51% interest in the operations and is the operator. The Anglo/Mitsui joint venture also has a 50/50 agreement with Molopo Australia Limited in CSG tenements off the coal mining leases. Details of these are given in the section on Molopo.

Anglo Coal has an estimated CSG production from its coal mining lease areas of 16 TJ per day [5.8 PJ per year]. Gas is supplied as a feedstock to the Dyno Nobel ammonium nitrate plant at Moura and to Gladstone markets via its own pipeline to the Moura compressor station on the QGP. Anglo has a gas treating facility and compressor station rated at 10 MPa at its mine which is linked with an 18 km, 168 mm pipeline to the QGP. These facilities are independent of those used by the Anglo-Molopo joint venture to the west of Anglo's coal leases.

Anglo does not publish gas reserve figures though it has been widely reported that it has 386 PJ of 2P reserves over its coal mining lease area. The Company has not made any statements about the potential size of its CSG resource. Earlier this year, Anglo advised that it was considering divesting its CSG operations at Dawson Valley and commissioned valuation studies and appointed financial advisors. To date no announcements have been made as to Anglo's ultimate intentions.

Any further expansion in CSG production from the Anglo-Mitsui leases is almost certain to be handled by augmentation of the Company's existing facilities which are integrated with the QGP. The Anglo CSG facilities are approximately 70 km west of the proposed QGC pipeline route with the rugged terrain of the Banana Range in between.

9. SUMMARY

A summary of the key features for each of the above listed small independent gas producers is given at Table 2.

Table 2
Summary of Relevant Small Independent CSG Producers

Company	PL/ATP	Est GIP [PJ]	Potential recoverable Gas [PJ]	Potential Gas Production [PJ/a]	QGC Pipeline Connection Requirements	Comment
Blue Energy	ATP 818P ATP 896P	2,436 3,435	880-1,760	44 - 88	95 km x 450mm	Eastern Surat. Likely to use RBP
Bow Energy	ATP [A] 1053P	970	145 -291	7 - 15	25 km x 250mm	Gunyah Prospect South Dawson Valley Likely to use QGP
Icon Energy	ATP 626P	4,000	600 – 1,200	30 - 60	75 km x 350mm	South Surat Likely to use RBP
Molopo	PL 94 [N] PLA 210/ ATP 564P ATP 602P	1,500 2,500 2,300	945 – 1,890	47 - 94	80 km x 400mm	Dawson Valley Likely to use existing gas facilities and QGP
Rawson Resources	ATP 893P ATP 901P	NK	-	-	50 km – 100 km	Area of poor coal/CSG prospectivity

None of the small independent CSG tenement holders with 100 km of the proposed pipeline for the Queensland Curtis LNG Project are likely to seek connection to the proposed QGC pipeline principally because of distance, as most are closer to either the QGP or the RBP. Furthermore, while the existing gas infrastructure is based on a 10 MPa system design pressure, it operates at between 7 MPa and 8 Mpa. The proposed QGC is being designed to operate at a higher pressure [10.2 MPa]. Small companies close to the existing network will generally opt for a closer, lower pressure and lower cost system of delivery to market. The extra expense of going to a higher pressure operating system does not deliver higher gas sales revenues.

The only possible exception is the Gunyah Block which has been offered to Bow Energy Limited. Until the title to the Block has been granted, the prospectivity of the area is an unknown though Bow is likely to seriously look at the equidistant and lower pressure Dawson Valley-QGP system to market gas in Gladstone than try to utilize the proposed QGC higher pressure pipeline.

This analysis concludes that it is unlikely that the small independent CSG producers would find it economic to treat their gas to the narrow specifications required by the Queensland Curtis LNG Plant on Curtis Island.

APPENDICES

APPENDIX A

Blue Energy Limited

BLUE ENERGY LIMITED
ABN 14 054 800 378

Registered and Principal Business Office:

Suite 15A Central Brunswick
421 Brunswick Street
Fortitude Valley Qld 4006

Company Structure

Blue Energy Limited is a public listed company registered with the Australian Securities Exchange [ASX] with the ASX Code: BUL.

The primary business of Blue Energy is in the exploration, appraisal, development and commercial production of oil and gas.

Blue Energy has an extensive portfolio of CSG and conventional natural gas tenements in the Bowen, Galilee, Maryborough and Surat Basins in Queensland and highly prospective conventional oil and gas farm-in opportunities in the Cooper-Eromanga Basin in both Queensland and South Australia. The Company also has four frontier off-shore tenements in the Gulf of Papua covering 67,000 km^2 to the south of Port Moresby in Papua New Guinea. The Company has applied for an inshore tenement adjacent to the four it already holds.

The Company's short term strategy is in the development of coal seam gas reserves in its Bowen and Surat Basin tenements for the supply of natural gas to domestic markets. A key part of this strategy was put in place in August 2008 when the Stanwell Corporation Limited entered into an Alliance Agreement with Blue Energy to facilitate a Gas Sales Agreement as well as acquiring a 19.9% stake in the Blue. This holding has subsequently been diluted to 13.78%. The Alliance Agreement with Stanwell Corporation Limited covers the supply to Stanwell of up to 8.5 PJ per year of gas for 25 years for use in a proposed gas fired power project.

In the medium term as it expands its reserve base, Blue Energy has indicated that it will further evaluate the use of gas for the export market. The export strategy is focused on development of Blue's northern Basin and Galilee Basin acreage. To this end it has entered into an agreement with Korea Gas Corporation [KOGAS] in which the Korean Group has taken up a 10% equity position in Blue Energy and has a Director on the Board of Blue Energy.

The principal investment vehicles used by the Company in its oil and gas activities are Blue Energy Pty Ltd, Everdue Pty Ltd, Eureka Petroleum Pty Ltd and Kompliment Pty Ltd. The company has a PNG subsidiary Energy Investments PNG Pty Ltd. All are wholly owned subsidiaries of Blue Energy Limited.

Blue Energy has a permanent staff of 15 as well as having a small number of professionals on contract.

Corporate information on Blue Energy Limited is appended as Appendix A.

Company Directors:

Mr. Peter Cockcroft	Executive Chairman
Mr. Garry Button	Non-Executive Director
Mr. Peter Flanagan	Non-Executive Director
Mr. Stephen Harrison	Non-Executive Director
Mr. Heung-Bog Lee	Non-Executive Director
Dr. Paul Massarotto	Non-Executive Director

Company Secretary:

Mr. Damien Cronin	Company Secretary

Company Executives:

Mr. John Phillips	Chief Operating Officer
Mr. Stuart Owen	Chief Financial Officer
Dr. Michael Swift	Exploration Manager
Mr. James van Rooyen	Drilling Manager
Mr. Drew Speedy	Finance Manager

Financial Profile

Capital Structure

In May 2009, Blue Energy raised $22.3 million through the issue of approximately 118 million shares through a share purchase plan. This, with the more recent $12.5 million placement from KOGAS and funds on hand of $9.6 million, will provide the Company with sufficient funds to undertake its revised work program over the next 18 to 24 months

At 18 September 2009, Blue Energy had 633,788,256 issued shares. These are held by 5,687 shareholders. The largest 20 shareholders held 55.66% of the stock with the largest three being ANZ Nominees Limited, 18.20%, Stanwell Corporation Limited, 13.78% and KOGAS with 9.92%. ANZ Nominees holding is as receiver for Primebroker Securities. The receiver is pursuing a policy of the orderly sale of this holding.

The market capitalization of Blue Energy at 21 September 2009 was $184 million.

The net assets of the Company at 30 June 2009 were $58.680 million.

Operating Results

For the financial year ended 30 June 2009, Blue Energy received total income of $934,000 and after allowing for expenses and income tax, it incurred a loss of $6,691 million.

At 30 June 2009, Blue Energy had $30.5 million in cash and no debt.

Exploration Activities

COAL SEAM GAS

Blue Energy holds eight ATP’s in Queensland focusing on coal seam gas. They cover acreage in the Bowen, Galilee, Maryborough and Surat Basins totaling approximately 27,200 km^2.

In early 2009 Blue Energy undertook a strategic review of the technical and geological information over its acreage and the exploration results which confirmed the prospectivity of ATP’s 813P, 814P, 818P/896P and 854P. The Company has initiated a commercialization strategy with a short term focus on achieving domestic gas sales within three years. A medium term strategy is focusing on achieving gas reserves to support export activities within five years.

As part of this strategy, Blue Energy has a current planned work program to drill up to 21 core-holes and establish a number of pilot operations across four tenements up to the end of 2010. The Company has secured a long term drilling contract for the Lucas Mitchell 180 Rig to undertake this program which commenced in July 2009.

Eureka Petroleum Pty Ltd, a wholly owned subsidiary of Blue Energy, has a farm-in agreement with Magellan Petroleum Australia Limited to fund work on the Burrum Syncline within the Maryborough Basin in ATP’s 613P, 674P and 733P. Blue Energy has assumed operatorship of this project.

Bowen-Surat Basins

The tenements held by Blue Energy that are within 100 km of QGC’s area of interest are its eastern Surat Basin permits ATP 818P and ATP 896P.

The Walloon Coal Measures in ATP 818P and the adjacent ATP 896P are located in the Surat Basin in an area generally between Toowoomba and Dalby. ATP 818P covers an area of 2,346 km^2 while ATP 896P has an area of 1,141 km^2. The tenements border on the eastern boundary of ATP 683P, which hosts the Tipton West gas field of Arrow Energy. The large Felton and Lochbar coal deposits are within ATP 818P. The RBP passes through these two tenements.

Five coreholes were recently drilled in ATP 896P. Wireline logs were also run in each of the wells which intersected the Walloon Coal Measures at depths between 500m and 600 m. The results of the drilling program are now being evaluated to establish if a pilot operation is warranted. Planning is for a projected pilot to be drilled during the first half of 2010.

Blue Energy has reported an estimated gas resource of 3,435 PJ as gas in place in ATP 896P while the estimated gas in place resource in the northern blocks of ATP 818P is 2,436 PJ.

A further section of ATP 818P is located in the Inglewood to Goondiwindi area. They border on the eastern boundaries of ATP 689P, the Inglewood Block held by Arrow Energy Limited.

Initially Blue Energy focused on the CSG potential of the Walloon Coal Measures in these southern blocks of the acreage where 106 km of 2D seismic was completed and the Indigo #2 core-well was drilled in the Yelarbon area. The well delineated 3 m net of gassy Walloon Coals. Two further core wells, Indigo #1 & 3, were planned to be drilled later in 2008 but were put on hold as a consequence of the disappointing results from Indigo #2.

Reserves and Resources

Blue Energy Limited is yet to hold any certified reserves to its own account though it has estimated that in its eastern Queensland tenements it has an aggregate gas in place resource of 22,200 PJ or 21.3Tcf.

The estimated gas in place resource of Blue Energy in its Surat Basin tenements within 100 km of QGC's assets and interests is 5,871 PJ. The breakdown of the gas in place estimates by tenement is:

Estimates of Gas in Place
[PJ's]

Tenement	Gas in Place
ATP 818P	2,436
ATP 896P	3,435
Total	**5,871**

The Company's gas commercialization strategy is be able to develop a certified reserve base to commence supply to domestic gas markets within three years and to be able to support export LNG production within five years.

The Company has a target of achieving 360 PJ of 2P and 1,000 of 3P of certified reserves by the end of 2010 from its Bowen Basin acreage and 1,250 PJ of 2P and 4,800 PJ of 3P reserves by late 2012 from both its Bowen and Surat Basin tenements.

Stanwell Alliance

CVC Limited, a diversified investment and funds management group, and a foundation investor in Blue Energy sold its 19.6% interest in the Company to the Stanwell Corporation Limited on 7 August 2008. Stanwell, a Queensland Government owned power generator, acquired CVC's interests for $87.28 million. Stanwell operates coal fired and hydro electric facilities across Queensland.

As part of the announcement of Stanwell's acquisition of the CVC stock in Blue Energy, it was announced that Blue and Stanwell had executed an Alliance Agreement for the provision by Blue Energy of up to 8.5 PJ per year of CSG to Stanwell for a proposed gas fired power project. The agreement is for 25 years and is structured for Stanwell to fund commercial field and infrastructure development. Stanwell also has an appointment on the Board of Blue Energy.

The drilling of three coreholes in ATP 854P targeting the Walloon Coal Measures of the Surat Basin as part of the Stanwell Alliance agreements was undertaken during the Third Quarter of 2009. Few results of the program have been released other than Blue commenting that the recorded gas contents from thinning Walloon Coals were disappointing.

As a consequence of a recent share purchase plan and the KOGAS placement, the relevant interest of Stanwell Corporation in Blue Energy is 13.78%.

KOGAS Agreement

Blue Energy announced on 29 May 2009 that it had entered into a Heads of Agreement [HoA] with Korea Gas Corporation [KOGAS]. The Korean company, which was founded in 1983, is the world's largest LNG importer operating three LNG terminals and over 2,700 km of gas pipelines across its home territory. In 2008, KOGAS had total revenues of $24 billion.

The terms of the HoA provided for KOGAS to acquire a 10% equity stake in Blue Energy through a placement of 62.855 million shares at 20 cents. As part of the agreement, KOGAS nominated Mr.Hueng-Bog Lee as a Director on the Blue Energy Board. The proposed transaction, valued at $12.571 million, received approvals by the Boards of both of the Companies on 29 June 2009.

KOGAS has also been granted an option to farm-in to ATP 813P in the Galilee Basin and into ATP 814P in the Northern Bowen Basin. The option expires on 30 June 2010. Blue Energy is embarking on an accelerated work program for ATP's 813P and 814P of 10 coreholes and three coreholes respectively to assist in reserve certification and identification of locations for pilot production wells. Drilling is scheduled to commence in ATP 814P in late 2009 and in the Galilee Basin acreage in early 2010.

Studies have also commenced on possible gas pipeline routes from ATP 813P in the Galilee Basin to a number of potential LNG export locations on the Queensland Coast from Gladstone to Abbot Point..

Gas Contracts

On 7 August 2008, Blue Energy announced that it had executed an Alliance Agreement with Stanwell Corporation Limited for the supply to Stanwell of up to 8.5 PJ per year of gas for 25 years [212.5 PJ] for use in a proposed gas fired power project.

Gas Processing and Gas Infrastructure

Blue Energy is still primarily an exploration company. While it is expected to shortly establish CSG pilot operations, the Company does not have any commercial gas gathering, gas treatment or compression facilities.

CORPORATE PROFILE

Registered and Business Office:

Suite 15A Central Brunswick
421 Brunswick Street
Fortitude Valley Qld 4006

Telephone: 07 3332 8800

Fax: 07 3332 8866

Web: www.blueenergy.com.au

ABN: 14 054 800 378

ASX Code: BUL

Company Directors:

Mr. Peter Cockcroft	Executive Chairman
Mr. Garry Button	Non-Executive Director
Mr. Peter Flanagan	Non-Executive Director
Mr. Stephen Harrison	Non-Executive Director
Mr. Hueng-Bog Lee	Non-Executive Director
Dr. Paul Massarotto	Non-Executive Director

Company Secretary:

Mr. Damien Cronin	Company Secretary

Company Executives:

Mr. John Phillips	Chief Operating Officer
Mr. Stuart Owen	Chief Financial Officer
Dr. Michael Swift	Exploration Manager
Mr. James van Rooyen	Drilling Manager
Mr. Drew Speedy	Finance Manager

APPENDIX B

Bow Energy Limited

BOW ENERGY LIMITED

ABN 63 111 019 857

Registered and Principal Business Office:

Level 5, 60 Edward Street Brisbane Qld 4000	GPO Box 5244 Brisbane Qld 4001

Company Structure

Bow Energy Limited is a public listed company registered with the Australian Securities Exchange[ASX] with the ASX Code: BOW.

Bow Energy's primary business is the discovery and commercial production of coal seam gas [CSG] and conventional oil and gas with projects in several Australian sedimentary basins. The Company's prime focus since formation has been in Queensland. Bow's current strategy is to develop its CSG projects in the Bowen and Surat Basins which are located close to both domestic and potential export markets.

Bow is currently focusing on establishing significant independently certified gas reserves enabling it to supply gas to one or more of the proposed LNG facilities planned for Gladstone as well as pursuing and creating domestic gas markets. The Company's strategy is to position itself as an independent CSG producer with significant uncontracted gas reserves close to gas infrastructure and near the planned LNG facilities at Gladstone.

The Company has a reserve target of achieving 450 PJ of 2P reserves and 1,900 of 3P reserves by the end of 2010 and 800 PJ and 2,500 PJ of 2P and 3P reserves respectively by 31 December 2011.

Bow has four wholly owned subsidiaries, Bow CSG Pty Ltd, Ocellaris Oil Pty Ltd, Roma CSG Pty Ltd and SEQOil Pty Ltd.

The Company directly employs 12 with a small number of professionals on contract.

Company Directors:

Mr. Ron Prefontaine	Managing Director
Mr. Nicholas Mather	Non Executive Director
Mr. Stephen Bizzell	Non Executive Director

Company Secretary:

Mr. Duncan Cornish	Company Secretary and Chief Financial Officer

Company Management:

Mr. John De Stefani	Chief Executive Officer – Commercial
Mr. Dusan Pribilovic	General Manager Engineering

Financial Profile

Capital Structure

At 30 June 2009, Bow Energy had 209, 641,395 ordinary shares and 28,389,854 unlisted options on issue. At 21 September 2009, a number of options had been exercised resulting in the Company having 214,373,829 ordinary shares and 23,907,420 unlisted options on issue. This gave Bow a market capitalization of $310.8 million at 21 September 2009.

The top 20 shareholders of the 6,542 registered shareholders in Bow hold 24.60% of the Company's issued stock with Mr. Ron Prefontaine, the Managing Director, the largest shareholder with 10, 510, 045 shares or 4.9% of the total issued stock.

The net assets of the economic entity at 30 June 2009 were $40, 457 million while the working capital was $20.876 million.

On 18 September 2009, Bow Energy was added to the ASX All Australian 200 Index and the ASX 300 Index.

Operating Results

For the financial year ended 30 June 2009, the economic entity of Bow Energy Limited received revenue totaling $929,453 and after allowing for expenses and income tax, it incurred a loss of $772, 034.

Following a number of capital raisings during 2008-2009, Bow Energy had $20.643 million in cash and no debt at the 30 June 2009.

The Directors of Bow Energy have stated in the 2009 Annual Report that the Company has sufficient funds to finance its operations and planned exploration activities to meet its end of 2010 reserve targets.

Exploration Activities

From its founding in May 2005 as a Company focused on conventional oil prospects, Bow Energy has evolved into an emerging CSG explorer and developer with a focus on tenements in the Bowen and Surat Basins.

Initial CSG development was at the Don Juan Prospect in the western Surat Basin [ATP's 593P & 771P] where initial net reserves to Bow of 19 PJ of 2P and 664 PJ of 3P have been certified. Development work at Don Juan is continuing. Bow has a 55% interest in Don Juan and is the operator. Victoria Petroleum NL holds the remaining 45% interest.

Bow was offered three high potential CSG blocks in the Bowen Basin in October 2008. Two of the blocks, the Comet CSG Block near Blackwater [ATP 1025P] and the Norwich Park Block [ATP 1031P] were granted to Bow on 1 March 2009. A detailed exploration and drilling program over each block has commenced. The third block, the Gunyah Block [ATP 1053P] to the south of the Dawson Valley CSG Fields requires resolution of Native Title prior to granting. The granting of this permit is expected to occur in early 2010. The Gunyah Prospect is within 100 km of the QGC assets.

Early in 2009, Bow drilled two CSG wells on the Canaway Ridge on the north eastern section of the Cooper-Eromanga Basin in South West Queensland. This large anticlinal structure, which separates the Cooper-Eromanga Basin from the Galilee Basin, hosts the Late Cretaceous Winton Coal Measures. As a consequence of the variable results from the drilling, the Canaway Ridge program has bee afforded a lower ongoing priority.

In addition to its CSG activities in the Bowen, Cooper-Eromanga and Surat Basins, Bow has been undertaking exploration and appraisal programs for conventional petroleum in the Carnarvon, Clarence-Moreton, Cooper-Eromanga and Surat Basins. These programs have focused on oil prospects.

COAL SEAM GAS ACTIVITIES

The exploration, appraisal and development of CSG is now a core energy business of Bow Energy Ltd. Bow Energy has five core CSG prospective areas. They are the Don Juan Prospect in ATP's 593 P and 771P, the Comet Block in ATP 1025P, the Norwich Block [ATP 1031P], the Gunyah Block [ATP 1053P] and the Canaway Ridge Project [ATP 560P – 100% and ATP 794P - 65%].

Gunyah Block

The Gunyah Prospect [ATP 1053P] of 388 km^2 in the Southern Bowen Basin was offered to Bow Energy in early October 2008 with title expected to be awarded in early 2010 following finalization of a Native Title Agreement.

The tenement offer, 100 % to Bow, is located south of Anglo Coal's Dawson CSG operations and to the immediate south of the Timmy Prospect [ATP 602P] of the Anglo-Molopo Joint Venture.

The permit hosts Permian Coals in the Bandanna Formation at depths of up to 800 m. From previous drilling in adjacent tenements, Bow expects to have coals with a net thickness of 20 m with gas contents of approximately 8 m^3 per tonne daf coal. A drilling program in ATP 1053P is expected to be undertaken during the first Half of 2010. It will initially target 3P reserves of some 500 PJ. Bow has made an initial estimate of the gas resource in the Gunyah Block as 970 PJ as gas in place.

While the Gunyah Block is expected to host good thickness of gassy Bandanna coals, they are expected to have low gas permeabilities due to the deposition structure of the coals along with a similar local compressive stress regime to that exists in the northern parts of the Dawson Valley. For commercial CSG production, it is almost certain that multi-seam, surface to in-seam wells will be required. For a given gas output, multi-seam wells generally cost 1.5 to 2.0 times the cost of an under-reamed vertical well.

Reserves and Resources

Bow Energy has established the following reserves, net to Bow:

Gas Reserves [net to Bow] in PJ's

Reserves	**2P**	3P
Don Juan	19	105
Comet Block [Blackwater]	-	559
TOTAL	19	664

Bow Energy's current drilling program is targeting reserves, net to Bow, of 450 PJ as 2P and 1,900 PJ as 3P by the end of 2010 from its Don Juan, Blackwater and Comet Prospects in the Comet Block and the Norwich Block. By the end of 2011, Bow has a reserves target of 800 PJ of 2P and 2,500 PJ of 3P from these same projects.

In addition to the gas reserves, Bow Energy has estimated it has a CSG resource as gas in place of 17,850 PJ of which 94% are in the Comet and Norwich Blocks. Bow's estimate of its gas resource in the Gunyah Prospect is 970 PJ as gas in place.

Gas Contracts

No Gas Supply Agreements have been entered into by Bow Energy at this stage of the Company's development.

Bow Energy has undertaken investigations into the monetization of CSG from its tenement interests. These include field power generation, gas supply to market via existing and proposed pipeline networks and small scale liquefied natural gas plants to supply regional gas markets in southern Queensland, northern New South Wales and the Cooper-Eromanga region.

Gas Processing and Gas Infrastructure

Bow Energy is still an exploration company and while it is moving to establish CSG pilot operations over its Comet, Don Juan and Norwich tenements, it has not established any commercial gas gathering, gas treatment or related gas and water infrastructure.

CORPORATE PROFILE

Registered Office:

Level 5, 60 Edward Street Brisbane Qld 4000	GPO Box 5244 Brisbane Qld 4001

Telephone: 07 3303 0675

Fax: 07 3303 0651

Web: www.bowenergy.com.au

ABN: 63 111 019 857

ASX Code: BOW

Company Directors:

Mr. Ron Prefontaine	Managing Director
Mr. Nicholas Mather	Non Executive Director
Mr. Stephen Bizzell	Non Executive Director

Company Secretary:

Mr. Duncan Cornish	Company Secretary and Chief Financial Officer

Company Management:

Mr. John De Stefani	Chief Executive Officer – Commercial
Mr. Dusan Pribilovic	General Manager Engineering

APPENDIX C

Icon Energy Limited

ICON ENERGY LIMITED

ABN 61 058 454 569

Registered and Principal Office:

Level 4
19 Arbour Court
Robina Town Centre
Queensland 4230

Company Structure

Icon Energy Limited is a public company listed on the Australian Securities Exchange [ASX] with ASX Code: ICN.

Icon Oil NL was incorporated on 5 January 1993 as an oil and gas exploration company with interests in both Australia and the United States of America. Icon Oil NL was listed as a public company on the Australian Securities Exchange (ASX) on 22 September 1997 with the ASX Code: ICN. The Company was restructured and registered as a public company limited by shares as Icon Energy Limited on 8 November 2000.

In the early years as a public company, Icon had interests in the USA, particularly in Louisiana, as well as acreage in the Browse, Cooper-Eromanga and Surat Basins. The initial focus was on oil in the USA prospects.

In the Surat Basin, Icon acquired a 100% interest in early 2000 in ATP's 610P, 620P, 632P and 648P, all of which had promising prospects for CSG recovery. Icon then farmed out these tenements, which straddle the Walloon Fairway, to the Queensland Gas Company Limited. Following settlement of litigation between Icon and Queensland Gas with Pangaea Oil and Gas Pty Ltd over the Argyle gas discovery in ATP 620P, Icon found itself unable to fully participate in the development of the CSG prospects operated by QGC within the Surat Basin. In March 2003, the Company sold its interest in these Surat Basin ATP's to QGC and Pangaea for $3.0 million. The funds were used to undertake further exploration and development activities in Louisiana, USA.

Icon Energy retained its 100% interest in ATP 626P in the southern Surat Basin. This permit, which was initially granted in August 1996, is a large area stretching from just south of Moonie to the New South Wales border. Goondiwindi is in the permit area. In early 2006, Icon reached an agreement with Santos Limited to farm-in to the permit and drill the Stitch-1 well targeting oil on the Moonie Fault, approximately 40 km south of the Moonie Oil Field. After numerous delays, Stitch-1 was drilled in November 2007 following Icon Energy assuming a 100% interest in the well. The well did not find recoverable oil but found good development in the Walloon Coals at a depth of approximately 1,100 m accompanied by strong gas flows. The well was cased and suspended as a future CSG well.

Subsequently Icon Energy drilled two further CSG wells in ATP 626P. Both of these wells, Lydia-1 and Natasha-1, delineated promising thickness of gassy Walloon Coals. All three wells were put on test.

At the end of 2008, the Stanwell Corporation, a Queensland Government power generating corporation, entered into a farm-in agreement with Icon covering 4 of the

30 blocks in ATP 626P. The 300 km^2 Stanwell farm-in area has been named the Lydia Project. The agreement covers Stanwell investing up to $36 million to earn 50% of the Lydia Project. Icon retains a 100% interest in the remainder of ATP 626P. As part of the agreement, Icon will be able to supply Stanwell with 225 PJ of gas over 15 years once it has established 340 PJ of 2P reserves. Stanwell has the option to increase the quantity of gas it takes.

Company Directors:

Mr. Stephen Barry	Non-Executive Chairman
Mr. Ray James	Managing Director
Dr. Keith Hilless	Non-Executive Director
Dr. Raymond McNamara	Executive Director-Finance
Mr. Derek Murphy	Non-Executive Director

Company Secretary:

Dr. Raymond McNamara	Company Secretary and Executive Director

Company Executives:

Mr. Larry Brown	Chief Operating Officer
Mr. Harry Duerden	Chief Geologist
Mr. Bob King	Chief Geophysicist
Mr. John Quayle	Director-Business Development

Financial Profile

Capital Structure

At 11 September 2009, Icon Energy has 438,845,003 shares on issue with a market value at that time of $237 million. The largest 20 shareholders hold approximately 30.8% of the stock.

Operating Results

For the six months ending 30 June 2009, Icon as a purely exploration company at this stage incurred a loss for the period of $3.062 million.

Icon’s cash balance at 30 June 2009 was $17.8 million with no debt.

Exploration Activities

COAL SEAM GAS

The CSG potential of Icon's ATP 626P in the Surat Basin is considered to be the prime asset of the Company. The current drilling program is planned to further delineate the CSG resource and establish reserves and production profiles.

ATP 626P

Icon Energy drilled three wells in the permit area in the latter part of 2007. As mentioned above, Stitch-1, approximately 40 km south of the Moonie Oil Field, failed to find commercial conventional petroleum but delineated gassy coals the Walloon Coal Measures at approximately 1,100 m. Stitch-1 has been cased and suspended and will be dewatered as a future CSG monitoring well.

Two specific CSG wells (Natasha-1 and Lydia-1) were drilled in the latter part of 2007 in the tenement. Natasha-1, 30 km south southeast of Stitch-1 was drilled to a total depth of 745 m. It found 11 m of gassy coals from the Juandah Formation from a depth of 611 m. A further 50 m of carbonaceous shales containing gas were identified. Water quality from the well was good (<600 ppm). Preliminary gas analysis was 89% methane with low CO_2 and a few percent heavier hydrocarbons (C_2 – C_5). The well was under reamed and cased for use as a future monitoring well.

The Lydia-1 well, 16 km east south east of Stitch-1 was drilled to a total depth of 780 m. 13 m of gassy Walloon Coals were delineated. Production casing to 614 m was set with the coals being under reamed. The well flowed modest quantities of gas. The well is being used as a monitoring well as part of the five well pilot at Lydia.

Early analysis of the performance of the three CSG wells in ATP 626P indicates that the coals are fully gas saturated while permeabilities are moderate to good. Formation water has been reported to be of good quality and suitable for stock watering without treatment.

As part of the Stanwell farm-in agreement, a further three wells have been drilled in 2009 within the Lydia Project area. These involve a three production wells with the two observation wells making up a five well pilot. The pilot is dewatering and gas is flowing. A further four wells are to be drilled at Lydia to establish reserves and increase the gas resource. Outside the Lydia Project area in ATP 626P, Icon has committed to the first five of a planned 20 well drilling program.

Netherland, Sewell & Associated Inc [NSAI] of Dallas, Texas, USA has recently reported that ATP 626P, including the Lydia Project area, has a contingent 2C gas resource of 1,150 PJ with a third of these 2C resources [373 PJ] being at Lydia. NSAI has also reported that its estimate of the gas in place across all of ATP 626P amounts to 6,115 PJ. Further upgrading of the reserves/resources is expected during the first half of 2010 as the results of the planned drilling program becomes available.

Reserves and Resources

As outlined above, Icon has established a resource base of 1,150 PJ as a 2C contingent resource with an estimated 6,115 PJ as gas in place within ATP 626P. Based on the distribution of the current contingent gas resource [2C] figures between the Lydia Project area and the rest of ATP 626P, the estimated gas in place held by Icon Energy outside its Stanwell agreements would be of the order of 4,000 PJ.

Based on a 30% conversion over time of gas in place to recoverable reserves, Icon would be able to market up to 1,200 PJ of gas or up to 60 PJ per year for 20 years.

Gas Contracts

On 29 December 2008, Icon Energy entered into a farm-in agreement with Stanwell Corporation to supply 225 PJ of CSG over 15 years after establishing 340 PJ of 2P reserves in the Lydia Project area within ATP 626P. Stanwell has the option to increase the amount of gas it takes. In return, Stanwell will invest up to $36 million to take a 50% interest in the Lydia Project of 300 km^2.

Gas Processing and Gas Infrastructure

Currently Icon Energy has no gas processing or related gas infrastructure other than the Lydia pilot.

CORPORATE PROFILE

Registered Office:

Level 4 19 Arbour Court Robina Town Centre Queensland 4230	PO Box 3366 Robina Town Centre Qld 4230

Telephone: 07 5562 0077

Fax: 07 5562 0011

Web: www.iconenergy.com

ABN: 61 058 454 569

ASX Code: ICN

Company Directors:

Mr. Stephen Barry	Non-Executive Chairman
Mr. Raymond James	Managing Director
Dr. Keith Hilless	Non-Executive Director
Dr. Ray McNamara	Executive Director- Finance
Mr.Derek Murphy	Non-Executive Director

Company Secretary:

Dr. Ray McNamara	Company Secretary and Executive Director

Company Executives:

Mr. Larry Brown	Chief Operating Officer
Mr. Harry Duerden	Chief Geologist
Mr. Bob King	Chief Physicist
Mr. John Quayle	Business Development Manager

APPENDIX D

Molopo Australia Limited

MOLOPO AUSTRALIA LIMITED

ABN: 79 003 152 154

Registered and Principal Business Office:

Level 14
31 Queen Street
Melbourne Vic. 3000

Company Structure

Molopo Australia NL was formed as a mineral explorer. It was listed on the Australian Securities Exchange on 23 December 1986 with ASX Code MPO. On 6 November 2003, Molopo Australia NL changed its name to Molopo Australia Limited. Currently Molopo's principal activities are in the upstream energy industry concentrating on coal seam gas projects in Queensland and New South Wales. It also has offshore CSG interests in Canada, China, South Africa and the USA.

Molopo now has a 50% interest in a number of CSG fields and developments in the Bowen Basin. These include the Mungi Field in the Dawson Valley near Moura in Central Queensland, the nearby Harcourt/Bindaree Gas Field and the Timmy Prospect south of Mungi.

Until recently, the Company had interests in two PELs in the Clarence-Moreton Basin in Northern New South Wales. They were PEL's 13 and 426 which it entered into farmed-out agreements with Metgasco Limited. Recently Metgasco reached agreement with Molopo to acquire 100% in each of these permits.

Molopo has interests in the Liulin CSG Project in ShanXi Province in China, in the free State[Virginia] and Mpumalanga [Evander] Exploration Rights areas in South Africa and in tight oil and shale gas prospects in Canada and in West Virginia in the USA.

Molopo Energy has a permanent staff of 15 with a small number of consultants on contract.

Corporate Information on Molopo Australia Limited is appended.

Company Directors:

Mr. Don Beard	Non-Executive Chairman
Mr. Stephen Mitchell	Managing Director
Mr. Ian Gorman	Executive Director and Chief Operating Officer
Dr. David Hobday	Non-Executive Director
Mr. Geoffrey Phillips	Non-Executive Director

Company Secretary:

`

Mr. Anthony Bishop	Company Secretary and Chief Financial Officer

Senior Executives:

Mr. Anthony Bishop	Chief Financial Officer
Mr. Ric Sotelo	Chief Commercial Officer

Financial Profile

Capital Structure

At 18 September 2009, Molopo Australia Limited had 182,850,415 ordinary shares held by 8,119 shareholders. The largest 20 shareholders held 28.41% of the issued stock in the Company. The market value of Molopo at 18 September 2009 was $265.1 million.

The net assets of Molopo at 30 June 2009 were $130 million.

Operating Results

For the year ending 30 June 2009, Molopo recorded a net profit of $72.6 million following the sale of its 30% interest in the Gloucester Basin CSG Project in New South Wales to AGL Energy Limited for $111 million cash. Molopo is debt free.

Exploration Activities

COAL SEAM GAS

Molopo's core exploration, appraisal and development activities in Queensland are focused on the development of commercial CSG operations in the Dawson Valley in Central Queensland which hosts the Bandanna Coals of the Bowen Basin..

Mungi

Molopo Australia Limited holds a 50 % interest in the Mungi coal seam gas project [34 km^2 over the Northern part of PL 94] near Moura in Central Queensland. Molopo's other partners in the Mungi CSG project are Anglo Coal [Moura] Limited [25.5% and operator] and Mitsui Moura Investments Pty Ltd [24.5%].

The Mungi CSG Field is near Moura in the Dawson Valley in Central Queensland. The project is based on extracting CSG from the Late Permian aged Baralaba Coal Measures of the Bowen Basin. Mungi currently has a mixture of vertical and surface to in-seam wells in production and connected to a gas treatment plant and a gas compressor. There is also a 23 km, 219 mm pipeline [PPL 61] that connects the Mungi processing facilities with the Moura compressor station on the Queensland Gas Pipeline which runs from Wallumbilla to Gladstone [PPL 30].

Production at Mungi is approximately 1.5 TJ per day though the facilities have been designed to handle up to 6 TJ per day. At Mungi the initial wells were fracced, vertical wells but owing to poor productivity from many of the wells Molopo has, on a sole risk basis, proceeded with a program to drill five multi seam, surface to in-seam wells.

Molopo has completed the drilling of the first three of the five sole risk multilateral, multi-seam wells at Mungi. In the first well [Mungi 22] three laterals with 1,100 m of in seam laterals were drilled. Mungi-20A has six in seam laterals tapping three seams for a total lateral length of 2,800 m while Mungi-20V similarly has 6 laterals tapping three seams but with an in-situ exposure to coal totaling 5,300 m. Mungi-21 is currently being drilled and will have six planned laterals with a total length of 7,000 m into two coal seams. The final well in the program [Mungi-23], to be drilled in early 2010, is planned to have nine laterals into three coal seams with a total in-situ length of 9,000 m. When completed, the five laterals are expected to increase production at Mungi to approximately 2 PJ per year. Molopo will have a 100% interest in this production increase.

Reserves at Mungi, independently certified by Netherland, Sewell and Associates, were recently upgraded to 22PJ in the Proved category [1P], 60 PJ on a Proved plus Probable [2P] basis and 152 PJ on a Proved plus Probable plus Possible [3P] basis. Molopo has a net 50% interest in these reserves. The estimated gas resource at Mungi is 1,500 PJ as gas in place.

Molopo has a Gas Supply Agreement with Dawson Sales Pty Ltd, a Company owned by Anglo Coal and Mitsui Moura for the purchase of up to 6 TJ per day of gas from their Mungi interests. Molopo also has a small 4 year gas contract with Queensland Cotton Corporation for supply of gas from Mungi.

Harcourt/Bindaree

The Harcourt/Bindaree Prospect [PLA 210 – 178 km^2, ATP 564P] lies to the immediate north of Mungi. Molopo holds a 50% interest in this prospect with Anglo Coal [Moura] Limited [25.5% and operator] and Mitsui Moura Investments Pty Ltd [24.5%] holding the balance.

Harcourt is contiguous with Mungi and is considered to be the northern extension of the Mungi Field. Three vertical wells have been drilled at Harcourt [Harcourt-1, 2 and 3]. The latest well, Harcourt-4/5, a surface to in-seam well intersecting a vertical well has had drilling difficulties which has held up testing. Three surface to in-seam wells are planned to be drilled on Harcourt in 2010 following the completion of the fifth Mungi well [Mungi-23].

Reserves of 37 PJ on a 2P basis and 318 PJ on a 3P basis have been independently certified by Netherland, Sewell and Associates for the Harcourt/Bindaree Field. A recent assessment of Harcourt Project has indicated that the 178 km^2 permit area has over 2,500 PJ of gas resource as gas in place with a potential recovery of up to 750 PJ.

Timmy Prospect

Molopo also has a 50% interest along with Anglo Coal [Moura] Limited [25.5% and operator] and Mitsui Moura Investments Pty Ltd [24.5%] in the Timmy Prospect south of Mungi.

The Timmy Gas Prospect [ATP 602P] covers an area of 71.5 km^2 within a total permit area of 310 km^2. It is located south of Anglo's Dawson Valley CSG fields and to the north of the Gunyah Prospect of Bow Energy Limited.

One vertical fracced connected to two surface to in-seam wells have been drilled at Timmy. Testing of Timmy-1, where it is suspected that the laterals are blocked, will be recommenced in 2010 after the wells are worked over. A further three core holes are planned to be drilled at Timmy later in 2010.

No reserves have been certified for the Timmy Prospect though the partners in the project estimate it contains a resource of 2,300 PJ as gas in place.

Reserves and Resources

Molopo Australia Limited has certified gas reserves to its own account of 15 PJ as 1P reserves, 40 PJ on a 2P basis and 241 PJ of 3P reserves in its Dawson Valley leases.

In addition to the certified reserves, Molopo has a significant CSG resource in the Dawson Valley totaling 3,750 PJ as gas in place

The reserve certification was undertaken by Netherland Sewell and Associates Inc.

Gas Contracts

Molopo has a Gas Sales Agreement with Anglo Coal [Moura] Limited and Mitsui Moura Investments Pty Ltd for the supply of up to 6 TJ per day of gas from Mungi. Molopo also has a small contract with the Queensland Cotton Corporation for the supply, from Mungi, of a minimum, on a take or pay basis, of 5,250 GJ per year for 4 years for use in the Moura cotton gin.

Gas Processing and Gas Infrastructure

Molopo has a 50% interest in three gas gathering facilities within PL 94 [N], PLA 210 and ATP 602P. It also has a 50% interest in the Mungi gas treating plant, related compression facilities and the 23 km, 219 mm Moura lateral [PPL 61] which connects to the QGP.

CORPORATE PROFILE

Registered and Principal Business Office:

Level 14 31 Queen Street Melbourne Vic 3000	GPO Box 223 Melbourne Vic 3001

Telephone: 03 9618 8722

Fax: 03 9620 2804

Web: www.molopo.com.au

ABN: 79 003 152 154

ASX Code: MPO

Company Directors:

Mr. Don Beard	Non-Executive Chairman
Mr. Stephen Mitchell	Managing Director
Mr. Ian Gorman	Executive Director and Chief Operating Officer
Dr. David Hobday	Non-Executive Director
Mr. Geoffrey Phillips	Non-Executive Director

Company Secretary:

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Mr. Anthony Bishop	Company Secretary and Chief Financial Officer

Senior Executives:

Mr. Anthony Bishop	Chief Financial Officer
Mr. Ric Sotelo	Chief Commercial Officer

APPENDIX E

Rawson Resources Limited

RAWSON RESOURCES LIMITED

ABN 69 082 752 985

Registered and Principal Business Office:

Suite 2
163 Burns Bay Road
Lane Cove
NSW 2066

Company Structure

Rawson Resources Limited is a small Sydney based petroleum explorer with exploration interests across Australia and New Zealand. Rawson was listed as a public company on the Australian Securities Exchange (ASX) on 22 September 2005 with the ASX Code: RAW

Rawson Resources Limited was initially incorporated as an unlisted public company on 27 May 1998. The Company's focus remains as an explorer for energy resources focusing on oil and gas exploration and development..

The Company has a portfolio of petroleum prospects across Eastern Australia with permits in the Bass, Cooper-Eromanga, Otway, Pedirka and Surat Basins. It also has joint venture interests in the exploration for uranium in both South Australia and in the USA. The Company has petroleum interests in the onshore Taranaki Basin in New Zealand.

A core area currently being explored by Rawson for oil and gas is in the eastern ans southern Surat Basin with a focus on coal seam gas.

Company Directors:

Dr. John Conolly	Executive Chairman
Mr. John Doughty	Director and General Manager
Mr. Paul Adams	Non-Executive Director
Mr. Keith Skipper	Non-Executive Director

Company Secretary:

Mr. Ian Morgan	Company Secretary

The Company has no full time employees with Mr. John Dohety and Mr. Ian Marshall being employed on contract.

Financial Profile

Capital Structure

Rawson Resources at 31 August 2009 had an issued capital of 71,567,150 shares distributed between 497 shareholders. The 20 largest shareholders control 61.59% of the stock. The market capitalization of the Company at 31 August 2009 was $5 million.

Operating Results

The Company made a net loss of $1.073 million being primarily exploration expenditure. It does not have any production revenue. At 30 June 2009, the Company had cash of $1.046 million and no debt.

Exploration Activities

COAL SEAM GAS

In the Surat Basin, the main areas of interest of Rawson Resources are the northern blocks of ATP 837P, and ATP 873P. However in the northern part of ATP 893P, where the principal target is conventional petroleum, the Walloon Coal Measures will be a secondary target. In ATP 901P covering the central Taroom Trough, Cretaceous Coals which occur at depths between 400m and 600 m will be a secondary target to determine their CSG potential.

ATP 837P

In the northern section of ATP 837 P, the Walloon Coal Measures occur at depths between 500 m and 800 m. The Rawson-Energetica joint venture has farmed out 70% of the CSG rights to TRUEnergy Queensland Pty Ltd though they have retained their 50/50 joint venture for the conventional hydrocarbon prospects. TruEnergy has funded two wells plus a 200 km^2, 3D seismic program which is scheduled to be completed by late 2009. Two CSG wells were drilled in early in 2009 where approximately 27 m of Walloon Coal was reached at depths between 1,200 and 1,385 m. Gas permeabilities were reported as reasonable but full drill stem tests were not completed due to well stability problems. A further two wells are planned for early 2010 following the analysis of the 3-D seismic.

Rawson had a free carried interest of 15% in the two CSG wells, free carriage through the seismic and retains a 50% interest in the deeper oil and gas rights in ATP 837P. The second tranche of two core wells are planned to be drilled during the first half of 2010.

ATP 901P

Exploration in ATP 901P over the Taroom Trough area is expected to commence in 2010 with a seismic program with drilling to be undertaken in late 2010 or early 2011. The CSG target is the Cretaceous Coals, which from some earlier drilling, are known to occur at depths between 400 m and 500 m. From seismic lines, the Cretaceous Coals may extend over a wide area of the ATP. There is no information available on the prospectivity of these coals for CSG production.

Reserves and Resources

Rawson Resources does not have any gas reserves in the Surat or Bowen Basins. It has not announced any estimates of its potential gas resource.

Gas Contracts

The Company has not entered into any commercial agreements for the supply of gas.

Gas Processing and Gas Infrastructure

Rawson Resources has no interests in gas processing equipment or gas infrastructure.

CORPORATE PROFILE

Registered Office:

Suite 2 163 Burns Bay Road Lane Cove NSW 2066	PO Box R 1868 Royal Exchange NSW 1225

Telephone: 02 9872 9810

Fax: 02 9672 9810

Web: www.rawsonresources.com

ABN: 69 082 752 985

ASX Code: RAW

Company Directors:

Dr. John Conolly	Executive Chairman
Mr. John Doughty	Director and General Manager
Mr. Paul Adams	Non-Executive Director
Mr. Keith Skipper	Non-Executive Director

Company Secretary:

Mr. Ian Morgan	Company Secretary

APPENDIX F

Petroleum Resources Management System

Petroleum Resources Management System

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

This document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information, and specific chapters are referenced herein. Appendix A is a consolidated glossary of terms used in resources evaluations and replaces those published in 2005.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

This SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, including its Appendix, may be referred to by the abbreviated term "SPE-PRMS" with the caveat that the full title, including clear recognition of the co-sponsoring organizations, has been initially stated.

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 sulfide and sulfur. 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 1-1 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.

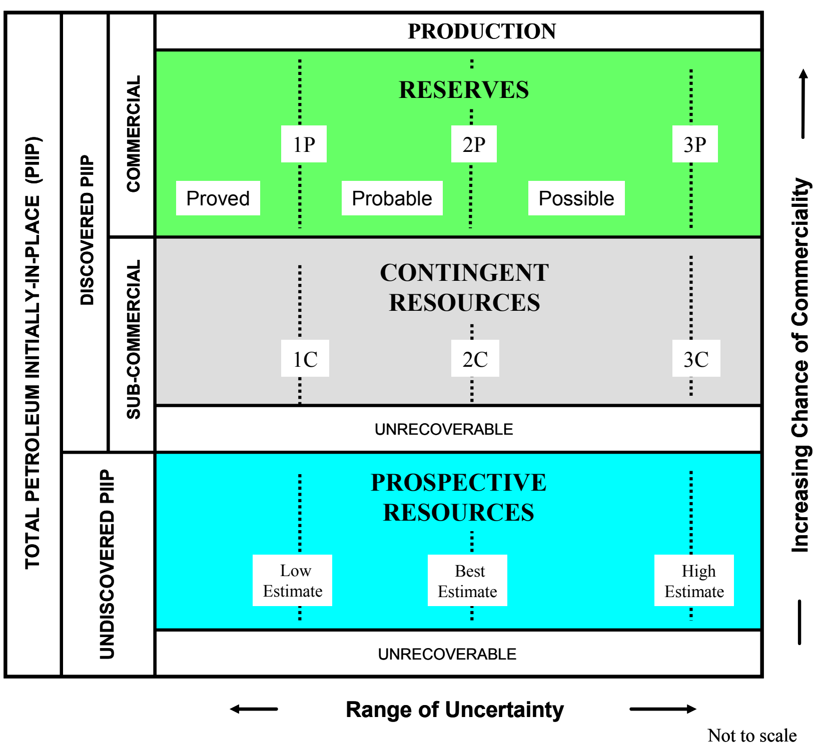

Figure 1-1: Resources Classification Framework.

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. 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 (see Production Measurement, section 3.2).

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 sub-classified 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).

In specialized areas, such as basin potential studies, alternative terminology has been used; the total resources may be referred to as Total Resource Base or Hydrocarbon Endowment. Total recoverable or EUR may be termed Basin Potential. The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." When such terms are used, it is important that each classification component of the summation also be provided. Moreover, these quantities should not be aggregated without due consideration of the varying degrees of technical and commercial risk involved with their classification.

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 1-2) that may be described as follows:

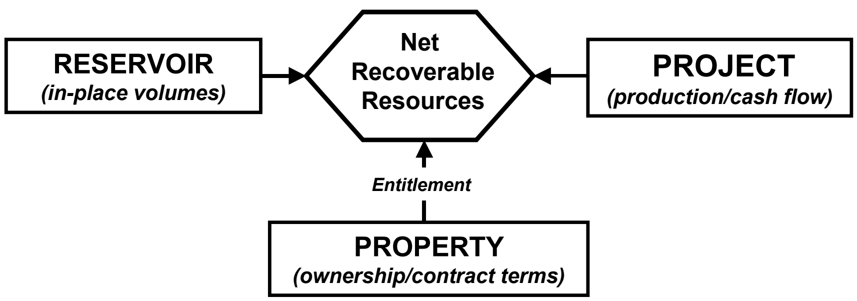

Figure 1-2: Resources Evaluation Data Sources.

- 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 (see Commercial Evaluations, section 3.1). “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 (see Reference Point, section 3.2.1). 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 (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system as shown in Figure 1-1. These guidelines reference this classification system and support an evaluation in which projects are “classified” based on their chance of commerciality (the vertical axis) and estimates of recoverable and marketable quantities associated with each project are “categorized” to reflect uncertainty (the horizontal axis). The actual workflow of classification vs. categorization varies with individual projects and is often an iterative analysis process leading to a final report. “Report,” as used herein, refers to the presentation of evaluation results within the business entity conducting the assessment and should not be construed as replacing guidelines for public disclosures under guidelines established by regulatory and/or other government agencies.

Additional background information on resources classification issues can be found in Chapter 2 of the 2001 SPE/WPC/AAPG publication: "Guidelines for the Evaluation of Petroleum Reserves and Resources," hereafter referred to as the "2001 Supplemental Guidelines."

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria:
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available:
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.1.3 Project Status and Commercial Risk

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized by standard project maturity level descriptions (qualitative) and/or by their associated chance of reaching producing status (quantitative).

As a project moves to a higher level of maturity, there will be an increasing chance that the accumulation will be commercially developed. For Contingent and Prospective Resources, this can further be expressed as a quantitative chance estimate that incorporates two key underlying risk components:

- The chance that the potential accumulation will result in the discovery of petroleum. This is referred to as the "chance of discovery."
- Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development."

Thus, for an undiscovered accumulation, the "chance of commerciality" is the product of these two risk components. For a discovered accumulation where the "chance of discovery" is 100%, the "chance of commerciality" becomes equivalent to the "chance of development."

2.1.3.1 <u>Project Maturity Sub-Classes</u>

As illustrated in Figure 2-1, development projects (and their associated recoverable quantities) may be sub-classified according to project maturity levels and the associated actions (business decisions) required to move a project toward commercial production.

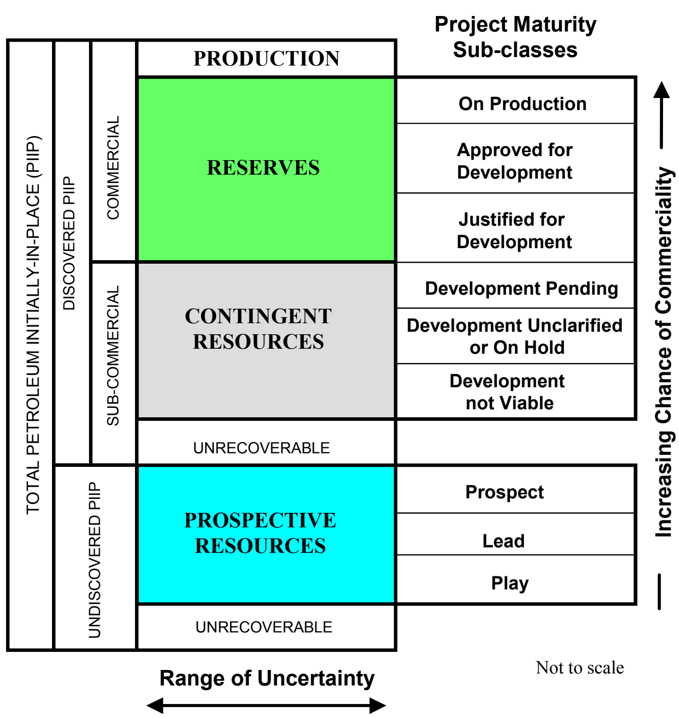

Figure 2-1: Sub-classes based on Project Maturity.

Project Maturity terminology and definitions have been modified from the example provided in the 2001 Supplemental Guidelines, Chapter 2. Detailed definitions and guidelines for each Project Maturity sub-class are provided in Table I. This approach supports managing portfolios of opportunities at various stages of exploration and development and may be supplemented by associated quantitative estimates of chance of commerciality. The boundaries between different levels of project maturity may be referred to as "decision gates."

Decisions within the Reserves class are based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. For Contingent Resources, supporting analysis should focus on gathering data and performing analyses to clarify and then mitigate those key conditions, or contingencies, that prevent commercial development.

For Prospective Resources, these potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under appropriate development projects. The decision at each phase is to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity where a decision can be made to proceed with exploration drilling.

Evaluators may adopt alternative sub-classes and project maturity modifiers, but the concept of increasing chance of commerciality should be a key enabler in applying the overall classification system and supporting portfolio management.

2.1.3.2 Reserves Status

Once projects satisfy commercial risk criteria, the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (detailed definitions and guidelines are provided in Table 2):

- Developed Reserves are expected quantities to be recovered from existing wells and facilities.
    - Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.
    - Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.
- Undeveloped Reserves are quantities expected to be recovered through future investments**.**

Where Reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Determination of Commerciality, section 2.1.2) is justified, a reasonable time frame is generally considered to be less than 5 years.

Development and production status are of significant importance for project management. While Reserves Status has traditionally only been applied to Proved Reserves, the same concept of Developed and Undeveloped Status based on the funding and operational status of wells and producing facilities within the development project are applicable throughout the full range of Reserves uncertainty categories (Proved, Probable and Possible).

Quantities may be subdivided by Reserves Status independent of sub-classification by Project Maturity. If applied in combination, Developed and/or Undeveloped Reserves quantities may be identified separately within each Reserves sub-class (On Production, Approved for Development, and Justified for Development).

2.1.3.3 Economic Status

Projects may be further characterized by their Economic Status. All projects classified as Reserves must be economic under defined conditions (see Commercial Evaluations, section 3.1). Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- Marginal Contingent Resources are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.

- Sub-Marginal Contingent Resources are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

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." Additional economic status modifiers may be applied to further characterize recoverable quantities; for example, non-sales (lease fuel, flare, and losses) may be separately identified and documented in addition to sales quantities for both production and recoverable resource estimates (see also Reference Point, section 3.2.1). Those discovered in-place volumes for which a feasible development project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Economic Status may be identified independently of, or applied in combination with, Project Maturity sub-classification to more completely describe the project and its associated resources.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods. (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Table III presents category definitions and provides guidelines designed to promote consistency in resource assessments. The following summarizes the definitions for each Reserves category in terms of both the deterministic incremental approach and scenario approach and also provides the probability criteria if probabilistic methods are applied.

- Proved Reserves are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

- Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

- Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

2.3 Incremental Projects

The initial resource assessment is based on application of a defined initial development project. Incremental projects are designed to increase recovery efficiency and/or to accelerate production through making changes to wells or facilities, infill drilling, or improved recovery. Such projects should be classified according to the same criteria as initial projects. Related incremental quantities are similarly categorized on certainty of recovery. The projected increased recovery can be included in estimated Reserves if the degree of commitment is such that the project will be developed and placed on production within a reasonable timeframe.

Circumstances where development will be significantly delayed should be clearly documented. If there is significant project risk, forecast incremental recoveries may be similarly categorized but should be classified as Contingent Resources (see Determination of Commerciality, section 2.1.2).

2.3.1 Workovers, Treatments, and Changes of Equipment

Incremental recovery associated with future workover, treatment (including hydraulic fracturing), re-treatment, changes of equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed or Undeveloped Reserves depending on the magnitude of associated costs required (see Reserves Status, section 2.1.3.2).

2.3.2 Compression

Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in Reserves estimates. If the eventual installation of compression was planned and approved as part of the original development plan, incremental recovery is included in Undeveloped Reserves. However, if the cost to implement compression is not significant (relative to the cost of a new well), the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

2.3.3 Infill Drilling

Technical and commercial analyses may support drilling additional producing wells to reduce the spacing beyond that utilized within the initial development plan, subject to government regulations (if such approvals are required). Infill drilling may have the combined effect of increasing recovery efficiency and accelerating production. Only the incremental recovery can be considered as additional Reserves; this additional recovery may need to be reallocated to individual wells with different interest ownerships.

2.3.4 Improved Recovery

Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir performance. It includes waterflooding, secondary or tertiary recovery processes, and any other means of supplementing natural reservoir recovery processes.

Improved recovery projects must meet the same Reserves commerciality criteria as primary recovery projects. There should be an expectation that the project will be economic and that the entity has committed to implement the project in a reasonable time frame (generally within 5 years; further delays should be clearly justified).

The judgment on commerciality is based on pilot testing within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

These incremental recoveries in commercial projects are categorized into Proved, Probable, and Possible Reserves based on certainty derived from engineering analysis and analogous applications in similar reservoirs.

2.4 Unconventional Resources

Two types of petroleum resources have been defined that may require different approaches for their evaluations:

- Conventional resources exist in discrete petroleum accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water. The petroleum is recovered through wellbores and typically requires minimal processing prior to sale.

- Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrates, natural bitumen, and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders).

For these petroleum accumulations that are not significantly affected by hydrodynamic influences, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum may not be possible. Thus, there typically is a need for increased sampling density to define uncertainty of in-place volumes, variations in quality of reservoir and hydrocarbons, and their detailed spatial distribution to support detailed design of specialized mining or in-situ extraction programs.

It is intended that the resources definitions, together with the classification system, will be appropriate for all types of petroleum accumulations regardless of their in-place characteristics, extraction method applied, or degree of processing required.

Similar to improved recovery projects applied to conventional reservoirs, successful pilots or operating projects in the subject reservoir or successful projects in analogous reservoirs may be required to establish a distribution of recovery efficiencies for non-conventional accumulations. Such pilot projects may evaluate both extraction efficiency and the efficiency of unconventional processing facilities to derive sales products prior to custody transfer.